January 23, 2003

Mr. Harold W. Keiser
Chief Nuclear Officer and President
PSEG LLC - N09
P. O. Box 236
Hancocks Bridge, NJ 08038

SUBJECT: HOPE CREEK NUCLEAR GENERATING STATION - NRC INSPECTION REPORT 50-354/2002-07

Dear Mr. Keiser:

On December 28, 2002, the NRC completed an inspection of your Hope Creek facility. The enclosed report documents the inspection findings which were discussed on January 8, 2003, with Mr. Lon Waldinger and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations, and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel. Specifically, this inspection involved thirteen weeks of resident inspection, a licensed operator requalification program inspection, an interim security compensatory measures audit, and a Mitigating Systems Performance Index audit.

Based on the results of this inspection, the inspectors identified two issues of very low safety significance (Green). One issue was determined to involve a violation of NRC requirements. However, because of its very low safety significance and because it has been entered into your corrective action program, the NRC is treating this issue as a non-cited violation, in accordance with Section VI.A.1 of the NRC's Enforcement Policy. If you deny this non-cited violation, you should provide a response with the basis for your denial, within 30 days of the date of this inspection report, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, and the NRC Resident Inspector at the Hope Creek facility.

The NRC has increased security requirements at Hope Creek Nuclear Generating Station in response to terrorist acts on September 11, 2001. Although the NRC is not aware of any specific threat against nuclear facilities, the NRC issued an Order and several threat advisories to commercial power reactors to strengthen PSEG Nuclear's capabilities and readiness to respond to a potential attack. The NRC continues to inspect PSEG Nuclear's security controls and its compliance with the Order and current security regulations.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Glenn W. Meyer, Chief
Projects Branch 3
Division of Reactor Projects

Enclosure: Inspection Report 50-354/02-07
Attachment: Supplementary Information

Docket No. 50-354
License No. NPF-57

cc w/encl: M. Friedlander, Director - Business Support
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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No:	50-354
License No:	NPF-57
Report No:	50-354/2002-07
Licensee:	PSEG LLC
Facility:	Hope Creek Nuclear Generating Station
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	September 29 - December 28, 2002
Inspectors:	J. G. Schoppy, Jr., Senior Resident Inspector M. S. Ferdas, Resident Inspector T. H. Fish, Senior Operations Engineer P. D. Kaufman, Senior Reactor Inspector E. W. Cobey, Senior Reactor Analyst D. M. Silk, Senior Emergency Preparedness Inspector G. C. Smith, Senior Physical Security Inspector P. R. Frechette, Physical Security Inspector
Approved By:	Glenn W. Meyer, Chief, Projects Branch 3 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000354-02-07; Public Service Electric Gas Nuclear LLC; on 9/29 - 12/28/02; Hope Creek Generating Station; Licensed Operator Requalification, Surveillance Testing.

The inspection was performed by resident inspectors, regional security specialists, a regional emergency preparedness specialist, a regional senior reactor analyst, a regional operations engineer, and a regional reactor inspector. This inspection identified two Green findings, one of which was also a non-cited violation. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609, *Significance Determination Process* (SDP). Findings for which the SDP does not apply may be "Green" or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, *Reactor Oversight Process*, Revision 3, dated July 2000.

A. <u>Inspector Identified Findings</u>

Cornerstone: Mitigating Systems

- **Green**. The inspectors identified a finding associated with licensed operator crew performance on the simulator. Of the nine crews evaluated, three failed to pass their facility-administered requalification examinations.

  The Operator Requalification Human Performance SDP establishes the risk importance for crew failure rate. The failure rate for Hope Creek crews was three of 9, or 33 percent. A failure rate of 20 percent to 34 percent is considered to be a Green finding, and is turned over to the facility licensee for corrective action. The finding is of very low safety significance, because the failures occurred during annual testing of the licensed operators on the simulator, because there were no actual consequences to the failures, and because all three crews were re-trained and re-evaluated before they were authorized to return to licensed duties. (Section 1R11.1)

- **Green**. The inspectors determined that PSEG failed to take adequate corrective actions to preclude repetition of a safety-related component failure. PSEG corrective actions for a B standby liquid control (SLC) pump inservice test (IST) failure in March 2002 did not adequately preclude a similar degraded condition from causing an A SLC pump IST failure on October 16, 2002.

  The inspectors identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion XVI, *Corrective Actions*, for this performance deficiency. This finding was considered to be more than minor, because it affected the Mitigating Systems cornerstone objective of ensuring the availability, reliability, and capability of the SLC system to respond to initiating events (ATWS) to prevent undesirable conditions. The inspectors determined that the finding was of very low safety significance (Green), because the B SLC pump remained operable and there was no loss of the SLC system safety function. Also, the inspectors determined that the inadequate corrective actions and poor problem identification were an example of a cross-cutting issue in problem identification and resolution. (Section 1R22.1)

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Report Details

SUMMARY OF PLANT STATUS

At the beginning of the period reactor power was approximately 56 percent with a power ascension in progress following a planned power reduction. Operators returned the unit to 100 percent power on October 1. Operators performed a short duration planned power reduction to 84 percent on October 6 for turbine valve testing (TVT). On October 6 the load dispatcher requested that Hope Creek operators reduce power to 1000 MWe for grid stability due to a need to remove a 500 KV line (Peach Bottom - Keeney line 5014) from service. Operators reduced power to 89 percent. On October 10 the load dispatcher removed the restriction on Hope Creek's generator output and operators restored power to 100 percent. Operators performed a planned power reduction to 60 percent on October 26 for TVT, a control rod pattern adjustment, and control rod scram time testing. On October 28 operators performed a planned power reduction to 95 percent to withdraw control rods to maintain rated reactor power. On November 23 operators reduced power to 92 percent due to an emergency request by the load dispatcher to reduce power for grid stability due to a trip of Peach Bottom - Keeney line 5014. Shortly thereafter, operators reduced power to 85 percent in response to an unexpected trip of the A feedwater pump. Operators returned the unit to 100 percent power on November 24. Operators performed a planned power reduction to 84 percent on December 1 for TVT. The unit operated at or near full power for the remainder of the period.

1. REACTOR SAFETY

Cornerstone: **Initiating Events, Mitigating Systems, and Barrier Integrity [REACTOR - R]**

1R04 Equipment Alignment

a. Inspection Scope

The inspectors performed equipment alignment verifications on the emergency diesel generators (EDGs), 4KV vital switchgear buses, and control room instrumentation panels prior to sequential short duration outages on each EDG to complete relay testing on December 13 (see NRC Inspection Report 50-354/03-02). The inspectors verified by plant walkdowns and main control room tours that the EDG outages did not adversely affect the redundant safety-related equipment. The inspectors also verified that operators restored each of the EDGs to an operable condition after technicians completed the relay testing. Additionally, the inspectors reviewed various corrective action notifications associated with equipment alignment deficiencies (see Supplementary Information, Section C, for a complete listing).

The inspectors also reviewed the following documents:

- *Emergency Diesel Generator System Operation* (HC.OP-SO.KJ-0001);
- *Power Distribution Lineup-Weekly* (HC.OP-ST.ZZ-0001).

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors performed walkdowns of the EDG rooms (rooms 5304, 5305, 5306, and 5307) on November 5. The plant walkdowns included observations of combustible material control, fire detection and suppression equipment availability, and compensatory measures. The inspectors performed fire protection inspections due to the potential to impact mitigating systems in these areas. The inspectors reviewed Hope Creek's Individual Plant Examination for External Events for risk insights concerning these areas. Additionally, the inspectors reviewed several notifications associated with fire protection deficiencies.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures

a. Inspection Scope

The inspectors reviewed two notifications (20115000 and 20124645) associated with flood protection issues.

b. Issues and Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

.1 Licensed Operator Requalification Program

a. Inspection Scope

The following inspection activities were performed using NUREG-1021, Rev. 8, *Operator Licensing Examination Standards for Power Reactors*; Inspection Procedure Attachment 71111.11, *Licensed Operator Requalification Program*; and NRC Manual Chapter 0609, Appendix I, *Operator Requalification Human Performance Significance Determination Process (SDP)*, as acceptance criteria.

The inspectors reviewed documentation of operating history since the last requalification program inspection. Documents reviewed included NRC inspection reports and PSEG deficiency reports. The inspectors also discussed facility operating events with the resident staff. The inspectors did not detect operational events that were indicative of training deficiencies.

Inspectors reviewed examples of the comprehensive written exams and observed the administration of annual operating tests. The quality of the written exams and the annual operating tests met or exceeded the criteria of the Examination Standards and 10 CFR 55.59.

The inspectors observed operator performance during the simulator examinations, which included requalification program scenario-based tests, and reviewed simulator discrepancy reports to verify compliance with the requirements of 10CFR55.46.

The inspectors reviewed a sample of operators' records related to requalification training attendance, license reactivations, and medical examinations and confirmed the operators were in compliance with license conditions and NRC regulations.

The inspectors interviewed instructors, training and operations management personnel, and a sample of individual licensed operators for feedback regarding the implementation of the licensed operator requalification program.

On December 30, 2002, the inspectors performed an in-office review of PSEG requalification exam results. These results included the annual operating test and comprehensive written exam. The inspection assessed whether pass rates were consistent with the guidance of Appendix I, *Operator Requalification Human Performance Significance Determination Process (SDP)*. The inspectors verified that:

- Crew pass rate was NOT greater than 80 percent. (Actual pass rate was 67 percent and is discussed below in paragraph b.)
- Individual pass rate on the dynamic simulator test was greater than or equal to 80 percent. (Actual pass rate was 90 percent.)
- Individual pass rate on the walk-through test was greater than or equal to 80 percent. (Actual pass rate was 98 percent.)
- Individual pass rate on the comprehensive written exam was greater than or equal to 80 percent. (Actual pass rate was 98 percent.)
- Overall pass rate among individuals for all portions of the exam was greater than or equal to 75 percent. (Actual pass rate was 86 percent.)

b. Findings

Introduction

The inspectors identified a finding of very low safety significance (Green) associated with crew performance on the simulator. Of the nine crews evaluated, three failed to pass their facility-administered requalification examinations.

Description

During November and early December, three crews failed their simulator scenario examinations. All three crews were staff crews. One crew failed because they failed a crew critical task and the other two crews failed due to competency errors (they did, however, complete the crew critical tasks). Facility staff noted that the performance weaknesses observed with the staff crews did not exist with the shift crews. PSEG issued a Level 2 notification (20123992) to determine the apparent cause(s) of the crew failures.

Analysis

The Operator Requalification Human Performance SDP establishes the risk importance for crew failure rate. The failure rate for Hope Creek crews was three of 9, or 33 percent. A failure rate of 20 percent to 34 percent is considered to be a Green finding, and is turned over to the facility licensee for corrective action. The finding is of very low safety significance, because the failures occurred during annual testing of the licensed operators on the simulator (i.e., not while the crews were standing control room watches), because there were no actual consequences to the failures, and because all three crews were re-trained and successfully re-evaluated before they were authorized to return to licensed duties. **(FIN 50-354/02-07-01)**

Enforcement

10 CFR 55.59 requires, in part, that operators pass an annual operating test; the rule does not specify pass/fail rates. When a failure occurs, the requirement is met by restricting the operator from licensed duties until the operator has been re-trained and successfully retested. Because PSEG did this, the inspector did not identify any violations of regulatory requirements related to crew failure rate.

.2 Simulator Observation

a. Inspection Scope

The inspectors observed one simulator training scenario to assess operator performance and training effectiveness. The scenario involved a recirculation pump seal failure, single loop operations, power oscillations, and an ATWS condition. The inspectors assessed simulator fidelity and observed the simulator instructor's critique of operator performance. The inspectors also observed control room activities with emphasis on simulator identified areas for improvement.

The inspectors also reviewed the following documents:

- *HCGS Event Classification Guide;*
- *HCGS Event Classification Guide Technical Basis*;
- *Reactor Power Oscillations* (HC.OP-AB.RPV-0002);
- *Recirculation System* (HC.OP-AB.RPV-0003);
- *ATWS - RPV Control* (HC.OP-EO.ZZ-101A).

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness

a. Inspection Scope

The inspectors reviewed the performance and condition history of the station service water (SSW) traveling screens and backwash system, the safety auxiliaries cooling system (SACS), and the service air and control air systems. The inspectors reviewed these systems to identify degraded conditions or declining system performance and to assess the effectiveness of Maintenance Rule (MR) activities and maintenance work practices. The inspectors compared documented functional failure determinations and unavailable hours to those in PSEG's MR database to evaluate the effectiveness of condition monitoring and to determine if the equipment met their established performance goals. The inspectors reviewed applicable work orders and corrective action notifications generated in the past two years for work practices, common cause, or generic implications. The inspectors also reviewed preventive and corrective maintenance tasks, system health reports, and Hope Creek Expert Panel Meeting Minutes (HCEP 01-003 and HCEP 01-010) to assess work practices and system performance (see Supplementary Information, Section C, for a complete listing).

To assess PSEG's implementation of 10CFR 50.65 *MR* requirements, the inspectors reviewed the following documents:

- SE.MR.HC.02, *System Function Level Maintenance Rule VS Risk Reference*;
- NRC Regulatory Guide 1.160, *Monitoring the Effectiveness of Maintenance at Nuclear Power Plants*, Revision 2;
- NUMARC 93-01, *Industry Guideline For Monitoring the Effectiveness of Maintenance at Nuclear Power Plants*, Revision 2.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

a. Inspection Scope

The inspectors evaluated on-line risk management for the following configurations:

- Emergent outage of the D EDG on October 6;

- Concurrent emergent unavailability of the C residual heat removal (RHR) pump, C EDG, and breaker H1PB-52-40301 (one of two offsite power feeds to the C 4KV vital bus) on October 23;

- Concurrent planned extended outage of the C EDG and the emergent unavailability of the A1 SACS heat exchanger on December 15;

- Concurrent planned extended outage of the C EDG and the emergent unavailability of the A EDG on December 18.

The inspectors reviewed maintenance risk evaluations, work schedules, recent corrective action notifications, and control room logs to verify that other concurrent planned and emergent maintenance or surveillance activities did not adversely affect the plant risk already incurred with the out of service components. The inspectors assessed risk management actions during shift turnover meetings, control room tours, and plant walkdowns. The inspectors also used PSEG's on-line risk monitor (Equipment Out Of Service workstation) to evaluate the risk associated with the plant configuration and to assess risk management. In addition, the inspectors reviewed other notifications involving risk assessment and emergent work (see Supplementary Information, Section C, for a complete listing).

To assess risk management, the inspectors reviewed the following documents:

- SE.MR.HC.02, *System Function Level Maintenance Rule VS Risk Reference;*
- HCGS PSA Risk Evaluation Forms for Work Week Nos. 91 - 103;
- SH.OP-AP.ZZ-108, *On-Line Risk Assessment;*
- NRC Regulatory Guide 1.182, *Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants;*
- Section 11, *Assessment of Risk Resulting from Performance of Maintenance Activities,* dated February 11, 2000, of NUMARC 93-01, *Industry Guideline For Monitoring the Effectiveness of Maintenance at Nuclear Power Plants*.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the operability determination for non-conforming conditions associated with (1) the A primary containment instrument gas compressor (notification 20115504), (2) the seismic design of installed Agastat relays (evaluation 70027461), and (3) reactor protection system K5 relay alarm function (evaluation 70028501). The inspectors also reviewed all other PSEG-identified safety-related equipment deficiencies during this report period and assessed the adequacy of the operability screenings.

The inspectors reviewed the following documents:

- *Operability Assessment and Equipment Control Program* (SH.OP-AP.ZZ-0108);
- *NRC Generic Letter No. 91-18, Revision 1;*
- *Notification Process* (NC.WM-AP.ZZ-0000).

b. Findings

No findings of significance were identified.

1R16 Operator Work-Arounds

a. Inspection Scope

The inspectors reviewed corrective action notifications, operator logs, and instrument panel status to evaluate potential impacts on the operators' ability to implement abnormal or emergency operating procedures.

The inspectors also reviewed the following documents:

- *Condition Resolution Operability Determination Notebook;*
- *Inoperable Instrument/Alarm/Indicators/Lamps/Device Log;*
- *Inoperable Computer Point Log;*
- *Hope Creek Operator Workarounds List*;
- *Hope Creek Operator Concerns List*.

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing

a. Inspection Scope

The inspectors witnessed post maintenance testing (PMT) and/or reviewed the test data for four residual heat removal (RHR) valves (HV-F003B, HV-F007B, HV-F010B, and SV-F080B) on October 1; the 862 Bailey Solid State Logic Module (SSLM 1-10-6 IN 1D-C-652) for the D EDG output breaker on October 8; the D channel 125V 1E battery cell single charge and subsequent battery cell replacement (H1PK-1D-D-411, cell No. 23) on November 26; and the high pressure coolant injection (HPCI) pump test line valve (1BJ-HV-F008) on December 12. The inspectors reviewed NC.NA-TS.ZZ-0050, *Maintenance Testing Program Matrix,* and verified that the PMTs were adequate for the scope of maintenance performed. The inspectors reviewed PSEG's Bailey reliability trending program report to verify that PSEG satisfied facility operating license condition 2.C.(5), *Baily 862 SSLM Reliability Program*. The inspectors also reviewed notifications concerning problems associated with PMTs (20115504, 20116691, 20117407, and 20120655).

The inspectors reviewed numerous documents to assess PSEG performance (see Supplementary Information, Section C, for a complete listing).

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

.1 A Standby Liquid Control Pump Failed Inservice Test

a. Inspection Scope

The inspectors reviewed the results of the failed A SLC pump IST on October 16, 2002, and the subsequent retest of the A SLC pump on October 18. The inspectors reviewed PSEG's corrective actions for this issue (notifications 20117073 and 20117142) and for a similar failure that impacted the B SLC pump in March 2002 (notification 20094810). The inspectors also interviewed plant personnel and reviewed other related corrective action documents (e.g. apparent cause investigation reports and work orders) to ascertain the adequacy of PSEG's evaluation and corrective actions.

The inspectors reviewed the following documents:

- *Standby Liquid Control Pump - AP208 - Inservice Test* (HC.OP-IS.BH-0001);
- A & B Standby Liquid Control Pump Inservice Test Results from April 2001 to October 7, 2002;
- Notifications: 2011777, 20118119, and 20098413;
- Work order: 60028054;
- Evaluations: 70023761 and 70027601.

b. Findings

Introduction

The inspectors determined that PSEG corrective actions for a B SLC pump IST failure in March 2002 did not adequately preclude a similar degraded condition from causing an A SLC pump IST failure on October 16, 2002. The inspectors determined that the finding was of very low safety significance (Green), because the B SLC pump remained operable and there was no loss of the SLC system safety function, and that it was an example of the cross-cutting issue of problem identification and resolution.

Description

On March 23, 2002, the B SLC pump failed its IST test due to flow less than the minimum acceptable flow rate. PSEG performed an investigation (evaluation 70023761) to determine the apparent cause of the pump's failure. PSEG determined that the B SLC pump's low flow rate was due to excessive wear of the angled cylinder check valves which are internal to the SLC pumps. Recommended corrective actions included repair of the B SLC pump cylinder check valves; inspection of the cylinder check valves for the A SLC pump and repair as required; and a review of the SLC pump preventive maintenance (PM) program for inclusion of periodic check valve inspections.

On October 16, 2002, during quarterly IST surveillance testing the A SLC pump failed to achieve the specified minimum acceptable flow rate. PSEG initiated notification 20117073 to document the pump's condition, and performed maintenance and retesting under work order 60028054. Operators declared the A SLC pump inoperable and entered a 7 day limiting condition for operation in accordance with technical specification (TS) 3.1.5.a. The B SLC pump was operable at the time.

PSEG performed an apparent cause evaluation (notification 70027601) and determined that the failure was due to mechanical wear of the SLC pump inlet and outlet check valves. This caused the valves to leak-by, which resulted in a decreased flow rate of the pump. The inspectors noted that the cause of the A SLC pump's failure was similar to the cause of the B SLC pump IST failure in March 2002.

The inspectors determined that PSEG did not perform the A SLC pump cylinder check valve inspection. Specifically, PSEG did not perform the A SLC pump inspection as originally scheduled and rescheduled it to occur in March 2004. The inspectors reviewed previous A and B SLC pump quarterly IST data dating back to April 2001 and noted that PSEG failed to recognize the declining performance of the A pump flow rates achieved during previous IST surveillances. The inspectors noted that the A SLC pump demonstrated similar degraded performance as the B SLC pump prior to its failure. The inspectors also noted that engineering closed out their corrective action to review the SLC pump PMs for possible inclusion of periodic check valve inspections without actually conducting this review. The inspectors reviewed SLC pump PMs and identified that they did not include a maintenance activity to periodically inspect the SLC pump cylinder check valves.

<u>Analysis</u>

The inspectors considered PSEG's failure to take timely and adequate corrective actions following the B SLC pump IST failure in March 2002 a performance deficiency since PSEG's corrective action program should correct conditions adverse to quality in a timely manner to preclude repetition.

The inspectors determined that this finding was more than minor because it affected the Mitigating Systems cornerstone objective of ensuring the availability, reliability, and capability of the SLC system to respond to initiating events (ATWS) to prevent undesirable conditions. The finding was associated with the equipment performance attribute.

The inspectors determined that the finding was of very low safety significance (Green) by the SDP Phase 1 screening worksheet for Mitigating Systems because the B SLC pump remained operable and there was no loss of the SLC system safety function. Also, the inspectors determined that the adequate corrective actions and poor problem identification were an example of a cross-cutting issue on problem identification and resolution.

Enforcement

10 CFR 50, Appendix B, Criterion XVI, *Corrective Actions,* requires that in cases of significant conditions adverse to quality, measures shall be established to assure that corrective actions are taken to preclude repetition. Contrary to the above, PSEG did not take appropriate corrective actions to preclude recurrence of a deficiency associated with the SLC pumps. Specifically, PSEG did not take appropriate corrective action for the B SLC pump degraded performance that occurred in March 2002 to preclude a similar recurrence in the A SLC pump in October 2002. However, because the violation is of very low significance (Green) and PSEG entered the deficiency into their corrective action system (order 70027601), this finding is being treated as a non-cited violation, consistent with Section VI.A of the Enforcement Policy, issued May 1, 2000 (65FR25368). **(NCV 50-354/02-07-02)**

PSEG initiated immediate corrective action at the time of the failure which involved replacing the valve discs and returning the A SLC pump to an operable status. PSEG planned to create a PM task for SLC pump check valve replacement and a method to improve the decision making process for removing system health related corrective maintenance from the work week schedule.

.2 Diesel Generator Relay Testing

a. Inspection Scope

At 1:07 p.m. on December 12, 2002, PSEG declared all four EDGs inoperable due to a failure to test EDG output breaker lockout relays in accordance with TS 4.8.1.1.2.h.14. PSEG invoked TS 4.0.3 which permitted 24 hours to complete the required surveillances. On December 13 PSEG requested that the NRC grant a Notice of Enforcement Discretion (NOED) to allow PSEG to meet the surveillance requirements when conducting the EDG surveillances at power vice during shutdown conditions. Following a conference call on December 13, the NRC verbally granted the NOED and documented the NOED in a letter dated December 20, 2002.

The inspectors participated in the NOED conference call and witnessed portions of the associated EDG testing. The inspectors observed relay testing (low lube oil pressure input to the 86R relay) on the A, B, C, and D EDGs on December 13. The inspectors also observed relay testing (86R, 86T, and ground input to the 86F relay) on the A, B, C, and D EDGs on December 18. The inspectors reviewed the test procedures and electrical schematics to verify that applicable system requirements for operability were incorporated correctly into the test procedures and the test methodology was consistent with the TS requirements for the relay tested (see NRC Inspection Report 50-354/03-02).

The inspectors reviewed the following documents:

- *Relay Testing* (SH.MD-PM.ZZ-0029);
- *Diesel Generator Lube Oil Low Pressure Lock Out Technical Specification Surveillance* (HC.MD-ST.KJ-0002).

b. Findings

No findings of significance were identified.

.3 Diesel Fuel Oil Transfer Pump and Core Spray Pump Testing

a. Inspection Scope

The inspectors observed portions of and/or reviewed the results of the D diesel fuel oil transfer pump IST on October 4, and the A and C core spray pumps IST on October 15. The inspectors reviewed the test procedures to verify that applicable system requirements for operability were incorporated correctly into the test procedures, test acceptance criteria were consistent with the TS and Update Final Safety Analysis Report (UFSAR) requirements, and the systems were capable of performing their intended safety functions. The inspectors observed chemistry technicians sample and analyze the reactor coolant system (RCS) to demonstrate that the specific activity was within TS 3.4.5 limits. The inspectors also reviewed notifications concerning problems encountered during surveillance testing (see Supplemental Information, Section C, for a complete listing).

The inspectors reviewed the following documents:

- *D Diesel Fuel Oil Transfer Pump - DP401 - Inservice Test* (HC.OP-IS.JE-0004);
- *A & C Core Spray Pumps - AP206 And CP206 - Inservice Test* (HC.OP-IS.BE-0001);
- *Operation of the Reactor Building/RHR Sampling Station* (HC.CH-SA.RC-002);
- *Gamma Spectroscopy Sample Preparation* (HC.CH-TI.ZZ-0021);
- *Gamma Spectroscopy Analysis Using CAS* (NC.CH-RC.ZZ-2525).

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed Hope Creek T-MOD 02-028, *Installation of Temporary Fiber-Optic Cable to Replace Failed Fiber-Optic Cable AX1Z6100G*. The objectives of this review were to verify that (1) the design bases, licensing bases, and performance capability of risk significant structures, systems, and components had not been degraded through this modification, and (2) implementation of the modification did not place the plant in an unsafe condition. The inspectors verified the modified equipment alignment through a plant walkdown of the accessible portions of the cable run in the bailey equipment room. Additionally, the inspectors reviewed several notification associated with temporary modification issues (20114479, 20115424, 20115425, 20115426, 20118319, and 20124500).

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness [EP]

1EP6 Drill Evaluation

a. Inspection Scope

The inspectors observed two PSEG-evaluated training evolutions on the simulator. The inspectors observed the evaluation team's critique to evaluate the adequacy of PSEG's assessment of operator performance to identify weaknesses and deficiencies. The inspectors reviewed the simulator scenarios and operators' performance with a primary focus on proper event classification.

The inspectors reviewed the following documents during this inspection:

- *HCGS Event Classification Guide;*
- *Operations Standards* (SH.OP-AS.ZZ-001).

b. Findings

No findings of significance were identified.

3. SAFEGUARDS

Cornerstone: Physical Protection [PP]

3PP1 Access Authorization

a. Inspection Scope

The inspectors reviewed the status of security operations and assessed PSEG implementation of the protective measures in place as a result of the current, elevated threat environment.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES [OA]

4OA1 Performance Indicator Verification

.1 Safety System Functional Failures

a. Inspection Scope

The inspectors verified the accuracy and completeness of the data that PSEG used to calculate and report the *Safety System Function Failure* (SSFF) performance indicator (PI). The inspectors reviewed all Hope Creek licensee event reports (LERs) dated October 1, 2001, through September 30, 2002, to determine whether issues meeting the SSFF definition in NEI 99-02 (Revision 1 or Revision 2, as applicable) *Regulatory Assessment Performance Indication Guideline*, were included in the data set. The inspectors also used NRC NUREG-1022, Revision 2, *Event Reporting Guidelines 10 CFR 50.72 AND 50.73*, to assess reportability for the PI.

b. Findings

No findings of significance were identified.

.2 Reactor Coolant System Specific Activity

a. Inspection Scope

The inspectors verified the methods used to calculate the *Reactor Coolant System (RCS) Specific Activity* PI and reviewed the accuracy of the PI data submitted for the months of April to October 2002. The inspector observed a chemistry technician sample and analyze the RCS (see also Section 1R22.3). The inspectors used the guidance provided in NEI 99-02, Revision 2, *Regulatory Assessment Performance Indicator Guideline*, to assess PSEG's collection and reporting of PI data. The inspector also used NC.NA-AP.ZZ-0071, *Fuel Integrity Program*, to assess the methodology and assumptions used for reporting the PI data. The inspectors also reviewed notification 20120957 concerning a problem encountered during collection and reporting of RCS Specific Activity PI data.

b. Findings

No findings of significance were identified.

.3 Reactor Coolant System Leakage

a. Inspection Scope

The inspectors verified the methods used to calculate the *Reactor Coolant System Leakage* PI. The inspectors verified the accuracy of PI data submitted through review of the applicable pages in the daily TS surveillance data sheet (HC.OP-DL.ZZ-0026, Surveillance Log - Control Room) for the period October 2001 through September 2002. The inspectors used the guidance provided in NEI 99-02, Revision 2, *Regulatory Assessment Performance Indicator Guideline*, to assess PSEG's collection and reporting of PI data.

b. Findings

No findings of significance were identified.

.4 Emergency Preparedness

a. Inspection Scope

The inspector reviewed PSEG's procedure for developing the data for the emergency preparedness PIs which are: (1) Drill and Exercise Performance, (2) Emergency Response Organization Drill Participation and (3) Alert Notification System Reliability. The inspector also reviewed PSEG's drill/exercise reports, training records and ANS testing data from the fourth quarter of 2001 to the end of the third quarter of 2002 to verify the accuracy of the reported data. The review was conducted in accordance with NRC Inspection Procedure 71151. The acceptance criteria are 10 CFR 50.9 and NEI 99-02, Revision 2, *Regulation Assessment Performance Indicator Guideline*.

b Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

.1 Two-Stage Target Rock Safety Relief Valve Leakage

a. Inspection Scope

In accordance with the guidance provided in Inspection Procedure 71152, *Identification and Resolution of Problems*, the inspector selected various corrective action notifications associated with safety relief valve (SRV) setpoint drift and pilot seat leakage problems for detailed review. SRV tailpipe temperature monitoring indicated that four SRVs were experiencing pilot seat leakage. SRV tailpipe temperatures have continued on an upward trend since the startup from the refueling outage in November 2001. The two-stage Target Rock SRVs installed on the main steam lines have experience setpoint drift and pilot seat leakage problems since 1999. The inspector reviewed the notifications to ensure that the full extent of the issues were identified, evaluations performed, extent of condition reviews performed, and corrective actions specified and prioritized.

The inspector also reviewed main steam system health reports, the operations procedure control console log, and daily plant status reports to ensure that the degraded SRVs were being adequately captured, trended, tracked, and received appropriate management attention. Additionally, the inspector reviewed SRV maintenance history records to ensure that SRV maintenance was being accomplished in accordance with vendor recommendations and specifications. The inspector compared maintenance procedures with TS requirements based on the SRV setpoint drift failure rate to ensure that PSEG was meeting TS requirements.

The inspector reviewed PSEG's action plan to determine the proposed corrective actions and schedule for the refurbishment of the four leaking SRVs. The inspector also verified that PSEG monitored the Boiling Water Reactor Owners Group (BWROG) guidance related to improving the performance of Target Rock SRVs.

a. Findings

No findings of significance were identified.

PSEG performed an apparent cause evaluation of the four current leaking SRVs and had initiated several corrective actions since 1999 to address the previous setpoint drift problem associated with their two-stage Target Rock SRVs. PSEG continued to monitor SRV tailpipe temperatures which are an indicator of SRV leakage and established a tailpipe temperature threshold action limit of 275 °F.

The inspector determined that the PSEG implemented corrective actions which installed ion beam implanted platinum on the SRV seats had improved the performance of the SRVs by reducing the corrosion bonding of the pilot valve to their seats. However, based on the continued setpoint drift and leakage problems of the SRVs at Hope Creek since 1999, the inspector concluded that the implemented corrective actions have not been fully effective to prevent recurrence.

PSEG planned corrective actions included: revising the SRV testing procedure to more represent plant conditions, purchasing an additional four SRVs to preclude quick SRV turnarounds, limiting the amount of lapping once the ion beam implanted platinum coating is applied to the pilot seat, continuing evaluation of the use of Stellite 21 pilot valve disks, and monitoring the BWROG guidance related to Target Rock SRVs. The inspectors determined that these actions appeared adequate to improve the overall performance of the Target Rock SRVs at Hope Creek.

.2 Emergency Response Organization Qualification

a. Inspection Scope

In accordance with the guidance provided in Inspection Procedure 71152, *Identification and Resolution of Problems*, the inspector selected corrective action evaluation 800038006-0060 regarding the issue of having approximately 3 percent of emergency response organization (ERO) qualification members routinely being out of qualification in 2001. The inspector reviewed the associated corrective actions for this issue to assess that appropriate evaluations were performed, that acceptable extent of condition reviews were performed, and that the corrective actions were specified and prioritized. The inspector also reviewed the current ERO status for both Salem and Hope Creek to verify the effectiveness of the corrective actions. The inspector verified that PSEG had implemented or revised administrative controls to monitor and maintain ERO member qualifications.

The inspector reviewed the following documents:

- *Emergency Response Organization Status Report*, Duty Week 11/12-19/02;
- *Maintenance of Emergency Response Organization* (NC.EP-AP.ZZ-1011);
- *Emergency Preparedness Training Administration* (NC.EP-AP.ZZ-1014).

b. Findings

No findings of significance were identified.

Evaluations were detailed and thorough. PSEG appropriately conducted an extent of condition review in order to implement comprehensive corrective actions. The inspector found that the corrective actions associated with evaluation 80038006-0060 were appropriate. Corrective actions have resulted in increased management oversight, and ownership of the qualification process and individual qualification status. PSEG implemented administrative controls that monitor and inform individuals of pending and actual lapses in ERO qualification. Training items which comprise ERO qualifications (annual training, respirator, physicals, rad worker, etc.) were integrated for ease of tracking. The net result was that fewer individuals' qualifications expired despite having a large (>900) ERO and are on par with other licensees. Adequate personnel are qualified to fill positions to support around the clock coverage if needed. Furthermore, administrative controls prevent unqualified individuals from responding to an event.

.3 Identification, Evaluation, and Resolution of Problems

Inspection findings in previous sections of this report also had implications regarding PSEG's identification, evaluation, and resolution of problems, as follows:

Section 1R22.1 - PSEG corrective actions for a B SLC pump IST failure in March 2002 did not adequately preclude a similar degraded condition from causing an A SLC pump IST failure on October 16, 2002.

Additional items associated with PSEG's corrective action program were reviewed without findings and are listed in Sections 1R04, 1RO5, 1R06, 1R12, 1R13, 1R15, 1R16, 1R19, 1R22.3, 1R23, 4OA1.2, and 4OA2 of this report.

4OA3 Event Followup

(Closed) LER 354/2002-007: Core Spray Discharge Line Alarms Inoperable. This LER discussed the operation of the plant with the B core spray loop pressure transmitter instrument root valve closed. PSEG entered this into their corrective action system under notification 20114659. The inspectors reviewed the LER and corrective actions and identified no findings of significance. The failure to maintain the B core spray loop high/low pressure alarm function operable as required by TS 3.5.1 Action f and TS 3.4.3.2 Action d constitutes a violation of minor safety significance and is not subject to formal enforcement action in accordance with Section IV of the NRC's Enforcement Policy.

4OA4 Cross-Cutting Issues

Of the nine licensed operator crews evaluated, three failed to pass their facility-administered requalification examinations. These failures involved human performance. (Section R11.1)

The poor problem identification and inadequate corrective actions for the B SLC pump IST failure represented an example of the cross-cutting issue of problem identification and resolution. (Section R22.1)

4OA5 Other Activities

.1 TI 2515/148, Revision 1, Appendix A - Inspection of Nuclear Reactor Safeguards Interim Compensatory Measures

a. Inspection Scope

An audit of PSEG's performance of the interim compensatory measures imposed by the NRC's Order Modifying License, issued February 25, 2002, was completed in accordance with the specifications of NRC Inspection Manual Temporary Instruction (TI) 2515/148, Revision 1, Appendix A, dated September 13, 2002.

b. Findings

No findings of significance were identified.

.2 TI 2515/149 Mitigating System Performance Index Pilot Verification

a. Inspection Scope

The inspectors and the Region I Senior Reactor Analyst (SRA) audited PSEG's Mitigating Systems Performance Index (MSPI) October 2002 data for the HPCI system and the cooling water support systems (SSW and SACS). The objective of the audit was to verify that PSEG correctly implemented the MSPI pilot guidance for reporting unavailability and unreliability as required by TI 2515/149. The audit was performed on November 26 to 27 and December 19, 2002. The audit included interviews with PSEG risk analysts and other technical staff, reviews of operating logs, maintenance records, conditions reports, UFSAR, *Maintenance Rule System Function and Risk Significant Guide*, system drawings, PSEG PRA and SPAR model, and the NRC SDP notebook.

b. Findings

PSEG made a reasonable best effort to provide accurate and complete data for this voluntary pilot program. The specific audit results of TI 2515/149 are documented in

Supplementary Information, Section E, and were discussed with PSEG on December 19, 2002.

4OA6 Management Meetings

a. Exit Meeting Summary

On January 8 the inspectors presented their overall findings to members of PSEG management led by Mr. Lon Waldinger. PSEG management stated that none of the information reviewed by the inspectors was considered proprietary.

b. PSEG/NRC Management Meeting

On December 17-18, 2002, the Deputy Regional Administrator, the Director of the Division of Reactor Projects, and members of the staff, toured Hope Creek and Salem Generating Stations, and met with resident inspectors and selected PSEG managers. The tour was part of the Region's program of site visits in accordance with NRC Inspection Manual Chapter 0102.

Attachment 1
SUPPLEMENTAL INFORMATION

a. Key Points of Contact

Craig Banner, EP Supervisor
Dave Burgin, EP Manager
Terry Cellmer, Radiation Protection Manager
Matt Conroy, Maintenance Rule Supervisor
Archie Faulkner, Supervisor Fundamentals and License Exam Preparation
Craig Johnson, Senior Staff Engineer
Kurt Krueger, Operations Manager
Doug McCollum, Valve Engineering Supervisor
Gabor Salamon, Nuclear Safety & Licensing Manager
Lon Waldinger, Director - Operations

b. List of Items Opened, Closed, and Discussed

Opened/Closed

50-354/02-07-01	FIN	Of the nine licensed operator crews evaluated, three failed to pass their facility-administered requalification examinations. (Section R11.1)
50-354/02-07-01	NCV	PSEG corrective actions for a B SLC pump IST failure in March 2002 did not adequately preclude a similar degraded condition from causing an A SLC pump IST failure on October 16, 2002. (Section R22.1)

Closed

50-354/02-007-00	LER	Core Spray Discharge Line Alarms Inoperable. (Section OA3)

c. List of Documents Reviewed

In addition to the documents identified in the body of this report, the inspectors reviewed the following documents and records:

Hope Creek Generating Station (HCGS) Updated Final Safety Analysis Report
Hope Creek Generating Station (HCGS) Technical Specifications
Technical Specification Action Statement Log (SH.OP-AP.ZZ-108)
HCGS NCO Narrative
HCGS Plant Status Report
Weekly Reactor Engineering Guidance to Hope Creek Operations

Hope Creek Operations Night Orders and Temporary Standing Orders
Station Operations Review Committee Meeting Minutes (02-038, 02-047, 02-048, 02-049, 02-053)
Nuclear Review Board Meeting Minutes (02-04)
Maintenance of Emergency Preparedness Performance Indicator (PI) Data (NC.EP-DG.ZZ-000(Z)

Section 1R04 corrective action notifications reviewed: 20114561, 20114604, 20114659, 20115156, 20115817, 20115939, 20118268, 20118322, 20120866, 20124241, 20125474, and 20125702.

Section 1R05 corrective action notifications reviewed: 20075347, 20114635, 20114983, 20116505, 20120809, 20123793, 20124081, 20124111, and 20124923.

Section 1R12 documents reviewed:

- *Maintenance Rule System Checkbook*
- *2002 Targeted Equipment List*
- *PSEG Preventable System Functional Failures Database*
- *Service Water (EA) & Traveling Screen/ Screen Wash (EP) System Health Report for Period 5/1/02 to 7/31/02*
- *Safety and Turbine Auxiliaries Cooling System Health Report for Period 2/1/02 to 4/30/02*
- *Service Air & Control Air System Health Report for Period 6/1/02 to 9/1/02*
- Notifications 20036641, 20059082, 20068754, 20069091, 20069141, 20077560, 20089864, 20090833, 20091287, 20091949, 20092424, 20095344, 20096280, 20096552, 20101266, 20101498, 20101872, 20102942, 20114601, 20116773, 20123866, 20124335, 20124683, and 20125232
- Work orders 30012200, 30002672, 30020921, 60010759, 60019832, 60019954, 60026194, 60029160, and 60032142
- Evaluations 70021447, 70022917, 70024144, 70027506, 70028220, 80027948, 80029511, and 80042379

Section 1R13 corrective action notifications reviewed: 201149531, 20115504, 20115546, 20116314, 20116437, 20116473, 20117961, 20117963, 20117987, 20118282, 20121466, and 20124800.

Section 1R19 documents reviewed:

- *Residual Heat Removal Subsystem B Valves - Inservice Test* (HC.OP-IS.BC-0102)
- *Residual Heat Removal Subsystem D Valves - Inservice Test* (HC.OP-IS.BC-0104)
- *Motor Operated Valve Thermal Overload Protection Surveillance* (HC.MD-ST.ZZ-0009)
- *Emergency Diesel Generator DG400 Operability Test* - Monthly (HC.OP-ST.KJ-0004)
- *Single Cell Battery Charge and/or Cell Replacement* (HC.MD-GP.ZZ.0014)

- *High Pressure Coolant Injection System Valves - Inservice Test* (HC.OP-IS.BJ-0101)
- *Bailey 862 Logic Module Trending Program* (HC.SE-PR.RL-0001)
- *Bailey Module Reliability Program* (HC.IC.AP.ZZ-0017)
- Bailey 862 System Solid Logic Module Failure Data File
- Safety Evaluation by the Office of Nuclear Reactor Regulation, Supporting Amendment No. 40 to Facility Operating License No. NPF-57, dated March 13, 1991.
- *125V Battery Quarterly Surveillance* (HC.MD-ST.PK-0002)
- Safety Evaluation by Office of Nuclear Reactor Regulations, Supporting Amendment No. 114 to Facility Operating License No. NPF-57, dated February 9, 1999.

Section 1R22.3 corrective action notifications reviewed: 20115706, 20115904, 20116810, 20116852, 20117073, 20120282, 20120283, 20121307, and 20124310.

d. List of Acronyms

ANS	Alert and Notification System
ATWS	Anticipated Transient Without Scram
BWROG	Boiling Water Reactor Owners Group
CST	Condensate Storage Tank
EDG	Emergency Diesel Generator
ERO	Emergency Response Organization
F-V	Fussell-Vesely
HCGS	Hope Creek Generating Station
HPCI	High Pressure Coolant Injection
IST	Inservice Test
LERs	Licensee Event Reports
MR	Maintenance Rule
MSPI	Mitigating Systems Performance Index
NCV	Non Cited Violation
NOED	Notice of Enforcement Discretion
NRC	Nuclear Regulatory Commission
PARS	Publicly Available Records
PI	Performance Indicator
PM	Preventive Maintenance
PMT	Post Maintenance Testing
PRA	Probabilistic Risk Assessment
PSEG	Public Service Electric Gas
RCS	Reactor Coolant System
RHR	Residual Heat Removal
SACS	Safety Auxiliaries Cooling System
SDP	Significance Determination Process
SLC	Standby Liquid Control
SPAR	Standard Plant Analysis Risk
SRA	Senior Reactor Analyst
SRV	Safety Relief Valve

SSFF	Safety System Function Failure
SSLM	Solid State Logic Module
SSW	Station Service Water
TI	Temporary Instruction
TS	Technical Specification
TVT	Turbine Valve Testing
UFSAR	Update Final Safety Analysis Report

e. Results of TI 2515/149 MSPI Pilot Verification - Hope Creek

Inspection Requirements

The inspectors performed Temporary Instruction (TI) 2515/149, "Mitigating Systems Performance Index (MSPI) Pilot Verification," at Hope Creek on November 26 through 27 and December 19, 2002. The inspectors verified the MSPIs for the high pressure coolant injection (HPCI) system and the cooling water support systems. The results were as follows (paragraph numbers correspond to the inspection requirements sections of TI 2515/149).

03.02 Risk Significant Functions

No discrepancies were noted. Public Service Electric & Gas (PSEG) correctly identified the risk significant functions for the selected systems.

03.03 Success Criteria

PSEG had not identified a complete list of parameter-based success criteria for the monitored systems. In the cases where PSEG had not identified success criteria, PSEG informed the inspectors that they defaulted to the design basis criteria. However, PSEG was unable to identify the design basis parameters and values during the inspection. Some examples included:

- Condensate storage tank (CST) and suppression pool level and temperature bands to support successful operation of HPCI;
- HPCI, station service water (SSW), and safety auxiliary cooling system (SACS) valve actuation times; and
- SACS pump flow rates.

In addition, differences were identified among PSEG's functional success criteria for the MSPI, PSEG's probabilistic risk assessment (PRA), NRC's Standardized Plant Analysis Risk (SPAR) model, and NRC's significance determination process (SDP) notebook. The inspectors noted the following specific examples.

- PSEG's PRA contained an inconsistency on the need for low pressure injection following successful HPCI operation for events that involve a stuck open relief valve. The PRA documentation indicated that low pressure injection was needed following successful HPCI operation to satisfy the inventory control function. However, the event trees for the initiating events that involved a stuck open relief valve did not consistently require low pressure injection following successful HPCI operation. PSEG was unable to explain the inconsistent treatment of HPCI success during the inspection.

- PSEG's PRA credits HPCI for level control and high pressure inventory control for anticipated transients without scram (ATWS) events, whereas the SPAR model does not.

- The SPAR model specifies that in a station blackout condition, fire water injection is needed for inventory control following successful HPCI injection to extend the time available to recover AC power beyond four hours to the station battery depletion time. However, PSEG credits HPCI as being capable of inventory control until battery depletion time without the need for fire water injection.

- The HPCI discharge valve to core spray, 1BJHV-F006, and the HPCI discharge valve to main feedwater, 1BJHV-8278, are not included in the SPAR model. These valves open on an HPCI actuation signal and are active components in the HPCI MSPI. These valves are not redundant.

- For successful operation of the SACS system, PSEG's PRA specifies two pumps and two heat exchangers in one loop, or one pump and two heat exchangers in one loop, and one pump and one heat exchanger in the other loop. However, the SPAR model assumes successful SACS operation with one pump and one heat exchanger in both loops.

- For successful operation of the SSW system, PSEG's PRA specifies one of two pump trains in each loop. However, the SPAR model specifies two of two pump trains per loop if the loop cross-tie is closed or three of four pump trains if the cross-tie is open.

03.04 Boundary Definitions

PSEG did not include all necessary active components for the monitored train or system in the MSPI calculation and incorrectly included a component in a system boundary. The inspectors noted the following specific examples.

- The HPCI suction valve from the CST, 1BJHV-F004, was not included as an active component. PSEG recognized that the valve should have been an active component, but because the valve was not modeled within their PRA, they were unable to include it within the MSPI calculation. The inspectors noted that the three valve failures in this system were associated with this valve.

- The HPCI minimum flow valve was not included as an active component. In the event that the valve does not close following an HPCI actuation, the HPCI system would not be able to fulfill its function. (The valve opens upon start of the pump and closes when pump discharge flow exceeds 560 gallons per minute.) Therefore, it should have been treated as an active component. In addition, PSEG's PRA did not model the HPCI minimum flow valve; consequently, PSEG did not have a Fussell-Vesely (F-V) importance measure for the valve to be used in the MSPI calculation.

- PSEG incorrectly included the RHR heat exchanger SACS discharge valves, HV2512A and HV2512B, in the cooling water support system performance indicator instead of the RHR performance indicator. The MSPI guidance specifies that the last valve, which connects the cooling water support system (SACS) to the other monitored system (RHR) is included in the other monitored system (RHR).

03.05 Train/Segment Unavailability Boundary Definition

PSEG did not identify the boundaries of the monitored systems in accordance with the guidance contained in Appendix A of TI 2525/149, particularly those boundaries (mechanical and electrical) associated with the MSPI active components (motor-driven pumps, turbine-driven pumps, etc . . .).

03.06 Entry of Baseline Data - Planned Unavailability

No discrepancies were noted.

03.07 Entry of Baseline Data - Unplanned Unavailability

No discrepancies were noted.

03.08 Entry of Baseline Data - Unreliability

PSEG was "pooling" the data (e.g., failures and demands) for like components and entering the pooled data for each individual component, thereby double counting the failures and demands. In addition, the valve demands used in the MSPI calculation were incorrect. The original valve demand estimate was based on the number of active valves multiplied by the total number of pump demands. However, the number of valve demands was not equivalent to the number of pump demands, because each valve was not demanded every time that the pump was demanded for testing. Also, several of the active components were not included within the EPIX database. At the end of the inspection, PSEG was in the process of determining an appropriate estimate for the number of demands for the active components.

03.09 Entry of Performance Data - Unavailability

No discrepancies were noted.

03.10 Entry of Performance Data - Unreliability

Please refer to section 03.08 for details.

03.11 MSPI Calculation

The MSPI F-V coefficients were not able to be verified against PSEG's PRA that was qualified for use by the NRC staff, because PSEG had not identified all of the F-V coefficients for the active components and the staff had not qualified the PRA.

PSEG did not include all of the failure modes of the active components (e.g., HPCI turbine-driven pump) in the evaluation to determine the limiting F-V/UR ratio for an active component. For example, PSEG considered the HPCI turbine stop valve part of the HPCI turbine-driven pump. However, the valve was treated as an independent component that would fail the HPCI train within their PRA. In accordance with the MSPI guidance, the F-V/UR ratio that is used in the MSPI calculation should be the maximum ratio of the F-V/UR ratios for each of the basic events that fail the train. Consequently, the F-V/UR ratio for the HPCI pump used in the MSPI calculation may not have been correct.

PSEG's PRA assumed a mission time of 24 hours for the HPCI system. However, the HPCI pump's failure-to-run basic event in the PRA model was based on a 4-hour mission time. The basic event failure probability would have been approximately a factor of six larger if it had been based upon a 24-hour mission time which would have, in turn, changed the importance measures for the HPCI pump. Consequently, the F-V/UR ratio for the HPCI pump used in the MSPI calculation may not have been correct.

PSEG's PRA model assumed that the A and B SSW pumps and the A and B SACS pumps were normally operating. Consequently, the PRA model did not contain basic events for these pump trains being unavailable or for the failure of these pumps to start in the event that the C and D pumps were operating. Also, because the model assumed that the A and B pumps were operating, the model did not contain basic events for the failure of the pump discharge valves to open. In each of these cases, PSEG used the importance measures associated with the C train as a surrogate for the A and B trains.

The inspectors noted the following minor errors in the calculations of the F-V/UA and F-V/UR ratios.

- The F-V/UA ratio for the HPCI train contained a rounding error. The ratio entered into the MSPI calculation should have been 11.97 instead of 11.91.

- The F-V/UR ratio for the HPCI injection valves (1BJHV-F006 and 1BJHV-8278) contained a rounding error. The ratio entered into the MSPI calculation should have been 5.22E-3 instead of 5.23E-3.

- The F-V/UA ratio for the D service water pump train unavailability should have been 4.46E-1 instead of 4.53E-1.

- The F-V/UA ratio for the D SACS pump train unavailability should have been 9.13E-2 instead of 9.84E-2.

PSEG used the F-V coefficients associated with the initiating event contribution for the cooling water support system pumps failing to run (e.g., SWS-MDP-FR-IA502/IB502/IC502/ID502 and SAC-MDP-FR-IA210/IB210/IC210/ID210). However, PSEG did not use the associated basic event failure probability when determining the F-V/UR ratio. Consequently, the F-V/UR ratio for these pumps used in the MSPI calculation may not have been correct.

The F-V importance value for several basic events associated with active components were below the truncation value of 1.0E-5. In these cases, PSEG used a default value of 1.0E-5.

General Observations

While conducting the TI, the inspectors made the following general observations.

- The MSPI for the HPCI and reactor core isolation cooling (RCIC) systems were invalid (one failure would result in the MSPI crossing a threshold, i.e., a false positive indication).

- The emergency AC power system, the residual heat removal (RHR) system, and the cooling water support system MSPIs needed a large number of failures for the indexes to cross the Green/White threshold. For example, approximately 20 failures of the diesel generators to start or 10 failures to run, would be necessary over the three-year period covered by the indicator before the Green/White threshold would be crossed. In addition, a large number of unavailability hours would be necessary before the indexes would cross the Green/White threshold. For example, if an additional 2200 hours of unavailability per diesel generator were added to the emergency AC power MSPI, the Green/White threshold would still not have been crossed for this indicator. These results did not appear to be consistent with the MSPI being capable of discerning significant adverse departures from expected performance (i.e., false negative indications).

The inspectors noted that the frequency of false positive and false negative indications will be evaluated following completion of the MSPI pilot.