U. S. NUCLEAR REGULATORY COMMISSION

REGION I

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Licensee:	Public Service Electric and Gas Company
Facility:	Hope Creek Nuclear Generating Station
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Inspectors:	R. J. Summers, Senior Resident Inspector S. A. Morris, Resident Inspector N. T. McNamara, Emergency Preparedness Inspector F. J. Laughlin, Emergency Preparedness Inspector A. L. Della Grecca, Senior Reactor Inspector D. A.Jaffe, Senior Project Manager
Approved by:	Larry E. Nicholson, Chief, Projects Branch 3 Division of Reactor Projects

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EXECUTIVE SUMMARY

Hope Creek Generating Station
NRC Inspection Report 50-354/96-07

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 7-week period of resident inspection; in addition, it includes the results of announced inspections by regional inspectors in the Emergency Preparedness area; followup inspection activities in engineering support and operations; and, a program assessment of the 50.59 process by the NRR project manager.

During the report period, a security program inspection was conducted by region-based specialist inspectors; however, the details of that inspection are contained in NRC Inspection Report 50-354/96-08.

Operations

Operators responded appropriately to an inadvertent reactor core isolation cooling system isolation. Despite their inability to establish a definitive root cause, good engineering department involvement in troubleshooting the suspected instrument drawer ensured prompt restoration of the RCIC system to operability. A strong determination to promptly identify the component failure mechanism was also evident. (Section O1.2)

Station operators exhibited good awareness and questioning attitude in the identification of a minor steam leak in a normally inaccessible area of the reactor building. Engineering personnel developed an appropriate safety evaluation to address an abnormal valve configuration that temporarily minimizes the impact of the noted steam leak. (Section O1.3)

Although the initial response to a potential tampering event at Salem appeared to be minimal, subsequent actions, including direct communication of management expectations and the development of an operational directive for reacting to suspected tampering events were thorough. Verification of the operability of remote shutdown equipment following a suspected sabotage event at another utility was timely and comprehensive. (Section O4.1)

Though a plant operator failed to self-check prior to implementing an important step in a procedure, no damage to safety related equipment resulted and licensee response to the event was good. (Section O4.2)

SORC activities were conducted in accordance with plant technical specifications. In addition, SORC questions were of sufficient depth to ensure that station activities were conducted safely. (Section O7.1)

The corrective action program performance indicators were effective for monitoring problems identified by station personnel and in ensuring that timely corrective actions were taken. (Section O7.2)

Maintenance/Surveillance

Control and conduct of maintenance and surveillance activities was good. Similarly, procedure adherence was good. Schedule adherence, especially for significant on-line activities, like the "A" emergency diesel generator, and response to emergent work was good. (Section M1.1)

Plant operators exhibited a timely and conservative response to indications of improper oil in two residual heat removal pump motor bearings. Good coordination with maintenance technicians resulted in the prompt restoration of affected equipment. Root cause assessment and corrective actions were comprehensive. (Section M2.1)

The backlog of corrective maintenance activities is high; however, licensee management has continuously assessed the backlog for impact on Operations and prioritization of maintenance. (Section M2.2)

Operator recognition of inoperable drywell leak detection system instrumentation that required a plant shut down was not timely; however, the condition was subsequently recognized avoiding any violation of the plant technical specifications. Subsequent response was appropriate, including prompt implementation of TS-required actions and documentation of the event in accordance with the corrective action program. (Section M4.1)

Engineering

PSE&G's framework for the 10 CFR 50.59 program was generally good. Two examples of changing the plant without an appropriate 10 CFR 50.59 evaluation were identified and resulted in a violation of NRC regulations. (Section E1.1, E1.2 & S8)

Plant operators modified the controls of a safety related component (valve 1EGHV-2522E), without use of proper engineering support to assess if this resulted in either a necessary change to the plant technical specifications or an unreviewed safety question. Once this concern was identified, operators restored the valve to its normal configuration in a timely manner. (Section E1.2)

Operators exhibited a good, conservative desire to maximize overall service water system reliability due to the impending severe weather by requesting engineering personnel to devise a means to restore the function of an associated subsystem made inoperable by partial implementation of a design change package. However, a review of the documentation associated with the modification to satisfy the operations department request highlighted weaknesses in the process for controlling and justifying design change package revisions. (Section E2.1)

The NAP-59 procedure for addressing the 10 CFR 50.59 process is well written, provides clear assignment of responsibility, and provides the user with good directions. (Section E3.1)

Certain aspects of the training program for 10 CFR 50.59 were good; however, qualification requirements had not yet been developed to ensure that personnel involved in the use of 10 CFR 50.59 had been appropriately trained. (Section E5.1)

The Offsite Safety Review Group review of safety evaluations were not consistently performed. PSE&G's corrective actions for similar prior findings were ineffective at Hope Creek in that sponsoring organizations at Hope Creek continued to be inconsistent in providing safety evaluations for OSRG review. Finally, the OSRG lacked reasonable initiative in ensuring that they received these safety evaluations from the sponsoring organizations. (Section E7.1)

Plant Support

The inspectors conducted numerous tours of the facility and noted that all required radiological postings and locked areas met regulatory requirements. Further, areas were clear of unnecessary equipment, well illuminated and free of safety hazards. (Section R2)

While some activities associated with effluent grab sampling and analysis were not conducted in a timely manner, overall performance of radiation protection program requirements were good. (Section R4)

A QA department audit of the radioactive waste program met the requirements of the Hope Creek technical specifications and provided good self-assessment of this area. (Section R7)

PSE&G maintained an adequate emergency preparedness program. The emergency plan and implementing procedures were current and effectively implemented. The emergency facilities, equipment, instruments and supplies were maintained in a state of readiness. All required 1995 and 1996 surveillance tests were completed. In the past six months, there have been EP management and organizational changes and it appears that these changes have not had an adverse effect on the EP program. A sampling of emergency response organization (ERO) personnel training records indicated that training qualifications were current. Routine verification that specified ERO personnel have maintained respirator requalification training was not being conducted. Reports indicated that quality assurance audits were thorough and satisfied NRC requirements. (Section P)

PSE&G's implementation of a design change package to replace the Hope Creek fire protection computer was generally acceptable, although interim compensatory measures were not properly evaluated to ensure that no unreviewed safety question existed. (Section F2)

Based on observed drill response, the inspectors concluded that the compensatory measures were effective in providing appropriate fire panel indication and alarm information to the control room for response to postulated fires in the facility. (Section F4)

TABLE OF CONTENTS

Report Details

Summary of Plant Status

Hope Creek began the inspection period at 100 percent power. Full power operations were maintained throughout the period spanning August 4, 1996 to September 21, 1996, except for minor power reductions to support maintenance and testing activities.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was professional and safety-conscious; specific events and noteworthy observations are detailed in the sections below.

O1.2 Reactor Core Isolation Cooling System Isolation

a. Inspection Scope (71707, 62707)

The inspectors observed PSE&G's response to an engineered safety feature actuation that resulted in an automatic isolation of the reactor core isolation cooling (RCIC) system.

b. Observations and Findings

On August 21, 1996, the RCIC system steam inlet valve and turbine trip throttle valve both closed in response to an isolation signal generated by the steam leak detection system. Station operators surmised that the actuation was the result of an instrumentation failure since a prompt inspection of the RCIC equipment room indicated that all conditions were normal. Operators verified that the system responded as expected to the isolation signal, implemented the applicable LCO action statements per TS 3.7.4, and reported the occurrence to the NRC operations center as required by 10 CFR 50.73. The inspectors witnessed appropriate concern by station management in response to this event, specifically because members of the TS surveillance improvement project were coincidentally reviewing the adequacy of past operability testing of the high pressure coolant injection system.

Initial troubleshooting by maintenance technicians identified multiple hardware problems on various cards internal to the RCIC system "NUMAC" instrumentation and control drawer, the device which houses the steam leak detection and actuation logic. However, the engineering department system manager subsequently determined that none of the discrepancies identified should have resulted in the observed RCIC system isolation. Discussions with the NUMAC vendor and a search of industry operating experience data, though a good initiative, did not assist in finding the root cause of the condition. Additionally, a search of maintenance history on other installed NUMAC drawers at Hope Creek determined that no

adverse equipment performance trend was evident. In order to minimize the duration of the unplanned RCIC system outage, station management elected to replace the entire NUMAC drawer with a spare. The inspectors observed that subsequent instrument calibration and testing was completed satisfactorily. The RCIC system was inoperable for less than two days.

PSE&G engineering personnel stated that, because of the inconclusive troubleshooting, and because much of the internal functional design of the component is proprietary, the suspect NUMAC drawer would be shipped to the vendor for additional testing and root cause analysis.

c. Conclusion

Operators responded appropriately to an inadvertent reactor core isolation cooling system isolation. Despite their inability to establish a definitive root cause, good engineering department involvement in troubleshooting the suspected instrument drawer ensured prompt restoration of the RCIC system to operability. A strong determination to promptly identify the component failure mechanism was also evident.

O1.3 Steam Leak From Main Steam Line Drain Piping

a. Inspection Scope (71707, 37551)

The inspectors observed the process by which a small steam leak in the steam tunnel was identified and (temporarily) resolved, including the steps taken by the operations department to locate the source of the leak and the follow up analysis performed by engineering personnel to justify a temporary change in an established isolation valve line up.

b. Observations and Findings

On August 7, 1996, station operators detected a slight rising trend on the reactor building exhaust ventilation radiation monitor. Operators subsequently correlated a slowly rising steam tunnel temperature indication to the reactor building exhaust readings. Suspecting a steam leak, operations, engineering, and radiation protection department personnel coordinated an effort which ultimately resulted in a determination that the source of the leak was from main steam line drain piping. Operators closed the drain line outboard containment isolation valve, 1ABHV-F019, and placed it under administrative control (caution tag); this action resulted in an immediate reduction in steam tunnel temperature and reactor building exhaust radiation levels.

Because thorough investigation and repair of the drain line piping would result in relatively high exposures to personnel in the vicinity, station management elected to defer the corrective maintenance until an outage of sufficient duration. As a result, since the UFSAR indicates that the 1ABHV-F019 valve is open during normal operation, engineering appropriately prepared a 10 CFR 50.59 safety evaluation for

the extended temporary condition during which the valve would remain closed. The inspectors reviewed the evaluation and observed the station operations review committee (SORC) deliberations on the merits of the assessment, and judged both to be appropriately focused on the design and safety implications. The evaluation was approved primarily since the valve remained operable (even though closed), and that it was placed in its design basis (safe) position.

c. Conclusion

Station operators exhibited good awareness and questioning attitude in the identification of a minor steam leak in a normally inaccessible area of the reactor building. Engineering personnel developed an appropriate safety evaluation to address an abnormal valve configuration that temporarily minimized the impact of the noted steam leak.

O4 Operator Knowledge and Performance

O4.1 Station Response to Potential Tampering Events

a. Inspection Scope (71707, 71750)

The inspectors reviewed the Hope Creek operations department response to reports and indications of suspected or actual tampering events at other commercial nuclear power stations.

b. Observations and Findings

On August 7, 1996, just prior to shift turnover, the Hope Creek senior nuclear shift supervisor (SNSS) was informed by his Salem station counterpart that Salem operators discovered mis-positioned valves (closed versus locked open) in a safety system, and that tampering was being considering as a possible explanation. The inspectors initially learned of the event from the relieving SNSS during his plant status briefing to station management. Based on a initial perception of minimal interest in this issue, the inspectors subsequently questioned the operating shift on their response to this issue, and, upon noting little appreciation of the nature of the issue by shift personnel, expressed the concern to senior PSE&G management.

Before substantive actions could be implemented, Hope Creek management learned that the Salem issue had been traced to a status control error in the tagging system. However, shortly afterward, the operations department issued a draft directive that provided specific guidance for expected operations response to suspected tampering events. Additionally, the inspectors noted that management expectations for handling tampering concerns were clearly expressed to the operating shifts, including an entry in the "night orders."

On August 15, 1996, Hope Creek management learned that an Unusual Event was declared at the St. Lucie plant in Florida because of suspected sabotage of the remote shutdown system (glue found in various keylock switches, rendering them inoperable). The inspectors witnessed an excellent response to this event. Specifically, the event was promptly communicated to appropriate station personnel with emphasis on its potential consequences, and, more significantly, the operations department conducted a comprehensive walkdown of all remote shutdown equipment at the station using the applicable integrated operating procedure as a guide. No discrepancies were found.

Later, on August 28, 1996, Salem reported to the Hope Creek SNSS that mis-positioned switches on safety-related battery chargers at Salem appeared suspicious, and that tampering had not been ruled out. The inspectors noted that, despite a subsequent determination that tampering was not involved, the Hope Creek operations department response was prompt and thorough, and followed the expectations outlined in the newly established directive.

c. Conclusions

Although the initial response to a potential tampering event at Salem appeared to be minimal, subsequent actions, including direct communication of management expectations and the development of an operational directive for reacting to suspected tampering events were thorough. Verification of the operability of remote shutdown equipment following a suspected sabotage event at another utility was timely and comprehensive.

O4.2 Operator Error During Post-Maintenance Testing of the "A" Emergency Diesel Generator

The inspectors reviewed an event on September 4, 1996, involving an operator error. At the time, post-maintenance testing was in progress on the "A" emergency diesel generator. An equipment operator was about to remove the EDG from service, which involved opening the output breaker. However, instead of opening the output breaker, the operator erroneously pressed the engine stop button. This caused the engine to stop with the generator output breaker still closed. Subsequently, the output breaker opened automatically on a reverse power condition (as designed). No damage to the equipment occurred as a result of this event because the automatic breakers controls performed appropriately.

The inspector observed that the licensee treated this condition seriously and performed an acceptable review of the causes for the operator error and to establish the extent of damage to the equipment.

The inspector concluded that while the operator failed to self check prior to implementing an important step in a procedure, no damage to safety related equipment resulted and licensee response to the event was good.

O6 Operations Organization and Administration

O6.1 Operations Department Management Change:

Just after the close of the inspection period, the licensee announced that the Operations Department Director resigned from the organization. The department management responsibilities will be temporarily charged to the Operating Engineers. The operating shifts will continue to report to H. Hanson, Acting Operations Manager and current SRO-license holder. The licensee plans to recruit a replacement for the Operations Department Director.

O7 Quality Assurance in Operations

O7.1 Station Operations Review Committee (SORC) Meeting Observations

The inspectors observed several routine SORC meetings during the inspection period. The inspectors verified that the SORC membership requirements of the plant technical specifications were met. The observed discussions were of excellent quality. Noteworthy examples included discussions on: operability determinations; the aggregate impact of degraded, but operable equipment; review of an event involving observed leakage from the emergency overboard discharge line of the service water system; and, review of the plans for retiring certain radioactive waste handling equipment.

The inspectors concluded that the SORC activities were conducted in accordance with plant technical specifications. In addition, SORC questions were of sufficient depth to ensure that station activities were conducted safely.

O7.2 Station Corrective Action Program (CAP) Performance Indicators

The inspectors reviewed the current CAP performance indicators for the months of July and August, 1996. Improved performance was noted in schedule adherence for corrective actions, for example 98 percent of the scheduled corrective actions for August were completed on time. The average time to complete corrective actions (57 days) remained within the licensee's goals; and, the number of overdue corrective actions was reduced from 60 in July to 10 in August.

The inspectors concluded that the licensee's CAP performance indicators were effective for monitoring problems being identified by station personnel and in ensuring that timely corrective actions.

O8 Miscellaneous Operations Issue

O8.1 (Closed) LER 50-354/96023: Reactor Core Isolation Cooling system isolation due to a failed steam leak detection monitor. This issue is discussed in detail in section O1.2 of this report. No new issues were revealed by this LER.

O8.2 (Closed) URI 50-354/93-11-01: This item involved apparent deficiencies in the licensee's corrective action program. The licensee subsequently modified this program in July 1995, with additional minor improvements being noted by the inspector since that time. The NRC has evaluated the licensee's program implementation and determined that the deficiencies identified in this prior inspection have been corrected.

O8.3 (Closed) Violation 50-354/94-09-04: mis-operation of the refueling bridge. The inspector verified the corrective actions described in the licensee response letter, dated December 8, 1994, to be reasonable and complete. Further, it was noted during the most recent refueling outage that no similar event occurred.

O8.4 (Closed) Special Report 50-354/94-003-01: operation of the facility in excess of the licensed thermal power limits. This was a required supplemental report of two events of operation above licensed thermal power limits. While additional assessment of the significance of these events and revised corrective actions were provided, no new significant issue were revealed by the supplemental report. The inspector considered the corrective actions to be reasonable and complete.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62703 and 61726)

The inspectors observed all or portions of the following work activities:

- "D" service water pump replacement
- 1CD-447 125 Volt battery cell equalizing charge
- service water traveling screen on-line maintenance
- high pressure coolant injection jockey pump repairs
- "A" emergency diesel generator on-line maintenance
- modification of the Hope Creek fire protection computer per DCP 4EC-3296
- Bailey module replacement affecting all indication and control for non-1E breakers
- reactor core isolation cooling system NUMAC drawer replacement
- south plant vent flow monitor repairs
- electrical backseating of valve 1ABHV-2016B

The inspectors observed all or portions of the following surveillance procedure(s):

- high pressure coolant injection jockey pump check valve in-service test
- "B" service water pump in-service test

b. Observations and Findings

In general, the inspectors found that the work performed during the conduct of the above noted maintenance and surveillance activities were in accordance with approved station procedures and work control programs.

Pre-job work briefings were observed to be appropriate for the planned tasks. The inspectors frequently observed maintenance supervisors and system engineers monitoring the activities and providing necessary support. When applicable appropriate radiation protection controls were observed to be followed.

The inspectors noted that on-line maintenance activities were conducted in accordance with pre-approved risk-based work schedules and LCO maintenance plans. For example, the "A" emergency diesel generator on-line maintenance activities were completed an hour prior to the planned activity schedule.

The inspectors observed that the licensee continued to self-assess the implementation of the work week schedules and when necessary, provide corrective actions to prevent recurrence of significant scheduler problems.

Emergent work activities, like the repeat failures of the south plant vent monitor, and the failure of the RCIC NUMAC drawer, were appropriately controlled, and where applicable, associated plant technical specification action statements implemented. While some planned activities were interrupted by the emergent work, the inspectors noted that overall schedule adherence was very good throughout the inspection period.

The licensee appropriately implemented 10 CFR 50.59 controls in support of the electrical backseating of valve 1ABHV-2016B. This valve is a main steam system valve that provides steam flow to the "B" steam jet air ejector. The licensee determined that the valve packing had a steam leak that was worsening. The backseating of the valve reduced the steam leakage considerably and restored environmental conditions in the steam tunnel and turbine building to normal. The inspector observed the SORC review of the associated 10 CFR 50.59 safety evaluation and found the level of questioning to be appropriately detailed.

c. Conclusions

The inspectors concluded that the control and conduct of maintenance and surveillance activities was good. Similarly, procedure adherence was good. Schedule adherence, especially for significant on-line activities, like the "A" emergency diesel generator, and response to emergent work was good.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Improper Oil Discovered in Residual Heat Removal Pumps

a. Inspection Scope (62707)

The inspectors reviewed and evaluated PSE&G's response to a self-identified condition in which an incorrect oil type was discovered in the residual heat removal (RHR) system pumps.

b. Observations and Findings

On August 14, 1996, while performing a post-maintenance surveillance run of the "C" RHR pump, operators observed an abnormal oil level condition on the pump's upper motor bearing concurrent with a "burning" smell. The pump was promptly secured and declared inoperable. Technicians determined that a small amount of oil had leaked down from the upper bearing area into the motor. This condition was subsequently corrected. In addition, oil samples were taken from both upper and lower bearing oil sumps. This analysis identified that the lower bearing sump contained an oil type not permitted by station configuration control documents.

Upon learning of the discrepancy, maintenance technicians replaced the improper oil with the correct type. Operations initiated an action request to address causal factors and required the oil in the redundant RHR pump motors (as well as core spray, SACS and service water) be sampled to determine the extent of the adverse condition. It was later determined that the "A" RHR pump motor was similarly affected. Concurrently, specialty engineering personnel provided an assessment of pump motor operability and concluded that the use of the incorrect oil in the RHR motor bearings would not adversely impact pump reliability or functionality. In spite of this assessment, plant operators, upon restoration of the "C" RHR pump, voluntarily removed the "A" RHR pump from an operable status to replace the improper oil in the motor bearing. The inspectors observed good coordination between operations and maintenance personnel during the ensuing work and the RHR pump was promptly restored to service.

The inspectors reviewed the root cause assessment performed by engineering personnel in response to this event and concluded that it thoroughly addressed the relevant issues in their recommended corrective actions. Specifically, engineering determined through a search of work order history that the wrong oil had been used during recent motor bearing oil changes. Several factors that likely contributed to this improper oil substitution, including the use of similar oil storage containers and storage locations, were all adequately addressed to preclude recurrence of this condition. Use of the wrong oil was considered a violation of station procedures; however, the oil in question did not adversely affect the equipment and the concern was both timely identified and corrected by the licensee. This licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

c. Conclusions

Plant operators exhibited a timely and conservative response to indications of improper oil in two residual heat removal pump motor bearings. Good coordination with maintenance technicians resulted in the prompt restoration of affected equipment. Root cause assessment and corrective actions were comprehensive.

M2.2 Maintenance Backlogs

The inspectors reviewed the maintenance backlog during the inspection period and the licensee's response in order to maintain the outstanding workload to a reasonable level. As of September 9, 1996, the non-outage backlog of corrective maintenance (CM) activities was about 1400 activities, with a goal of about 400 by Refueling Outage 7 (currently scheduled for September 1997). The backlog of overdue non-outage preventative maintenance (PM) activities was about 130 activities, with a goal of 0 overdue by November 1996. Due to recent emphasis on reducing the overdue PM backlog, the CM backlog remained about the same over the last few inspection periods. Of the non-outage backlog activities, approximately 450 of the work orders were on-hold for various reasons, including: about 100 on-hold for parts, and about 250 on-hold for engineering support. This exceeded the station goal of having no more than 150 work orders on-hold.

While the backlogs were consistently above the licensee's expectations throughout the inspection period, the inspectors noted the following: (i) work-week schedule adherence has improved and remained above 90% adherence throughout the inspection period: and, (ii) licensee efforts to reduce the overdue PM backlog has been effective. Once the overdue PM backlog is eliminated, additional resources will be available to begin a reduction of the CM backlog. In the interim period, the inspectors observed increased management focus and assessment to ensure that the backlog is a station priority and to assess the impact of the outstanding work on safe operations. As an example, all CMs associated with control room indicators and alarms are considered a high priority and receive special management. However, the number of control room deficiencies remains high.

The inspectors concluded that the outstanding corrective maintenance work is high; however, licensee management has continuously assessed the backlog for impact on operations and prioritization of maintenance.

M4.1 Both Channels of Drywell Leak Detection Inoperable

a. Inspection Scope (71707, 62707, 61726)

The inspectors reviewed and evaluated the operations department response to a self-identified event in which both channels of the drywell leak detection system instrumentation were discovered to be simultaneously inoperable.

b. Observations and Findings

On August 23, 1996, while Hope Creek maintenance technicians were performing a surveillance test on the drywell leak detection (DLD) system noble gas radiation monitor, radiation protection department personnel noted that the drywell floor drain sump flow instrument indicated an "operate failure." After receiving this report, plant operators reviewed the alarm chronology print out in the control room and determined that the floor drain sump flow monitor had failed 36 minutes earlier. The shift supervisor quickly determined that, as a result of this instrument failure, in combination with the redundant channel of DLD being inoperable (due to the in-progress surveillance on the noble gas monitor), the station did not satisfy the requirements of TS 3.4.3.1 (RCS Leakage Detection Systems). Action "d" of this TS mandates that the plant be placed in hot shutdown within 12 hours.

Despite the good questioning attitude exhibited by radiation protection personnel in this event, the inspectors judged that plant operators failed to recognize the inoperable floor drain instrument in a timely manner. The shift supervisor determined that 36 minutes had passed from the time when the station should have recognized the hot shut down action statement until the condition was recognized. An additional twenty minutes passed until maintenance technicians could successfully complete the DLD noble gas monitor surveillance, effectively terminating the hot shut down requirement about an hour after it began.

Operations department follow up to this adverse condition was appropriate. The "pre-planned manual calculation" for quantifying floor drain sump in-leakage per TS 3.4.3.1 action a.1 was properly implemented until the floor drain monitor was repaired. In addition, the operators involved in this event initiated an action request in accordance with PSE&G's corrective action program, and developed a list of "lessons learned" from the event that was promptly communicated to all of the other operating shifts. Significant among the issues raised in this "self-assessment" was a reinforcement of the expectation that reactor operators question the validity of each alarm received on the radiation monitoring system display; in the noted event the inspectors learned that an operator acknowledged the alarm indicating the initial failure of the floor drain instrument but (in part) assumed that it was attributed to the in progress surveillance on the noble gas monitor.

c. Conclusions

Operator recognition of inoperable drywell leak detection system instrumentation that required a plant shut down was not timely; however, the condition was subsequently recognized avoiding any violation of the plant technical specifications. Subsequent response was appropriate, including prompt implementation of TS-required actions and documentation of the event in accordance with the corrective action program.

M8 Miscellaneous Maintenance Issues

M8.1 (Closed) Violation 50-354/94-09-01: containment integrated leak rate test (Type A). The inspector verified the corrective actions described in licensee response letter, dated December 8, 1994, to be reasonable and complete.

M8.2 (Closed) LER 50-354/96005: inadequate surveillance testing for the residual heat removal system suppression pool and spray modes of operation due to unaccounted for RHR heat exchanger bypass valve leakage. This event was discovered by the licensee during the last refueling outage and involved an inadequate surveillance test procedure. The procedure failed to consider design leakage through the RHR heat exchanger bypass valves in determining the flow through the heat exchangers. Since actual flow from the RHR pumps was about 10,000 gallons per minute total, the flow through the heat exchanger (about 9650 gpm) was calculated to be less than the technical specification minimum (10,000 gpm) required for the suppression pool cooling test. The licensee determined that this event was caused by the lack of a rigorous design review when developing the plant technical specifications. The licensee also determined that the Operational Experience Feedback process had an opportunity to identify this problem in 1992 based on the report of a similar problem at the Limerick Generating Station.

The licensee provided corrective actions, including: a proposed change to the technical specifications to correctly account for the design leakage through the RHR bypass valves; changes to the OEF process that should better screen such information to determine if external issues are applicable to Hope Creek; and, incorporating lessons learned from this event into the Technical Specification Surveillance Improvement Process. The inspector had no further questions and found the licensee's corrective actions to be reasonable and complete.

M8.3 (Closed) LER 50-354/96020: operations prohibited by technical specification - failure to perform actions for inoperable radioactive gaseous effluent monitoring instrumentation. This event involved less than timely actions to the grab sampling requirements due to a failed South Plant Vent radiation monitor. On several occasions grab samples were not taken within the specified 12-hour requirements. The licensee implemented corrective actions to ensure more timely sampling and analysis for conditions required by the plant technical specifications. This licensee identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. This LER is closed.

M8.4 (Closed) LER 50-354/95-033, Supplements 7, 8, 9 and 10: technical specification surveillance requirement implementation deficiencies identified by the TSSIP.

These LER supplements document additional findings of the licensee's long-term corrective action for surveillance testing inadequacies originally described in LER 95-033. While different surveillance requirements were identified in these reports as not having been appropriately demonstrated, the associated root causes and corrective actions were the same as previously identified. In addition, the

equipment was subsequently tested and determined to be operable. No other new issues were revealed by the supplements.

III. Engineering

E1 Conduct of Engineering

E1.1 10 CFR 50.59 Activities

a. Inspection Scope (37551)

The inspector reviewed those 10 CFR 50.59 activities described in Table 1 for Hope Creek. The 10 CFR 50.59 activities were conducted at Hope Creek during the period of January 1995 to June 1996 with an emphasis on more recent activities.

b. Observations and Findings

For each activity, the inspector requested that the licensee provide a NAP-59 safety evaluation or a NAP-59 Applicability Review. Test procedure, THC.OP-SO.GQ-0002, (item 3 of Table 1), was determined by the licensee to require a safety evaluation. However, the inspector found that the safety evaluation had not been prepared until after the activity had been initiated which is a violation of 10 CFR 50.59(a)(1). The requirements of 10 CFR 50.59(a)(1) allow the licensee to make changes in the facility, as described in the FSAR, provided that the change does not involve a USQ or a change to the TSs. Since the licensee did not prepare a safety evaluation to determine if the activity involved a USQ, or to determine if a change to the TSs was involved, prior to undertaking this activity, this is a violation of 10 CFR 50.59(a)(1). The inspector noted that the licensee identified this violation and terminated use of the procedure until a safety evaluation was prepared and approved, which was considered an effective corrective action. This licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

The inspector found that the licensee did not prepare a NAP-59 Applicability Review or NAP-59 safety evaluation in connection with a March 18, 1996 revision to the design change package, 4EC-3546, Package 12, Revision 1, (item 13 of Table 1). The inspector noted the revision involved changing the leak test method from "hydrostatic" to "in-service leak test." The inspector noted that, while a procedure to perform a test associated with a design change may be included in a design change package, the procedure change should still be subjected to the 10 CFR 50.59 process in that the new test may pose its own safety issues, independent of the design change. Although the example discussed here did not result in a violation of 50.59, it does point to a vulnerability in the process that governs revisions to design changes.

The remaining activities reviewed by the inspector (see Table 1) were observed to be of generally good quality and in accordance with NRC requirements.

c. Conclusions

The inspector concluded that, in general, PSE&G had a good framework for the 10 CFR 50.59 program.

E1.2 Station Auxiliary Cooling System Valve 1EGHV-2522E Operation

a. Inspection Scope (71707 and 37551)

The inspectors observed PSE&G's response to a possible oil leak in the hydraulic operator associated with safety auxiliaries cooling system (SACS) valve 1EGHV-2522E.

b. Observations and Findings

On August 13, 1996, operators suspected that the hydraulic operator of valve 1EGHV-2522E had an internal oil leak. This condition, if left uncorrected, could lead to the valve not operating properly and possibly resulting in a transient condition due to a loss of turbine auxiliaries cooling system (TACS) water.

Based on a review of the UFSAR Sections 9.2 and 9.5, the inspectors determined that TACS is a non-safety related "load" that is cooled by the safety-related SACS system. The TACS system is designed to lesser quality standards than the SACS system and, as a result, during the initial licensing of the facility, PSE&G considered the effects of a postulated break in the TACS pipe. To account for the hydrodynamic effects, accumulators were placed in the SACS lines to act as dampeners for possible water hammer. To account for possible inventory losses to the SACS system, two fast-acting hydraulically-operated isolation valves (1EGHV-2522E and F) were installed in series in the TACS supply piping. The 2522E and F valves are automatically closed on any indicated low pressure in the SACS to TACS supply line that possibly results from a catastrophic failure of the TACS line.

Normally, one of the two SACS subsystems is lined up to supply cooling water to TACS. While there are no logical or physical barriers preventing the operators from lining up both SACS subsystems to provide TACS cooling, the system operating procedure does not permit this alignment. In addition, such an alignment could lead to sluicing water inventory from one SACS head tank to the redundant counterpart in the other subsystem, which could lead to operational transients. The TACS system is isolated from the SACS system by two pairs of isolation valves on the supply side (one pair from each SACS subsystem) and by a pair of isolation valves on the return side of SACS. All of these valves receive automatic closure signals in response to LOCA or LOP actuations. These valves are similar to the TACS isolation valve 2522E, except their closure response time is significantly longer (about 20 seconds vs. 10 seconds for 2522E).

It is not clear in the UFSAR that the TACS isolations valves (2522E and F) provide a safety function; although, they do perform a required isolation function to limit SACS coolant inventory loss on a postulated TACS line break. In addition, while

the isolation valves are considered part of the safety-related portions of the SACS system, the instrumentation that initiates closure of the valves are not safety related.

On August 13, 1996, in response to the possible valve operator hydraulic leak, station operators "locked" open the 2522E valve by blocking its fluid vent port. This action was not a specified action in either the system operating or alarm response procedure. As such, it resulted in the system not being able to operate as described in the UFSAR and no safety evaluation was conducted to determine whether that change in the component operation constituted an unreviewed safety question. While the inspectors noted that the valve function did not include automatic response to LOCA or LOP accident signals, it was designed to mitigate a large or complete break of the largest non-safety related TACS line and prevent a functional failure of the associated safety-related SACS system. Once the inspectors communicated this concern to the operators, the valve controls were restored to a normal configuration (for a total of about three hours in the abnormal configuration). This issue was considered a violation of 10 CFR Part 50.59(a)(1). **(VIO 50-354/96-07-01)**

c. Conclusions

The inspectors concluded that plant operators modified the controls of a safety related component, valve 1EGHV-2522E, without use of proper engineering support to assess whether this action resulted in either a necessary change to the plant technical specifications or an unreviewed safety question. Once this concern was identified, operators restored the valve to its normal configuration in a timely manner.

E2 Engineering Support of Facilities and Equipment

E2.1 Station Service Water Traveling Screen Controls Modification

a. Inspection Scope (37751)

The inspectors reviewed the documentation associated with a modification to an approved design change package for the station service water system traveling screen controls. The inspectors interviewed appropriate licensee representatives associated with this modification, using established station procedures governing design changes and safety evaluations as a basis for assessment.

b. Observations and Findings

During July 1996, Hope Creek maintenance technicians implemented an approved design change package which upgraded the station service water system traveling screen controls to resolve long-standing performance problems and improve overall system reliability. On July 12, 1996, with the work on the "D" screen controls only partially completed, operations personnel requested that the engineering department

devise a means to restore the function of the screen temporarily due to the anticipated arrival of Hurricane Bertha the next day.

Since the "D" service water subsystem was already inoperable due to the in-progress design change, engineering management concluded that a temporary modification and associated 10 CFR 50.59 evaluation was not necessary to make the traveling screen available for operation, but not *operable*. Instead, a manual change request (MCR #78) was approved that modified the original screen control design change package (DCP 4EC-3599) permitting the installation of jumpers in the control logic to allow manual high speed operation of the traveling screen. The inspectors reviewed the MCR and judged that the supporting documentation was weak, specifically because the technical basis for justifying the revision to the original design change package was not provided.

Based on this review, the inspectors noted that the MCR process (defined in design engineering procedure NC.DE-AP.ZZ-0017 (Q)) requires that a "revision justification sheet" be completed and approved. This justification sheet implements a screening process like that mandated by 10 CFR 50.59, but does not require a documented basis for why revisions to a design change package do not invalidate the original safety evaluation. As a result, though MCR #78 of DCP 4EC-3599 met the requirements of the governing station procedure, it was not clear to the inspector that the implementation of jumpers in the traveling screen control logic was not considered a major revision to the overall design change package, and therefore invalidate the conclusion of the original supporting safety evaluation.

During interviews with engineering department supervision, the inspectors agreed that MCR #78 was technically adequate and met the requirements of station procedures, primarily because this design change package revision also ensured that the screen control logic jumpers would be removed from the affected service water subsystem prior to returning the subsystem to an operable status. In spite of the licensee's assurance that the MCR provided sufficient control to ensure the design change would be appropriately installed, the inspector noted that the MCR resulted in a change to the system configuration different than analyzed. While noting that the system was not considered operable during the time that the MCR was in effect, the inspector considered the supporting analysis to be weak.

c. <u>Conclusions</u>

Operators exhibited a good, conservative desire to maximize overall service water system reliability due to the impending severe weather by requesting engineering personnel to devise a means to restore the function of a an associated subsystem made inoperable by partial implementation of a design change package. However, a review of the modification engineering personnel developed for installation to satisfy the operations department request highlighted weaknesses in the process for controlling and justifying design change package revisions.

E3 Engineering Procedures and Documentation

E3.1 10 CFR 50.59 Reviews and Safety Evaluations

The inspector reviewed procedure NC.NA-AP.ZZ-0059(Q)-Rev. 4, "10 CFR 50.59 Applicability Reviews and Safety Evaluations," referred to as NAP-59. The strategy of NAP-59 is to apply the procedure to a wide range of activities where 10 CFR 50.59 may, or may not, be applicable. The user is required to first perform an "Applicability Review" to determine if a particular activity is within the scope of 10 CFR 50.59. If the results of the Applicability Review show that 10 CFR 50.59 is not applicable, the Applicability Review form is saved for future reference. If the Applicability Review indicates that 10 CFR 50.59 is applicable, the user is required to perform a safety evaluation. The NAP-59 procedure also provides procedural interfacing with the FSAR update program of NAP-35, should the subject activity require a change to the FSAR.

The NAP-59 procedure is based on the industry guidance in NSAC-125, "Guidance for 10 CFR 50.59 Safety Evaluations," draft dated June 1989. Consequently, NAP-59 indicates that a small increase in the probability or consequences of an accident or malfunction previously evaluated in the safety analysis report may not indicate that the activity involves an Unreviewed Safety Question (USQ). The NRC issued guidance on this issue in an April 9, 1996 revision to the NRC Inspection Manual, Part 9900, "Interim Guidance on the Requirements Related to Changes to Facilities, Procedures and Tests." The guidance indicates that a small increase in the probability or consequences of an accident or malfunction previously evaluated in the safety analysis report does indicate that the activity involves an Unreviewed Safety Question (USQ). The licensee's memorandum of July 12, 1996 informs those involved in the 10 CFR 50.59 process of NRC's April 9, 1996 positions on 10 CFR 50.59.

In summary, the inspector found that NAP-59 is well written, provides clear assignment of responsibility, and provides the user with good directions for addressing the 10 CFR 50.59 process.

E5.1 Staff Training and Qualification on 10 CFR 50.59 Reviews

The inspector reviewed the 10 CFR 50.59 aspects of the training program. The lesson plans for initial training (L.P. No. 0905-300.20-5059ZZ-03) and periodic retraining (L.P. 0905-300.99N-5059-03) were reviewed. The lesson plans were found to be clearly written with good examples to demonstrate the use of NAP-59. Conversations with the licensee indicated that periodic 10 CFR 50.59 training is not a program requirement.

With regard to qualifications, the inspector ascertained through conversations with the licensee that no PSE&G-wide qualifications have been established for those individuals involved in the 10 CFR 50.59 process. The licensee also stated that a soon-to-be-released revision of NAP-59 will provide additional guidance on this.

The inspector concluded that certain aspects of the training program for 10 CFR 50.59 were good; however, qualification requirements had not yet been developed to ensure that personnel involved in the use of 10 CFR 50.59 had been appropriately trained.

E7 Quality Assurance in Engineering Activities

E7.1 Safety Review Committee Activities for 10 CFR 50.59 Evaluations

Hope Creek TS 6.5.1.6.e requires that the Site Operations Review Committee (SORC) perform a review of the safety evaluations that have been completed under the provisions of 10 CFR 50.59. In reviewing the activities described in Table 1 (attached to this report), the inspector noted evidence that the SORCs had performed the required safety evaluation reviews. Attendance at a Hope Creek SORC meeting gave the inspector the impression that the SORCs set a fairly high standard for approval of 10 CFR 50.59 safety evaluations. The rejection rates for safety evaluations presented to SORCs is trended and varied from approximately 10 to 20 percent during the period of August 1995 to January 1996 with an improving trend at the end of the period; during the same period, the Hope Creek SORC rejection rate varied from approximately 5 to 35 percent, also with an improving trend at the end of the period.

The Hope Creek Offsite Safety Review Group (OSRG) also has a role in reviewing 10 CFR 50.59 safety evaluations as required by Hope Creek TS 6.5.2.4.2.a. The inspector requested that the licensee provide evidence that the activities described in Table 1 had been reviewed by the OSRG. In response, the licensee indicated that activities 1, 3, 18, 19 and 20 in Table 1 had not been reviewed by OSRG because they had not been received from the sponsoring organizations. Hope Creek TS 6.5.2.4.2.a requires that the OSRG review all safety evaluations prepared pursuant to 10 CFR 50.59. The failure of the OSRG to review the noted activities in Table 1 is a violation of the facility technical specifications. **(VIO 50-354/96-07-02)**

The inspector determined that the OSRG had previously known that sponsoring organizations were not consistently forwarding safety evaluations for OSRG review. A memorandum dated October 19, 1994, from Nuclear Safety Review to the Salem and Hope Creek General Managers, noted this fact.

The inspector concluded that OSRG review of safety evaluations were not consistently performed. This led to a violation of NRC requirements. The inspector further concluded that the licensee's corrective actions for similar prior findings were ineffective at Hope Creek in that sponsoring organizations at Hope Creek continued to be inconsistent in providing safety evaluations for OSRG review. Finally, the inspector concluded that the OSRG lacked reasonable initiative in ensuring that they received these safety evaluations from the sponsoring organizations.

E8 Miscellaneous Engineering Issues

E8.1 (Closed) Unresolved Item (50-354/96-03-05): on January 31, 1996, PSE&G declared four Hope Creek radiation detectors inoperable. PSE&G had found that the detectors were being used outside their design temperature range. The detectors monitor beta radiation in the intake of the control room ventilation system and on high radiation, initiate an alarm and redirect the control room air from the outside to a filter train.

PSE&G's subsequent review of the detector design determined that, besides low temperature, high humidity was also an issue requiring resolution. As described in NRC inspection report 50-354/93-06, after consultation with the detector vendor, PSE&G concluded that the low temperature was not a concern. Regarding humidity, calculations performed by PSE&G determined that a film of vapor droplets could form on the aluminum foil end of the detector, limit the amount of beta radiation entering the detector, and attenuate the radiation signal. PSE&G calculated that the maximum film thickness could be 0.0048 inches, corresponding to an attenuation coefficient of 44%. This attenuation, when included in the detector error analysis, was acceptable and within the current beta allowable settings for the control room.

To confirm the calculations, PSE&G hired a consultant to build a full scale mockup of the control room ventilation ducting and test the detector within the postulated limiting environmental conditions. In this experiment two beta energy sources were used and the temperature and relative humidity were slowly changed. In the end the film thickness was less than that calculated and the measured attenuation coefficients due to moisture were 38% with the low energy beta source, and 26% with the high energy source. Based on the results of their analyses and experiment, PSE&G concluded that the installed detectors were always operable over all temperature and humidity ranges.

As a result of the above review, PSE&G found that exposure to moisture could cause pitting of the foil. Therefore, they decided that the foil should be changed each time the detectors would be calibrated. The 18-month period between calibrations, and foil changes, was based on the results of their surveillance of the detectors as well as calculations.

Based on a review of the above calculations and test results, the inspector concluded that PSE&G had properly addressed and resolved the issue.

E8.2 (Closed) Violation 50-354/95-10-01: failure to update the Hope Creek Generating Station FSAR in accordance with 10CFR50.71(e)(4). The licensee responded to the violation by letter dated September 11, 1995 providing the following corrective actions: (1) elimination of the change notice backlog, (2) update of the Salem and Hope Creek FSARs and (3) review of procedures to assure proper assignment of responsibility.

The inspector reviewed PSE&G procedure NC.LR-AP.ZZ-0013(Z) - Revision 0, "UFSAR Maintenance Process", dated February 1, 1996. The inspector found the procedure to be well written with clear assignment of program responsibility and correctly reflecting the requirements of 10 CFR 50.71(e). The inspector interviewed the UFSAR Coordinator and found this individual to be knowledgeable concerning program requirements. The UFSAR Coordinator indicated that the change notice backlog had been eliminated and the Hope Creek UFSAR had been brought up-to-date with UFSAR Revision 7, dated December 28, 1995. The next Hope Creek UFSAR update is scheduled for September 25, 1996, which is 6 months following restart from the refueling outage in accordance with 10 CFR 50.71(e). The UFSAR Coordinator indicated that the Salem change notice file was also current, the last FSAR update having been made on June 10, 1996. The schedule for Salem UFSAR update is uncertain due to the continuing unit outages.

The inspector reviewed UFSAR update packages associated with activities 6, 8 and 16 of Table 1 for Hope Creek. The inspector concluded that PSE&G had taken effective corrective action for this violation.

E8.3 (Closed) Violation 50-354/94-13-02: RHR system suppression pool suction valve (BC-HV-F004A) could not be controlled properly from the remote operating switch in accordance with plant design. The inspector verified the corrective actions described in licensee response letter, dated October 18, 1994, to be reasonable and complete. No similar examples were identified.

IV. Plant Support

R2 Status of RP&C Facilities and Equipment

During this inspection, the inspector conducted numerous tours of the facility during operating conditions and noted that all required radiological postings and locked areas met regulatory requirements. Further, areas were clear of unnecessary equipment, well illuminated and free of safety hazards.

R4 Staff Knowledge and Performance in RP&C

During this inspection, the licensee identified several missed technical specification required sampling and analysis activities due to poor tracking of such, coincident with inoperable effluent monitoring equipment. This matter is described in Section M8.3 of this report. The licensee has directed all departments to decrease the required action times for technical specification action statements in order to better achieve required results. For example, 12 hour actions will be scheduled every eight hours, etc.

In addition, Hope Creek operators observed a minor increase on two of the effluent radiation monitors associated with the turbine building exhaust. The inspectors considered the troubleshooting of the associated detectors and investigation of the

possible causes of the minor increase in radiation levels to be appropriate. The inspectors also noted that no releases were made in excess of technical specification requirements. Further, once the licensee corrected the minor packing leak in the steam tunnel associated with main steam valve, 1ABHV-2016B, monitored turbine building exhaust ducting returned to normal conditions.

The inspector concluded that while some activities associated with effluent grab sampling and analysis were not conducted in a timely manner, overall performance of radiation protection program requirements were good.

R7 Quality Assurance in RP&C Activities

The inspectors reviewed Audit Report 96-151/152, Radioactive Material Control, issued September 9, 1996. The inspector observed that the audit scope was sufficiently detailed to ensure that the Hope Creek Process Control Program and implementing procedures for processing and packaging radioactive wastes was successfully maintained. Several concerns were identified, including: deficiencies in radiation monitoring system equipment and missed compensatory sampling; deficient QA oversight of the program; deficient procedure adherence. All of the deficient conditions were appropriately entered into the licensee's corrective action program. One positive attribute was identified associated with technical knowledge of responsible individuals and ownership of the radioactive waste transportation program.

The inspector concluded that the QA audit of the Hope Creek radioactive waste program met the requirements of the Hope Creek technical specifications and provided good self-assessment of this area.

P1 Conduct of Emergency Preparedness (EP) Activities

P1.1 Effectiveness of Licensee Controls

a. Inspection Scope (82701)

The inspectors reviewed the licensee's tracking systems used for tracking EP related action items. Also, the EP self-assessment program was reviewed to determine the effectiveness of licensee controls.

b. Observations and Findings

Procedure NC.NA-AP-ZZ-0000(Q), PSE&G Nuclear Business Unit "Action Request (AR) Process," describes the licensee's method for reporting conditions requiring corrective action, program enhancement or interdepartmental support. ARs are tracked by a newly developed automated system termed the Performance Improvement Review System (PIRS), which is maintained by the audit department staff who screen, classify and distribute the ARs. ARs are assigned significance

levels (one to four, in descending priority) depending on circumstances, conditions or at management discretion. All ARs are given significant management attention and the highest significance levels (one and two) require a root cause analysis.

The inspectors requested a demonstration of the PIRS but the licensee was not able to locate any recently closed ARs. Licensee individuals stated that PIRS is not "user-friendly" and has the potential for losing data if a user incorrectly inputs information. Due to these problems, the EP staff utilizes three other internal office systems for tracking repetitive EP activities required by E-Plan commitments, procedure/E-Plan changes, drill/exercise critiques, training classes reviews and EP administrative review items. The inspectors discussed the problems noted during the demonstration of the PIRS with members of the audit department. They stated that they were aware of the computer program problems and are currently modifying the program for easier and more efficient use. Once the problems are resolved, it is the licensee's intent that the PIRS will become the sole tracking system for Salem and Hope Creek.

The inspectors reviewed several ARs and found them to be very detailed, thorough and were reviewed by management.

The licensee had recently implemented an "EP Group Planned Self-assessment Program" to evaluate the effectiveness and performance of the EP program. The inspectors reviewed several self-assessment reports and found them to include evaluation plans, strengths, weaknesses and/or potential areas for improvement. As the self-assessment program develops, the licensee plans to become more self-critical, establish trending data and closely evaluate repeat findings.

c. Conclusions

The EP staff uses the AR process plus three other automated systems for tracking issues such as audit findings, procedure changes and self-assessment findings. The systems are effective and ensure adequate management attention. The recent addition of a self-assessment program is a good initiative for the EP program.

P1.2 Relationship with Offsite Agencies

a. Inspection Scope (82701)

The inspectors interviewed state and county representatives from the States of New Jersey and Delaware to assess the licensee's relationship with offsite agencies.

b. Observations and Findings

The inspectors interviewed the Radiological Administrator for the Delaware Emergency Management Agency, the Manager, Bureau of Nuclear Engineering (BNE), New Jersey, and the Deputy Coordinator for the Department of Emergency Services, Salem County, New Jersey, to discuss the licensee's relationship with

those agencies. Both Delaware and Salem County, NJ representatives stated that, overall, the licensee worked hard to maintain an excellent rapport with their agencies.

However, the Manager, BNE stated that while the communications and information flow between the licensee and the State has improved since October, 1995, further improvement is needed in the following areas: 1) planning of the Emergency Operational Facility (EOF) renovation; 2) quality of the station status checklists used for transmitting event information; and 3) the verification of information contained in press releases from the licensee's emergency news center. He further stated that recent communications with the licensee on the proposed NUMARC EALs was constructive.

c. Conclusions

Overall, the licensee maintained good rapport with the offsite agencies. However, the Manager, BNE identified some issues where coordination and communication between the licensee and the State of New Jersey could be improved.

P2 Status of EP Facilities, Equipment and Resources

P2.1 Operational Readiness of Emergency Facilities

a. Inspection Scope (82701)

The inspectors toured the following Salem facilities: the EOF, Control Room (CR), Technical Support Center (TSC), Operations Support Center (OSC), and Control Point. The Hope Creek facilities were evaluated during the May, 1996 annual exercise and found to be operationally ready. The inspectors also reviewed 1996 facility equipment inventories and surveillance tests for completeness and accuracy.

b. Observations and Findings

The inspectors checked the inventory of several emergency equipment lockers and one field monitoring team emergency kit for completeness and equipment readiness. One locker contained two radiation survey instruments with dead batteries, which were immediately replaced. All other survey meters inspected were calibrated and operational. The inspectors found two unshielded Cesium-137 check sources in supply lockers located in the EOF and TSC, used for verifying instrument response. The check sources are routinely stored near a supply of personnel thermoluminescent dosimeters (TLDs) used for offsite field monitoring teams. These sources could potentially produce an erroneous radiation dose to the field TLDs prior to use in an actual emergency. The licensee acknowledged this problem and agreed that the check sources and TLDs should be stored in separate lockers.

While touring the TSC, the inspectors noticed that a key for a radiation protection (RP) locker was missing. Apparently, an RP staff member had changed the lock,

without informing the EP staff, and stored the key at the Salem control point. According to the licensee's emergency plan implementing procedure (EPIP) 203S, the key is to be stored near the locker. Relocation of the key could potentially result in the locker being inaccessible to field teams during an emergency. The licensee initiated a procedure change to ensure that during emergency conditions, an RP technician, assigned to the TSC, would bring the locker key from the control point and unlock the locker.

The licensee was in the process of constructing a new OSC inside the CR ventilation boundary and renovating the existing EOF. During construction, a temporary OSC, outside the CR, was being utilized in case of an actual emergency event. The inspectors concluded that the EOF and temporary OSC were adequate if needed for this purpose.

The inspectors determined that equipment inventories, communication surveillance tests, and siren surveillance tests were conducted at correct frequencies, and inventory checklists were properly completed and reviewed. Identified deficiencies and corrective actions were well documented.

c. Conclusions

The inspectors concluded that the licensee maintained an effective inventory and surveillance test program and that the Salem/Hope Creek emergency facilities and equipment were operationally ready.

P3 EP Procedures and Documentation

a. Inspection Scope (82701)

The inspectors reviewed emergency plan (E-Plan) and EPIP revisions in the regional office, prior to the inspection, to determine if the changes reduced the effectiveness of the E-Plan. While onsite, the inspectors reviewed the documentation for the last E-Plan changes.

b. Observations and Findings

The inspectors reviewed the licensee's 10 CFR 50.59 safety evaluation and 10 CFR 50.54(q) licensee review for Revision 5 to Section 2 of the E-Plan. The inspectors concluded that these were thorough, well-documented, and adequate for making this revision. EPIP revision changes were documented in NRC Inspection Report 50-354/96-01, 50-272 & 311/96-01 and no additional revisions were reviewed prior to this inspection.

c. Conclusions

The inspectors determined that the reviewed E-Plan and EPIP changes did not reduce the effectiveness of the E-Plan. Also, the licensee's procedure change process was good.

P5 Staff Training and Qualification in EP

a. Inspection Scope (82701)

The inspectors reviewed EP training records, training procedures, lesson plans, EPIPs and the licensee's E-Plan to evaluate the licensee's EP training program. The inspectors also conducted interviews with Salem Senior Reactor Operators (SROs) to assess the licensee's EAL classification training.

b. Observations and Findings

The EP off-site supervisor maintained the EP training records for emergency response organization (ERO) responders. The inspectors randomly selected the training records of approximately 75 responders from Salem and Hope Creek and verified that the ERO responders were qualified to fill their assigned emergency response positions. Approximately a quarter of the responders are required to have respirator training which is provided by RP. EP does not routinely track the RP training to ensure that all responder training requirements are met. In early 1996, the EP off-site supervisor, discovered that respirator training for 9 out of 16 maintenance workers on the ERO list had elapsed. Also, in August 1996, it was reported in the licensee's morning management meeting, that an Instrument and Control technician was reported not to have current respirator qualifications and was listed on the current ERO list. The EP staff appeared to be unaware of this incident.

The inspectors stated to the licensee that although the RP Department is responsible to provide respirator training, the EP staff is responsible to ensure that all members on the ERO list meet the required qualifications stated in the Emergency Plan and EPIPS. The licensee plans to review this area of concern and to review the RP records to ensure that all individuals on the current ERO list meet all training requirements. Additionally, the licensee mentioned plans to have one automated training tracking system for better utilization by the EP staff.

The licensee had made changes to their EP training program due to problems identified in drills and exercises. The licensee was conducting quarterly unannounced call-out muster drills, weekly pager tests, and were completely revising procedures and EP overview lesson plans. In addition, a letter was sent from upper management to the ERO members addressing their EP roles and responsibilities.

The inspectors interviewed two Salem SROs to assess the quality of the licensee's present EAL training. Both SROs stated that the NUMARC EAL training was good, however, they did not think the one-hour training session on the present EAL scheme was very thorough or detailed. They both stated that if the NUMARC EALs are not approved prior to restart of Salem 1 & 2, they would expect comprehensive retraining on the present EALs.

The inspectors stated to the licensee that until the NUMARC EALs are approved, adequate and appropriate training should be provided to the SRO's for classifying events using the present EALS.

The inspectors reviewed training records for annual offsite emergency response training for medical, fire-fighting, and media personnel. The inspectors found that the required drills had been conducted and were well-documented. Media training was offered by the licensee, but may not have been implemented in accordance with the E-Plan (see Section P8). With this one exception, all on-site and off-site required drills, exercises and training were conducted in 1995 and 1996 in accordance with the licensee's E-Plan.

The licensee conducted monthly pager drills for all four duty ERO teams and weekly drills for the on-call duty team. Additionally, they conducted quarterly muster exercises where the duty team must actually report to the site, alternating between Salem and Hope Creek. The inspectors noted that documentation regarding these drills and exercises indicated an overall improvement in ERO response. However, in May 1996, NRC inspectors attended an unannounced call-out drill and observed poor drillmanship and command and control. (See Section P8.3)

The inspectors reviewed the training records for annual EAL training with the states and counties and found them to be satisfactory.

c. Conclusions

The inspectors determined that the ERO members, for whom training was reviewed, were currently qualified. However, the EP department was not fully effective at ensuring that individuals listed on the ERO list meet all training requirements to fill their position. Training of offsite agencies and support organizations is of good quality and completed as required.

The inspectors concluded that the periodic pager tests and mustering drills, as well as holding ERO responders accountable for their responsibilities is a positive step to upgrade their overall emergency response capability. Overall, the inspectors assessed this area as adequate.

P6 EP Organization and Administration

a. Inspection Scope (82701)

The inspectors reviewed the licensee's EP staffing and management to determine the changes that have occurred since the last program inspection (August 1994), and to assess if those changes had any adverse effect on the EP program.

b. Observations and Findings

The EP Department has had several management and organization changes in the past year. In January 1996, the Manager, EP & Radiological Safety was replaced. In September 1996, this position is being eliminated and split into two management positions. The intentions are to add an experienced EP manager and an experienced radiological health manager. In July, the EP and Radiological Support Division was moved from Site Support Services and placed in the Nuclear Training Center (NTC) Division. The Director, NTC reports directly to the Sr. Vice President, Nuclear Operations. The licensee is planning additional changes in the responsibilities of the EP staff members.

Discussions with the Sr. Vice President and Director, NTC indicated that management is committed to bringing a serious EP attitude to the ERO members. They also stated that the addition of a manager with EP experience will enhance EP staff performance.

c. Conclusions

Discussions with the members of the EP staff, the inspectors determined that the recent organizational changes have not had an adverse effect on the EP staff. At this time, it does not appear that these changes have reduced the ability to administer the EP program effectively.

P7 Quality Assurance (QA) in EP Activities

a. Inspection Scope (82701)

The inspectors reviewed Audit Reports No. 95-030 and 96-030, of the EP Department, conducted in 1995 and 1996, respectively. The inspectors also reviewed audit plans, checklists procedures and interviewed personnel from the QA Department regarding the process for conducting a program audit.

b. Observations and Findings

Based on document review and interviews, the inspectors determined that the audits were conducted utilizing an audit plan and checklists, and that the audit team included several technical specialists from other nuclear utilities with EP experience.

The audit reports were appropriately detailed and met the requirements specified in 10 CFR 50.54(t). No programmatic problems were identified.

c. Conclusion

The audit reports were comprehensive and the audit plan was extensive. The use of independent technical specialists is particularly noteworthy. The reports met the requirements of 10 CFR 50.54(t) and the inspectors assessed this area as very good.

P8 Miscellaneous EP Issues

P8.1 Updated Final Safety Analysis Report (UFSAR) Inconsistencies

A recent discovery of a licensee operating its facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedures, and/or parameters to the UFSAR description. Since the UFSAR does not specifically include EP requirements, the inspectors compared licensee activities to the E-Plan, which is the applicable document. The following inconsistences were noted between the E-Plan and licensee activities by the inspectors.

1. Section 9, paragraph 4.4 of the E-Plan discusses additional radiological instrumentation located in the licensee's Training Center laboratory to be available as backup to the EOF. The inspectors determined that the instrumentation had never been calibrated and the laboratory is currently being dismantled.

2. Section 8, paragraph 3.0 of the E-Plan, states that annually, an information program is provided to local news representatives and covers specific outlined topics on nuclear energy, radiation and emergency planning. It also states that this program may take place as part of the annual exercise. A public information (PI) representative stated that media training actually consisted of an information calendar sent to local media personnel, followed by a phone call, inviting them to the licensee's annual exercise. This is inconsistent with the commitments in the E-Plan.

The inspectors discussed these issues with the licensee, and E-Plan changes have been submitted to delete the use of the Training Center laboratory as a backup to the EOF and to provide a better description of media training. These concerns are considered unresolved pending NRC review and approval of the proposed changes. **(URI 50-354/96-07-03)**

P8.2 Missed Alert Declaration

During this inspection, the inspectors reviewed the missed alert declaration for an event that occurred at Salem on June 7, 1995. Details of this inspection are contained in Salem inspection report 50-272, 311/96-15.

S1 Conduct of Security and Safeguards Activities

During this inspection, the inspector observed some conditions that were not in accordance with the licensee's security plan and its implementing procedures. These activities are fully discussed in NRC Inspection Report 50-354/96-08.

S8 Miscellaneous Security and Safeguards Issues

S8.1 (Closed) Followup Item 50-354/93-28-01: inspection followup of perimeter assessment aid upgrades. The upgrade project has been completed on the Hope Creek site. The inspectors have noted that routine maintenance is now effective at maintaining these aids available. Some additional planned work is still to be completed on the Salem upgrades and those issues will be reviewed separately; however, the Hope Creek portion of this item is considered closed.

F2 Status of Fire Protection Facilities and Equipment

The inspectors toured various portions of the licensee facilities and observed that fire protection response equipment was maintained appropriately. During this inspection period, the licensee initiated a previously approved design change package (DCP 4EC-3296) to replace the Hope Creek fire protection computer. This activity was conducted on-line, which resulted in a temporary loss of the fire protection alarm and indication function in the control room. As a result, compensatory measures were established to provide fire watch monitors of local fire panels for indication and alarm for all safety related portions of the facility. These monitors included use of closed circuit television (CCTV) for certain local panels in lieu of a watchstander.

The inspectors reviewed the use of CCTVs, which is described in procedure HC.FP-AP.ZZ-0004(Q), "Actions for Inoperable Fire Protection - Hope Creek," dated September 9, 1996. In lieu of using a specific safety evaluation for installing the CCTVs, the licensee relied upon acceptance criteria provided in a radiation protection procedure for use of this same equipment. That procedure required associated cables for the CCTVs not be placed within one inch of any safety related cable tray, cable or conduit. The inspectors walked down the installation of the CCTV cables for this fire protection procedure change and observed that several cables did not meet the established criteria. In addition, the licensee subsequently informed the inspectors that the one inch criteria was not really meant to pre-

approve installation of CCTV cables over open safety-related cable trays or traversing multiple trains of safety-related cable trays, as was the condition identified by the inspectors.

After the inspectors identified this condition, licensee individuals took immediate corrective actions to remove all CCTV cables in close proximity to safety-related cables, cable trays, and conduit.

The inspectors determined that the safety evaluation associated with this procedure revision failed to address that use of CCTVs resulted in a hardware change to the facility, especially regarding placing non-safety related cables over and in close proximity to safety related cables, cable trays and conduit. These conditions were not previously evaluated by the licensee per 10 CFR 50.59 (a) (1) as required to ensure that the necessary cable runs for the CCTVs did not result in an unreviewed safety question. This matter was considered another example of a violation of 10 CFR 50.59. **(VIO 50-354/96-07-01)**

The inspectors concluded that the licensee's implementation of the design change package to replace the Hope Creek fire protection computer was generally acceptable; although interim compensatory measures were not properly evaluated to ensure that no unreviewed safety question existed.

F4 Fire Protection Staff Knowledge and Performance

The inspectors observed two fire department drills to evaluate the effectiveness of the previously described (section F2) fire alarm outage contingency plan. The drills were appropriately developed and implemented. The inspectors concluded that the compensatory measures were effective in providing appropriate fire panel indication and alarm information to the control room for response to postulated fires in the facility.

V. Management Meetings

X1 Exit Meeting Summary

A recent discovery of a licensee operating their facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR descriptions. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters.

On October 1, 1996, the inspectors presented the inspection results to members of licensee management. Licensee management acknowledged the presented findings.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

PSE&G

M. Bezilla, Hope Creek General Manager
C. Banner, Emergency Preparedness
J. McMahon, Director, Nuclear Training Center
J. Polyak, Manager, Radiological Safety
L. Storz, Sr. VP, Nuclear Operations
J. Benjamin, Manager, Quality Assurance

New Jersey Bureau of Nuclear Engineering

K. Tosch, Manager

Delaware Emergency Management Agency

E. Falone, Radiological Administrator

Department of Emergency Services, Salem County, New Jersey

C. Wentzell, Deputy Coordinator

INSPECTION PROCEDURES USED

IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 37551:	Onsite Engineering
IP 71750:	Plant Support
IP 82701:	Emergency Preparedness Program
IP 92901:	Plant Operations Followup
IP 92902:	Maintenance Followup
IP 92903:	Engineering Followup
IP 92904:	Plant Support Followup
IP 93702:	Event Response

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-354/96-07-01	VIO	Two examples of licensee failure to evaluate changes to the facility in accordance with 10 CFR 50.59, including temporary installation of cables associated with fire protection compensatory measures; and, blocking open a safety auxiliary cooling system isolation valve.
50-354/96-07-02	VIO	Failure of the offsite safety review group to review safety evaluations in accordance with technical specifications.
50-354/96-07-03	URI	Media Training not being conducted in accordance to the E-Plan (UFSAR item); and, Training Center Laboratory radiological equipment not maintained to meet the intentions stated in the E-Plan.

Closed

50-354/96023	LER	Reactor Core Isolation Cooling system isolation due to a failed steam leak detection monitor.
50-354/93-11-01	URI	This item involved apparent deficiencies in the licensee's corrective action program.
50-354/94-09-04	VIO	Mis-operation of the refueling bridge.
50-354/94-003-01	SR	Operation of the facility in excess of the licensed thermal power limits.
50-354/94-09-01	VIO	Containment integrated leak rate test (Type A) deficiencies.
50-354/96005	LER	Inadequate surveillance testing for the residual heat removal system suppression pool and spray modes of operation.
50-354/96020	LER	Operations prohibited by technical specification - failure to perform actions for inoperable radioactive gaseous effluent monitoring instrumentation.
50-354/95-033	LER	Supplements 7, 8, 9 and 10: technical specification surveillance requirement implementation deficiencies identified by the TSSIP.
50-354/96-03-05	URI	Event on January 31, 1996, when PSE&G declared four Hope Creek radiation detectors inoperable.
50-354/95-10-01	VIO	Failure to update the Hope Creek Generating Station FSAR in accordance with 10CFR50.71(e)(4).

50-354/94-13-02	VIO	RHR system suppression pool suction valve (BC-HV-F004A) could not be controlled properly from the remote operating switch in accordance with plant design.
50-354/93-28-01	IFI	Inspection followup of perimeter assessment aid upgrades.

LIST OF ACRONYMS USED

AR	Action Request
BNE	Bureau of Nuclear Engineering (NJ)
BP	Business Process
CR	Condition Resolution
CR	Control Room
CM	Corrective Maintenance
EAL	Emergency Action Level
ED	Emergency Director
EOF	Emergency Operations Facility
E-PLAN	Emergency Plan
EPIP	Emergency Plan Implementing Procedures
EP	Emergency Preparedness
ERO	Emergency Response Organization
ECG	Event Classification Guide
CCTV	Closed Circuit Television
I&C	Instrument & Control
LOCA	Loss of Coolant Accident
LOP	Loss of Offsite Power
NUMARC	Nuclear Management and Resources Council
NTC	Nuclear Training Center
OSC	Operations Support Center
PIRS	Performance Improvement Review System
PI	Public Information
QA	Quality Assurance
RHR	Residual Heat Removal
RP	Radiation Protection
SACS	Safety Auxiliaries Cooling System
SNSS	Senior Nuclear Shift Supervisor
SRO	Senior Reactor Operator
STA	Shift Technical Advisor
SERT	Significant Event Review Team
TACS	Turbine Auxiliaries Cooling System
TS	Technical Specifications
TSC	Technical Support Center
TLD	Thermoluminescent Dosimeter
UFSAR	Updated Final Safety Analysis Report

TABLE 1
HOPE CREEK
10 CFR 50.59 ACTIVITIES

PROCEDURES		
ITEM NO.	**IDENTIFICATION**	**DESCRIPTION**
1	HECG-ATT 2, 3, 4 & 8	Emergency Plan
2	HC.OP-IS.BD-0001(Q)	RCIC
3	THC.OP-SO.GQ-0002(Q)	SW Intake
4	HC.NA-AP.ZZ-0024(Q)	Radiation Protection
5	HC.CH-EO.SH-0001(Q)	PASS
DESIGN CHANGES		
6	4EC-3546 Packages 5-8	SSW Strainer Backwash Valve Mod
7	4EC-3500 Package 1	Turbine Trip
8	4EC-3411 Package 3	RHR Cross Tie
9	4EC-3579 Package 1	Drill Weep Hole - Core Spray
10	4EC-3546 Package 6, Revision 0 to 4	Station Service Water
11	4EC-3546 Package 7, Revision 0 to 3	Station Service Water
12	4EC-3546 Package 9, Revision 0 to 2	Station Service Water
13	4EC-3546 Package 12, Revision 0 to 3	Station Service Water
14	4HE-0075 Package 2	Feeder Cable (FSAR Change)
15	4HE-0262	RCIC Strainer
16	4EC-3394 Package 2	4" RWCU Valve
TEMPORARY MODIFICATION		
17	TM# 96-010	EDG Room Recirc.
18	TM# 95-060	SSWS Discharge
19	TM# 95-065	RV Level-Shutdown
TEST		
20	4EX-3510	Fills in Cooling Tower