U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report Nos. 50-272/94-11
50-311/94-11
50-354/94-09

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

Licensee: Public Service Electric and Gas Company
P.O. Box 236
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Facilities: Salem Nuclear Generating Station
Hope Creek Nuclear Generating Station

Dates: March 27, 1994 - April 30, 1994

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<u>Inspection Summary</u>:

This inspection report documents inspections to assure public health and safety during day and backshift hours of station activities, including: operations, radiological controls, maintenance and surveillance testing, emergency preparedness, security, engineering/technical support, and safety assessment/quality verification. The Executive Summary delineates the inspection findings and conclusions.

EXECUTIVE SUMMARY

Salem Inspection Reports 50-272/94-11; 50-311/94-11

Hope Creek Inspection Report 50-354/94-09

March 27, 1994 - April 30, 1994

OPERATIONS (Modules 71707, 93702)

Salem: Salem Unit 1 tripped from about 25% power on April 7, as a result of loss of circulating water to the main condenser. Salem Unit 2 operated at power throughout the inspection period. Inspectors performed a walkdown of the Salem auxiliary feedwater systems, noting proper system alignment. Control room operator aids for RCS pressure temperature were not up to date, but were more conservative than current Technical Specification curves. The licensee responded well to an inadvertent actuation of the safeguard equipment control system caused by an isolated instance of personnel error. The inspectors determined that, prior to restart, the licensee took adequate corrective actions to address a number of operations concerns identified as a result the April 7, Salem Unit 1 transient which was the subject of a previous Augmented Inspection Team effort. NRC Inspection Report 50-272/94-80 pertains.

Hope Creek: When plant staff noted that a reactor coolant sample had been missed they took immediate corrective action. No safety significance was noted, and the licensee changed procedures to prevent recurrence. An isolated pressure transmitter caused a brief loss of shutdown cooling which resulted in a coolant temperature increase of 2°F. Overall, the containment integrated leak rate test was successful. However, inspectors noted two inadequacies in control of the test resulting in a violation. Two ESF actuations and an inadvertent reactor pressure vessel letdown will remain unresolved pending inspector review of the licensee's root cause determinations. The licensee completed the fifth refueling outage and performed a safe, controlled startup after shift crews received refresher training for this evolution. Inspectors verified operability of the reactor core isolation cooling system, noting good material condition. Corrective action for a December 17, 1993 refuel bridge mis-operation did not adequately preclude an additional mis-operation on March 9, 1994.

MAINTENANCE/SURVEILLANCE (Modules 61726, 62703)

Salem: Inspectors noted no inadequacies during observation of ten maintenance and ten surveillance activities. The inspectors observed, however, that performance of some types of surveillances by a single technician, rather than by two technicians, resulted in lost opportunities to identify procedure weaknesses or potential performance pitfalls. The inspectors noted that the safeguards equipment control logic actuation on April 11, occurred during performance of a surveillance by a single worker.

Hope Creek: Poor procedures for control of spent fuel pool gate seal replacement, failure to follow other procedures, and equipment labeling inadequacies, contributed to the cause of an 11,000 gallon loss of inventory to the reactor cavity. In addition, the inspectors noted that the design of the air supply to the seals was subject to several single failure vulnerabilities, and that maintenance had never been performed on most of the components in the air supply, including those subject to single failure. Quick action on the part of alert operators in mitigating leakage past the spent fuel pool gate seals prevented in water level dropping below the level required by Technical Specification 3.9.9

ENGINEERING (Modules 71707, 71711)

Salem: Inspectors noted that licensee had not removed eyebolts installed in Motor Operated Valve housings in 11 months from the time NRC Information Notice 93-37 had been issued. The inspectors determined that, prior to restart, the licensee took adequate corrective actions to address a number of engineering concerns identified as a result the April 7, Salem Unit 1 transient.

Hope Creek: Reactor engineers provided good oversight of the reactor startup. Systems engineers effectively completed a 10 CFR 50.59 safety evaluation for operation of the "B" reactor recirculation pump with a No. 2 seal leak.

PLANT SUPPORT (Modules 71707, 90712, 93702)

Hope Creek: Strong radiological management oversight, prompt and effective feedback, good radiological work practice and training, and a dedicated team effort allowed the licensee to achieve significant ALARA success during the recent refueling outage.

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1.0 SUMMARY OF OPERATIONS

1.1 Salem Units 1 and 2

The inspection period began with both units at 100% power. Operators reduced power on both units on various occasions in order to clean river grass from the main condenser water boxes. On April 7, 1994, an exceptionally severe river grass intrusion occurred at Unit 1, resulting in the crew rapidly reducing power. The ensuing turbine trip, reactor trip, and two safety injection actuations are discussed in detail in NRC Inspection Report 50-311/94-80. Salem Unit 1 remained in mode 5 (cold shutdown) for the remainder of the inspection period. On April 11, with Unit 2 at 48% power, a switching error by an instrumentation and controls technician performing a routine surveillance in the safeguard equipment control cabinets actuated the blackout logic for the vital busses. All systems responded as designed. The operators restored the normal electrical line-up, raised power, stopping at 65% for river grass concerns. On April 12, 1994, the inspector noted that the Reactor Vessel Level Indicating System (RVLIS) indicated a slight unexpected decrease in water level. The finding was subsequently confirmed and identified as a gas bubble. Previously, operators had dismissed RVLIS as a valid indicator since the instrument was not required below Mode 3 operations.

1.2 Hope Creek

The plant was in cold shutdown for the fifth refueling outage from the beginning of the inspection period until April 25, 1994. That day, the licensee performed reactor startup and on the morning of April 27, synchronized the main generator to the grid. The reactor operated at power for the remainder of the period.

2.0 OPERATIONS

2.1 Inspection Activities

The inspectors verified that Public Service Electric and Gas (PSE&G) operated the facilities safely and in conformance with regulatory requirements. The inspectors evaluated PSE&G's management control 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. The inspectors performed normal and back-shift inspections, including 67 hours of deep back-shift inspections.

2.2 Inspection Findings and Significant Plant Events

2.2.1 Salem

A. Engineered Safety Feature (ESF) System Inspection

The inspectors performed an inspection of the Unit 2 auxiliary feedwater (AFW) System and verified proper system alignment for automatic initiation, proper installation of hangers and the orientation of flow orifices. The inspectors noted that the terry turbine trip mechanism and the overspeed trip linkage for both units were free of interference from piping insulation. Additionally, overspeed test data demonstrated that the trip mechanism successfully tripped within its acceptance criteria on January 9, 1994 for Unit 1 and May 22, 1993 for Unit 2. The inspectors noted no deficiencies during review of the inservice testing data for the three AFW pumps, the stroke time testing of the air operated AFW control valves, and the lubrication analysis of the pumps. The inspector noted that the responsible system engineer properly maintained and trended this data.

The inspector also reviewed the licensee's actions in response to Generic Letter 88-03, *Steam Binding of Auxiliary Feedwater Pumps*. The licensee is currently monitoring AFW piping temperature upstream of the AFW header stop check valves (21-24AF23) once per shift while in Modes 1-3. Current temperatures average 88°F for the four AFW lines. However, Unit 2 previously experienced minor leakage past the stop check valves from the main feedwater lines resulting in elevated piping temperature (about 120°F). When this situation occurred, operators used existing guidance to start the appropriate pump and flush the line in an attempt to reseat the check valve. As a long term corrective action, a design change has been developed to replace the check valves during the next refueling outage. The inspectors considered the licensee's action to monitor and correct AFW backleakage to be appropriate.

B. Salem Reactor Coolant System (RCS) Pressure-Temperature Curves

During the inspectors' walkdowns of the Unit 1 and 2 control boards, the inspectors noted that the operator aides for RCS pressure-temperature limitations curves were not accurate based on the current Technical Specifications. These operator aides were controlled copies and were maintained within operations directive 55, but were last updated and approved on July 11, 1985. These curves provide operators with a graphical representation of RCS operational limits based on the following: pressurizer relief valve settings, steam generator delta pressure limits, the cooldown curve, low temperature overpressure protection setpoint, and reactor coolant saturation temperature. The inspector noted that new RCS heatup and cooldown limitation curves were approved by the NRC on January 29, 1990, per license amendments 108 and 86 for Salem Units 1 and 2 respectively. These amendments updated the RCS pressure-temperature limits to 15 effective full power years (EFPY) for Salem 1 and 10 EFPYs for Salem 2 based on analysis results of reactor vessel surveillance capsules. Subsequent review of the current Technical Specification curves indicated they provide a greater margin to the region of unacceptable operation. A comparison of the operator aides to the current Technical Specification curves show that the operator aides have a more restrictive operating band and are more conservative. The inspectors thus did not have any safety concerns, but considered the failure to update the operator aides in a timely manner (i.e., within four years) to be a weakness in providing operators with accurate information relative to reactor operating parameters.

C. Inadvertent Safeguards Equipment Control (SEC) Actuation

On the morning of April 11, 1994, a maintenance worker performing S2.MD-FT.4KV-0001, *ESFAS Instrumentation Monthly Functional Test 2A 4KV Vital Bus Undervoltage*, positioned the wrong undervoltage test switch in the "B" SEC cabinet, resulting in actuation of the SEC logic and starting the emergency diesel generators (EDGs). Section 3.3.1.B pertains.

At the time of the occurrence, Unit 2 was at 48% power. Since the SEC actuation isolated service water to non-essential turbine heat loads, the operators reduced power to 21% to minimize the heat load from the main turbine auxiliary cooling system. The inspector noted that the crew used the appropriate procedures for the transient. The inspector also determined that the operators employed a troubleshooting procedure to carefully control exiting the aborted SEC test since there was no specific guidance for backing out of the surveillance. By late afternoon the operators had successfully returned the vital busses to their normal power supplies and secured the EDGs. The inspector observed this evolution and noted it a cautious approach by the operations staff to insure that the safeguards equipment was properly restored to standby condition, and electrical loads were properly restored to their normal supplies. The inspector concluded that the licensee responded appropriately to the occurrence.

2.2.2 Salem - Restart Inspection Activities

The inspectors reviewed licensee corrective actions for the following items to insure adequacy for Salem Unit 1 restart.

A. Operator Training and Procedure Enhancements

In response to the April 7, 1994, reactor trip and safety injection event at Unit 1, the licensee committed in letters to the NRC dated April 25 and April 29, to perform various procedure enhancements and operator training on the event. These included: 1) coordination and control of rapid power reductions; 2) operator response to reactor coolant system (RCS) temperature less than the minimum temperature for criticality; 3) operator response to safety injection (SI) logic train disagreement; 4) the use of critical safety function (CSF) "yellow paths" while in the emergency operation procedures (EOPs); 5) the monitoring of reactor vessel level indication system (RVLIS) in Modes 5 (Cold Shutdown) and 6 (Refueling); and 6) manual operation of the atmospheric steam dumps. The licensee required that each operator complete this training prior to their assuming watchstanding duties in either Salem unit.

The inspectors reviewed the training lesson plan and observed operator training on April 28, 1994. The inspectors noted good use of the simulator to recreate the event and to emphasize the licensee lessons learned. The inspectors also reviewed procedure changes with the operators during this training session. The inspectors interviewed various operators from different shifts who had completed the training to assess its effectiveness. The inspectors concluded that the training effectively presented the event, lessons learned, and corrective actions taken to prevent recurrence. The licensee revised Operating and Abnormal Occurrence Procedures for Unit 1 and 2 to address operator actions for low condenser vacuum, loss of two or more circulating water pumps, RCS temperature below the minimum temperature for criticality, and RVLIS level indicating less than minimum valve. The licensee was still evaluating the need for procedure revisions to address SI logic train disagreement, the use of CSF "yellow paths" during the EOPs, and rapid power reductions. However, the inspectors concluded that training on use of the yellow provided acceptable means of insuring appropriate use of the yellow paths for the interim.

Operations management issued information directive (ID) 94-012 on April 25, 1994, to clarify and emphasize management expectations and hardware and operator performance issues resulting from the April 7 event. The inspectors reviewed the ID and concluded that in conjunction with the operator training lesson plan, it provided adequate guidance on the event and lessons learned. On April 28, operations management required that the ID be read by and reviewed with all operators prior to Unit 1 startup. The inspectors concluded that the completed operator training and procedure revisions were adequate to address the appropriate issues prior to restart of Unit 1.

B. Reactor Vessel Level Indication System (RVLIS) Indication of Non-Condensable Gases in Reactor

On April 12, 1994, the inspector noted that RVLIS channel A indicated 93% reactor vessel level. Unit 1 was in cold shutdown (mode 5), reactor coolant system (RCS) temperature 173°F, RCS pressure 32 psig with all reactor coolant pumps (RCPs) off. The inspector confirmed that full range and upper range on both channels indicated 93% level (four indications total). Although operators initially suspected an instrument calibration problem, they subsequently concluded that the indication was accurate, that non-condensable gases had accumulated in the vessel head, and that the space occupied by the gases extended approximately 18 inches from the top of the reactor vessel head. They found that reactor vessel level had trended downward very slowly since April 9, when the RCPs were secured. They also concluded that because the bubble was relatively small there was no immediate safety concern.

The licensee sampled the gas volume on April 13, and found it to be 96% Nitrogen and 3% Hydrogen. They believed the source of the nitrogen was VCT cover gas being pumped into the RCS via the charging system and then coming out of solution. The licensee vented the gas bubble per procedure on April 17. Subsequent to venting, RVLIS indicated vessel level was 100%.

In response to concerns identified by the NRC regarding the control of gas accumulation in the reactor head during shutdown the licensee revised the shutdown logs and issued guidance in Information Directive (ID) 94-012. The ID clarified instructions for operation of the VCT at lower temperature and higher pressure than the RCS. This condition led to the accumulation of nitrogen in the reactor vessel head area and subsequent decrease in reactor vessel inventory. The ID provided management expectations for monitoring vessel level and instruction on minimizing the amount of nitrogen coming out of solution. Operators were directed to:

1) Increase monitoring of RVLIS for any condition less than 100%. Shutdown log SC.OP-DD.ZZ-OD22(z)-A, Revision 6, has been updated to provide required actions for decreasing level.

2) Monitor and maintain VCT pressure between 15-18 psig unless degassing evolutions are in progress. Shutdown log SC.OP-DD.ZZ-OD22(z)-A, Revision 6, has been updated to show the acceptable VCT pressure range.

3) Use AD-46 (a troubleshooting control procedure) as an interim procedure to vent the head through RC40-43, when RVLIS full range indicates 80%, until new procedures are developed.

Operator interviews and control room observation confirmed that the new shutdown logs were being used and that operators were aware of the previous gas accumulation problem. The inspector concluded that the steps the licensee has taken to minimize gas accumulation in the reactor head area were effective. The inspector determined that Technical Specification 3.3.3.7 for units 1 and 2 does not require RVLIS to be operable in Modes 4, 5, and 6. Although RVLIS indication was available to the operators in mode 5, it was not initially included in the shutdown and refueling (Modes 4, 5, and 6) Control Room log. The operators were not accustomed to monitor this indication and failed to notice vessel level had dropped to 93%. In addition, operators initially suspected the accuracy of RVLIS rather than believe the indication, despite close agreement of two upper range and two full range indications. The inspector concluded the operators could have been more attentive to indicated vessel level and more willing to believe their instrumentation.

2.2.3 Hope Creek

A. Missed Reactor Coolant System Sampling Frequency

On April 4, 1994, the licensee exceeded the required Reactor Coolant System alternate sampling frequency contained in Technical Specification (TS) surveillance requirement 4.4.4.c.2. Continuous monitoring instrumentation was not available due to a reactor water cleanup (RWCU) System outage. TS 4.4.4.c.2 requires that conductivity samples be taken once every 24 hours when continuous monitoring is not available. The April 3 sample was obtained at 1:00 a.m., while the April 4 sample was taken at 8:22 a.m. This exceeded the allowable time interval, including the 25% extension, by 1 hour and 22 minutes.

The licensee identified deficiencies in communications and procedures as contributing to the missed surveillance. Subsequently, chemistry procedures were revised to specify the correct alternate sampling frequency when the reactor water cleanup system is out of service, and nuclear shift personnel were counseled to notify chemistry personnel when Technical Specification required reactor water cleanup and chemistry systems and instrumentation are removed from service.

This event had no safety significance since reactor water samples taken before and after the missed sample were within the required limits. The inspector also noted that the violation could not have been prevented by corrective action for a previous violation or licensee finding within the last two years, since no similar violations occurred. In addition, the missed surveillance was corrected immediately, and the licensee revised procedures to prevent recurrence. The inspectors found no indication that the violation was intentional.

Based on the above, the inspector concluded that this TS violation met the criteria of 10 CFR 2, Appendix C, Section VII.B. for non-cited violations.

B. Loss of Shutdown Cooling (SDC)

On April 5, 1994, the station experienced a loss of SDC. A licensee investigation revealed that a reactor pressure vessel high pressure trip signal existed on the "D" channel of the nuclear steam supply shutoff system (NSSSS). Pressure indication was 90 psig, while the trip setpoint was 82 psig. The trip signal automatically isolated the "A" residual heat removal (RHR) loop which was providing SDC. The SDC cooling was isolated for approximately 45 minutes, resulting in a reactor coolant temperature rise of 2 degrees (95 to 97 degrees). Initial licensee evaluation showed that a rise in ambient temperature caused thermal expansion of water in the isolated pressure transmitter, which caused an increase in pressure and the resulting trip. A second trip resulted when restoring SDC due to failure to reset the trip signal after venting the isolated transmitter. Operators immediately recognized the cause and restored SDC in four minutes with no appreciable temperature rise.

These events had minimal safety significance since the reactor coolant temperature rise was small. Technical Specifications did not require operability of the RHR low pressure protection logic for the plant's operational condition, since the reactor coolant system was vented at the time. The inspector concluded that licensee immediate actions to restore SDC were appropriate and long-term corrective actions for procedure deficiencies were adequate.

C. Containment Integrated Leak Rate Test

During the containment integrated leak rate test (CILRT or type A test) performed on April 11 and 12, 1994, the licensee closed the control rod drive (CRD) header vent valves to mitigate leakage from several CRD directional control valves (DCVs). Because this is a non-seismic portion of the CRD system, closure of these valves during a Type A test had the potential of masking the leak rate from the directional control valves during a design basis accident. A prerequisite of the procedure *Primary Containment Integrated Leak Rate Test*, HC.RA-IS.ZZ-0008(Q) - Rev 0, and a statement in the FSAR section 6.2 require venting non-seismic portions of the CRD system during Type A (CILRT) testing. Although the procedure permits closing valves to mitigate leaks which would affect the results of the CILRT, the licensee did not reconcile this with the requirements in the procedure and the FSAR, nor did the licensee determine whether closing the vent valves constituted an unreviewed safety question. The licensee did, however, determine that leakage past the DCVs was less than the Technical Specification limit for leakage into the reactor building for a system penetrating containment.

Although, 10 CFR 50 Appendix J section II.A.1.b states, "Closure of containment isolation valves for the Type A test shall be accomplished by normal operation and without any preliminary exercising or adjustments," and the licensee's CILRT procedure section 3.7 requires containment isolation valves to be positioned by normal remote operation, the licensee stroked several directional control valves in the CRD system to reduce RCS leakage during the CILRT preparations. The NRC brought to the licensee's attention that the initial leakage rate though the CRD control valves was incorrectly calculated. A subsequent licensee determination reviewed by the inspectors showed a higher leak rate, but within the Technical Specification (TS) 3.6.1.2.e limit for combined leakage rate of less than or equal to 10 gpm.

The inspectors concluded that these licensee's actions did not invalidate the CILRT test results. Notwithstanding, the licensee's failure to vent the non-seismic portion of the CRD piping or perform an evaluation for closure of the CRD header vents, incorrect calculation of CRD valve leakage rate, and stroking the directional control valves were not activities permitted for CILRT testing, and were in violation of 10 CFR 50 Criterion XI "Test Control". **(VIO 50-354/94-09-01)**

D. Engineered Safety Feature (ESF) Actuations

The licensee experienced two ESF actuations during this period during the reactor vessel inservice leak test. On April 19, 1994, testing of the turbine combined intermediate valves resulted in closure of the inboard main steam isolation valves (open for reactor vessel leak test) and other containment isolation valves. On April 20, a voltage fluctuation caused the loss of "B" reactor protection system bus and closure of some outboard containment isolation valves. Both actuations caused small pressure increases, but all reactor vessel parameters remained within Technical Specification limits. The licensee made the appropriate reports to the NRC and initiated root cause analysis. The inspector concluded these events had minimal safety significance since reactor parameters were within limits at all times. This item will remain unresolved pending review of the licensee root cause determination. **(URI 50-354/94-09-02)**

E. Inadvertent Reactor Pressure Vessel (RPV) Letdown

On April 21, 1994, the plant experienced an inadvertent loss of RPV inventory while aligning the "A" residual heat removal (RHR) system for shutdown cooling (SDC). RPV level dropped 41 inches before the operator restored the original valve line-up to stop the level decrease. More than 400 inches of water remained above the top of active fuel.

Initial licensee investigation revealed the suction valve for "B" residual heat removal SDC was not fully closed, although it had a closed indication in the control room. Licensee root cause analysis was still in progress at the end of the inspection period. This item is unresolved pending inspector review of the licensee's analysis. **(URI 50-354/94-09-03)**

F. Reactor Startup

On April 25, 1994, the licensee commenced a reactor startup at the completion of the fifth refueling outage in accordance with HC.OP-IO.ZZ-0003(Q), *Startup From Cold Shutdown to Rated Power*. The inspector noted that the startup was a well-controlled evolution, with appropriate management oversight. Operators adhered strictly to procedures, exhibited good communication, and made a slow methodical approach to criticality. Additionally, each crew involved in the startup received simulator refresher training in preparation for this evolution.

G. Engineered Safety Feature (ESF) System Walkdown

The inspector independently verified the operability of the reactor core isolation cooling (RCIC) system by performing a walkdown of the accessible portions of the system. The walkdown confirmed that system valve lineups and as-built configuration matched plant drawings and that no adverse equipment conditions existed which could degrade system performance.

The inspector reviewed the Final Safety Analysis Report, Technical Specifications, 10 CFR 50 Appendix A, and industry codes and standards to verify that the RCIC System was operated and maintained in accordance with these requirements. No deviations or violations were identified. The inspector discussed system performance with the responsible systems engineer, including component trending data. The engineer had extensive trending data. He was very knowledgeable of the system, associated industry concerns and operability considerations, and was actively involved with its maintenance and operation. The inspector examined the licensee configuration baseline documentation, system setpoint calculations and surveillance test data which showed good system documentation and operation.

The inspector observed good housekeeping practices in the areas observed. For the scope of this inspection, the inspector concluded the RCIC System was capable of performing its intended safety function.

H. (Closed) Unresolved Item 50-354/94-04-01 Refueling Operations

On March 9, 1994, operators inadvertently moved the refueling bridge in a horizontal direction while the mast was still extended and grappled to a "dummy" fuel bundle. At the close of the inspection period, inspectors considered this occurrence unresolved, pending review of the licensee's root cause investigation. The licensee determined that operator inattention to detail, failure to self-check and to adhere to procedure requirements caused the failure to ungrapple the dummy fuel bundle. As described in NRC inspection report 50-354/94-04, the inspectors concluded that this issue was not safety significant. However, the licensee previously attributed a refueling bridge mis-operation on December 17, 1993, to failure to self-check and to adhere to procedures. Mis-operation of the refueling bridge on March 9, 1994, demonstrated that the licensee did not adequately insure that corrective actions for the mis-operation on December 17, 1993 precluded repetition of the mis-operation, as required by 10 CFR 50, Appendix B, Criterion XVI. Based on these findings, this unresolved item was closed and is now considered a violation of the regulatory requirement. **(VIO 50-354/94-09-04).**

I. Operator Response to Loss of Water from the Spent Fuel Pool

On April 13, an alert operator noticed that water level in the spent fuel pool (SFP) skimmer surge tank was dropping, and initiated response before an alarm was annunciated. The operator concluded that water was leaking from the SFP, and initiated action for additional makeup to the skimmer surge tank. Operators also were quickly dispatched to identify the source of the leak and found that a valve, supplying air to the inflatable seals for the SFP gates, had been mispositioned. The valve was placed in the correct position, and the seals reinflated. As a result of the operator alertness combined with quick and effective response, the level in the spent fuel pool never dropped below the required minimum of 23 feet above the top of the fuel required by Technical Specification 3.9.9. Section 3.3.2.A pertains.

3.0 MAINTENANCE and SURVEILLANCE

3.1 Maintenance Inspection Activity

The inspectors observed selected maintenance activities on safety-related equipment to ascertain that the licensee conducted these activities in accordance with approved procedures, Technical Specifications, and appropriate industrial codes and standards.

The inspector observed portions of the following activities:

Unit	Work Order(WO) or Design Change Package (DCP)	Description
Salem 1	WO 940421129	No. 11 Safety Injection Pump Mechanical Seal Replacement
Salem 1	WO 940409156	Solid State Protection System (SSPS) Train B High Steam Flow Input Relay Replacement
Salem 1	WO 940412140	Steam Generator Steam Flow Protection Channel II Calibration Following Installation of Dampening Circuit (DCP-1EC-3328)
Salem 1	WO 940414151	Pressurizer Pressure Channel III Calibration
Salem 1	WO 940409217	SSPS "B" Mini-SI Time Response Test
Salem 2	WO 930619108	Main Steam Atmospheric Relief Valve 21MS10 Troubleshooting
Hope Creek	WO 931001230	CRD Header Vent Installation
Hope Creek	WO 920626073	"A" Circulator Pump Replacement
Hope Creek	WO 930422061	Service Water Vacuum Breaker Replacement
Hope Creek	WO 940415149	T-Mod 94-11: "A" Service Water Yard Discharge to Storm Drain

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

3.2 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.

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

Unit	Procedure No.	Test
Salem 1	S1.IC.ST.RHR-0014	RHR Interlock and Alarm Verification
Salem 2	S2.OP-ST.AF-003	23 Auxiliary Feedwater Pump Inservice Test
Salem 2	S2.OP-ST.CVC-004	22 Charging Pump Inservice Test
Hope Creek	HC.RE-ST.BF-001	CRD Scram Time Determination
Hope Creek	HC.MD-GP.ZZ-040	Inservice Leak Test Inspection
Hope Creek	HC.OP-IS.ZZ-0001	Inservice Leak Test of Reactor Vessel
Hope Creek	HC.OP-ST.BD-0003	RCIC Functional and Flow Verification - 18 Months
Hope Creek	HC.OP-ST.BJ-0002	HPCI System Functional Test
Hope Creek	HC.OP-ST.SN-0001	ADS and Safety Relief Valve Manual Operability Test
Hope Creek	HC.RE-ST.ZZ-007	Shutdown Margin Demonstration

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

3.3 Inspection Findings

3.3.1 Salem

A. Pressurizer Pressure Protection Channel Calibration

During the pressurizer pressure protection channel calibration, the inspectors observed that the licensee did not use a "reader and performer" methodology in conducting the calibration. The inspectors were informed that it is standard practice to assign only one technician to such a protection channel calibration. Although the observed activity was satisfactorily performed, in this instance, the inspector noted that the licensee had not established the practice of having a second individual verify performance, as was determined as a corrective measure to remediate deficiencies in other surveillance and testing activities, such as described in Section 3.3.1.B, below.

B. Inadvertent Safeguards Equipment Control (SEC) Actuation

On the morning of April 11, 1994, while performing S2.MD-FT.4KV-0001, *ESFAS Instrumentation Monthly Functional Test 2A 4KV Vital Bus Undervoltage*, a Controls Technician positioned the wrong undervoltage test switch in the "B" SEC cabinet. This error completed the blackout logic for the "B" SEC, and consequently the "A" and "C" SEC as well. The SECs responded as designed and opened the supply breakers to the vital busses, started the emergency diesel generators (EDGs), and completed the blackout loading of the busses. All systems responded as designed.

The licensee attributed the root cause to isolated instance of personnel error. Corrective actions included reviewing the SEC occurrence immediately with all technicians and then again during a work stand-down on April 14, and requiring a second technician to provide concurrent verification of the correct test switch being selected prior to positioning the switch.

The inspector concluded that the licensee accurately identified the root cause and took appropriate corrective action.

C. Previous Inspection Findings

In the Maintenance and Surveillance section of the Executive Summary for NRC Inspection Report 50-272/94-06, 50-311/94-06, and 50-354/94-04, the inspectors noted that, despite procedure improvements and a temporary middle management review group, problems continued to occur as a result of troubleshooting activities at Salem. The summary concluded that corrective actions appeared to be generally ineffective in preventing recurrence of deficiencies of a similar nature. The inspectors summarized the results of a special inspection, performed as directed by NRC Region I Temporary Inspection (TI) 94-01, "Review of Troubleshooting Activities," in Section 3.3.1.C of that report.

The TI inspection concluded that licensee actions to prevent inadequate troubleshooting activities had proven ineffective as demonstrated by several examples of problems during troubleshooting. The most recent example of a problem cited in that report was the inadvertent steam dump actuation. As a result of the steam dump actuation, licensee management instituted the middle management review group. Inspectors did not have a basis for assessing the effectiveness of the review group during the inspection period covered by NRC Inspection Report 50-272/94-06, 50-311/94-06, and 50-354/94-04. However, during the current inspection period, the inspectors noted that no abnormal plant operations occurred as a result of trouble-shooting activities, and the review group has actively reviewed trouble-shooting activities in an effort to improve the control and effectiveness of trouble-shooting at Salem units 1 and 2.

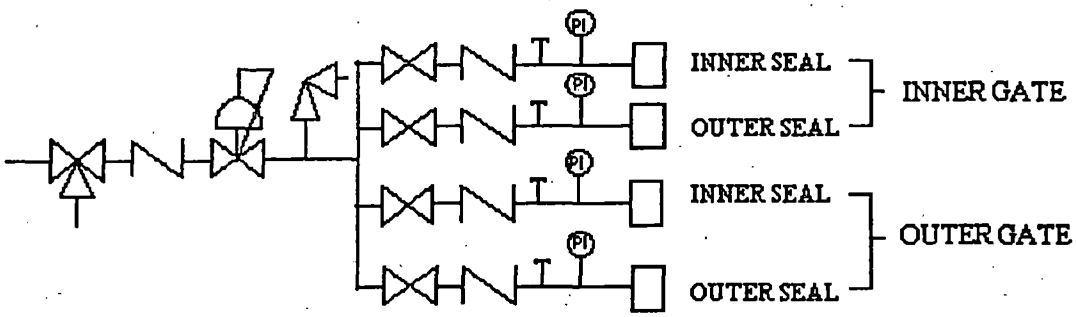
3.3.2 Hope Creek

A. Loss of Spent Fuel Pool (SFP) Inventory to Reactor Cavity

On April 13, 1994, a Hope Creek nuclear control operator (NCO) observed fuel pool skimmer surge tank level decreasing rapidly, indicating leakage from the SFP. The SFP low level alarm sounded, followed by a report that the SFP outer gate inflatable seals were leaking. The inner gate seals (2 seals per gate) had just been replaced and were still deflated. The licensee discovered that the air supply isolation valve to the inflatable seals was in the closed position and opened it, re-inflating the gate seals and stopping the leak. SFP level was restored to normal within 50 minutes of leak discovery. The water leaked from the SFP to the reactor cavity, with some spillover into the dryer-separator pool. No leakage into the drywell was discovered and no refuel floor radiation monitor alarms were received.

Licensee root cause analysis revealed equipment, procedure and personnel problems during the April 11-13 replacement of the SFP inner gate inflatable seals. The inflatable seals' air supply isolation valve was listed as normally closed in the Tagging Request Inquiry System (TRIS). This valve was recorded as open on April 5 after SFP gate installation and was subsequently closed sometime before inner gate seal replacement on April 13. The SFP gate inter-space drain valve, required to be open by procedure HC.OP-IO.ZZ-0001(Q), *Refueling to Cold Shutdown*, was improperly left closed after gate installation, which disabled the alarm for leakage into the inter-space region between the two SFP gates. The work order for gate seal replacement referenced the wrong procedure and excluded the correct procedure from the package. Mechanical maintenance practices for SFP gate seal replacement did not meet management expectations in that the job supervisor proceeded without an approved procedure. Maintenance personnel repositioned valves without a tagout. Lastly, the in-line check valves to the outer gate seals leaked, since those seals deflated during this event.

Licensee corrective actions addressed the identified root causes and included other considerations as well. The TRIS for the air supply isolation valve was changed to reflect a normal position of locked open. Operators responsible for the failure to reopen the gate



Air Supply to Spent Fuel Pool Inflatable Seals

Figure 1

inter-space drain valve were appropriately disciplined. The mechanical maintenance engineer discussed the importance of procedure compliance with all members of the mechanical maintenance shop, directed the creation of a new procedure dedicated to SFP gate seal replacement, and instituted a work package evaluation program to ensure procedure effectiveness. The operations department initiated a work order to replace the in-line check valves to each of the four inflatable seals. Additionally, the licensee wrote and answered a deficiency report to evaluate the effect of flooding the reactor well drywell cavity with the drywell head installed. This evaluation showed no negative impact on the drywell head by hydraulic forces or water damage/corrosion effects. Long term corrective actions included operator checks of SFP gate seal pressures, recurring tasks for periodic calibration of the gate seal pressure gages and in-line check valve replacement, and a design change request to improve gate seal air supply reliability.

The inspector concluded that licensee immediate actions in accordance with Abnormal Procedure OP-AB.ZZ-0144, *Loss of Fuel Pool Inventory/Cooling*, were appropriate and timely. During the event, SFP level dropped approximately 12 inches, for a total inventory loss of about 11,000 gallons (903 gal./in.). Technical Specification 3.9.9 requires 23 feet of water above the irradiated fuel in the SFP. The one foot level drop resulted in 23 feet 6 inches of water over the top of the fuel racks. Therefore, SFP level never dropped below the TS requirement.

The inspector concluded that licensee root cause analysis and corrective actions were adequate to prevent recurrence. However, the inspector observed some weaknesses which were not addressed. The procedure that was expected to be used required tagging valves, while the work order did not require a tagout. The procedure required pressurizing and depressurizing the SFP gate inflatable seals, but did not specify which seals or how to do it. Additionally, the licensee knew of the inner gate seal leak when installing the gates on April 4, but completed the installation and drained the reactor cavity without repairing it. The inspector also found that the licensee had never performed preventive or corrective maintenance on any of the valves or the pressure regulator in the air supply system (refer to figure 1., above). The existing design permits failure of a single component to permit loss of air to the seals. The inspector also determined that the loss of spent fuel pool inventory required failure of multiple barriers, including: hardware (check valve leakage), process controls (incorrect positioning of the three-way valve, failure to hang tags, inadequate control of isolation valve position), and people (lack of recognition that the newly replaced seal did not properly inflate, failure to check the three-way valve, failure to clarify and correct the work package reference to an incorrect procedure for seal replacement, performing work without a procedure, failure to recognize that the tag requirement had not been met).

While the potential for a more serious event existed, this event had minimal safety significance since the spent fuel was adequately covered at all times and radiation levels never indicated any abnormal increase. However, licensee failure to use a procedure for gate seal replacement, manipulation of the air supply valves without using a tagout as required by procedure, and to follow a procedure to open the inter-gate drain valve is a violation of Technical Specification 6.8.1.c. **(VIO 50-354/94-09-05)**

4.0 ENGINEERING

4.1 Salem

A. Motor Operated Valve (MOV) Housing Cover Eyebolts

During inspection of the Salem auxiliary building, the inspectors noted that a number of MOVs used in safety-related applications had eyebolts installed on the actuator housing cover. On May 19, 1993, the NRC issued Information Notice 93-37 to alert licensees that the material grade of the eyebolts is in question. The correct housing cover bolt is a hex head bolt that is considered a critical component by Limitorque since the bolts receive the resulting thrust load in the closing direction of the valve. Limitorque recommended that the eyebolts be replaced by the grade five housing cover bolts at the next scheduled maintenance opportunity. The inspector discussed this issue with the responsible MOV engineers to ascertain the status of the eyebolt changeout.

Hope Creek just completed a refueling outage and performed 73 MOV inspections (176 total) as part of the preventive maintenance program. No eyebolts were identified. At the time of the inspection the Salem staff was re-writing the procedure for the 18 month MOV preventive maintenance, incorporating a requirement to perform a one time visual inspection of the housing cover bolts to confirm the presence of eyebolts. Identified eyebolts will be replaced with the proper hex head bolts. However, the inspectors concluded that the licensee missed an opportunity to examine those MOVs located inside containment as part of the preventive maintenance inspections during the recently completed Unit 1 refueling outage. Additionally, the licensee's preventive maintenance schedule does not prioritize the inspection schedule for those SMB 00/000 actuators that are relying on the Kalsi 140% allowable increased load rating as was discussed in the Limitorque maintenance update. Although the licensee is currently taking the appropriate action to address this issue, the inspectors considered the timeliness of implementation to be weak as no MOV eyebolts at Salem have yet been removed in the 11 months since the issuance of the generic communication.

4.2 Salem - Restart Inspection Activities

The inspectors reviewed licensee corrective actions for the following items to insure adequacy for Salem Unit 1 restart.

A. Steam Flow Transmitter Damping Circuit Modification

On April 7, 1994, a spurious high steam flow signal was sensed by the Rosemount flow transmitters and resulted in an "A" train safety injection signal. Subsequent to this event, these steam flow transmitters were modified per design change package (DCP) 1EC-3328 to add a damping adjustment. Previous to the April 7 event, transmitter time responses ranged from 0.020 to 0.110 seconds. After modification, the transmitter time response was adjusted to 0.225 $\pm$ 0.025 seconds. This transmitter time response setting will prevent spurious steam line pressure spikes from tripping the steam flow bistable when the reactor is tripped and actual main steam flow is below 40%.

The inspectors reviewed modification package DCP 1EC-3328 and the work orders used to modify the eight Rosemount flow transmitters. The inspectors noted that the DCP contained a good evaluation of how the modification affected the design basis of the affected protection circuits. The inspector also reviewed the sensor calibration and time response test results and concluded that the transmitters were adequately tested. The Technical Specifications and FSAR were reviewed to evaluate what limits and design basis may be affected by the modification. The DCP contained a thorough design analysis of the modification which was SORC reviewed and approved. The inspector agreed with the licensee conclusion that implementation of the modification did not constitute an unreviewed safety question, since the transmitter response after the modification was less than the time assumed in the design basis. The inspectors concluded that the modification was well performed and adequately addressed the associated Unit 1 restart issue.

B. Solid State Protection System Steam Flow Input Relays

During the initial investigation of the short duration high steam flow signal the licensee identified that twelve of sixteen steam flow input relays were discolored. Subsequent time response testing demonstrated that the relays were all functioning acceptably. Test data for Train A shows that the actuation signal duration must be at least 16 msec for the master relay contact to close. Train B requires an actuation signal of 31 msec. The variance in the response time of these relays had minimal impact on the ability of the system to meet overall design requirements. The design specification for time delay of the high steam flow SIS actuation is less than 600 msec.

After the input relay and TS channel time response testing were completed the licensee replaced the discolored relays. The apparent cause of the discoloration was the accumulation of a powder-like carbon buildup due to cycling of the relays. The licensee elected to replace the relays based on their appearance, even though the test results indicated the time response of all the relays was acceptable.

The inspector reviewed the licensee's evaluation, test results, and the discolored relays. The inspector made a visual examination of the relays and compared the extent of the carbon buildup to the time response test data. No correlation was observed between the apparent carbon buildup and the time response performance. The licensee stated that discolored relays will also be replaced in Unit 2 during the next outage and that they have no reason to question their operability. The inspector concluded that the licensee's actions regarding the input relay evaluation were acceptable.

C. Steam Flow Summator

The licensee examined the output of the steam flow summators during Maintenance and Controls troubleshooting to determine if the summator had caused the spurious signal. The test simulated the auxiliary contacts of the reactor trip breakers opening and monitoring the output of the summator module. The high steam flow function compares actual steam flow to a programmed setpoint of 40% of full steam flow between 0 and 20% load and then increasing linearly to 110% of full steam flow at full load. When the reactor trip breakers open the output of the setpoint should decrease to the 40% steam flow value (1.34 VDC). Strip chart data shows the setpoint actually dipped below the 40% value by 100 mVDC before returning to the low value setpoint.

The licensee is currently investigating the phenomenon however, there is no safety significance because the lower setpoint output would correspond to a lower reference value being used to determine high steam flow. Based on the minor extent of the phenomenon and its safety significance, the inspector determined that no further NRC review of the issue is necessary at this time.

D. Power Operated Relief Valve (PORV) Operability

During the plant response to the Salem Unit 1 transient on April 7, the PORVs operated a total of at least 300 times. The valves functioned as designed, and during the cooldown at the conclusion of the event, plant staff tested both valves for stroke time and seat leakage. The valves were judged operable. Details of PORV operation during the transient are provided in NRC Inspection Report 50-272/94-80. Upon valve disassembly, mechanics did not experience difficulty indicative of severe binding while removing valve internals. As a result of the numerous valve operations, the licensee opened 1PR1 (cycled more than 100 times) and 1PR2 (cycled more than 200 times) for inspection. They discovered that 1PR1 had a small amount of wear randomly distributed around the plug and the interior of the cage. The licensee concluded that 1PR1 exhibited typical wear for the circumstances. The licensee also found that 1PR2 had heavy scuffing on the outlet side of the plug and the cage, and galling on the corresponding side of the valve stem. Additionally, the licensee found small cracks in the plugs for both valves radiating from a hole drilled in the plug.

Because of the degree and orientation of galling wear noted on 1PR2, the licensee assembled a team of engineers to determine the root cause of the wear patterns and to assess the effects of the wear on operation. The internals were shipped to a Westinghouse materials laboratory for analysis of the cracks and assay of the materials on the scuffed surface of the plug. Correspondence from the valve manufacturer, Copes-Vulcan, indicated that the wear on 1PR1 was normal and 1PR2 was more than desired but not unusual. The team preliminarily determined that several factors contributed to the wear observed in 1PR2. The manufacturer designed the valve with small clearances between the plug and cage. Installation of the valve internals was performed using a procedure which may have contributed to misalignment of internal components. Chrome coating from galling of the stem may have migrated to a location between the plug and the cage, contributing to the scuffing of the plug. The hydrodynamic forces present in the valve during valve lifting under operating conditions caused a differential pressure across the valve plug pushing it against the outlet side of the cage.

The licensee team noted that the cage-guided design of these PORVs assumed a certain degree of contact wear between the plug and the cage. Dimensional tolerances of 3 to 5 mils between the plug and cage provide lateral support to the plug which otherwise would only be provided by the stem guide near the top of the valve. The team also noted that the PORVs were reassembled during 1R11 by installing the bonnet of the valve into the body with the stem, stem packing, and plug pre-assembled into the bonnet. This method was used primarily as a means to reduce personnel radiation exposure during valve maintenance, but did not allow for an adequate check for valve binding or misalignment during installation. Based on the investigation, the licensee revised the re-assembly procedure to include a vendor recommended piece by piece assembly process, including checks for clearance and freedom of movement at each stage of installation.

During valve reassembly, the licensee installed new valve internals for both PORVs using the revised procedure. No anomalies were noted. Further, as a one-time check to ensure the 1PR2 valve body did not contribute to the unusual wear pattern, the licensee cycled the valve 10 times using the air operator. When plant staff subsequently disassembled the valve for inspection they found no signs of wear. Plant staff again reassembled the valve using the revised procedure.

In summary, licensee engineering determined that the galling and scuffing found in 1PR2, although heavy, was acceptable. They attributed the wear to misalignment of the valve internal during installation. To prevent future misalignments, the licensee changed the procedure for reassembly. The modified procedure includes manually stroking the valve during various stages of reassembly to insure that the plug moves freely within the cage. The team noted that the valves operated more than 300 times during the transient, and then passed the operability test. In addition, the vendor considered the observed wear acceptable. The licensee installed new internals in 1PR1 and 1PR2.

At the end of the inspection period the licensee had not determined the cause of the crack. In addition, the licensee had not yet completed the safety evaluation of PORV operability. The inspectors will review licensee root cause and corrective actions in a future inspection report. **(IFI 50-311/94-11-01)**

E. Atmospheric Steam Relief Valve (MS-10) Modification

During the April 7 transient, one or more steam generator code safety valves lifted on high steam pressure. The MS-10 valves did not automatically operate as designed to prevent challenges to the steam generator code safeties. Although the Final Safety Analysis Report (FSAR) does not take credit for operation of the MS-10 valves in response to an accident, the design of the MS-10 valves was intended to provide steam pressure control, whereas the main steam code safety valves were designed to protect the steam generators and piping from failure due to overpressure. As a result of the lack of MS-10 automatic operation a steam generator code safety valve lifted. This caused the reactor coolant system (RCS) temperature to reduce sufficiently to result in a RCS pressure drop. Low RCS pressure initiated a safety injection.

The licensee found that the MS-10 valves did not open because of saturation of the control circuit, as a result of a modification performed in 1977. The licensee consulted with Westinghouse in 1977 to identify a solution for inadvertent MS-10 opening during load transients. They concluded that removing a "drain circuit," consisting of two diodes and a resistor, would prevent inadvertent MS-10 opening. The licensee and Westinghouse did not identify that removal of the "drain circuit" created the circuit saturation conditions which caused considerable delay in MS-10 response to rapid changes in steam pressure. In response to the April 7 transient, the licensee reinstalled the drain circuits to provide the correct MS-10 response to pressure changes. In addition, the licensee adjusted settings for control circuit response to insure adequate MS-10 response to rapid transients, while minimizing the undesirable response to normal load changes, such as inadvertent opening. Plant staff modified a spare control card and performed response tests of the card in the simulator control room. The tests demonstrated that reinstalling the drain circuit eliminated the saturation condition experienced on April 7. The licensee planned to confirm the adequacy of the corrective action through startup testing.

The inspectors reviewed the circuit modification, supporting documentation, the safety evaluation, and results of simulator testing. The inspectors concluded that the modification addressed the saturation condition. The inspectors will monitor startup testing to confirm the that the modified circuit permits proper operation of the MS-10 valves.

4.3 Hope Creek

A. Discovery of Wrong Size Fuel Pellet in A Fuel Bundle

Hope Creek received 232 new fuel bundles from General Electric (GE) for their fifth refueling outage. The licensee inadvertently damaged one bundle and returned it to GE for inspection. The vendor inspection revealed one fuel pellet of the wrong size in one of the fuel pins. Because of this, GE inspected the records of all fuel bundles sent to Hope Creek and found 62 gamma scan anomalies of other pellets similar to the one indicating the wrong-sized pellet. These anomalies were located in 55 pins in 51 different fuel bundles.

The Hope Creek reactor uses GE-9 fuel bundles, which are 8x8 arrays of fuel pins with pellets 0.441 in. in diameter. The undersized pellet was one used in the GE-11 fuel bundle, a 9x9 array with pellets 0.376 in. in diameter.

GE statistical analysis concluded that this was not a widespread problem. Nevertheless, the licensee chose five of the 51 suspect bundles, containing nine pellet anomalies, for an x-ray inspection, to ensure there was not a large-scale problem with fuel pellet size. If any defective pellets were found, the licensee intended to expand the sample. This inspection revealed no more wrong-sized fuel pellets so the licensee determined that the fuel was satisfactory for loading into the core.

The inspector concluded that licensee actions to perform a random sample inspection of suspect fuel bundles was appropriate. The inspector had no additional concerns.

5.0 PLANT SUPPORT

5.1 Radiological Controls and Chemistry

5.1.1 Hope Creek Outage Radiological Controls

During the outage, the inspector closely observed the licensee's control of radiation exposure and radioactive material contaminations. The inspector noted good use of radiological controls and practices in the performance of work in high radiation and contaminated areas. Health Physics (HP) technicians provided detailed RWP briefings, extensive and up-to-date surveys, expert radiological assistance, and strict access control. The inspector determined that the licensee's radiation workers were experienced, highly competent, well-trained, and very knowledgeable. The inspector observed many good As Low As Reasonably Achievable (ALARA) practices throughout the outage.

The inspector met periodically with the radiation protection manager to discuss radiological performance during the outage. The inspector determined that the radiation protection staff effectively planned work to maintain exposures ALARA and within prescribed limits. The licensee established challenging radiation exposure and contamination goals based upon past exposure data and an arduous refueling scheduling. The inspector noted that, as challenging as those pre-outage goals appeared, the licensee managed to achieve significantly less man-rem exposure and personnel contaminations. The inspector attributed this success to strong radiological management. Oversight, prompt and effective feedback for improvement, good radiological work practices and training, and a dedicated team effort. The inspector concluded that the licensee's radiation work practices and controls were exemplary and in strict compliance with ALARA principles.

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

6.1 LERs and Reports

The Salem and Hope Creek Monthly Operating Reports for February 1994 were reviewed for accuracy and content, and were determined to be acceptable. The inspectors also reviewed the following LERs to determine whether the licensee took the corrective actions stated in the report, and to determine if licensee responses to the events were adequate, met regulatory requirements conditions, and commitments:

Salem LERs

Unit 1

Number	Event Date	Description
LER 93-020	December 23, 1993	Reactor Coolant System Accumulator Level inaccuracies.
LER 94-001	January 5, 1994	Voluntary entry into TS 3.0.3 to support troubleshooting of the analog rod position indication system.
LER 94-006	February 21, 1994	Voluntary entry into TS 3.0.3 to support troubleshooting of the analog rod position indication system.

Unit 2

LER 94-001	January 15, 1994	Voluntary entry into TS 3.0.3 to support troubleshooting of the analog rod position indication system.

For the LERs listed above, the inspectors determined that there were no violations or deviations, and considered the LERs closed.

Hope Creek

LER 94-001	March 5, 1994	Inadvertent loss of shutdown cooling (SDC) and reactor water cleanup (RWCU) due to personnel error.

Hope Creek (HC) LER 94-002 documented that a HC operator with a Senior Reactor Operator's (SRO) license had served on shift in a dual role as Nuclear Shift Supervisor (NSS)/Shift Technical Advisor (STA) without meeting the educational requirements for STA. Technical Specification (TS) 6.2.2.a requires that any individual serving as NSS/STA have an SRO license, and either a professional engineer's license or a technical degree. Since this individual did not have a professional engineer's license or the required degree while serving as NSS/STA, the TS requirement was not met.

The individual's application for employment in 1982 indicated that he would attain a Bachelor of Science in Mechanical Engineering (BSME) in June 1982. He subsequently claimed to have earned a BSME on NRC Form 398 in July, 1985 when applying for an SRO license. He never completed the degree. The licensee discovered this discrepancy during routine background checks conducted when the individual re-applied for unescorted site access in November 1993. He served on shift in the NSS/STA role without proper credentials between 1986 and 1991.

The licensee-identified root cause of this incident was the failure of the employee hiring process to verify that the individual had actually completed the BSME degree. Subsequent verifications by the Training Department and Operations Department also failed to identify the false information. Corrective actions included termination of the individual's employment, a review to verify the educational qualifications of all STAs, and a change in the hiring process to require that grade transcripts be provided directly from educational institutions. This matter is unresolved pending NRC assessment. **(UNR 50-354/94-09-06)**

6.2 Open Items

The inspector reviewed the following previous inspection items during this inspection. These items are tabulated below for cross reference purposes.

Site	Report Section	Status
Hope Creek		
50-354/94-04-01	2.2.2.H	Closed

7.0 EXIT INTERVIEWS/MEETINGS

7.1 Resident Exit Meeting

The inspectors met with Mr. J. Hagan and Mr. R. Hovey 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 NRC Region I review and discussions with PSE&G, it was determined that this report does not contain information subject to 10 CFR 2 restrictions.

7.2 Specialist Entrance and Exit Meetings

Date(s)	Subject	Inspection Report No.	Reporting Inspector
4/4-8/94	Radiological Environmental	50-272 and 311/94-10; 50-354/94-08	Struckmeyer
3/28 - 4/15/94	Overhead Annunciator Followup	50-272 and 311/94-07; 50-354/94-05	Calvert
4/8-21/94	Reactor Trip With Multiple Safety Injections	50-272/94-80	Summers

7.3 Management Meetings

A public meeting for the Augmented Inspection Team was held at the Salem Station on April 26, 1994. Details will be in NRC Inspection Report 50-272/94-80.