May 13, 2004

Mr. Roy A. Anderson
Chief Nuclear Officer and President
PSEG LLC - N09
P. O. Box 236
Hancocks Bridge, NJ 08038

SUBJECT: HOPE CREEK NUCLEAR GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 05000354/2004002

Dear Mr. Anderson:

On March 31, 2004, the US Nuclear Regulatory Commission (NRC) completed an inspection at your Hope Creek Station. The enclosed integrated inspection report documents the inspection findings, which were discussed on April 26, 2004, with Mr. Jim Hutton 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.

This report documents six findings of very low safety significance (Green), all of which were determined to involve violations of NRC requirements. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these six findings as non-cited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. Additionally, a licensee-identified violation which was determined to be of very low safety significance is listed in this report. If you contest any NCV in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, 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, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at Hope Creek.

Since the terrorist attacks on September 11, 2001, the NRC has issued five Orders and several threat advisories to licensees of commercial power reactors to strengthen licensee capabilities, improve security force readiness, and enhance access authorization. In addition to applicable baseline inspections, the NRC issued Temporary Instruction 2515/148, "Inspection of Nuclear Reactor Safeguards Interim Compensatory Measures," and its subsequent revision, to audit and inspect licensee implementation of the interim compensatory measures required by order. Phase 1 of TI 2515/148 was completed at all commercial nuclear power plants during calendar year 2002, and the remaining inspection activities for Hope Creek Generating Station were completed in 2003. The NRC will continue to monitor overall safeguards and security controls at Hope Creek Generating Station.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure, and your response (if any) 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/

Daniel J. Holody Jr.
Acting Branch Chief
Projects Branch 3
Division of Reactor Projects

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

Enclosure: Inspection Report 05000354/2004002
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No:	05000354
License No:	NPF-57
Report No:	05000354/2004002
Licensee:	PSEG LLC
Facility:	Hope Creek Nuclear Generating Station
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	January 1, 2004 - March 31, 2004
Inspectors:	M. Gray, Senior Resident Inspector M. Ferdas, Resident Inspector J. Schoppy, Senior Reactor Inspector S. Pindale, Senior Reactor Inspector F. Bower, Senior Reactor Inspector T. Fish, Senior Operations Engineer J. Furia, Senior Health Physicist P. Kaufman, Senior Reactor Inspector S. McCarver, Reactor Inspector A. Dimitriadis, Physical Security Inspector D. Caron, Physical Security Inspector J. Talieri, Reactor Inspector
Approved By:	Daniel J. Holody Jr. Acting Branch Chief Projects Branch 3 Division of Reactor Projects

Enclosure

TABLE OF CONTENTS

SUMMARY OF FINDINGS

IR 05000354/2004-002; 01/01/2004 - 03/31/2004; Public Service Electric Gas Nuclear LLC, Hope Creek Generating Station; Fire Protection, Maintenance Effectiveness, Operability Evaluations, Refueling and Outage Activities, Temporary Plant Modifications, Other Activities.

The report covered a 13-week period of inspection by resident inspectors, and an announced inspection by a regional radiation specialist and security inspectors. Six Green non-cited violations (NCVs) were identified. Additionally, one licensee identified Green NCV was documented. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter (IMC) 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. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. A self revealing finding occurred on January 12 when the primary containment isolation system (PCIS) actuated during a sensor calibration on the reactor building exhaust (RBE) radiation monitoring system (RMS). The operators manually scrammed the reactor when two main steam isolation valves drifted off their full open positions due to a PCIS isolation. An evaluation determined that the PCIS actuated due to an inadequately made-up electrical connection to an RBE RMS detector. This finding was determined to be a non-cited violation (NCV) of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings."

  This finding was more than minor because it affected the procedure quality attribute of the initiating events cornerstone. The finding was of very low safety significance because the inadequate procedure or work instruction guidance did not contribute to a primary or secondary system loss of coolant accident initiator, did not increase the likelihood of a fire or flooding condition, and did not contribute to a loss of mitigation equipment functions. (Section 1R12)

Cornerstone: Mitigating Systems

- Green. The inspectors identified that transient combustible control requirements were not met during a maintenance activity in the A core spray pump room because engineering approval had not been provided for storing oil, and the oil drum was stored in a location different than specified in the transient combustible permit. This finding was determined to be a non-cited violation of Hope Creek Technical Specification 6.8.1, "Procedures and Programs."

The finding was more than minor because the quantity of combustible material stored was greater than assumed in the fire hazards analysis limits. The finding affected the human performance attribute of the mitigating systems cornerstone. The finding was determined to be of very low risk significance because it did not result in an impairment or degradation of fire protection features or defense in depth elements. (Section 1R05)

- Green. The inspectors identified two instances where the basis was not supported with correct information for concluding the B emergency diesel generator (EDG) remained operable with a load wandering condition. The finding was determined to be a non-cited violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings."

  This finding was more than minor because the issues affected the equipment performance attribute of the mitigating systems cornerstone objective to maintain the B EDG reliable. The finding was determined to be of very low safety significance for mitigation systems because the finding is a qualification deficiency confirmed not to result in a loss of EDG safety function. (Section 1R15)

- Green. The inspectors determined that PSEG did not adequately identify drywell pipe insulation deficiencies during a December 2003 plant outage such that the inspectors observed additional deficiencies during a March 2004 plant outage that required correction. Additionally, the inspectors identified problems with an evaluation performed on the use of tape on drywell piping insulation. This finding was determined to be a non-cited violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action."

  The finding was more than minor because it affected the design control attribute of the mitigating systems cornerstone objective to maintain mitigation equipment reliable. The finding was determined to be of very low safety significance because the finding is a design deficiency confirmed not to result in a loss of safety function. (Section 1R20)

- Green. The inspectors identified temporary modification instructions were not followed for controlling battery room temperatures. This impacted the reliability of 125 VDC safety-related batteries because room temperatures decreased to a temperature outside the specified band. The finding was determined to be a non-cited violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings."

  This configuration control issue was more than minor because it affected the mitigating systems cornerstone objective of maintaining the reliability of the 1BD411 125 VDC battery capacity. The finding was of very low safety significance because it did not result in the safety-related batteries being declared inoperable. (Section 1R23)

- Green. The inspectors identified that the acceptance criteria for 4.16 kv vital bus under-voltage relay reset setpoints used in calibration procedures did not ensure successful fast bus transfer to the redundant offsite power source if the first offsite source was unavailable. The finding was determined to be a non-cited violation of 10 CFR 50, Appendix B, Criterion III, “Design Control.”

This finding was more than minor because it affected the design control attribute of the mitigating systems cornerstone objective to ensure the availability, reliability, and capability of electrical systems to prevent undesirable conditions. The finding was of very low safety significance because the degraded voltage relays had been set with sufficient margins to avoid a loss of electrical distribution function. (Section 4OA5.1)

B. Licensee Identified Violations

A violation of very low safety significance, which was identified by PSEG, has been reviewed by the inspectors. Corrective actions taken or planned by PSEG have been entered into PSEG's corrective action program. This violation and corrective actions are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

The Hope Creek Generating Station started the inspection period at 100% power. On January 10 operators performed a planned power reduction to 68% for maintenance on switchyard equipment and the A reactor feedwater pump. On January 12 operators manually scrammed the reactor when they observed the B and D inboard main steam isolation valves (MSIV) indicating dual position. The MSIVs began to close when operating air to the MSIVs was isolated due to a spurious trip of a reactor building exhaust (RBE) radiation monitoring system (RMS) during a detector calibration. The cause of the spurious trip was due to a loose connector on an RBE RMS detector. The connector was repaired and other similar connectors were verified to be properly installed. The plant was returned to 100% power on January 19.

On January 31, operators performed a planned power reduction to 61% for power suppression testing. The testing identified the location of a minor fuel clad defect within the reactor. Operators inserted control rods adjacent to the affected fuel assembly to reduce power in the affected fuel assembly and returned the plant to 100% power on February 4.

On February 23, the A and B station service water system (SSWS) strainers experienced elevated differential pressure due to grass intrusion. At the time the C SSWS pump and traveling water screen (TWS) and the B control room emergency filtration (CREF) unit were out of service for scheduled maintenance. While the condition cleared on the B SSWS strainer, the A SSWS strainer motor tripped and there was a decrease in A SSWS pump cooling water flow to the A station auxiliaries cooling system (SACS), which provided cooling to the A CREF unit. With both the A and B CREF units inoperable, operators commenced a plant shutdown in accordance with technical specification requirements. The plant shutdown was terminated at 94% power after the C SSWS pump and screen were returned to service to restore cooling water to A SACS loop and A CREF unit. The unit was returned to 100% power on February 24.

On March 19, operators commenced a planned reactor shutdown to support a planned maintenance outage. The purpose of the outage was to repair a valve in the main steam pipe tunnel (F020), replace two main steam safety relief valves (SRV), replace seven control rod drive mechanism (CRDM) o-rings, repair a reactor core isolation cooling (RCIC) system valve (F008), and investigate an abnormal noise originating on the A RHR shutdown cooling piping. At the end of the inspection period operators were preparing to return the plant to operation.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

The inspectors reviewed one adverse weather preparation activity and PSEG's response to one actual severe weather condition. The inspectors reviewed applicable documents associated with adverse weather as listed in the Supplemental Information report section.

Cold Weather Preparation. The inspectors reviewed the scope of PSEG's cold weather preparations to verify they adequately prepared equipment to operate reliably in freezing conditions. The inspectors focused on the adequacy of heating equipment and pipe insulation for equipment in the service water intake structure and fire water pump house.

Freezing Weather Conditions. The inspectors verified that heat tracing, insulation, and space heaters were properly protecting equipment during freezing weather conditions in January. The inspectors walked down portions of the SSWS, condensate storage tank, and the fire water pump house.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

a. Inspection Scope

The inspectors performed three partial equipment alignment inspections and one complete alignment inspection on the residual heat removal (RHR) system. Partial alignment inspections were completed on the filtration recirculation ventilation system (FRVS), service air system, and SSWS. The inspectors reviewed applicable documents associated with equipment alignments as listed in the Supplemental Information report section.

Partial System Walkdowns. On January 7, the inspectors verified that FRVS was properly returned to a standby alignment after it was taken out of service. The inspectors reviewed FRVS system drawings and operating procedures, performed field walkdowns of accessible portions of FRVS, and observed control room indications.

The 10K107 service air compressor was out of service for scheduled maintenance on January 28. The inspectors verified that the operability of the redundant 00K107 service air compressor and other service air system components by verifying the system was aligned in accordance with its operating procedure. The inspectors performed a field walkdown of accessible portions of the service air system and observed control room indications.

On January 5, the inspectors walked down the SSWS traveling water screens and supporting equipment to ensure the system was aligned and operating as described in the updated final safety analysis report and procedures to remove debris from the river water intake.

Complete System Walkdowns. The inspectors conducted an alignment verification of the B train of the RHR system. The inspection included a review of procedures and drawings to determine the correct system lineup and a field walkdown of accessible plant areas to identify any discrepancies and verify that the RHR system was configured to perform its safety function. In addition, the inspectors reviewed the RHR system operating procedure and observed control room indications to independently verify the RHR alignment was consistent with plant procedures. A field walkdown was performed to ascertain the material condition of the RHR system. The attributes verified during the field walkdown included electrical power requirements, labeling, hangers and support installation, and associated support systems status. The inspectors also verified there were not visible indications of leakage.

A review of notifications initiated in the last year was performed to verify that PSEG was identifying and resolving RHR system problems and to verify that outstanding orders did not significantly affect the function of the B train of the RHR system.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope

The inspectors performed nine plant walkdowns to observe combustible material control, fire detection and suppression equipment availability, and active fire protection compensatory measures. The inspectors reviewed Hope Creek's Individual Plant Examination for External Events (IPEEE) for risk insights and design features credited in these areas. Additionally, the inspectors reviewed notifications documenting fire protection deficiencies to verify identified problems were being evaluated and corrected. The following plant areas were inspected:

- B 1E switchgear room on January 15
- B 125 volt (V) DC battery charger room on January 20
- B RHR pump and heat exchanger room on January 22
- Torus room on February 10
- A core spray room on March 4
- A/C bay in the service water intake structure (SWIS) on March 10

- A and B primary containment instrument gas (PCIG) rooms on March 10
- Primary Containment (Drywell) on March 22
- A and B emergency diesel generator (EDG) rooms on March 25

b. Findings

Introduction. The inspectors identified that transient combustible control requirements were not met during a maintenance activity in the A core spray pump room because engineering approval had not been provided for storing oil and the oil drum was stored in a location different than specified in the transient combustible permit. The finding was of very low safety significance (Green) and a non-cited violation of Hope Creek TS 6.8.1 to correctly implement fire protection program procedures.

Description. During a walkdown of the reactor building on March 4, the inspectors observed a fifty-five gallon drum of oil was stored in the A core spray pump room (room 4118). The inspectors reviewed fire program and maintenance records and determined operations personnel had requested transient combustible permit (TCP) HTC-04-RB1-002 on February 20 to store this oil. This was for changing the A and C core spray pump motor oil (work orders 40017604 and 40017660). The inspectors observed that while TCP HTC-04-RB1-002 approved the storage of oil in the vestibule area outside the A core spray room (room 4117), the oil was stored in the core spray pump room (room 4118).

Additionally, in response to the inspectors' questions, PSEG fire protection personnel could not verify that an engineering assessment was completed as required by fire protection procedures. PSEG procedure NC.FP-AP.ZZ-0025, "Precautions Against Fire," Section 5.6 states that the storage of combustibles in safety areas must be approved by engineering to address fire loading and compensatory measures. The fire loading created by the fifty-five gallons of oil stored in the core spray room was greater than the fire hazards analysis limit of fifteen gallons. The inspectors observed that while the engineering assessment block was checked as required on the TCP form, the block affirming engineering approval was not checked. Notwithstanding these deficiencies, PSEG had initiated an hourly fire watch for room 4117. However, it was not clear whether the fire watch also entered room 4118 where the oil was actually stored.

Analysis. The performance deficiency involved a failure to comply with procedural requirements regarding storage of transient combustible material and ensuring an engineering assessment was completed for this fire condition. The finding was more than minor because the quantity of combustible material incorrectly stored or evaluated was greater than the limits assumed in the fire hazards analysis (See example 4.k in NRC Inspection Manual 0612, Appendix E). The finding affected the human performance attribute of the mitigating systems cornerstone objective to maintain the availability of the A core spray pump. This finding had a human performance cross-cutting aspect because it involved personnel not following procedural instructions.

The inspectors evaluated the finding in accordance with NRC Inspection Manual 0609, Appendices A and F. The fire hazard analysis and the IPEEE did not credit core spray as equipment necessary for safe shutdown. The finding did not result in an impairment or degradation of fire protection features or defense in depth elements. The finding was determined to be of very low risk significance (Green) because the drum was sealed closed and no ignition sources were identified.

Enforcement. Hope Creek TS 6.8.1.g requires that written procedures be established, implemented, and maintained for activities which include implementation of the fire protection program. Contrary to this requirement, from February 23 to March 4, 2004, PSEG did not control the storage of combustible material in a safety-related room in accordance with PSEG procedure NC.FP-AP.ZZ-0025, Section 5.6 and the applicable transient combustible permit. However, because the violation was of very low safety significance (Green) and PSEG entered the deficiency into their corrective action system in notifications 20186049 and 20183570, this finding is being treated as a non-cited violation, consistent with section VI.A of the NRC Enforcement Policy.
(NCV 50-354/04-02-01)

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

The inspectors performed one internal flood protection activity in the B and D RHR pump rooms. The Hope Creek Updated Final Safety Analysis Report (UFSAR), Individual Plant Examination (IPE) and plant procedures were reviewed to verify that PSEG's flooding mitigation plans and installed equipment for the B and D RHR pump rooms were consistent with design bases and risk analysis assumptions. The inspectors toured the areas to determine whether flood vulnerabilities existed and to assess the physical condition of flood barriers and floor drains.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

a. Inspection Scope

Annual Review. The inspectors reviewed the test data from two heat exchanger performance tests. The inspectors verified that the A and B SACS heat exchanger performance was acceptable after a high grass condition on February 23. The inspectors walked down accessible portions of SACS and SSWS and reviewed notifications (20148516, 20178993, 20178663) associated with heat sink performance and conditions. Documents associated with these reviews are listed in the Supplemental Information report section.

Biennial Review. Based on a plant specific risk assessment and previous inspections, the inspectors selected three heat exchanger samples for this review: SACS, EDG lube oil, and high pressure coolant injection (HPCI) room coolers. The SACS provides cooling to the EDG lube oil coolers and the HPCI room coolers. The SACS heat load is transferred to the SSWS via the SACS heat exchangers. The SSWS supplies cooling water from the Delaware River which is the ultimate heat sink for the plant.

The inspectors reviewed PSEG's methods (inspection, cleaning, maintenance, and performance monitoring) used to ensure heat removal capabilities for the SACS heat exchangers and compared them to PSEG's commitments made in response to Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment." The inspectors verified that periodic SSWS side pressure drop readings for the SACS heat exchangers had been recorded in order to monitor for potential macro-fouling conditions. The inspectors reviewed the eddy current test methodology and results to verify that the number of plugged SACS heat exchanger tubes was bounded by assumptions in the engineering analyses.

The inspectors reviewed the design fouling factor assumptions for the HPCI room coolers and the engineering analyses of minimum calculated SACS flow rate to the room coolers. This review was performed to verify that the minimum calculated SACS flow rate, in conjunction with the heat transfer capability of the room coolers, supported the minimum heat transfer rates assumed for the HPCI area during accident and transient conditions. Preventive maintenance procedures were reviewed to ensure activities existed for cleaning of the HPCI room coolers to ensure the fouling factors assumed in engineering analyses were reasonable. The inspectors reviewed EDG lube oil cooler modeling analyses against the heat exchanger specification sheets to ensure the analysis was valid. This included calculations related to minimum allowable SACS flow rate to the coolers. The inspectors also reviewed SSWS silt survey results and engineering associated trending data and action plans.

The inspectors compared surveillance test and inspection data to the established acceptance criteria to verify that the results were acceptable and that operation was consistent with design. The inspectors walked down the selected heat exchangers, control room instrumentation panels, the chlorination system, and the SSWS to assess the material condition of these systems and components.

Furthermore, the inspectors reviewed a sample of corrective action notifications related to these heat exchangers to ensure that PSEG appropriately identified, characterized, and corrected problems related to these components. Documents associated with these reviews are listed in the Supplemental Information report section.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

The resident inspectors observed one simulator training scenario to assess operator performance and training effectiveness. The scenario involved a turbine trip from 100% power. The scenario was designed to allow reactor operators to practice scram actions and post-scram level control with feedwater. 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. Finally, the inspectors reviewed applicable documents associated with licensed operator requalification as listed in the Supplemental Information report section.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

Routine Maintenance Effectiveness Inspection. The inspectors reviewed the performance and maintenance history of three systems or components to verify that PSEG was effectively evaluating and monitoring the effectiveness of their maintenance activities. Specifically, the inspectors reviewed the effectiveness of maintenance regarding the following degraded conditions: C EDG jacket water leaks from cylinder jumper o-rings, reactor building exhaust (RBE) radiation monitoring system (RMS), and A SSWS strainer. Additionally, the inspectors compared documented functional failure determinations and unavailable hours to those being tracked by PSEG to evaluate the effectiveness of condition monitoring and to determine if performance goals were being met per maintenance rule (MR) implementation. Applicable work orders and corrective action notifications were reviewed for work practice issues that could have common cause or generic implications. The inspectors also reviewed preventive maintenance tasks, system health reports and Hope Creek MR Expert Panel Meeting Minutes to assess work practices and system performance. Documents reviewed are listed in the Supplemental Information section of this report.

Biennial Periodic Evaluation Inspection. The inspectors conducted a review of the Hope Creek periodic evaluation of implementation of the MR required by 10 CFR 50.65 (a)(3). The evaluation covered the period from September 2001 to June 2003. The purpose of this review was to ensure that PSEG effectively assessed its (a)(1) goals, (a)(2) performance criteria, system monitoring, and preventive maintenance activities. The inspectors reviewed the assessment to determine whether it was completed within the required time period and that industry operating experience was properly utilized. Additionally, the inspectors assessed whether Hope Creek appropriately balanced equipment reliability with unavailability when planning maintenance activities.

The inspectors selected a sample of four risk-significant systems in category (a)(1) and (a)(2) status to verify that: 1) failed structures, systems, and components were properly characterized, 2) goals and performance criteria were appropriate, 3) corrective action plans were adequate, and 4) performance was being effectively monitored in accordance with PSEG Procedure NC.NA-AP.ZZ-0016(Q), “Monitoring the Effectiveness of Maintenance.” The following systems were selected for this detailed review:

- Main Steam SRV
- Containment Atmospheric Control System (Hydrogen/Oxygen Analyzers)
- RHR system
- EDG

During the assessment period, these systems were either in (a)(1) status, were previously in (a)(1) status, or had experienced degraded performance. The inspectors reviewed corrective action documents for malfunctions and failures of these systems to determine whether 1) they had been correctly categorized as functional failures, 2) were correctly categorized as maintenance preventable, and 3) system performance was properly evaluated to support appropriate (a)(1) status determinations.

b. Findings

A Channel RBE RMS Failure

Introduction. A self-revealing finding occurred on January 12 during a manual reactor scram when the PCIS actuated during a sensor calibration on the RBE RMS. The PCIS actuated due to an inadequately made-up electrical connection to an RBE RMS detector. This finding was determined to be a non-cited violation of 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings.”

Description. The RBE RMS consists of three channels that monitor the reactor building exhaust flow for radioactivity. When two channels reach their setpoints the RBE PCIS closes containment penetration valves of those systems in contact with the primary containment atmosphere.

On January 12, technicians removed the C channel RBE RMS detector from service for calibration. During this work the A channel of the RBE RMS failed high. This completed the RBE logic and PCIS actuated, isolating containment penetrations as designed, including the primary containment instrument gas (PCIG) lines. The PCIG system provides compressed air to maintain the inboard main steam isolation valves (MSIVs) open. Approximately thirty minutes after the PCIS actuation, operators manually scrammed the reactor after observing the B and D inboard MSIVs were not fully open (dual position indication). Shortly after the scram, operators restored the C RBE RMS channel, reset the PCIS signal, and returned the PCIG system to service so that the MSIVs returned to their full open position.

PSEG investigated the root causes of the event and identified the RBE A channel signal had failed high due to a loose electrical connector on the associated signal cable. The connector was spring loaded and designed to be compressed and locked to complete the connection. Each end of the connector also had a threaded collar which was not part of the quick disconnect design. PSEG personnel identified that one of the threaded collars was not fully engaged. Personnel were able to repeat the signal failure with the connector in the as-found condition by agitating nearby conduit. This conduit was likely moved when technicians were calibrating the adjacent C channel detector. This condition resulted in the PCIS isolation and MSIV movement and the operator response to manually scram the reactor.

PSEG determined the likely cause of the loose electrical connector was due to inadequate technician skills or knowledge resulting from inadequate verbal or written communication. The A RBE RMS channel detector was last operated during a calibration on June 15, 2003 under work order 50048729. There were no written instructions or specific training regarding how to disconnect and reconnect the detector cable. PSEG validated this conclusion by requesting a number of I&C technicians to demonstrate how they would operate the connector. Several I&C technicians inappropriately unscrewed the connector collars rather then operating it in accordance with the design. Considering the inconsistency in correctly operating the connectors, the inspectors concluded the procedures and work instructions for performing this task were not adequately detailed to ensure the detector connection was reliable.

The inspectors reviewed PSEG's evaluation of this problem and determined it was of sufficient detail to identify the likely causal factors. The extent of the problem was adequately addressed by PSEG's identification of similar detectors installed in the plant and inspections that verified the threaded collars were tight. The inspectors reviewed these activities in notifications 20173614, 20173615, 20173656. 20173618, 20173619, 20173620, 20173652, 20173651 and 20173653.

Analysis. The inspectors concluded the procedures and work instructions for performing the RBE RMS detector calibrations were not adequately detailed to ensure technicians correctly assembled these detector electrical connectors. This self-revealing finding was more than minor because it affected the procedure quality attribute of the initiating events cornerstone and impacted the initiating events cornerstone objective to limit the likelihood of upset plant conditions. The inspectors reviewed this finding using the Phase 1 SDP worksheet for initiating events and determined the issue was of very low safety significance (Green) because, although the finding was a casual factor in a plant scram, the finding did not contribute to a primary or secondary system loss of coolant accident initiator, did not increase the likelihood of a fire or flooding condition, and did not contribute to a loss of mitigation equipment functions. This mitigation function was not affected because the MSIVs remained open and the condenser operated to remove decay heat after the event.

Enforcement. 10 CFR Part 50, Appendix B, Criterion V requires that activities affecting quality shall be prescribed by documented instructions and procedures of a type appropriate to the circumstance. Contrary to this, procedures and instructions used on June 15, 2003 under work order 50048729 for assembling the A channel RBE RMS detector cable electrical connector during channel calibration was not adequate to ensure the detector would operate reliably. Instructions would be appropriate for this task because the technicians' knowledge was insufficient to reliably make-up the

connector in accordance with their design. However, because the violation was of very low safety significance (Green) and PSEG entered the deficiency into their corrective action system (Notification 20173531), this finding is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy.
(NCV 50-354/04-02-02)

A SSWS Strainer Failure

The inspectors reviewed the performance history and the effectiveness of maintenance for the A SSWS strainer. This component was selected because of equipment problems during the inspection period.

On June 1, 2003, while performing maintenance on the A SSWS strainer PSEG determined the strainer backwash arm was worn and required replacement. The backwash arms are driven by a motor gearbox which rotates the arms inside the strainer. During installation of a new strainer backwash arm, maintenance personnel identified the arm shaft was approximately 3/8 inches too long (notification 20146858). This resulted in the strainer port shoes interfering with the strainer filter support. PSEG personnel further determined the shaft nut adjustment was not able to make up the length discrepancy. Engineering personnel developed an equivalent change package under order 70031821 to shim the gearbox motor and use longer hold down bolts to accommodate the longer shaft. The A SSWS strainer was returned to service on June 1, 2003.

On June 6, 2003, PSEG personnel documented in notification 20146880 that the strainer was exhibiting internal rubbing. This condition was also described in the SSWS system health report for the period of September 1 to November 30, 2003. The system health report categorized this issue as a potential seasonal readiness issue which could impact reliable operation through the grassing season. PSEG scheduled an inspection of the A SSWS strainer under work order 60037998 and other preventive maintenance activities for December 2003. However, this work was subsequently deferred (order 60038730) and rescheduled to a planned system maintenance outage on February 29, 2004.

On February 23, 2004, the A and B SSWS strainers were in operation and experienced elevated differential pressure (dp) alarms due to an apparent grass intrusion condition. At the time of the grass intrusion the C SSWS pump was tagged out of service while its associated traveling water screen was being inspected. The B control room emergency filtration (CREF) unit was also out of service for scheduled maintenance. The B SSWS strainer high dp condition cleared; however, the A strainer high dp and low pump flow condition remained and the strainer motor breaker tripped open on high motor overload. With both the A and C SSWS pumps inoperable, operators concluded the A SACS loads would not be adequately cooled, and this affected the A CREF unit. With the A CREF unit declared inoperable because of the low SSWS flow condition and the B CREF out of service for maintenance, operators initiated a plant shutdown in accordance with technical specification requirements. The plant shutdown was terminated at 94% power when the C SSWS pump was restored to service.

Maintenance personnel investigated the as-found condition of the A SSWS strainer on February 24 and identified that the restraining nut on the strainer shaft had backed off and the backwash arm had vertically dropped and was rubbing against the strainer element support. This condition likely resulted in increased friction and caused the strainer motor breaker to trip open during the grassing conditions. Maintenance personnel repaired the strainer under work order 60043083 by adjusting the backwash arm within specification and removed the interference. The shaft lock nut was also tightened, a new set screw installed, and a torque stick mark was applied to provide a visual indication if the lock nut backed off the shaft. The A SSWS pump and strainer were returned to service on February 24 within the TS allowed outage time. PSEG inspected the other strainers and determined that there was no indication of the lock nut or adjustment nut loosening.

At the end of the inspection period PSEG was completing their root cause investigation into the A SSWS strainer failure under order 70037087. The inspectors were reviewing the strainer maintenance history, post-maintenance testing completed in June 2003 and strainer performance trending. This issue is unresolved pending PSEG's completion of the root cause evaluation and the inspectors review of the evaluation, strainer maintenance history, post-maintenance testing, and equipment trending activities. **(URI 50-354/04-02-03)**

1R13 Maintenance Risk Assessments and Emergent Work Evaluation (71111.13)

a. Inspection Scope

The inspectors reviewed five on-line risk management evaluations through direct observation and document reviews for the following configurations:

- planned unavailability of A EDG, 500 KV 1-3 breaker, and the unplanned unavailability of the B 1E switchgear room cooler on January 6
- emergent addition of 500 kv bus section one outage to work scope and downpower on January 10
- unplanned unavailability of A SSW pump and planned unavailability of the B RHR pump on January 21
- unplanned unavailability of A SSWS pump on February 23
- planned unavailability of B EDG and the A core spray loop on March 30

The inspectors reviewed the applicable risk evaluations, work schedules and control room logs for these configurations to verify that concurrent planned and emergent maintenance and test activities did not adversely affect the plant risk already incurred with these configurations. PSEG's risk management actions were reviewed 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) and off-line ORAM Model to gain insights into the risk associated with these plant configurations. Finally, the inspectors reviewed notifications documenting problems associated with risk assessments and emergent work evaluations. Documents reviewed are listed in the Supplemental Information report section.

b. Findings

No findings of significance were identified.

1R14 Operator Performance During Non-Routine Evolutions and Events (71111.14)

a. Inspection Scope

The inspectors evaluated PSEG's performance and response during five non-routine evolutions to determine whether the operator responses were in accordance with applicable procedures, training, and PSEG's expectations. The inspectors observed control room activities and reviewed control room logs and applicable operating procedures to assess operator performance. PSEG's evaluations of operator performance were also reviewed. The inspectors walked down control room displays and portions of plant systems to verify status of risk significant equipment and interviewed operators and engineers. Documents reviewed are listed in the Supplemental Information report section.

Operator performance during the following non-routine evolutions were reviewed:

Primary Containment Isolation System (PCIS) Actuation and Reactor Scram. On January 12, during performance of the C RBE RMS sensor calibration, a spurious trip of the A RBE RMS occurred resulting in a full actuation of the PCIS for a high exhaust radiation signal. PCIS is a two-out-of three logic and was actuated due to the C RBE RMS being in a tripped condition as part of the sensor calibration when the spurious trip of the A RBE RMS occurred. All expected automatic system isolations and equipment starts occurred. Operators confirmed there was not a high radiation condition and directed actions to terminate the in-progress sensor calibration and restore the C RBE RMS.

Upon restoration of the C RBE RMS, operators proceeded to restore PCIS. A reactor operator monitored main steam isolation valve (MSIV) position due to the potential for MSIVs to drift close on a PCIS actuation. Approximately thirty minutes after the PCIS actuation, the reactor operator (RO) observed the B and D inboard MSIVs indicating dual position. The RO informed the senior reactor operator (SRO) of the condition and then performed a manual reactor scram. Approximately two minutes after the reactor scram, the PCIG system was restored and the inboard MSIVs returned to the full open position.

Power Suppression Testing. On January 31, operators performed a planned power reduction to 61% for power suppression testing. The testing identified the location of a minor fuel clad defect within the reactor. Operators inserted control rods adjacent to the affected fuel assembly to reduce power in the affected fuel assembly and returned the plant to 100% power on February 4.

Service Water Grassing Event. On February 23, operators received a high strainer differential pressure (dp) alarm for the A and B SSWS pump strainers due to a grassing condition. This event is described in Section 1R12 of this report. The inspectors determined that operators entered the applicable procedures and performed the required actions to attempt to clear the high SSWS strainer dp condition. Additionally, the inspectors concluded technical specification requirements were correctly implemented during this event.

J and P SRV Infrequently Performed Test or Evolution (IPTE) - 04-003. On March 24, 25, and 29, PSEG implemented IPTE 04-003 to control a maintenance condition that involved rendering all low pressure emergency core coolant system (ECCS) pumps inoperable while the plant was shutdown for a maintenance outage. In order to protect maintenance personnel during the planned SRV replacement activities, PSEG tagged out of service all high volume injection sources into the reactor to prevent inadvertent injection. Operators entered the applicable action statement requirements of TS 3.5.2, established secondary containment, and precluded activities with the potential to drain the vessel. Additionally, as a contingency, an operator was stationed at the electrical buses to promptly restore power to an RHR pump and two B loop core spray pumps if needed for level control.

CRDM O-Ring Replacement IPTE - 04-002. PSEG performed maintenance on March 25 through March 29 to replace the o-rings on seven control rod drive mechanisms (CRDM) that were leaking. An IPTE plan was utilized by PSEG to control the maintenance activity because it created a potential leakage path from the bottom of the reactor vessel.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed nine operability determinations for non-conforming conditions associated with:

- D source range monitor (SRM) intermittent spiking (70035928)
- 125V DC ground received during B EDG surveillance (20175625)
- B 1E 125 V DC Battery room heater (5541) tripped (70035901)
- C SSWS traveling water screen insert wear (70037000)
- 13 KV breaker bushing degradation (2013079)
- ECCS suction strainer performance with improper drywell pipe insulation (70038514 and 70037944)
- RHR pipe vibration and abnormal noises (70037702)
- B EDG load wandering problem (70035290)
- A25X type Gould Fuse Failure (20182406)

The inspectors reviewed the technical adequacy of the operability determinations to ensure the conclusions were justified. The inspectors evaluated and discussed with operators and engineers the completed and planned actions to ascertain whether PSEG appropriately addressed the degraded condition. The inspectors also walked down accessible equipment to corroborate the adequacy of PSEG's operability determinations. Documents reviewed are listed in the Supplemental Information report section.

With regard to the RHR pipe vibration operability assessment, the inspectors reviewed the Surface Examination Record (Order 70037702) associated with liquid penetrant examinations performed on selected welds in piping attached to the RHR system piping. Four field welds were selected on the small bore piping (1 inch diameter) based upon their location being susceptible to vibration induced damage.

Additionally, the inspectors performed a follow-up review of the operability assessment for the B EDG completed under order 70035290 for a problem with electrical load wandering during monthly surveillance tests. This operability assessment was originally reviewed in NRC Inspection Report 50-354/2003006 dated February 11, 2004, Section 1R15.

b. Findings

Introduction. The inspectors identified two instances where the basis was not supported with correct information for concluding the B emergency diesel generator (EDG) remained operable with a load wandering condition. This finding was determined to be of very low safety significance (Green) and a non-cited violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings."

Description. The B EDG has exhibited a load wandering problem where the electrical load occasionally increases or decreases from a steady state operating point during monthly surveillance testing such that operator action is necessary to manually adjust the load to within the required band. PSEG performed troubleshooting of the problem in May 2003 by measuring the B EDG electrical governor input and output voltages under varying EDG loads and concluded the load wandering problem was likely due to electrical noise induced into the electrical governor input by an unshielded cable installed between the EDG governor and the isochronous/droop (IDR) relay. PSEG developed design change modification 80060791 to add a supplemental IDR relay in the circuit to provide a shorter path of control wire that would be less susceptible to electrical noise. This modification was installed on November 2003, but did not eliminate the load wandering problem. Notification 20168094 was initiated to address that the design change did not correct the B EDG load wandering problem.

The inspectors reviewed the operability assessment completed under notification 20168094 on November 25, 2003 to determine the basis for continuing to conclude the B EDG was operable. The operating assessment referenced a previous operability assessment (order 70014671) which concluded the load wandering problem was due to a degraded motor operator potentiometer (MOP). However, the inspectors determined the B EDG MOP had since been replaced and this was not likely the cause of the B EDG load wandering. The inspectors concluded at that point the cause of the B EDG load wandering condition was not known and questioned PSEG operators as to the basis for concluding the B EDG was operable.

In response to the inspector's questions, PSEG developed an operability assessment under order 70035290 on December 20, 2003. The assessment concluded the B EDG remained operable, but degraded because the load wandering only occurred when the B EDG was loaded in parallel to the electrical grid in its non-safety related mode (droop mode). Furthermore, PSEG concluded that based on successful periodic testing of the B EDG in the isochronous (safety-related) mode, the engine was operable. In the isochronous mode, safety-related loads were automatically sequenced onto the EDG such that it would be loaded to about 3500 kw, which was below the load where this problem had occurred.

On January 19, PSEG worked with vendor specialists to troubleshoot the B EDG load wandering problem by instrumenting and running the B EDG to collect data on governor output voltage, MOP voltage, fuel rack position and other parameters. Preliminary results suggested the problem was caused by fuel rack binding. PSEG disassembled, cleaned and inspected the rack from the governor output to the fuel rack cross bar and checked the force required to move the linkage. The load wandering was shown to have decreased somewhat during the subsequent post maintenance test, but not eliminated. The results of this investigation were provided to PSEG in a report dated February 12, 2004 that concluded the likely cause of the B EDG load wandering was fuel rack linkage binding.

On February 16, PSEG initiated notification 20177854 to document that one of the mechanical linkages between the B EDG governor and the fuel rack exhibited some visual misalignment. The operability assessment under this notification referenced the previous operability assessment under order 70035290. The inspectors reviewed the previous assessment and determined it had not been updated with information that the load wandering problem was likely due to fuel rack binding. The inspectors concluded this information would change the operability basis because the rack binding problem would affect both the droop mode and safety-related isochronous mode of EDG operation.

In response to the inspectors observations, PSEG revised the operability assessment in order 70035290 on March 18, 2004 with the new causal information. The conclusions remained that the B EDG was operable, but degraded because the load swing problem only occurred when the B EDG was loaded well above the design basis automatic accident loading. PSEG initiated notification 20187886 to address inadequate updating of operability assessments within the corrective action process.

The inspectors reviewed the revised operability assessment and confirmed that during accident conditions the B EDG would likely be loaded below the range where the load wandering problem has occurred. This was based on a review of UFSAR Table 8.3-1, Calculation E-9(Q), "Standby Class 1E Diesel Generator Sizing," and Procedure HC.OP-

AB.ZZ-0135(Q), “Station Blackout/Loss of Offsite Power/Diesel Generator Malfunction.” In regard to the potential for the operators to add non-safety related loads to the B EDG in addition to safety-related loads during postulated post-accident conditions, the inspectors reviewed Procedure HC.OP-AB.ZZ-0135(Q), and confirmed that, while the note to step 4.7.7 indicated EDGs may be loaded to 4430 KW, step 4.7.6 required operators to closely monitor EDG load and minimize equipment operation when loading EDGs during accident conditions. The inspectors determined that in the unlikely event the B EDG was loaded above 4000 KW during postulated accident conditions, operators would monitor the loading and take manual action if required to prevent load wandering. At the end of the inspection period, PSEG continued to investigate the rack binding problem.

Analysis. The inspectors identified performance issues involving two operability determinations for B EDG load wandering that were based on outdated information. This finding was more than minor because the issues affected the equipment performance attribute of the mitigating systems cornerstone objective to maintain the B EDG reliable. Specifically, the operability assessments completed under notification 20168094 on November 25, 2003 and order 70035290 on February 16, 2004 did not use current information. In the first instance, the operability assessment determined the problem was a MOP that had since been replaced. In the second instance, new casual information regarding rack binding was not considered when this information was applicable to the safety-related isochronous mode of B EDG operation. However, the finding was determined to be of very low safety significance using the SDP Phase 1 screening worksheet for mitigation systems because the finding is a qualification deficiency confirmed not to result in a loss of EDG safety function.

Enforcement. 10 CFR Part 50, Appendix B, Criterion V requires that activities affecting quality shall be prescribed by documented instructions and procedures of a type appropriate to the circumstance. PSEG Procedure SH.OP-AP.ZZ-0108(Q), “Operability Assessment and Equipment Control Program,” Step 5.1.12, and the note to this step, state that an operability assessment and follow-up assessment may be revised if new information pertaining to the condition is identified and a revision to these documents is required. Contrary to the above, notification 20168094 on November 25, 2003 referenced an operability assessment that contained outdated causal information and the operability assessment in order 70035290 was not revised on February 16, 2004 when new information as to the cause was identified that altered the basis for operability. However, because the violation was of very low safety significance (Green) and PSEG entered the deficiency into their corrective action system in notification 20187886, this finding is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 50-354/04-02-04)**

1R16 Operator Work-Arounds (71111.16)

a. Inspection Scope

The inspectors evaluated the cumulative effects of operator workarounds as related to (1) the reliability, availability, and potential for misoperation of plant systems; (2) the potential to increase an initiating event frequency or to affect multiple mitigating systems; and (3) operator ability to respond in a correct and timely manner to plant transients and accidents. The inspectors reviewed operator logs and control room instrument panels to evaluate potential impacts on the operators' ability to implement abnormal or emergency operating procedures. The inspectors also toured the plant and control room to identify potential workarounds or deficiencies not previously identified by PSEG. Documents reviewed are listed in the Supplemental Information report section.

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors observed portions of and /or reviewed the results of four post maintenance tests (PMT) on the following equipment:

- A EDG on January 7
- C EDG on January 14
- A SSW strainer on February 24
- A standby liquid control (SLC) injection isolation valve (F006A) on March 4

The inspectors verified that the PMTs conducted were adequate for the scope of the maintenance performed. The inspectors reviewed notifications documenting deficiencies identified during PMTs. The inspectors also reviewed applicable documents associated with PMTs as listed in the Supplemental Information report section.

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

a. Inspection Scope

January 12 Reactor Scram. Following the January 12 reactor shutdown the inspectors evaluated PSEG's shutdown risk management, forced outage configuration control, reactor shutdown and startup, and power ascension. The inspectors reviewed notifications concerning problems identified during the shutdown/forced outage.

March 19 Planned Maintenance Outage. On March 19 operators commenced a reactor shutdown to support a planned maintenance outage. The purpose of the outage was to repair a leaking valve in the main steam pipe tunnel (F020), replace two SRVs, replace

CRDM o-rings, repair a leaking RCIC valve (F008), and investigate an abnormal noise originating on the A RHR shutdown cooling piping.

The inspectors evaluated PSEG's shutdown risk management and forced outage configuration control, and also observed portions of the reactor shutdown from the control room. The inspectors verified that PSEG was adhering to their operating license and TS requirements. The inspectors also walked down the drywell when it was accessible to observe the condition of equipment. Finally, the inspectors reviewed notifications concerning problems identified during the shutdown/forced outage.

b. Findings

Introduction. The inspectors determined that PSEG did not adequately identify drywell pipe insulation deficiencies during a December 2003 plant outage such that the inspectors observed additional deficiencies during a March 2004 plant outage that required correction. Additionally, the inspectors identified problems with an evaluation performed in January 2004 on the use of tape on drywell piping insulation. The finding was determined to be of very low safety significance (Green) based on the strainer surface area margin, and also was a non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, Corrective Action.

Description. On December 10, 2003, the inspectors walked down equipment in the drywell during a plant maintenance outage. The inspectors identified some minor debris and a number of pipe locations (mainly chilled water piping to drywell coolers) where the insulation metal jacket was missing and insulation was secured to the pipe with what appeared to be tape. Insulation in this condition could be dislodged in steam environments in addition to the insulation assumed to be dislodged in the vicinity of a postulated pipe break location. The inspectors reviewed applicable procedures and determined that these pipe insulation problems did not conform to PSEG Procedure HC.MD-GP.ZZ-0056, "Insulation Removal and Installation." This procedure required that insulation be held in place with the required fasteners specified in insulation specifications. Specification M-164-QS was applicable in this case and required metallic jacketing.

PSEG management performed similar drywell walkdowns and identified additional pipe insulation problems (notification 20171100). PSEG repaired these insulation problems during the maintenance outage as documented in orders 60041270, 60041271 and 60041272. PSEG engineering personnel completed an evaluation of these problems (order 70035814) in January 2004 to determine whether the pipe insulation problems would have impacted the operability of ECCS pump strainers during postulated accident conditions. The evaluation calculated that about 9 cubic feet of insulation and debris were removed from the drywell in December 2003. Engineering personnel concluded this debris would not have affected emergency cooling water pump performance during the postulated worst case drywell pipe breaks because Calculation V12100.F02.08, "Hope Creek ECCS Strainer Design," determined that a maximum of 405 cubic feet would be generated from the worst case postulated pipe break location and the analysis allowed for an additional 20 cubic feet of debris loading.

The inspectors reviewed the evaluation and questioned whether what appeared to be adhesive tape on chilled water piping was in accordance with the design and accounted for in debris generation calculations. The inspectors were verbally informed that the observed tape may have been a vapor barrier tape described in drywell pipe insulation specification M-164-QS and accounted for in insulation generated debris calculations. Additionally, the inspectors were informed that this specification allowed for the use of adhesive backed tape in the drywell as long as it met certain chemical requirements.

The inspectors questioned whether the tape was a vapor barrier because it was used in selective locations where the chiller piping metal jacket was missing or damaged (possibly from personnel stepping on the insulation during outages). Additionally, the inspectors concluded that while the piping insulation specification may have allowed for use of tape, the ECCS strainer Calculation V12100.F02.08 and Engineering Evaluation H-1-BB-MEE-1168, "Determination of Drywell Insulation Material Debris Sources and Quantities Generated Due to Postulated High Energy Pipe Breaks," did not identify tape as a potential type of insulation debris.

While these questions were in review, the Hope Creek plant was shutdown for a planned maintenance outage in March 2004. The inspectors toured the drywell on March 22 and noted additional instances of improperly installed chilled water piping insulation (notifications 20183021). PSEG engineering personnel performed confirmatory walkdowns and identified a total of twenty-two insulation deficiencies, mostly involving chilled water piping with tape applied and missing metal jacketing. PSEG engineering personnel further determined that the observed tape was indeed an adhesive tape and not vapor barrier tape and was not accounted for in ECCS strainer calculations (notification 20183022). The inspectors concluded these issues involved inadequate problem identification aspects from the December 2003 plant outage which are referenced in Section 4OA2.

During the March 2004 plant outage, PSEG repaired the identified insulation deficiencies involving tape and missing metal jacketing. Engineering personnel evaluated the collective pipe insulation deficiencies identified during the December 2003 and March 2004 drywell walkdowns (notification 20183517) and concluded the additional debris loading from these problems remained within the margin provided in Calculation V12100.F02.08 and would not have increased differential pressure losses across the ECCS pump strainers greater than the design head loss. PSEG also tracked a corrective action to revise engineering evaluation H-1-BB-MEE-1168 to provide for an assumed loading from tape. Additionally, PSEG tracked a corrective action to control tape use within the drywell. These corrective actions were tracked in order 70037944.

<u>Analysis</u>. The inspectors identified performance issues involving inadequate identification of drywell pipe insulation problems during the December 2003 plant outage and inadequate evaluation of tape that was not accounted for in ECCS strainer calculations. The inspectors determined this finding was more than minor because the issues affected the design control attribute of the mitigating systems cornerstone objective to maintain mitigation equipment reliable. The extent of pipe insulation problems impacted the debris margin assumed to be available in design calculations

and the calculations did not fully account for the debris resulting from the use of tape for insulation repairs. However, the finding was determined to be of very low safety significance using the SDP Phase 1 screening worksheet for mitigation systems because the finding was a design deficiency confirmed not to result in a loss of safety function. The additional debris that would have resulted from these pipe insulation problems would not have reduced ECCS pump suction pressure below the minimum required during postulated pipe break conditions.

Enforcement. 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. Contrary to the above, PSEG failed to promptly identify and correct the drywell pipe insulation nonconformances during the December 5 through 18, 2003 maintenance outage that was subsequently identified and repaired during a plant outage in March 2004. Additionally the use of tape was not identified as a non-conforming condition in December 2003. However, because the finding was determined to be of very low safety significance and has been entered into the PSEG corrective action program (notifications 20171100, 20183022, and 20183517), this violation is being treated as a non-cited violation, consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 50-354/04-02-05)**

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors observed portions of and/or reviewed the results of the following eight surveillance tests:

- RBE radiation monitor A channel on January 13
- B & D core spray pump inservice test (IST) on January 20
- B RHR pump IST on January 22
- HPCI pump IST on February 7
- Control rod scram time testing on February 2
- A SSWS spray water pump IST on February 24
- RCIC pump IST on March 18
- A RHR shutdown cooling (SDC) check valve (FO50A) leak rate test on March 30

The inspectors evaluated the test procedures to verify that applicable system requirements for operability were adequately incorporated into the procedures and that test acceptance criteria were consistent with the TS requirements and the UFSAR. The inspectors also reviewed notifications documenting deficiencies identified during these surveillance tests. Applicable documents associated with surveillance testing were reviewed as listed in the Supplemental Information report section.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed two temporary plant modifications (T-Mods) as follows:

- Temporary Space Heater for Battery Room 5541 (T-Mod 03-55)
- Temporary Shield on Platform Near MOV ABHV-F020 to Deflect Steam Leak (T-Mod 04-005)

The inspectors verified the modifications were consistent with the design and licensing bases of the affected systems and that the performance capability of these systems were not degraded by these modifications. The modifications were also reviewed to verify applicable TS operability requirements were met during installation. The inspectors verified the modified equipment alignment plant walkdowns of accessible portions of the affected equipment. The inspectors further reviewed notifications documenting problems associated with equipment affected by temporary modifications (20173605 and 20173293). Applicable documents are listed in the Supplemental Information report section.

b. Findings

Introduction. The inspectors identified instances where operators did not follow T-Mod instructions needed to maintain minimum temperatures in a safety-related battery room. The finding was of very low safety significance (Green) and a non-cited violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings."

Description. On December 24, 2003, PSEG installed an electric space heater in battery room BD5541 under T-Mod 03-055 because the duct heater element had failed and replacement parts were not available. The electric heater used power available in the adjacent hallway and required the battery room door to be open when the heater was energized. The T-mod instructions directed operators to monitor the heater when inservice and then close the battery room door when the space heater was not in use. This was necessary because the hallway to the battery room was not heated and its temperature trended with outside ambient temperatures. Operations personnel instituted a temporary log to monitor battery room temperatures once every two hours and verify temperatures were a minimum of 74 ^{o}F.

This T-mod maintained the battery room temperatures at or above 74 ^{o}F in accordance with the description of the system in UFSAR Section 9.4.1.1.4. Maintaining the battery room temperature ensured the (1BD411) 125 VDC battery capacity design margin would not be reduced by temperatures that were lower than assumed in the battery sizing calculation. TS 3.8.2.1 requires actions to check electrolyte level, float voltage and specific gravity if average battery temperatures are at or below 72 ^{o}F.

The inspectors observed the T-Mod implementation during several plant walkdowns from January 2 through 10 during seasonally colder ambient temperatures. During these walkdowns, the door had been open with the heater not operating. The inspectors reviewed T-Mod 03-055 and the implementing instructions on January 10 and concluded this was contrary to the T-Mod instructions. Operators were informed of this problem. The inspectors performed a follow-up inspection on January 13 to determine if the concerns that were raised were corrected. The inspectors noted that the door was open when the heater was in service; however, operators were not monitoring the heater as directed in the T-Mod instructions. PSEG initiated notification 20173605 to address these concerns and the heater was secured and door to the hallway closed.

In reviewing this issue the inspectors determined that on January 9, notification 20173293 had been initiated to document that battery room temperatures decreased to 73 ^{o}F (below the minimum 74 ^{o}F) for approximately three hours. This was identified during review of the log by the control room supervisor who noted the readings were below the minimum temperature. As a result, the applicable abnormal procedure was entered and actions were taken to measure a battery pilot cell temperatures. Cell temperatures were found to be below 72 ^{o}F and TS action statement 3.8.2.1.c was entered. PSEG operators completed the applicable technical specification action statement requirement actions to verify the battery's pilot cell electrolyte level, float voltage and specific gravity remained within limits. Operators also increased battery room temperatures above 74 ^{o}F using the electric heater and exited the action statement. The inspectors determined the technical specification action statement time requirements were met notwithstanding the delayed identification of the low room temperature.

PSEG determined this had occurred because the equipment operator recorded the temperatures on scrap paper when taking readings and not on the log sheet. PSEG identified a contributing cause to be an increased workload on the equipment operator because of emergent equipment problems during the shift. The inspectors concluded that not using the log sheet was an additional example of not following the T-Mod implementing instructions. Although the issue was documented by PSEG, the problem was self revealing because temperatures were allowed to decrease to the point where the functionality of the equipment was affected and the TS 3.8.2.c action statement was entered.

The inspectors identified an additional T-Mod implementation problem, in that the comment section of the temporary log sheets used to monitor battery room temperature contained inconsistent minimum temperature limits. The log sheets for December 28, 29, 31, January 1, 2, and 4 through 9 referenced a minimum battery room temperature of 72 ^{o}F and the log sheets for the remaining days in this time period described the correct minimum temperature of 74 ^{o}F. Operations personnel initiated notification 20178465 to address this problem and review the process for controlling temporary log revisions.

<u>Analysis</u>. The inspectors identified instances where T-Mod 03-055 implementing instructions were not followed between January 2 and 10 because a battery room door was left open when the heater was not operating. An additional self revealing problem regarding T-mod 03-055 implementation occurred on January 9 when an equipment

operator did not use the temporary log during rounds, and room temperatures decreased below the specification. The failure to follow T-mod instructions impacted the reliability of the 125V DC safety-related batteries because with the hallway door open, the heating provided by the temporary heater dissipated to the colder hallway and decreased battery temperatures. On January 9 room temperatures decreased below the TS minimum temperature. This configuration control issue was more than minor because it affected the mitigating systems cornerstone objective of maintaining the reliability of the 1BD411 125 VDC battery capacity. However, the inspectors determined the finding was of very low safety significance (Green) by the SDP Phase 1 screening worksheet for mitigating systems because room and corresponding battery temperatures did not decrease to a value where the batteries were inoperable. This finding had a human performance cross-cutting aspect because the finding involved personnel not following temporary modification instructions.

Enforcement. 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings" requires, in part, that activities affecting quality shall be prescribed by documented instructions of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions. Contrary to the above, PSEG did not follow temporary modification instructions in T-mod 03-055 associated with maintaining temperatures in battery room BD5541. However, because the violation was of very low safety significance (Green) and PSEG entered the deficiency into their corrective action system (notifications 20173605 and 20173293), this finding is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 50-354/04-02-06)**

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

The inspectors observed one emergency preparedness (EP) drill from the control room simulator and the emergency operations facility on February 18. The inspectors evaluated the conduct of the drill; performance related to developing classifications, notifications, and protective action recommendations; and the drill critique. The inspectors reviewed EP Training Drill Critique Report H04-01 to evaluate the adequacy of PSEG's drill critique. Notifications documenting EP weaknesses and deficiencies identified during the drill were also reviewed (20179654, 20179182, and 20178508). Additional applicable documents that were reviewed associated with EP are listed in the Supplemental Information report section.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

a. Inspection Scope

The inspectors completed two inspection samples relative to access control to radiologically significant areas. The inspectors identified two exposure significant work areas within radiation areas, high radiation areas (<1 R/hr), or airborne radioactivity areas in the plant and reviewed associated PSEG controls and surveys of these areas to determine if controls (e.g., surveys, postings, barricades) were acceptable. The two areas reviewed were rooms 1509 ("A" reactor feed pump and turbine room) and 1510 ("B" reactor feed pump and turbine room).

The inspectors walked down these areas and their perimeters to determine whether prescribed radiation work permit (RWP), procedures, and engineering controls were in place, whether PSEG surveys and postings were complete and accurate, and whether air samplers were properly located. The controls implemented were compared to those required under plant TS 6.12 and 10 CFR 20, Subpart G, for control of access to high and locked high radiation areas. The inspectors also observed PSEG personnel performing their quarterly locked high radiation area door and lock checks in the turbine building.

The inspectors reviewed the apparent cause evaluation report (order 70035641) and corrective actions taken for notification 20170646, involving an unidentified high radiation area, previously discussed in NRC Inspection Report 05000354/2003-006. Two additional orders (70036802 and 70036803) were also reviewed related to problems identified in the radiation protection program.

Finally the inspectors reviewed the planned 2004 Quality Assurance assessment plans in the radiation protection area. This plan was developed in accordance with the Radiation Protection Integrated Master Assessment Plan, dated April 28, 2003.

b. Findings

No findings of significance were identified.

2OS2 ALARA Planning and Controls (71121.02)

a. Inspection Scope

The inspectors completed two inspection samples relative to as low as reasonably achievable (ALARA) planning and access control to radiologically significant areas. The inspectors observed radiation worker and RP technician performance during work activities being performed in radiation areas, airborne radioactivity areas or high radiation areas. The inspectors determined that workers demonstrated the ALARA philosophy in practice. Radiation worker performance was also observed to determine whether the training/skill level was sufficient with respect to the radiological hazards and the work involved.

The inspectors determined there were four declared pregnant workers being monitored during the current assessment period. Procedures and monitoring controls were reviewed that are employed by PSEG with respect to requirements of 10 CFR 20.

The inspectors reviewed the 2004 annual dose goal (134 person-rem), which included: a refueling outage dose goal of 98 person-rem (RF12); 25 person-rem for on-line operations; 5 person-rem for on-line emergent work; and, 6 person-rem for forced outages.

b. Findings

No findings of significance were identified.

2OS3 Radiation Monitoring Instrumentation (71121.03)

a. Inspection Scope

The inspectors completed two inspection samples relative to radiation monitoring instrumentation. The inspectors reviewed UFSAR Section 12.5.2.2 to identify applicable radiation monitors associated with transient high and very high radiation areas including those used in remote emergency assessment.

The inspectors identified the types of portable radiation detection instrumentation used for job coverage of high radiation area work, other temporary area radiation monitors currently used in the plant, and continuous air monitors associated with jobs with the potential for workers to receive 50 mrem CEDE.

The inspectors conducted a review of selected radiation protection instruments located in the radiological control area (RCA). Items reviewed were verification of proper function; certification of appropriate source checks and calibration for those instruments used to ensure that occupational exposures were maintained in accordance with 10 CFR 20.1201.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

a. Inspection Scope

The inspectors reviewed PSEG's program to gather, evaluate and report information on the following five performance indicators (PIs). The inspectors used the guidance provided in NEI 99-02, Revision 2, "Regulatory Assessment Performance Indicator Guideline" to assess the accuracy of PSEG's collection and reporting of PI data.

Reactor Safety Cornerstone. The inspectors reviewed the methods used to calculate the safety system unavailability (SSU) PIs for HPCI System Unavailability and Emergency AC Power (EDG) System Unavailability. The inspectors reviewed selected control room narrative logs, Licensee Event Reports (LERs), MR unavailability databases and PI data sheets to verify the accuracy and completeness of the unavailability hours calculated for the HPCI and EDG systems for the period of January 1, 2003, through December 31, 2003. The unavailability hours were compared to the PI data submitted for the previous four quarters. In addition, the inspectors interviewed selected PSEG personnel associated with the PI data collection, evaluation, and distribution. The inspectors verified that minor issues regarding compilation of EDG and HPCI unavailability data and the calculation of the SSU PIs were entered into the corrective action program in notification 20179963.

Physical Protection Cornerstone. The inspectors reviewed PSEG's programs for gathering, processing, evaluating, and submitting data for the Fitness-for-Duty, Personnel Screening, and Protected Area Security Equipment PIs. The review included PSEG's tracking and trending reports, personnel interviews and security event reports for the PI data collected from the January 1, 2003 through January 1, 2004. The inspectors noted from PSEG's submittal that there were no reported failures to properly implement the requirements of 10 CFR 73 and 10 CFR 26 during the reporting period.

b. Findings

No findings of significance were identified.

4OA2 Problem Identification and Resolution (71152)

As required by Inspection Procedure 71152, "Identification and Resolution of Problems," and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into PSEG's corrective action program. This review was accomplished by attending daily screening meetings and accessing PSEG's computerized database.

1. Annual Sample Review

a. Inspection Scope

Selected Issue Follow Up Inspection - Instrument Air

The inspectors performed a problem identification and resolution sample inspection for issues related to the reliability of the instrument air system. These issues were documented in various notifications, including 20044153, 20154749, 20138021, 20138215 and 20138249.

In April 2003 a temporary loss of header pressure in the instrument air system occurred due to problems with solenoid valves associated with the system's air dryers. PSEG performed an apparent cause evaluation which also discussed an increase in flow rates seen in the instrument air system over the past few years.

The inspectors reviewed PSEG's apparent cause evaluations to ensure that they captured all relevant elements. The inspectors also reviewed the corrective actions that were taken to verify that they were appropriately focused and complete. This review included preventive maintenance activities on the affected solenoid valves and an August 2003 Hope Creek Instrument Air Usage Action Plan. In addition, the inspectors interviewed PSEG personnel involved with the instrument air issues and conducted walkdowns of the instrument air dryers.

Selected Issue Follow Up Inspection - North Plant Vent RMS

In accordance with the guidance provided in Inspection Procedure 71152, Identification and Resolution of Problems, the inspectors selected three notifications (20169862, 20158753, 20127603) for detailed review. The notifications were associated with performance of the North Plant Vent (NPV) RMS. The inspectors reviewed these reports to ensure that the full extent of the issues were identified, that appropriated corrective evaluations were performed, and that the appropriated corrective actions were specified and prioritized.

The inspectors also interviewed the Process RMS engineer and walked down the NPV, South Plant Vent (SPV) and FRVS RMS effluent monitoring skids with the system engineer.

b. Findings

No findings of significance were identified.

2. Cross-References to PI&R Findings Documented Elsewhere

Section 1R20 of this report describes a finding regarding an instance where PSEG did not adequately identify drywell pipe insulation deficiencies during a December 2003 plant outage such that the inspectors observed additional deficiencies during a March

2004 plant outage that required correction. Additionally, the inspectors identified problems with an evaluation performed in January 2004 on the use of tape on drywell piping insulation. The finding had problem identification aspects because the extent of insulation problems was not identified and corrected in December 2003 and the evaluation did not identify that tape used on drywell insulation was not accounted for in design calculations.

Section 4OA5 of this report describes closure of an NRC unresolved item and a finding identified during the inspectors review of PSEGs evaluation regarding inadequate implementation of 4.16 kv vital bus undervoltage relay reset setpoints. The finding had problem identification and evaluation aspects because PSEG's evaluation of this issue did not identify that the recalculated relay reset setpoints that were not adequately implemented in plant procedures.

4OA3 Event Followup (71153)

1. Unexpected PCIS Actuation and Reactor Scram on January 12

The inspectors observed control room personnel responding to an unexpected PCIS actuation and subsequent manual reactor scram during a calibration of the C RBE RMS radiation detector on January 12. The inspectors arrived in the control room shortly after the PCIS actuation and observed the followup actions by operational personnel, including operator briefings, actions required by procedures, and monitoring of plant conditions. As part of the followup to this event, the inspectors observed plant chart recorders, reviewed post transient response reports, attended startup Station Operations Review Committee (SORC) meetings, and discussed the event with PSEG personnel. The inspectors also reviewed applicable documents associated with event response as listed in the Supplemental Information report section.

2. Service Water Grass Intrusion Results in Power Reduction on February 23

The inspectors performed a review of event notification (NRC #40539) documenting a service water grassing condition that resulted in an entry into TS 3.0.3. The inspectors responded to the site once informed of the unit shutdown in accordance with TS 3.0.3. The inspectors arrived onsite shortly after the unit shutdown was terminated due to exiting of TS 3.0.3 conditions. The inspectors observed the followup actions by operational personnel, including operator briefings, actions required by procedures, and monitoring of plant conditions. As part of the followup to this event, the inspectors conducted field walkdowns of the SSW and SACS; and reviewed plant data during the event, the control room narrative logs, post transient response report, and discussed the event with PSEG personnel.

3. (Closed) LER 50-354/03-009, Technical Specification Non-Compliance - Inoperable High Range Noble Gas Effluent Monitor on NPV

On December 10, 2003, PSEG identified that the NPV RMS was inoperable for greater than the TS allowed outage time without performing the necessary TS actions.

Specifically, on September 14, 2003 through December 10, 2003, the NPV wide range noble gas effluent monitor bypass flow pump was inoperable and the preplanned alternate monitoring method was not initiated in accordance with TS 3.3.7.5. At the time of discovery, Hope Creek was shutdown so the TS action statement did not apply, but subsequent troubleshooting revealed that problems discovered would have prevented the components from fulfilling the system's design function.

A review of previous maintenance activities identified that on September 14, 2003, a relay was replaced on the radiation monitor power controller. The original relay was a different type than the replacement relay. An inadequate post maintenance test led technicians to consider the NPV RMS operable. The work performed on December 10, 2003, identified that the work performed in September prevented the bypass flow pump from operating properly. Further investigation determined that the as-built configuration of the NPV RMS did not match design documents, leading to the use of a different type relay. Other issues related to a lack of a questioning attitude and assessing the adequacy of post-maintenance testing following work scope changes contributed to this occurrence. Corrective actions included rewiring the NPV bypass pump controller to match design documents and performing a functional test. Additionally, due to a common system design, similar design noncompliance were identified for the SPV and FRVS RMS. A review of surveillance and functional test records indicated proper operation of the SPV and FRVS RMS even while in a noncompliance condition. Corrective actions have been initiated to bring the SPV and FRVS RMS into compliance with design documents.

This PSEG identified finding is more than minor because it created the possibility for an unmonitored gaseous effluent release through the NPV. This finding affects the Public Radiation Safety cornerstone. However, because the normal range monitoring system was not affected and there were no unplanned or unmonitored releases from the NPV, it was considered to have a very low safety significance (Green) using Appendix D of the SDP. This finding involved a violation of TS 3.3.7.5, Accident Monitoring Instrumentation. The enforcement aspects of the violation are discussed in Section 40A7. This LER is closed.

4. (Closed) LER 50-354/04-001, Manual Reactor Scram Following Isolation of Primary Containment Instrument Gas (PCIG)

This LER describes an A RBE RMS channel failure during performance of the 18-month TS calibration of the C RBE radiation monitor, which resulted in an actuation of the PCIS. The actuation of PCIS caused the isolation of the PCIG supply to the inboard MSIVs. Operators manually scrammed the reactor when they received indication of two MSIVs drifting from their full open position. The event described in this LER was reviewed by the inspectors in Section 1R12 of this report. This LER is closed.

5. (Closed) LER 50-354/04-002, Control Room Emergency Filtration (CREF) System Train Inoperable For Greater Than 7 Days

This LER discussed the operation of the plant with the B CREF unit inoperable for greater than seven days contrary to the requirements of TS 3.7.2. The inspectors identified that the screening performed during system evaluations and corrective maintenance did not identify the TS noncompliance condition of the CREF unit. PSEG entered this into their corrective action system under notification 20174638 and subsequently submitted this LER in accordance with 10 CFR 50.73. The inspectors documented this issue in NRC Inspection Report 05000354/2003007, Section 4OA2.c.2.2. This LER is closed.

4OA4 Cross Cutting Aspects of Findings

Section 1R05 of this report describes a finding regarding transient combustible material control that involved human performance as a primary underlying causal factor. Similarly, Section 1R23 of this report describes a finding regarding failure to follow temporary modification instructions that involved human performance as a primary underlying causal factor.

4OA5 Other

1. (Closed) Unresolved Item 50-354/2003-002-03 Offsite Power Grid Separation Vulnerability

Introduction. The inspectors identified that the acceptance criteria for 4.16 kv vital bus under-voltage relay reset setpoints used in calibration procedures did not ensure successful fast bus transfer to the redundant offsite power source if the first offsite source was unavailable. The finding was determined to be of very low safety significance (Green) and a non-cited violation of 10 CFR 50, Appendix B, Criterion III, "Design Control."

Description. During a safety system design inspection (SSDI) performed in December 2003, the inspectors determined that PSEG had not evaluated the voltage relay reset setpoints of the 4.16 kv vital bus degraded voltage relays to include the effects of voltage transients from fast transfer of buses or unit trips, to assure that the design would prevent offsite power grid separation during these transients. This issue was tracked as unresolved item 50-354/2003-002-03.

Following the SSDI, PSEG revised voltage calculations E-15.5(Q), "Hope Creek Fast Bus Transfer Analysis," Revision 2, and E-15(Q), "Load Flow Study," Revision 7. PSEG also completed relay setpoint calculation SC-PB-0002, "Hope Creek 4 KV Vital Bus Degraded Voltage Relay Setpoint/Accuracy," Revision 0. In addition, PSEG revised relay functional test procedure HC.MD-ST.PB-0003(Q), "Class 1E 4.16 KV Feeder Degraded Voltage Monthly Instrumentation Channel Functional Test," Revision 17, to incorporate the results of the three calculations and changed the setpoint acceptance criteria accordingly. The inspectors reviewed these calculations and the revised relay calibration procedure to determine the adequacy of PSEG's corrective actions for the closure of the unresolved item.

Calculation E-15.5(Q) showed that when one offsite power source was lost, post-accident safety-related loads would be powered by the other independent offsite source. Immediately following the fast transfer between offsite sources, the 4.16 kV vital bus voltage was calculated to decrease to about 87%, causing the degraded voltage relays to dropout (set at about 92%). The calculation indicated the final voltage recovered to 0.96456 per unit (based on 4160V) and reached steady-state conditions within one-third of a second. However, when this final voltage was translated to a 4200V basis (the basis used by the potential transformer ratio, 35x120V), the recovery voltage would be 95.51% of the base voltage.

The inspectors determined that relay functional test procedure HC-MD-ST.PB-0003(Q) specified the maximum allowable as-left reset voltage to be 113.97V and relay setpoint calculation SC-PB-0002 showed the relay setpoint uncertainty to be 1.25V. Therefore, the maximum reset voltage, including the relay setpoint uncertainty, could be 115.22V, representing 96.02% of the base voltage.

The inspectors determined that since the calculated recovery voltage was not above the maximum reset voltage setting, the dropped-out relays may not be able to reset within 20 seconds (degraded voltage relay time delay setting), causing the second offsite power source to be unavailable. The inspectors concluded this was a design control deficiency because the plant configuration did not ensure requirements were met for providing two independent offsite power sources as specified in 10 CFR 50 Appendix A, General Design Criteria 17, “Electric Power Systems.”

In response to the inspectors observations, PSEG reviewed the as-left reset setpoints of the 4.16 kv vital bus degraded voltage relays (total 16 relays for four 4.16 kv vital buses) and determined that all the relays had been set with sufficient margins to avoid the grid separation problem. The inspectors additionally reviewed a historical sample of 48 as-left reset voltage setpoints and determined that the setpoints were set low within the band so that the design was not actually exceeded.

PSEG revised relay setpoint calculation SC-PB-0002 (Revision 1 dated March 5, 2004) and relay calibration procedure HC-MD-ST.PB-0003(Q) (Revision 18 dated March 10, 2004) to limit the maximum as-left reset voltage to 112.7V. PSEG also revised the conclusions of Calculation E-15.5(Q) to correctly compare the recovery voltages with the relay reset voltages and Calculation E-15(Q) to include the effects of a voltage transient from a Hope Creek unit trip following a postulated accident. These two calculations were based on the assumption that the pre-accident and pre-transfer voltages at the 4.16 kV vital buses were steady state and maintained at 4200V. The revised documents were reviewed and found acceptable.

<u>Analysis</u>. The inspectors identified that the acceptance criteria for 4.16 kv vital bus under-voltage relay reset setpoints did not ensure successful fast bus transfer to the redundant offsite power source if the first offsite source was unavailable. This finding was more than minor because it affected the design control attribute of the mitigating systems cornerstone objective to ensure the availability, reliability, and capability of electrical systems to prevent undesirable conditions. The issue affected the mitigation

systems cornerstone because the deficiency could have occurred only after an initiating event when post-accident electrical mitigation loads were applied. However, this design deficiency was determined to be of very low safety significance (Green) using the SDP phase 1 evaluation of findings for at-power situations because it was confirmed not to result in a loss of function per Generic Letter 91-18.

Enforcement. 10 CFR 50, Appendix B, Section III, "Design Control," requires, in part, that measures shall be established to assure that applicable regulatory requirements and the design basis, as defined in 10 CFR 50.2 and specified in the license application, for those structures, systems, and components to which this appendix applies are correctly translated into specifications, drawings, procedures, and instructions. Contrary to the above, the inspectors identified on March 4, 2004, that the acceptance criteria specified in relay calibration procedure HC-MD-ST.PB-0003(Q) incorrectly allowed the maximum reset setpoints of the 4.16 kv vital bus degraded voltage relays, including setpoint uncertainty, to exceed the calculated recovery voltages. However, because this finding is of very low safety significance and has been entered into PSEG's corrective action program under notification 20180132, this violation is being treated as a non-cited violation, consistent with Section V1.A of the Enforcement Policy.
(NCV 50-354/04-02-07)

2. (Opened) URI 50-354/04-02-08 4 kV Vital Buses Not Maintained at Voltages Supported by Design Basis Calculations

a. Inspection Scope

The inspectors determined that calculations E-15.5(Q), "Hope Creek Fast Bus Transfer Analysis" and E-15(Q), "Load Flow Study," that were used to support the closure of URI 50-354/2003-002-03 assumed the pre-accident and pre-transfer voltages at the 4 kV vital buses were steady state and maintained at 4200 V. The inspectors reviewed procedures and recorded data provided by PSEG to verify that the 4.16 kv vital bus operating voltages were consistent with these design calculations.

The inspector's review of two station procedures showed that both procedures specified acceptance criteria for 4.16 kv vital bus voltage that was not consistent with the design calculations. The two procedures reviewed were:

- HC.OP-DL.ZZ-0003(Q), Log 3 Control Console Log Condition 1, 2 and 3, Revision 46
- HC.OP-ST.ZZ-0001(Q), Power Distribution Lineup - Weekly, Revision 18

The first procedure required control room operators to log the voltages of the four vital buses once every shift and provided an acceptance criterion of 4.1 kV minimum and 4.3 kV maximum. The second procedure (weekly surveillance test) required the technicians to read and record the voltages of the four vital buses during testing and provided an acceptance criterion band of 3744 - 4576 V. The inspector's review of the logged voltages for two of the four 4.16 kv vital buses (Bus 10A402 and 10A404) for the period

March 6 through 12 (total 28 sets of data) indicated that most of the recorded voltages were below 4200V, with one at 4.15 kV and five at 4.16 kV.

The inspectors questioned PSEG personnel to determine whether the specified minimum voltages and the recorded voltages were acceptable. In response, PSEG initiated notification 20184513 on April 5, 2004 to document that procedure HC.OP-DL.ZZ-0003(Q) had a non-conservative minimum voltage acceptance criteria. PSEG issued Temporary Standing Order HC-2004-11 on April 8 to ensure operators manually maintained the 4kV vital bus voltages consistent with design basis calculations. This condition was also the subject of an 8-hour notification made to the NRC on April 6, 2004 in accordance with the requirements of 10 CFR 50.72.

b. Findings

This issue remains unresolved pending review of PSEG's root cause evaluation and further corrective actions. **(URI 50-354/04-02-08)**

3. Temporary Instruction 2515/TI-154, Spent Fuel Material Control and Accounting at Nuclear Power Plants.

Phase I and Phase II inspection of 2515/TI-154 was completed during this inspection period. Appropriate documentation was provided to NRC management as required. No findings of significance were identified.

4. NRC Review: PSEG Independent Assessment Team (IAT).

On March 23, a review was completed to assess the adequacy of PSEG's IAT interview process. PSEG formed the IAT to conduct an in-depth assessment of the work environment for raising and addressing safety concerns at Salem and Hope Creek. As stated in PSEG's February 27 letter (ADAMS Accession: ML040580600) the IAT would be utilizing several sources of information in its assessment efforts, including interviews with personnel at Salem, Hope Creek, and PSEG corporate. At the completion of the review, issues regarding interview population demographics and size, and the availability of the IAT to interested parties (i.e., "open door policy") were discussed with PSEG management. In response to the NRC's observations, PSEG expanded its interview population and established an "open door" policy for the IAT that was communicated to personnel at Salem and Hope Creek.

4OA6 Meetings, Including Exit

NRC/PSEG Management Meeting To Discuss Work Environment

The NRC conducted a meeting with PSEG on March 18 to discuss the work environment at the Salem and Hope Creek power plants. During the meeting the NRC discussed the contents of its letter dated January 28, Work Environment for Raising and Addressing Safety Concerns at the Salem and Hope Creek Generating Stations (ADAMS Accession:ML040280476). PSEG provided a synopsis and status of activities described in their letter dated February 27, PSEG Plan for Assessing and Improving the Work Environment to Encourage Identification and Resolution of Issues (ADAMS Accession:ML040580600). The meeting occurred at the Holiday Inn Select Bridgeport and was open for public observation. A copy of the slide presentations can be found in ADAMS under accession numbers ML040830072 and ML040790261.

Exit Meeting

On April 26, 2004 the inspectors presented their overall findings to members of PSEG management led by Mr. Jim Hutton. None of the information reviewed by the inspectors was considered proprietary.

4OA7 Licensee-Identified Violations.

The following violation of very low significance (Green) was identified by PSEG and is a violation of NRC requirements which meets the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as an NCV.

- TS 3.3.7.5 requires that the NPV high range noble gas monitor be operable when the plant is in operating condition 1, 2, or 3. If not operable then either restore the monitor to an operable status within 72 hours or initiate the preplanned alternate method of monitoring and submit a special report to the NRC. Contrary to this, the NPV high range noble gas monitor was inoperable on September 14, 2003 - December 10, 2003 and the required TS actions were not performed. This was identified in PSEG's corrective action program as notification 20169862. This finding is of very low safety significance because the normal range monitor was not affected and there were no unplanned or unmonitored releases through the NPV during this period.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel

S. Afarian, System Engineer
J. Anthes, System Engineer
M. Bergman, System Engineer
D. Boyle, Operations Superintendent
T. Carrier, Supervisor, PRA Group
J. Cichello, System Engineer
M. Conroy, Senior Engineer (Maintenance Rule Program Manager)
G. Cranfield, Quality Assurance Functional Area Lead
J. Dower, Hope Creek Training Supervisor
R. Fisher, Supervisor, Access Authorization
K. Fleischer, Supervisor , Design Electrical Engineering
J. Frick, Shipping Supervisor
J. Hutton, Hope Creek Plant Manager
M. Ivanick, Security Operations Coordinator
C. Johnson, Staff Engineer
P. Lindsay, Design Engineering Mechanical Supervisor
E. Martin, System Engineer
D. McCullum, Engineer Supervisor, Systems
J. Melchionna, 89-13 Program Manager
K. Meyers, Nuclear Quality Assurance Auditor - Operating Experience
G. Modi, Engineer, Design Electrical Engineering
S. Morisky, System Engineer
D. Price, Refueling/Outage Manager
M. Quadir, Engineer, Design Electrical Engineering
L. Rajkowski, Hope Creek System Engineering Manager
B. Sebastian, Radiation Protection Manager
G. Sosson, Hope Creek Operations Manager
J. Stavely, Hope Creek Reactor Engineering Supervisor
T. Straub, Emergency Services Manager
B. Thomas, Sr. Licensing Engineer
P. Tocci, Hope Creek Maintenance Manager
R. Villar, Senior Engineer, Licensing
L. Wagner, Plant Support Manager
H. Wolfe, Heat Exchanger Eddy Current Program Manager

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-354/04-02-03	URI	Failure of A Service Water Strainer (Section 1R12)
50-354/04-02-08	URI	4 kV Vital Buses Not Maintained at Voltages Supported by Design Basis Calculations (Section 4OA5.2)

Opened and Closed

50-354/04-02-01	NCV	Improper Control of Transient Combustibles in Core Spray Room (Section 1R05)
50-354/04-02-02	NCV	Inadequate Procedural Guidance Related to Electrical Connector Contributes to Cause of Reactor Scram (Section 1R12)
50-354/04/02-04	NCV	Inadequate Operability Evaluations for the B EDG Load Wandering Problem (Section 1R15)
50-354/04-02-05	NCV	Inadequate Identification of Degraded Pipe Insulation In Drywell (Section 1R20)
50-354/04-02-06	NCV	Inadequate Procedure Adherence During Temporary Modification on 125V DC Battery Room (Section 1R23)
50-354/04-02-07	NCV	Failure to Properly Translate Design Bases Requirements Into Plant Procedures for Under Voltage Relay Reset Setpoints (Section 4OA5.1)

Closed

50-354/03-002-03	URI	Offsite Power Grid Separation Vulnerability (4OA5.1)
50-354/03-009	LER	Technical Specification Non-Compliance - Inoperable High Range Noble Gas Effluent Monitor on NPV (Section 4OA3.3)
50-354/04-001	LER	Manual Reactor Scram Following Isolation of Primary Containment Instrument Gas (Section 4OA3.4)
50-354/04-002	LER	Control Room Emergency Filtration (CREF)System Train Inoperable For Greater Than 7 Days (Section 4OA3.5)

Discussed

None

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
Technical Specification Action Statement Log (SH.OP-AP.ZZ-108)
HCGS NCO Narrative Logs
HCGS Plant Status Reports
Weekly Reactor Engineering Guidance to Hope Creek Operations
Hope Creek Operations Night Orders and Temporary Standing Orders

Adverse Weather Protection (71111.01)
Station Preparation For Winter Conditions (HC.OP-GP.ZZ-0003)
Condensate Storage and Transfer System Operation (HC.OP-SO.AP-0001)
P&ID Condensate & Refueling Water Storage & Transfer (M-08-0)
CST Temperature Plots, January 1 to January 9, 2004
Notifications: 20176318, 20173153, 20174035, 20174330, 20177000, 20174547
Order: 30081749

Equipment Alignment (71111.04)
Filtration, Recirculation, and Ventilation System Operations (HC.OP-SO.GU-0001)
Service Air System Operation (HC.OP-SO.KA-0001)
Residual Heat Removal System Operation (HC.OP-SO.BC-0001)
RHR System Piping and Flow Path Verification - Monthly (HC.OP-ST.BC-0001)
P&ID Reactor Building Supply Control Diagram (M-83-1), sheet 1
P&ID Reactor Building Exhaust Control Diagram (M-84-1)
P & ID Residual Heat Removal (M-51-1)
NRC Information Notice 2002-15: Hydrogen Combustion Events in Foreign BWR Piping
NRC Information Notice 2002-15, Supplement 1: Potential Hydrogen Combustion Events in BWR Piping
Notifications: 20178353, 20167454, 20167454, 20153163, 20170372, 20103482, 20089666, 20165356, 20132105, 20171761, 20054405, 20089165, 20141176, 20176037, 20162879, 20152033, 20146178,
Oders:60040867, 60041238,70032644, 70025568, 70034806, 70031101, 70036195, 80023348, 80057706, 80040167, 80062840, 80040594,

Fire Protection (71111.05)
Hourly Firewatch Patrol Inspection Log (NC.FP-AP.ZZ-0020), dated 3/1/04 - 3/14/04
Actions For Inoperable Fire Protection - Hope Creek Station (HC.FP-AP.ZZ-0004)
Hope Creek Generating Station Fire & Medical Emergency Response, Volume 2
Precautions Against Fire (NC.FP-AP.ZZ-0025)
Hope Creek Pre-Fire Plan - Core Spray Pump Room and CRW/DRW Pump (FRH-11-414)
Transient Combustible In Safety Related Areas Impairment Log
Transient Combustible Permit for Work Orders 40017604 and 40017660
Notifications: 20183111, 20183471, 20178521, 20177395, 20183570, 20186049

Heat Sink Performance (71111.07)

Validating SSWS Flow Through SACS HXS (HC.OP-FT.EA-0001), performed 2/24/04
Validating SSWS Flow Through SACS HXS (HC.OP-FT.EA-0001), performed 2/25/04
Station Service Water System Hydraulic Model, EA-0001, Revision 3
STACS - Required Flows and Heat Loads, EG-0020, Revision 8
STACS - Operation, EG-0046, Revision 4
Hope Creek Generating Station - Safety and Turbine Auxiliaries Cooling System (STACS)
Proto-HX Heat Exchanger Models, EG 0044, Revision 1
Maximum Plugged Tubes for EDG Coolers, Evaluation H-1-EG-MEE-1555, Rev. 0
NUPM 30088944 Deferral (A SW Pump Silt Survey Deferral)
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C EDG Lube Oil Analysis Report, dated 1/14/04
D EDG Lube Oil Analysis Report, dated 1/25/04
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36 MO 1A VH209 Fan PM Inspection, 30070017, dated 8/21/02
1B1E-201 SACS HX Inspection, dated 4/28/03
1B2E-201 SACS HX Inspection, dated 4/28/03
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Hope Creek B SACS Upper Heat Exchanger Eddy Current Inspection - RF09, dated 5/1/00
Hope Creek A SACS Lower Heat Exchanger Eddy Current Inspection - RF09, dated 5/12/00
Hope Creek A SACS Upper Heat Exchanger Eddy Current Inspection - RF09, dated 5/11/00
Hope Creek A Lower Safety Auxiliary Cooling System (SACS) Eddy Current Inspection - RF10, dated 10/25/01
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1Y HC Unit 2 SW Bays Silt Removal, dated 6/4/03
A SW Intake Silt Survey Results 10/19/99 - 5/27/03

B SW Intake Silt Survey Results 10/04/99 - 9/02/03
C SW Intake Silt Survey Results 11/23/99 -12/20/03
D SW Intake Silt Survey Results 10/12/99 - 3/24/03
Examination of SACS Corrosion Coupons, dated 2/3/97 - 7/13/03
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Validating SSWS Flow Through SACS HXS (HC.OP-FT.EA-0001), Rev. 3
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Service Water System Operation (HC.OP-SO.EA-0001), Rev. 23
Service Water Traveling Screens System Operation (HC.OP-SO-EP-0001), Rev. 15
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QA Assessment Report 2003-0065, dated 6/13/03
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QA Assessment Report 2003-0119, dated 4/30/03
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QA Assessment Report 2003-0246, dated 9/8/03
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SW Reliability Generic Letter (89-13) Engineering Programs Assessment, dated 12/8/03
Assessment of Emergency Diesel Generator Maintenance Practices Hope Creek and Salem Nuclear Operating Units, dated 9/5/03
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A Service Water Pump-AP502 - Inservice Test (HC.OP-IS.EA-0001), dated 1/8/04 and 1/9/04
B Service Water Pump-BP502 - Inservice Test (HC.OP-IS.EA-0002), dated 1/23/04
C Service Water Pump-CP502 - Inservice Test (HC.OP-IS.EA-0003), dated 2/12/04
D Service Water Pump-DP502 - Inservice Test (HC.OP-IS.EA-0004), dated 1/3/04
A Spray Water Pump-AP507 - Inservice Test (HC.OP-IS.EP-0002), dated 12/20/03
B Spray Water Pump-BP507 - Inservice Test (HC.OP-IS.EP-0002), dated 11/22/03
C Spray Water Pump-CP507 - Inservice Test (HC.OP-IS.EP-0003), dated 2/12/04
D Spray Water Pump-DP507 - Inservice Test (HC.OP-IS.EP-0004), dated 12/29/03
A SACS Pump-AP210 - Inservice Test (HC.OP-IS.EG-0001), dated 1/8/04
B SACS Pump-BP210 - Inservice Test (HC.OP-IS.EG-0002), dated 12/21/03
C SACS Pump-CP210 - Inservice Test (HC.OP-IS.EG-0003), dated 2/13/04
D SACS Pump-DP210 - Inservice Test (HC.OP-IS.EG-0004), dated 12/4/03
Service Water Subsystem A Valves - Inservice Test (HC.OP-IS.EA-0101), dated 2/6/04
Service Water Subsystem B Valves - Inservice Test (HC.OP-IS.EA-0102), dated 12/29/03
Emergency Diesel Generator AG400 Operability Test - Monthly (HC.OP-ST.KJ-0001), dated 2/2/04

Emergency Diesel Generator BG400 Operability Test - Monthly (HC.OP-ST.KJ-0002), dated 2/16/04
Emergency Diesel Generator DG400 Operability Test - Monthly (HC.OP-ST.KJ-0004), dated 1/25/04
Emergency Diesel Generator CG400 Operability Test - Monthly (HC.OP-ST.KJ-0003), dated 2/9/04
System Health Reports Emergency Diesel Generators (KJ), 9/1/03 to 11/30/03
System Health Reports Safety and Turbine Auxiliary Cooling System (STACS-EG), 9/1/03 to 11/30/03 (4th Quarter)
System Health Reports Service Water (EA) and Traveling Screen / Screen Wash - (EP), 9/1/03 To 11/30/03
Notifications: 20094355, 20094531, 20095020, 20097052, 20127317, 20130011, 20130730 20137653, 20138694, 20139969, 20141907, 20144508, 20146545, 20148464, 20148516, 20157446, 20161537, 20166529, 20167235, 20172044, 20176976, 20177416, 20177867, 20177868, 20177944, 20178006
Orders: 60027015, 60032894, 60036996, 60042665, 70032154, 70032161, 70033361, 70034143, 70034963, 70035180, 70023696, and 80055631

Licensed Operator Requalification (71111.11)
Reactor Scram Hard Card (HC.OP-AB.ZZ-0001 attachment 1)
Reactor Feed Pump Turbine and Startup Level Control Operation Hard Card (HC.OP-AB.ZZ-0001 attachment 14)

Maintenance Effectiveness (71111.12)
Maintenance Rule System Function and Risk Significance Reference (SE.MR.SA.01)
System Function Level Maintenance Rule VS Risk Reference (SE.MR.HC.02)
Maintenance Rule (a)(1) Evaluations and Goal Monitoring (SH.ER-DG.ZZ-0002)
System Specific Performance Criteria (SH.ER-SE.ZZ-0009)
Maintenance Rule Scoping (SH.ER-SE.ZZ-0014)
Preventable and Repeat Preventable System Functional Failure Determination (SH.ER-DG.ZZ-0001)
Monitoring the Effectiveness of Maintenance (NC.NA-AP.ZZ-0016)
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
Report #80057735, 2003 10CFR50.65(a)(3) Periodic Assessment (September 2001 - June 2003)
Lesson Plan NECNRULEIMPL, Maintenance Rule Implementation Training
Lesson Plan NECDMAINTRLC, Maintenance Rule Overview Training
DCP 4-HMM-86-0855, Installation of Double Nut to Backwash Arm Shaft
Vendor Manual: Strain-o-matic Instruction Manual, Service Water Self-Cleaning Strainer (10855-M-076)
Potential for Radiolytic Gas Detonation (GE Nuclear Energy SIL No. 643), dated 6/14/02
NRC Information Notice 2002-15: Hydrogen Combustion Events In Foreign BWR Piping, dated 4/12/02

NRC Information Notice 2002-15, Supplement 1: Potential Hydrogen Combustion Events In BWR Piping, dated 5/6/03
Potential for Hydrogen Detonation in the Piping Downstream of BC-HV-F052B Valve (H-1-BC-MEE-1829), Rev. 0, dated 3/31/04
Service Water Strainer Overhaul and Repair (HC.MD-CM.EA-0003)
System Health Reports - Auxiliary Feedwater System
System Health Reports - Gas Turbine
System Health Reports - Residual Heat Removal System
System Health Reports - Emergency Diesel Generators
Post Transient Response Report - Hope Creek PCIS Isolation/Reactor Scram, dated 1/12/04 (20173532/31)
Process Radiation Monitoring-Channel A, Channel 1SP-RE-4857A Reactor Building Exhaust (HC.IC-SC.SP-0050)
LEMO's Minature Coaxial Connectors (NIM-CAMAC NBS-549), www.Lemousa.com
Evaluations: 70025568, 70037145
Notifications: 20096912, 20148682, 20167133, 20167134, 20167454, 20170372, 20176672, 20173622, 20173609, 20166881, 20130871, 20127734, 20131516, 20146609, 20117537, 20146880, 20178785, 20173531, 20170372, 20178353, 20183265
Orders: 30081305, 60042213, 70016036, 70027584, 70029886, 70031717, 70032685, 70032722, 70032723, 70032774, 7003279, 70036167, 80057735, 80063522, 80063885, 80063886, 80063887, 80063888

Maintenance Risk Assessment and Emergent Work Control (71111.13)
System Function Level Maintenance Rule VS Risk Reference (SE.MR.HC.02)
HCGS PSA Risk Evaluation Forms for Work Week Nos. 143(10) to 156(12)
On-Line Risk Assessment (SH.OP-AP.ZZ-108)
NRC Regulatory Guide 1.182, Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants
NUMARC 93-01, Industry Guideline For Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, Section 11- Assessment of Risk Resulting from Performance of Maintenance Activities, dated February 11, 2000
ORAM Model for HCGS (H-1-ZZ-RZZ-0032)
Notifications: 20182645, 20182971, 20183017, 20183101, 20177359,
Order 60036488 (Confirmation of B PCIG compressor repair prior to A PCIG outage)

Operator Performance During Non-Routine Evolutions and Events (71111.14)
Conduct of Infrequently Performed Tests or Evolutions (NC.NA-AP.ZZ-0084)
Power Suppression Testing (HC.RE-RA.ZZ-0007)
CRD Removal and Replacement (HC.MD-PM.BF-0010)
Hope Creek Reactivity Plan, dated January 29, 2004 (HRE:2004-0021)
IPTE Summary For Cycle 12 January 2004 Power Suppression Testing
J and P SRV IPTE Briefing (IPTE 04-003)
Maintenance Outage 3-20-2004 Reactor Water Heatup Curves
Refuel/Core Alterations Log (HC.OP-DL.ZZ-0026)
OD-7 Rod Position and Substitutions Display Print Out, dated 3/25/04
In-Sequence Critical SDM Measurement (HC.RE-ST.ZZ-0007), dated 5/12/03

Notifications: 20175805, 20182770, 20182812, 20182901

Operability Evaluations (71111.15)

Operability Assessment and Equipment Control Program (SH.OP-AP.ZZ-0108)
NRC Generic Letter No. 91-18, Revision 1, Resolution of Degraded and Nonconforming Conditions
Notification Process (NC.WM-AP.ZZ-0000)
SRM Functional Test (HC.IC-FT.SE-0001)
SRM Preamp/Gain Channel Calibration (HC.IC-CC.SE-0042)
SRM Channel Calibration (HC.IC-CC.SE-0004)
Emergency Diesel Generator BG400 Operability Test - Monthly (HC.OP-ST.KJ-0002)
High Voltage AC Insulation Testing (5-DTP-1)
P&ID Residual Heat Removal (M-51-1)
Isometric - RHR System - Inside Drywell Reactor Building (1-P-BC-034)
Isometric - RHR System - Inside Drywell Reactor Building (1-P-BC-037)
Isometric - Reactor Building - Inside Drywell Vent Valve Configuration (FSK-P-1-BC-660)
Isometric- Reactor Building - Inside Drywell Vent Valve Configuration (FSK-P-1-BC-663)
Logic Diagram Safety Auxiliaries Cooling (Dwg J-11-0)
Panel 1YF405 Aux Bldg El/Area 102/25 (Dwg No. E1417-0, sheet 6A)
Panel 1YF404 Aux Bldg El/Area 102/26 (Dwg No. E1417-0, sheet 5A)
Panel 1YF404 Aux Bldg El/Area 102/26 (Dwg No. E1417-0, sheet 5B)
Panel 1YF209 Reac Bldg El/Area 102/13 (Dwg No. E1417-0, sheet 1A)
Panel 1YF401 Aux Bldg El/Area 102/26 (Dwg No. E1417-0, sheet 2A)
Panel 1YF406 102/26 (Dwg No. E1417-0, sheet 7B)
Panel 1YF402 Aux Bldg El/Area 102/26 (Dwg No. E1417-0, sheet 3A)
Panel 1YF403 Aux Bldg El/Area 102/26 (Dwg No. E1417-0, sheet 4A)
Evaluation of Hope Creek In-Drywell Pipe Vibration (H-1-BB-CEE-1830)
Technical Specification 3.3.7.6, Instrumentation - Source Range Monitors
Technical Specifications 3.9.2, Refueling Operations - Instrumentation
Technical Specification 3.8.2 Electrical Power Systems - DC Sources
FSAR 8.3.2.1.2, Class 1E DC Systems
FSAR 9.4.6.2, Battery Room Supply
Calvert Cliffs 10 CFR Part 21 Interim Report Concerning Failure of Gould-Shawmut Fuses (9505150034)
Calvert Cliffs 10 CFR Part 21 Follow-up Report Concerning Failures of Gould-Shawmut Fuses (9604030315)
System Readiness Affirmation Form - 13 kV Breaker Bushings Issue
System Readiness Affirmation Form - A25X Type Gould Fuse Failure Issue
Notifications: 20161115, 20175893, 2016745, 20183079, 20183092, 20183095, 20183098, 20183099, 20183452, 20182046, 20182406, 20183456, 201883533, 20183534, 20183536, 20183537, 20183538, 20193539, 20183571, 20153163, 20146178, 20152033, 20162879, 20181388, 20181743, 20182421, 20182400, 20182395, 20182394, 20182398, 201822397, 20174173, 20174172
Orders: 50041705, 50055526, 50072060, 70031451, 80062840

Operator Workarounds (71111.16)

Operability Determination (CROD) / Follow-up Assessment (CFA) Log, dated 3/13/04
Inoperable Instrument/Alarm/Indicators/Lamps/Device Log
Daily Temporary Log Record
Hope Creek Operations Night Orders
Operations Temporary Standing Orders
Inoperable Computer Point Log
Hope Creek Operator Workaround List
Hope Creek Operator Concerns List
Hope Creek Operations Turnover Sheet, dated 3/25/04
Quarterly Operator Burden Assessment, dated 9/12/03
Temporary Modification Log
Operator Burden Program (SH.OP-AP.ZZ-0030)
Notifications: 20181359, 20183319, 20183526

Post Maintenance Testing (71111.19)
Maintenance Testing Program Matrix (NC.NA-TS.ZZ-0050)
Emergency Diesel Generator CG400 Operability Test - Monthly (HC.OP-ST.KJ-0003)
A Service Water Pump - AP502 - Inservice Test (HC.OP-IS.EA-0001)
Standby Liquid Control System Valves - Inservice Test (HC.OP-IS.BH-0101)
Limitorque Valve Operator Inspection and Lubrication (HC.MD-PM.ZZ-0004)
Notification:20183122
Order: 40011081

Refueling and Other Outage Activities (71111.20)
Outage Management Program (NC.NA-AP.ZZ-0055)
Outage Risk Assessment (NC.OM-AP.ZZ-0001)
Preparation for Plant Startup (HC.OP-IO.ZZ-0002)
Startup From Cold Shutdown to Rated Power (HC.OP-IO.ZZ-0003)
Shutdown From Rated Power to Cold Shutdown (HC.OP-IO.ZZ-0004)
Shutdown Cooling (HC.OP-AB.RPV-0009)
Startup Reactivity Plan Part 1, dated January 14, 2004 (HRE:2004-0010)
ORAM Model for HCGS (H-1-ZZ-RZZ-0032)
Planned Outage - Outage Risk Assessment, dated 3/20/04
Decay Heat Removal Operation (HC.OP-SO.BC-0002)
Transient Loads (NC.CC-AP.ZZ-0011)
CRD Insertion and Withdrawal Speed Test, Adjustment and Stall Flows (HC.OP-FT.BF-0001)
Pre-Startup Missile Hazard Inspection Report, dated 3/31/04
WCDs: 4120648, 41211494, 4121586, 4121588, 4121610
Notifications:20182502, 20182531, 20182578, 20182819, 20182860, 20183009, 20183115, 20183122

Surveillance Testing (71111.22)
Process Radiation Monitoring - Channel A, Channel 1SP-RE-4857A Reactor Building Exhaust (HC.IC-SC.SP-0050)
B & D Core Spray Pumps - BP206 and DP206 - Inservice Test (HC.OP-IS.BE-0002)
BP202, B Residual Heat Removal Pump Inservice Test (HC.OP-IS.BC-0003)

Control Rod Scram Time Testing Surveillance (HC.RE-ST.BF-0001)
HPCI Main and Booster Pump Set - OP204 and OP217 - Inservice Test (HC.OP-IS.BJ-0001)
A Spray Water Pump - AP507 - Inservice Test (HC.OP-IS.EP-0001)
Reactor Core Isolation Cooling Pump-OP203-Inservice Test (HC.OP-IS.BD-0001)
Reactor Coolant System Pressure Isolation Valves Seat Leakage Measurement/Test (HC.RA-IS.ZZ-0017)
FSAR 6.3, Emergency Core Cooling System
Notifications: 20176522, 20167898, 20182230, 20176113, 20176763

Temporary Plant Modifications (71111.23)
125 Volt Weekly Battery Surveillance (HC.MD-ST.PK-0001)
Temporary Modification 03-055 - Temporary Space Heater for Battery Room 5541
Temporary Reading Sheets (SH.OP-DL.ZZ-0027) from 12/26/03 to 2/15/04
Control Narrative Log 1/9 to 1/10/04
NRC Safety Evaluation Related to Amendment Number 127
HVAC Abnormal Procedure (HC.OP.AB.HVAC-0001)
P&ID Auxiliary Building Diesel Area Air Flow Diagram (M-85-1, sheets 1 and 2)
P&ID Auxiliary Building Diesel Area Control Diagram (M-88-1, sheets 1 and 2)
Notifications: 20171767, 20173293, 20173605, 20178465
Orders: 70036263

Drill Evaluation (71114.06)
Artificial Island Emergency Plan
Hope Creek Emergency Classification Guide
Hope Creek Event Classification Guide Technical Basis

Performance Indicator Verification (71151)
Licensee Event Report 2003-005-00, Hope Creek "B" Emergency Diesel Generator Inoperable Beyond Technical Specification Allowed Outage
PSE&G Salem/Hope Creek Security IDS/CCTV Performance Indicator Report - 1st Quarter 2003 through 1st Quarter 2004
PSE&G Salem/Hope Creek Fitness For Duty Performance Indicator Report 1st Quarter 2003 through 4th Quarter 2003
Notifications: 20179963
Orders: 80036395

Identification and Resolution of Problems (71152)
Vendor Technical Drawing PJ373Q-0435
Special Report 354/03-001, January 27, 2003, NPV High Range Noble Gas Monitor Being Inoperable for Greater Than 72 Hours
Special Report 354/03-006, October 1, 2003, NPV High Range Noble Gas Monitor Being Inoperable for Greater Than 72 Hours
Licensee Event Report (LER) 354/03-009-00, February 6, 2004, Technical Specification Noncompliance - Inoperable High Range Noble Gas Effluent Monitor on NPV (refer to section 40A3 for more information)
Hope Creek Technical Specification 3.3.7.5

Event Followup (71153)
P&ID Service Water (M-10-1, sheet 1)
P&ID Service Water (M-10-1, sheet 2)
P&ID Service Water (M-10-1, sheet 3)
P&ID Service Water (M-10-1, sheet 4)
Lesson Plan Service Water System (0301-000.00H-000079-15)
Plant Historian Plots: SSW Strainer Diff Pressure A-D on 2/23/04
Plant Historian Plots: SACS Heat Exchanger (A1-B2) SSW Out Temperatures on 2/23/04
Plant Historian Plots: SACS Loop Pump Suction Temperatures (A and B) on 2/23/2004
Plant Historian Plots: Service Water Flow Rates (A and B Loop) on 2/23/04
Plant Historian Plots: Service Water Strainer Diff Pressure (A-D) on 2/23/04
Vendor Manual: Hayward Tyler Vertical Turbine Centrifugal Pump (10855-M-080)
Control Room Narrative Logs on 2/23/2004
Notifications: 20178650, 20178691, 20178721, 20178662, 20178953, 20178785, 20179237, 20179238, 20179240, 20179232, 20179150

LIST OF ACRONYMS

ALARA	As Low As Reasonably Achievable
BWR	Boiling Water Reactor
CEDE	Committed Effective Dose Equivalent
CFR	Code of Federal Regulations
CR	Condition Report
CRDM	Control Rod Drive Mechanism
CREF	Control Room Emergency Filtration
CST	Condensate Storage Tank
DCP	Design Change Package
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EP	Emergency Preparedness
FRVS	Filtration, Recirculation and Ventilation System
GE	General Electric
HCGS	Hope Creek Generating Station
HPCI	High Pressure Coolant Injection
IAT	Independent Assessment Team
IDR	Isochronous/droop
IPEEE	Individual Plant Examination For External Events
IPTE	Infrequently Performed Test or Evolution
IST	Inservice Test
kV	Kilo-Volt
LERs	Licensee Event Reports
MOP	Motor Operated Potentiometer
MR	Maintenance Rule
MSIV	Main Steam Isolation Valve
NCV	Non Cited Violation
NPV	North Plant Vent
NRC	Nuclear Regulatory Commission
ORAM	Outage Risk Assessment and Management
PARS	Publicly Available Records
PCIG	Primary Containment Instrument Gas
PCIS	Primary Containment Isolation System
PIs	Performance Indicators
PMT	Post Maintenance Testing
PSEG	Public Service Electric Gas
QA	Quality Assurance
RBE	Reactor Building Exhaust
RCA	Radiologically Controlled Area
RCIC	Reactor Core Isolation Cooling
RHR	Residual Heat Removal
RMS	Radiation Monitoring System
RO	Reactor Operator

RWP	Radiation Work Permit
SACS	Safety Auxiliaries Cooling System
SDC	Shutdown Cooling
SDM	Shutdown Margin
SDP	Significance Determination Process
SLC	Standby Liquid Control
SORC	Station Operations Review Committee
SPV	South Plant Vent
SRM	Source Range Monitor
SRO	Senior Reactor Operator
SRV	Safety Relief Valve
SSDI	Safety System Design Inspection
SSU	Safety System Unavailability
SSWS	Station Service Water System
T-Mod	Temporary Modification
TCP	Transient Combustible Permit
TS	Technical Specifications
TWS	Traveling Water Screen
UFSAR	Updated Final Safety Analysis Report
V	Volt
WCD	Work Clearance Document