U. S. NUCLEAR REGULATORY COMMISSION

REGION I

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| Docket No: | 50-354 |
| License Nos: | NPF-57 |
| Report No. | 50-354/96-11 |
| Licensee: | Public Service Electric and Gas Company |
| Facility: | Hope Creek Nuclear Generating Station |
| Location: | P.O. Box 236<br>Hancocks Bridge, New Jersey 08038 |
| Dates: | December 22, 1996 - February 1, 1997 |
| Inspectors: | R. J. Summers, Senior Resident Inspector<br>S. A. Morris, Resident Inspector<br>J. R. Tappert, Reactor Engineer, NRR<br>L. M. Harrison, Reactor Engineer<br>D. H. Jaffe, Project Manager, NRR<br>F. J. Laughlin, Emergency Preparedness Specialist |
| Approved by: | Larry E. Nicholson, Chief, Projects Branch 3<br>Division of Reactor Projects |

## EXECUTIVE SUMMARY

Hope Creek Generating Station
NRC Inspection Report 50-354/96-11

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection; in addition, it includes the results of announced inspections by regional inspectors in the areas of emergency preparedness and engineering support; and follow up inspection support by NRR staff in the areas of operations, maintenance, engineering and plant support.

### Operations

In general, the conduct of operations was professional with conservative, safety-conscious performance. Operator response to plant events and transient conditions were acceptable. Operators appropriately handled significant concerns requiring reporting to the NRC. (Section O1)

The Offsite Safety Review (OSR) group review requirements for selected License Change Requests were found to be acceptable. (Section O7)

### Maintenance

The inspectors concluded that the licensee adequately planned and controlled the maintenance activities associated with the "C" EDG on-line maintenance. The work was pursued aggressively and conducted in a professional manner. A weakness was identified with regard to licensee commitment management, in that the licensee failed to revise the Technical Specification Bases to include the conditions upon which an extended allowable outage time license change was granted as was described in the license change request. This was considered a deviation from a licensee commitment. While the licensee focused on, and explicitly addressed the more safety significant conditions of the license amendment, the inspector concluded that the licensee did not clearly address the condition concerning EDG overall unavailability. (Section M1)

The inspectors reached several conclusions as a result of their evaluation of the multiple events involving emergent corrective maintenance issues, including: (1) Operator response to the events was appropriate and timely with respect to declaring affected systems inoperable and taking required compensatory measures; reportability was completed as necessary. (2) With the exception of the core spray pump issue, station personnel adequately implemented the principles of the PSE&G corrective action program, in that problems were identified and documented, causal factors were determined, and corrective actions were completed. (3) Poor maintenance practices and weak follow up to industry operating experience contributed significantly to the unavailability of the service water and RCIC systems, respectively. (4) Numerous degraded equipment material conditions exhibited by the various events increased the overall unavailability times of the affected systems and reduced the effectiveness of previously established work week plans. Station

(5) Maintenance rule implementation for the plant systems involved in the events was appropriate and satisfied current guidelines. (Section M2)

Engineering

The inspectors concluded that an adequate bases had been established to support the licensee's conclusion that degraded DC microswitches would not prevent satisfactory accomplishment of safety functions by safety-related equipment. Weaknesses were noted regarding engineering's interim documented bases to assure that no safety concerns existed with the switches. Additionally, enforcement discretion was exercised to not cite an associated corrective action violation due to the NRC assessment that it was minor. (Section E2)

Plant Support

The inspectors concluded that the failure to successfully transfer responsibility for the control and accounting of the filtration, recirculation and ventilation system (FRVS) radioactive effluent releases was an indicator of weakness in the procedure development, review and approval process; however, the self-identification of the deficiency was considered a positive indicator for problem identification. (Section R1)

Emergency Response Organization (ERO) members demonstrated good overall performance during mini-drill scenarios. However, the inspectors noted several deficiencies with the EP Department's implementation of the action item tracking system. Additional conclusions regrading EP at the Salem station were made during the inspection and are included in NRC Inspection Report 50-272/96-18; 50-311/96-18. (Sections P3, P4 and P8)

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## Report Details

### Summary of Plant Status

Hope Creek began the inspection period at 100 percent power. Full power operations were maintained throughout the inspection period spanning December 22, 1996 to February 1, 1997, 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 Operator Response to Events

a. Inspection Scope (71707 and 93702)

The inspectors reviewed the operator response to a number of events and transient conditions during the period to determine if the response was appropriate, including meeting reporting requirements when necessary.

b. Observations and Findings

On December 20, 1996, plant operators notified the NRC of a possible degraded condition of the primary containment. Subsequent to licensee review of water hammer concerns for containment coolers as required by Generic Letter 96-06, it was determined that a water hammer might occur if certain drywell cooler containment isolation valves were opened during postulated post-LOCA conditions. The associated piping was not designed to withstand the effects of such water hammer transients, and therefore, such an event might challenge primary containment integrity. The operators stated that they had implemented administrative controls to prevent operation (opening) of the subject isolation valves during the subject post-LOCA conditions. Additional information regarding future planned measures to either qualify the "at risk" piping, or to revise current emergency operating procedures were committed to by the licensee in an LER, dated January 20, 1997, on this same event (see LER 50-354/96-028).

On December 28,1996, plant operators notified the NRC of a single-train, accident mitigation system failure when the reactor core isolation cooling (RCIC) system failed an in-service test involving a stuck open RCIC turbine governor valve. Further details regarding this matter are discussed in Section M2.1 of this report.

On December 30, 1996, plant operators notified the NRC of a single-train, accident mitigation system failure when the high pressure coolant injection (HPCI) system was taken out of service to correct a stuck open HPCI barometric condenser condensate pump discharge check valve. Further details regarding this matter are discussed in Section M8 of this report.

On January 3, 1997, plant operators notified the NRC of a condition where the plant was operated outside of its design basis, leading to declaring all four emergency diesel generators (EDG) inoperable and entry into technical specification (TS) 3.0.3. This event involved a non-conservative design feature that allowed a failure of non-class 1E instrumentation (fire suppression circuitry) coupled with a specific postulated degraded voltage condition to result in a potential failure of all four EDGs due to a loss of area ventilation. While the postulated degraded voltage condition did not exist at the time of the event, the facility design basis includes such a postulated event. As such, until the inadequate design feature was corrected, operators appropriately considered all four EDGs inoperable and commenced appropriate actions. The interface control circuits between the non-class 1E fire suppression system and the class 1E EDG ventilation system that led to the vulnerability were immediately corrected by lifting associated leads. As a result, the operators were able to restore the EDGs to an operable condition prior to implementing the plant shutdown required by TS 3.0.3. Additional information on the technical aspects of this event is documented in NRC Inspection Report 50-354/96-09 and was the basis for a violation of NRC requirements described in Section E8.1 of that report.

c. Conclusions

Operator response to plant events and transient conditions were acceptable. Operators appropriately handled significant concerns requiring reporting to the NRC.

## O7 Quality Assurance in Operations

O7.1 Offsite Safety Review:

The inspector performed a review of Offsite Safety Review (OSR) review summary records to verify the reviews were being conducted by qualified personnel. Technical Specification (TS) 6.5.2.4.2 requires the OSR staff to perform an independent review of numerous licensee documents including procedure changes, design changes, license change requests (LCR), and 10 CFR 50.59 evaluations. TS 6.5.2.2 requires the OSR staff to meet or exceed the qualifications described in Section 4.7 of ANS 3.1 - 1981, "An American Standard for Selection and Training of Nuclear Power Plant Personnel." The OSR reviews sampled were performed by dedicated engineers meeting the qualifications of ANS 3.1 - 1981.

SALEM LCR 95-13/Hope Creek LCR 95-06 was a technical specification amendment request which revised TS Section 6 (Administrative Controls). OSR review of this LCR and its first three revisions were performed by the OSR Principal Engineer between September 18, and December 21, 1995. As documented in

Inspection Report 50-272/96-05, 50-311/96-05, the OSR Principal Engineer, who supervises and concurs on the work of the OSR staff, does not fill a position required by TS 6.5.2.2, and is therefore not governed by NRC regulatory requirements. The inspector determined that the review by the OSR Principal Engineer did not fulfill the requirements of TS 6.5.2.4.2. Discussions with the Principal Engineer indicated that these reviews were to provide comments on the LCR and not to provide the official OSR review. The OSR Principal Engineer review of this LCR appeared unique and isolated based on a search of the OSR document database. LCR 95-13/95-06 was subsequently reviewed by a qualified member of the OSR staff on December 22, 1995. The license amendment application was submitted to the NRC on January 11, 1996. The inspector also verified that the OSR was staffed with eight engineers that met the qualifications described in Section 4.7 of ANS 3.1 - 1981, four assigned to Hope Creek and four to Salem. In summary, although the LCR review by the OSR Principal Engineer did not fulfill the TS requirements, an OSR review by a qualified dedicated engineer occurred prior to submission to the NRC. The inspector concluded that the CSR review requirements for the selected LCR were met.

**O8 Miscellaneous Operations Issue**

O8.1 (Closed) LER 50-354/96-017: failure to perform electrical distribution system line-up within the required time frame. This event involved a procedural violation of a surveillance test procedure by an equipment operator when, during the conduct of a routine emergency diesel generator (EDG) test, he failed to notify the control room operators of an unsatisfactory test condition in a timely manner. This led to operators not being able to complete the required electrical distribution system line-up verification within the time required by plant technical specifications. The event was identified by the licensee.

The required system line-up verification was completed within one hour after control room operators were aware of the adverse condition (and within four hours of the actual occurrence). The associated technical specification requirement is to perform the electrical distribution verification within one hour. The cause of the procedure violation was personnel error. Appropriate disciplinary actions for this individual and training for all operators was implemented. The cause of the unsatisfactory surveillance test was due to a degradation of a lube oil temperature control valve. The licensee determined that: this condition resulted in the lube oil temperature exceeding the manufacturer specification by 2 degrees F; further analysis showed that this higher-than-expected temperature would have no detrimental affect on the EDG; and, that one other EDG temperature control valve exhibited similar performance problems, although had not yet exceeded the temperature limits. The temperature control valves were repaired. The inspectors reviewed the licensee root cause analysis and corrective actions for this event and found them to be acceptable. This example of a licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

O8.2 (Closed) LER 50-354/96-027: engineered safety feature (ESF) actuation - unplanned automatic start of the "A" safety auxiliaries cooling system pump due to personnel error. This event involved a procedure adherence violation by a control room operator on December 2, 1996, that led to the ESF actuation. This event resulted in a Non-Cited Violation, as described in NRC Inspection Report 50-354/96-10. No new issues were revealed by this LER.

## II. Maintenance

### M1 Conduct of Maintenance

M1.1 "C" Emergency Diesel Generator (EDG) Maintenance

a. Inspection Scope (71707, 62707)

The inspectors observed and reviewed various portions of the planning and execution of an on-line maintenance outage of the "C" emergency diesel generator (EDG). On January 26, 1997, the licensee began a scheduled five-day outage of the "C" EDG to perform preventive and corrective maintenance.

b. Observations and Findings

The allowed outage time (AOT) for EDG "C" and "D" was extended to 14 days in license amendment 75 which was issued on August 1, 1995. As documented in the NRC's safety evaluation, the amendment was granted based on the licensee satisfying seven conditions. These conditions included the following: the licensee should verify that the required systems, subsystems, trains, components, and devices are available and operable before removing an EDG for extended preventive maintenance; removal from service of safety systems and important non-safety equipment should be minimized during the extended 14-day AOT; any component testing or maintenance that increases the likelihood of a plant transient should be avoided; the overall unavailability of the EDG should not exceed the value that was used in the PRA supporting the proposed AOT; and others. The licensee, in a July 25, 1995 letter, stated that they would revise the Technical Specification (TS) Bases to include these conditions. The inspector determined that the TS Bases were not revised to include these conditions. This was considered to be a deviation from a commitment. **(DEV 50-354/96-11-01)**

The inspector reviewed the licensee's limiting condition for operation (LCO) maintenance plan to verify compliance with the AOT commitments. The licensee protected the "A", "B", and "D" trains of equipment from maintenance during the duration of the "C" EDG outage. The equipment was administratively protected by the work control process. The licensee also precluded high risk evolutions with a risk of a plant transient. The licensee performed a risk assessment to determine the risk increase associated with the planned activities and determined the configuration was acceptable.

The inspector also reviewed the licensee's control of the EDGs' unavailability. The licensee is monitoring EDG unavailability as part of their maintenance rule implementation. As such, the licensee has established a performance criterion of 325 hours of unavailability per rolling 18 month period per EDG. Three of the EDGs are currently meeting the goal with the "D" EDG exceeding the desired unavailability goal. The "C" EDG had 101 hours of unavailability in the 18 months prior to the planned on-line maintenance. The inspector also reviewed the unavailability that was used in the licensee's probabilistic risk assessment (PRA) developed to support the increased technical specification allowable outage time (AOT) license change request. The PRA that was submitted with the original July 27, 1994 license amendment application calculated the risk increase associated with taking each EDG out of service for 30 days. To perform the calculations, the licensee assumed that one EDG was out of service for the full 30 days for test and maintenance and the other three EDGs had no test or maintenance unavailability during that same period. Further, the inspector noted that the nominal value assumed for test and maintenance unavailability of the EDGs in the Hope Creek PRA was 80 hours per year. The inspector found that these values were inconsistent when comparing the maintenance rule performance criteria, the assumed unavailability in the Hope Creek PRA, and that of the TS amendment 75 bases. In developing the "Limiting Condition for Operation (LCO) maintenance plan," the licensee assessed the risk increase associated with the outage and was tracking unavailability in accordance with the maintenance rule, but it was not clear which criteria the licensee intended to use to ensure that the overall EDG unavailability was acceptable.

Additionally, the inspector reviewed several field maintenance activities that were conducted on the EDG including W/O 970210036 EDG/1C-G400/Check Generator IAW MD-PM.KJ-003 (Clean and Inspect Excitor and Regulator). W/O 960211091 Replace EDG C Lubricating Oil switch 1KJPDSH-7400C, W/O 96029103 1C-G-400 Flexible Hose Inspection, and W/O 970217008 1C-G-400/Relay Maintenance Out of Service/18 month preventive maintenance. Numerous activities were being worked simultaneously but appeared to be adequately coordinated and controlled. The inspector observed appropriate foreign material exclusion controls; good procedure and work package development; and, generally good procedural adherence.

c. Conclusions

The inspectors concluded that the licensee adequately planned and controlled the maintenance activities associated with the "C" EDG on-line maintenance. The work was pursued aggressively and conducted in a professional manner. A potential weakness was identified with regard to licensee commitment management, in that the licensee failed to revise the Technical Specification Bases to include the conditions upon which an extended allowable outage time license change was granted as was described in the license change request. This was considered a deviation from a licensee commitment. While the licensee focused on, and explicitly addressed the more safety significant conditions of the license

amendment, the inspector concluded that the licensee did not clearly address the condition concerning EDG overall unavailability.

## M2 Maintenance and Material Condition of Facilities and Equipment

### M2.1 Emergent On-line Maintenance of Safety-Related Systems/Equipment

a. Inspection Scope (71707, 62707, 37551)

During the report period, the station experienced numerous safety system material condition problems which led to unplanned on-line maintenance outages of the affected systems. In most cases, technical specification LCO action statement entries were required while the various degraded conditions were addressed. The inspectors observed and assessed the station's response to these emergent issues, and evaluated both the immediate actions taken to address the specific concerns, as well as the subsequent maintenance and engineering support employed to resolve them satisfactorily. Additionally, the inspectors reviewed related performance indicator data compiled for Hope Creek management to better understand the means by which PSE&G assesses overall plant material condition.

b. Observations and Findings

The frequency and magnitude of emergent corrective maintenance resulting from failed system surveillance tests or abnormal equipment operation are two indicators of plant material condition. While no standard exists to measure material condition in absolute terms, the inspectors witnessed a relatively high number of emergent material condition issues during the report period that required station operators to declare safety-related systems inoperable for corrective maintenance. All of the events occurred while the plant was operating at 100% power (Mode 1). Specific details and assessment of the station's response to four such issues are described below.

**"D" Service Water System (pump discharge strainer)**

On December 23, 1996, operators removed the "D" service water system from service for emergent corrective maintenance following an equipment operator's observation that the pump discharge strainer's rotating backwash mechanism was binding. The inspectors witnessed PSE&G maintenance technicians implement a quickly devised troubleshooting and repair plan, which included an initial inspection of the strainer internals. Technicians noted that both strainer baskets, which had been installed (new) only 5 weeks before, exhibited signs of contact with the backwash arms and had broken tack welds on the strainer mesh. Following the completion of an authorizing engineering evaluation, maintenance personnel performed weld repairs to the two strainer baskets since no replacements were available in inventory. Vertical alignment of the backwash arms was also necessary. Within 28 hours of its removal from service, on December 25, operators declared the "D" service water train operable following a satisfactory retest.

19 hours later, a shift equipment operator conducting rounds again observed signs of "D" service water strainer binding. Again, operators removed the system from service and declared it inoperable for emergent repairs. However, in this instance, technicians discovered that mounting bolts for the external backwash arm drive assembly were loose, causing degraded strainer operation. Maintenance department supervision concluded that poor maintenance work practice during system restoration during the initial strainer work was to blame for the subsequent abnormal operation. Following appropriate repairs and testing lasting nearly one day, the system was restored to an operable status on December 26, 1996.

Unreliable operation and relatively high unavailability time for corrective maintenance are well established indicators of current and past service water system performance. Problems with discharge strainer performance has been well documented and analyzed in previous inspection reports. PSE&G engineering personnel have appropriately categorized Hope Creek service water as an "a(1)" system in accordance with 10 CFR 50.65, and, as such, have devised realistic goals for improved system performance. However, despite the significant effort that PSE&G has expended on achieving increased system reliability, the inspectors continued to observe performance resulting in increased system unavailability; and, material conditions that challenged the effectiveness of scheduled work week activities, and forced station operators to operate the plant in an off-normal condition.

**"A" Emergency Diesel Generator (main air start valve)**

On December 26, 1996, following the start of the monthly "A" emergency diesel generator surveillance test in accordance with TS 4.8.1.1.2.a.4, the "A" main air start valve failed to return to its normally shut condition which allowed the associated air receiver pressure to decay well below 325 psig (TS limiting condition). Before the condition was discovered, the equipment operator implementing the field portion of the test failed to recognize the abnormally low "A" receiver pressure and reduced the redundant "B" receiver pressure to 10 psig lower than "A" as directed by the applicable procedure. When the shift supervisor was informed that both air start receiver pressures were below TS minimum, he declared the "A" EDG inoperable to investigate. Action requests to document both issues were initiated in accordance with PSE&G's corrective action program.

The inspectors observed initial troubleshooting and repair planning associated with this emergent maintenance activity. Following component inspection and testing, Hope Creek engineering personnel determined that the piston in the air start valve was under-lubricated and caused the valve to bind in the open position allowing the receiver air to escape unabated. Engineering additionally determined that the under-lubrication concern was potentially applicable to every EDG main air start valve at the station (eight total - two per engine). The frequency of performing the preventative maintenance activity to inspect and lubricate the noted valves had been changed in January 1996 from "every 18 months" to "once every fourth cycle," a significant increase initially justified by reliable valve operation. Maintenance technicians corrected the deficient condition on the "A" start valve,

and the EDG surveillance was subsequently tested satisfactorily. Similar work on the redundant "B" valve was deferred to the upcoming refueling outage on the basis that it had operated reliably, had been replaced within the prior two years, and that only one air start train was credited in the UFSAR design assumptions for the EDG's.

The inspectors verified that the lubrication preventative maintenance frequency on the air start valves had been returned to 18 months. Additionally, the planning department generated work orders to inspect redundant valves in upcoming EDG system outages (completed on "C" EDG during scheduled outage week of January 27). The inspectors also reviewed the operations department follow up regarding the inadvertent depressurization of the "B" air receiver during the test, and concluded that the department adequately addressed the root causes of the issue, including upgrading the test procedure to include expected receiver pressure following engine starts. Lastly, the inspectors evaluated the operator's basis for not reporting the aborted monthly EDG surveillance as a "valid test failure" in accordance with TS. Based on a review of Regulatory Guide 1.108 criteria for determining what constitutes valid tests, the inspectors concurred with PSE&G's position.

**Reactor Core Isolation Cooling System (turbine governor valve stem)**

On December 28, 1996, following the initial start of the reactor core isolation cooling system (RCIC) for a quarterly in-service test, the turbine tripped on an overspeed condition. Operators promptly declared the RCIC system inoperable per TS 3.7.4 and made a four hour notification to the NRC in accordance with 10 CFR 50.72. Following validation of the actual trip condition, maintenance technicians discovered that the turbine governor valve, normally full open with the system in a standby mode, failed to throttle closed as the turbine achieved rated speed during the start. Subsequent PSE&G engineering evaluation determined that the governor valve stuck open due to valve stem corrosion.

Engineering department investigation into the cause(s) of this event concluded that industry operating experience feedback (OEF) pertaining to the governor valve corrosion issue had not been adequately incorporated into PSE&G procedures. The inspectors reviewed PSE&G's response to NRC Information Notice 94-66, which discussed this same failure mechanism at other reactor sites, and noted that it failed to provide positive measures to assure that governor valve stems made of the susceptible material (liquid-nitrided 410 stainless steel) would be prevented from installation into the RCIC turbine. In fact, the inspectors learned that during the last refueling outage (completed in March 1996), the governor valve stem of the less susceptible material (gas-nitrided 410 stainless steel) was replaced as part of the preventative maintenance program with a new stem of the susceptible variety. This new stem failed within nine months.

Because a replacement stem of the desired material was not immediately available at the time of the emergent corrective maintenance, technicians installed a liquid-nitrided version to restore the system to an operable condition. Following a well

coordinated effort to promptly effect repairs, operators completed a satisfactory RCIC in-service test on December 30, 1996. However, in recognition of the increased potential for future RCIC turbine governor valve failures, Hope Creek management committed to cycling the governor valve on a weekly basis to minimize corrosion build up and valve sticking; the inspectors verified that this activity has been completed without incident. Additionally, PSE&G stated that the currently installed valve stem will be replaced by April 30, 1997. The inspectors noted that this work was scheduled for completion during a planned RCIC system outage in March 1997. Finally, because of the ineffective implementation of operating experience highlighted by this event, the licensee committed to review a sample of other OEF response activities to determine whether programmatic changes were warranted. (See LER 50-354/96-29 and Section M8.1 below). The inspectors verified that all of these commitments were tracked as corrective action requests in the PSE&G corrective action program.

The inspectors also verified that this event was properly categorized as a maintenance-preventable functional failure in accordance with PSE&G's program implementing the requirements of 10 CFR 50.65. Additionally, in part because of the additional RCIC unavailability time accrued as a result of this event, the system was being considered for increased monitoring as an "a(1)" category system under this same program.

**"A" Core Spray Subsystem (pump vibration)**

On January 30, 1997, station operators declared the "A" core spray subsystem inoperable after maintenance technicians discovered that "A" pump exhibited high vibration, above the threshold for "required action" per the governing test procedure. System engineering evaluation determined the likely cause to be improper vertical positioning of impeller vanes inside the pump casing. The inspectors observed a joint planning meeting of operations, maintenance and engineering personnel to discuss troubleshooting options and potential event causal factors. The test equipment used to collect the vibration data was checked for proper calibration and the pump vendor was queried in an attempt to ascertain the implications of the vibration data. The inspectors also noted that the pump differential pressure and flow characteristics were found satisfactory during the test.

Maintenance technicians uncoupled the pump and motor and discovered that the respective shafts were slightly misaligned at the coupling. Additional checks of the pump were satisfactory. The pump and motor were reassembled and on February 1, 1997, plant operators repeated the in-service test using the original vibration test equipment and a redundant measuring device. All data during this subsequent testing indicated that the vibration signature had returned to the prior normal value, and that the pump flow and pressure parameters remained in the satisfactory range (essentially unchanged from the January 30, 1997 data).

During inspector questioning, system engineers revealed that the vibration data collected during the original (failed) test represented a "step increase" in magnitude over all previously trended data, and as such was not predictable per the in-service test program. Additionally, the inspectors learned that the repairs implemented during the troubleshooting (i.e. realignment of pump/motor shafts), should not have resolved the discrepant condition. As a result of these issues, engineers exercised conservative decision-making by placing the core spray pump on an increased testing frequency to better understand the factors that influence gathered test data (proper system fill and vent, pump cavitation, etc.). Because the pressure and flow data were acceptable and the vibration levels satisfactory, the inspectors concluded that the restoration of the pump to an operable status was acceptable. However, despite the fact that the described problem was promptly identified and successfully ameliorated, the inability to determine the root causes of the unusual vibration indicates some weakness in the licensee's corrective action program implementation.

In addition to the on-line corrective maintenance activities described above, several other unscheduled system outages were necessary during the period to resolve material condition concerns, including a failed high pressure coolant injection system check valve, a faulted EDG fuel oil storage tank transfer pump, and anomalies associated with the effluent radiation monitoring system for the "A" train of the filtration, recirculation, and ventilation system. Though disruptive to previously established work schedules, station management effectively directed the timely resolution of all of the emergent concerns.

c. <u>Conclusions</u>

The inspectors reached several conclusions as a result of their evaluation of the multiple events involving emergent corrective maintenance issues, specifically:

- Operator response to the events was appropriate and timely with respect to declaring affected systems inoperable and taking required compensatory measures; reportability was completed as necessary.

- With the exception of the core spray pump issue, station personnel adequately implemented the principles of the PSE&G corrective action program in that problems were identified and documented, causal factors were determined, and corrective actions were completed.

- Poor maintenance practices and weak follow up to industry operating experience contributed significantly to the unavailability of the service water and RCIC systems, respectively.

- Numerous degraded equipment material conditions exhibited by the various events increased the overall unavailability times of the affected systems and reduced the effectiveness of previously established work week plans. Station management's use of a performance indicator to track unscheduled entries into TS action statements indicated recognition of an overall weakness in this area.

- Maintenance rule implementation for the plant systems involved in the events was appropriate and satisfied current guidelines.

**M7 Quality Assurance in Maintenance Activities**

M7.1 QC Inspector Certification:

The inspector reviewed the licensee's certification records for quality control inspectors. Some minor administrative deficiencies were noted but the records provided the information necessary to demonstrate certification in accordance with ANSI/ASME N45.2.6, "Qualifications of Inspection, Examination, and Testing Personnel for Nuclear Power Plants." Annual proficiency examinations and annual visual examinations are being tracked through a computer database. After sampling the qualification records, the inspector concluded that this system was adequate to ensure timely fulfillment of these periodic requirements.

**M8 Miscellaneous Maintenance Issues**

M8.1 (Closed) LER 50-354/96-029: unplanned reactor core isolation cooling system inoperable due to a stuck open governor valve caused by stem corrosion. This issue is discussed in detail in Section M2.1 of this report. No new issues were revealed by this LER.

M8.2 (Closed) LER 50-354/96-030: unplanned high pressure coolant injection (HPCI) system inoperable due to a stuck open extended containment boundary valve. This event involved: an inadequate review of the design basis during the development of the HPCI in-service test procedure; an error in UFSAR Table 6.2-26, which identifies the extended containment boundary valves; and, corrosion induced failure of a check valve for the HPCI barometric condenser condensate pump discharge line. Initially, on November 30, 1996, the check valve failure was identified during the conduct of a HPCI in-service test. At that time the failure was not determined to be of significance and corrective actions were deferred.

During a subsequent review of the UFSAR HPCI system prints by operations personnel on December 30, 1996, the licensee identified that the subject valve was in fact an extended containment boundary valve, even though it was not listed in UFSAR Table 6.2-26. Once this concern was identified, operators took timely corrective action to isolate the system, initiated the required technical specification actions, and increased the priority on correcting the stuck valve. On December 31, 1996, the valve was repaired and the HPCI system restored to an operable condition. In addition, the licensee performed a rigorous review of the UFSAR table and determined that this was an isolated event. The licensee committed to correct the inadequate in-service test procedure before its next use; correct the UFSAR deficiency by July 31, 1997; as well as, committed to use the lessons learned from this event in the Station Qualified Reviewer and 10 CFR 50.59 refresher training programs for to improve the review of the design basis information when developing or revising station procedures. The inspectors considered the licensee's analysis of this event's significance, root cause determinations and both corrective

and committed preventive actions to be comprehensive. Due to the fact that this violation was licensee-identified, that corrective actions were comprehensive, and that the significance was minimal, this violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

M8.3 (Closed) Unresolved Item 50-354/96-06-01: logic functional testing of the traversing in-core probe (TIP) system containment isolation logic. Based on review of the licensee provided information (see LER 50-354/95-033-07), the inspectors determined that logic functional testing observed by the NRC on July 17, 1996, did in fact, involve a violation of NRC requirements. See NRC Inspection Report 50-354/96-06 Section M1.3 for appropriate detail of the NRC inspector observations. The inspectors determined that the licensee failed to establish and maintain procedures for surveillance or test of safety related equipment as required by technical specification 6.8.1 when the test procedure, HC.IC-FT.SM-0023(Q), "Functional Test Automatic TIP Withdraw and Isolation," was approved and implemented. The procedure was found inadequate because it failed to test all of the required logic pathways. Further, the NRC inspectors found the licensee's root cause analysis, safety significance determination, and corrective actions described in the referenced LER to be appropriate and complete. Based on these actions, the NRC considers this violation closed. However, due to the fact that it was NRC identified, the violation is being considered a Cited Violation Not Requiring Response in accordance with the NRC Enforcement Policy. **(VIO 50-354/96-11-02)**

## III. Engineering

### E2 Engineering Support of Facilities and Equipment

#### E2.1 Environmental Qualification of Comsip DC Microswitches

a. Inspection Scope (92903)

The inspectors reviewed the safety evaluation developed to support continued plant operation following the identification of several degraded Comsip DC Microswitches in 1993. As discussed in NRC Inspection Report No. 50-354/94-27, a 10 CFR Part 21 notification was reported by PSE&G to address this identification.

b. Observations and Findings

The inspectors found that the safety evaluation (DR# HMD 93-015) developed by PSE&G concluded that no unreviewed safety question (USQ) existed and that the switches were capable to continue to perform their intended function until the switches could be replaced. The inspectors noted that the continued qualification of these microswitches were subject of numerous discussions and evaluations between the Offsite Safety Review and Program Analysis Groups and Engineering Sciences. The possibility of switches short circuiting during a postulated design basis accident due to moisture intrusion was considered as the basis for the possible creation of a USQ. A USQ was considered to address the possibility that

an upstream current interrupting device (fuse or circuit breaker) would open due to the short across the microswitch causing a loss of power to associated circuits, and subsequently preventing any safety functions of associated circuits from being accomplished. However, all departments determined that there was no USQ and that this issue did not impose any safety concerns. The justification for continued operation of the plant with the degraded microswitches had been based on a walkdown of installed switches and evaluation of the heat rise of the energized switches over ambient temperature. The safety evaluation stated that a heat rise of 114°F would evaporate any moisture and reduce the humidity at the switch, making the probability of a short circuit occurring extremely low. The inspectors determined that adequate technical bases existed to support the licensee's final conclusion that the degraded switches would not create a short circuit and subsequently not prevent satisfactory accomplishment of safety functions by safety-related equipment, as required by 10 CFR 50.59.

Although the degraded switches were replaced and a satisfactory bases had been established for the interim prior to replacement, the inspectors noted that the licensee had missed opportunities to recognize the root cause for the switch degradation earlier and subsequently to replace the switches. Although the condition of the switches was not described in the Final Safety Analysis Report, 24 switches were identified with heat damage and were replaced during the previous seven years. The inspectors considered PSE&G's failure to replace the remaining switches in a more timely manner and identify the root cause a violation of NRC requirements. The inspectors further noted that the interim engineering evaluation used to support continued plant operation and the Part 21 report, used the Arrhenius equation for predicting catastrophic failure of the switches. The inspectors found that the use of the Arrhenius equation was inappropriate because the switches had deteriorated. However, this failure to identify the root cause constitutes a violation of minor significance and is being treated as a Non-Cited Violation, consistent with Section IV of the NRC Enforcement Policy. This determination was based on consideration of actual safety consequence, potential safety consequence, and regulatory significance.

c. Conclusions

The inspectors concluded that an adequate bases had been established to support the licensee's conclusion that degraded DC microswitches would not prevent satisfactory accomplishment of safety functions by safety-related equipment. Weaknesses were noted regarding engineering's interim documented bases to assure that no safety concerns existed with the switches. Additionally, enforcement discretion was exercised to not cite a corrective action violation due to the NRC assessment that it was minor.

## E8 Miscellaneous Engineering Issues

E8.1 (Closed) Unresolved Item 50-354/96-10-02:

By letter from David R. Powell, PSE&G, to the U.S. NRC, LR-N96381, dated November 20, 1996, the NRC was informed that PSE&G had failed to notify the NRC of errors in the accepted ECCS model for Hope Creek Generating Station (HCGS) as required by 10 CFR 50.46(a)(3)(ii). Conversations with the licensee indicate that only the evaluations dated June 26, 1992, December 15, 1995, February 1 and 20, 1996, relate to HCGS. The remainder of the evaluations referenced in the November 20, 1996 letter address other facilities. We have completed our evaluation of the subject letter and conclude that while the analyzed peak clad temperature for HCGS does not exceed the 10 CFR 50.46 limit of 2200 degrees F, the licensee did fail to report changes to an acceptable ECCS evaluation model in violation of 10 CFR 50.46(a)(3)(ii). The licensee committed to update the Updated Final Safety Analysis Report to include the new Peak Clad Temperature limit. The inspector concluded that the licensee's handling of this matter was acceptable since they identified the problem through an independent audit of the fuel vendor documentation and took appropriate corrective actions, including reporting the matter to the NRC. This is an example of a licensee-identified and corrected violation, and as such, is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

E8.2 (Closed) LER 50-354/96-028: potential loss of containment integrity due to water hammer in drywell cooler piping. This event was discussed in Section O1.2 of this report. The licensee immediately corrected this condition by adding an administrative control to prevent operator use of drywell coolers during postulated post-LOCA conditions. Also, the licensee committed to completing more permanent action by either revising appropriate emergency operating procedures to preclude operator use of the drywell coolers during post-LOCA conditions, or to qualify the affected piping to meet the analyzed post-LOCA conditions. These actions were to be completed by the end of Refueling Outage 7, currently scheduled for the fall of 1997. The inspectors reviewed these actions and determined that they were acceptable.

# IV. Plant Support

## R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 Filtration, Recirculation, and Ventilation System (FRVS) Effluent Monitoring Review (71750)

The inspector reviewed action request 00970110196 dated January 13, 1997 concerning FRVS effluent releases. The FRVS consists of two subsystems that are required to perform post-accident, safety-related functions. These are the recirculation system, which recirculates the reactor building air through filters for cleanup, and the ventilation system, which maintains the reactor building at a

negative pressure with respect to the environment by discharging air through filters to the environment via a vent at the top of the reactor building. The FRVS is normally maintained in a standby condition but Technical Specification (TS) 4.6.5.3.1 (b) requires a monthly operational test for 10 hours. This surveillance and any other operation of the FRVS results in a potential release of radioactive materials to the environment. Normally, radioactive effluent releases are controlled by approved release permits. However, the licensee identified that there have been no release permits for the FRVS path since 1994. The inspectors noted that this effluent path is both monitored and filtered, in that the system has an online noble gas monitor for this release point, and filters for removal of Iodine and other principal gamma emitters.

The inspector determined that the licensee uses a permitting process to administratively control effluent releases. TS 4.11.2.2 requires cumulative dose assessments from noble gases to be performed at least once every 31 days and TS 6.9.1.7 requires an annual radioactive effluent release report. Prior to 1994, all gaseous effluent releases were approved via permit issuance by the radiation protection department. On September 6, 1994, the radiation protection procedure was revised to require their issuance of permits only for containment purges. The balance of the gaseous effluent permit issuance was transferred to the chemistry department. Due to an internal communication breakdown, the chemistry department began permit issuance for releases from the north and south plant vents, but not for the FRVS release point. Several licensee internal documents in 1995 and 1996 were written to address questions about sampling requirements for the FRVS effluent stream; these questions were raised because associated effluent sampling requirements are not covered in the associated TS. In January 1997, the question of permit issuance was raised by licensee personnel. The licensee corrected this oversight and is currently issuing release permits for the FRVS release path to ensure appropriate administrative control of, and accounting for these releases.

The inspectors verified that the actual releases through the FRVS release path have been minimal. The FRVS has a short-term discharge capacity of 9000 cubic feet per minute (cfm) and a long-term capacity of 250 cfm. For comparison, the maximum flows through the north and south plant vents are 41,900 cfm and 440,000 cfm respectively. In addition, use of the FRVS release path has been restricted to short periods of time to conduct surveillance testing. Nevertheless, effluents from the FRVS should have been included in the monthly noble gas assessment and the annual radioactive effluent release report, and as such represents a violation of TS requirements. Due to the fact that this violation was licensee identified, the licensee has taken corrective actions, and the safety significance was minimal, this violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

The inspectors concluded that the failure to successfully transfer responsibility for the control and accounting of the FRVS releases was an indicator of weakness in the procedure development, review and approval process; however, the self-identification of the deficiency was considered a positive indicator for problem identification.

## P3 Emergency Preparedness (EP) Procedures and Documentation

A region-based, emergency preparedness inspection was conducted on December 16 - 19, 1996. The results of that inspection are discussed in NRC Inspection Report 50-272/96-18;50-311/96-18. Excerpts from that inspection report are included in this section and Sections P4 and P8 as they pertain to Hope Creek.

The scope of that inspection was primarily to follow up on previous inspection activities at the Salem Generating Station, and included emergency response organization (ERO) drill observation and Emergency Plan (Plan) and Emergency Plan Implementing Procedure (EPIP) revision reviews at Hope Creek.

The inspector reviewed various Plan and EPIP revisions in the regional office prior to the inspection to determine if the changes reduced the effectiveness of the Plan. Based on the licensee's determination that the changes do not decrease the overall effectiveness of the Plan, and that it continues to meet the standards of 10 CFR 50.47(b) and the requirements of Appendix E to Part 50, NRC approval of the changes is not required Initial review of these changes found that they were in accordance with 10 CFR 50.54(q). Implementation of these changes will be subject to inspection to confirm that they do not decrease the overall effectiveness of the Plan and EPIPs.

## P4 Staff Knowledge and Performance in EP

The inspectors observed table-top mini-drills for Salem/Hope Creek (S/HC) operators, S/HC Technical Support Center (TSC) groups, and Emergency Operations Facility (EOF) groups (common to S/HC), to determine EP training effectiveness, and to ensure that emergency response organization (ERO) managers could correctly classify emergency events using the new Nuclear Management and Resources Council (NUMARC) emergency action levels (EALs). Licensee ERO responders demonstrated that EP training was effective through good mini-drill performance. The ERO managers demonstrated the ability to accurately classify emergency events using the NUMARC EALs.

## P8 Miscellaneous EP Issues

The inspectors reviewed Condition Reports (CRs), generated by the licensee's action item tracking system, to close outstanding items. They also interviewed EP, licensing, and quality assessment staff members concerning the use of the tracking system. The licensee's action item tracking system was adequate for tracking and resolving EP issues, but inspectors noted several deficiencies with the implementation of the system by the EP Department. These issues will be reviewed further in conjunction with the Salem restart item III.a.10 concerning the licensee's corrective action system.

## F8 Miscellaneous Fire Protection Issues

### F8.1 Fire Protection Follow up of Licensee Corrective Actions

The inspector reviewed the licensee's response to certain fire protection issues identified by station employees. One such issue was submitted to the Employee Concerns Program, which is governed by procedure NC.NA-NB.ZZ-008 (Z), and involved a number of concerns, including use of improper sprinkler heads and undercharged fire extinguishers. The inspector verified that the licensee evaluated and investigated the concerns in accordance with their procedures. The concerns were validated and corrected, as necessary. Associated corrective work was prioritized commensurate with its safety significance. The inspector independently walked down selected portions of the fire protection systems to verify that the corrective actions had been implemented. The inspector verified that the sprinkler heads in question had been replaced and numerous portable fire extinguishers were examined and found to be acceptable.

The licensee's corrective actions were completed approximately seven months after receipt of the concern. At that time, the licensee sent information describing the evaluation and disposition of the concerns to the individual who identified the issues. As a result of a follow up survey conducted several months later, the licensee determined that the concerned individual apparently never received this information. The licensee plans to resend the information. The inspector concluded that the licensee's Employee Concerns Program was effective in evaluating and resolving the technical concerns but was less effective in providing timely feedback to individuals regarding the results of their review of the concerns as required by 5.3.2 of procedure NC.NA-NB.ZZ-008 (Z).

# 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.

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on February 7, 1997. The licensee acknowledged the findings presented.

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

## INSPECTION PROCEDURES USED

| | |
|---|---|
| IP 61726: | Surveillance Observations |
| IP 62707: | Maintenance Observations |
| IP 71707: | Plant Operations |
| IP 37551: | Onsite Engineering |
| IP 71750: | Plant Support |
| IP 92901: | Operations Follow up |
| IP 92902: | Maintenance Follow up |
| IP 92903: | Engineering Follow up |
| IP 93702: | Event Response |
| IP 92700: | Event Reports |
| IP 90712: | In Office Report Reviews |

## ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

| | | |
|---|---|---|
| 50-354/96-11-01 | DEV | failure to complete a commitment to revise the TS Bases |
| 50-354/96-11-02 | VIO | inadequate test procedure for the TIP isolation logic test |

Closed

| | | |
|---|---|---|
| 50-354/96-017 | LER | failure to perform electrical system lineup verification |
| 50-354/96-027 | LER | ESF actuation - unplanned auto-start of the "A" SACS pump |
| 50-354/96-028 | LER | potential loss of primary containment integrity |
| 50-354/96-029 | LER | unplanned RCIC system inoperability |
| 50-354/96-030 | LER | unplanned HPCI system inoperability |
| 50-354/96-06-01 | URI | functional testing of the TIP isolation system logic |
| 50-354/96-11-02 | VIO | inadequate test procedure for the TIP isolation logic test |
| 50-354/96-10-02 | URI | peak clad temperature change reporting requirements |