November 9, 2004

Mr. A. Christopher Bakken, III
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 05000354/2004004

Dear Mr. Bakken:

On September 30, 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 September 30, 2004, with Messrs. Mike Brothers and John Carlin 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 four NRC identified findings and one self-revealing finding of very low safety significance (Green). These five findings 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 five 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.

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/

Eugene W. Cobey, Chief
Projects Branch 3
Division of Reactor Projects

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

Enclosure: Inspection Report 05000354/2004004
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No:	05000354
License No:	NPF-57
Report No:	05000354/2004004
Licensee:	PSEG LLC
Facility:	Hope Creek Nuclear Generating Station
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	July 1 - September 30, 2004
Inspectors:	M. Gray, Senior Resident Inspector M. Brown, Operations Engineer M. Ferdas, Resident Inspector J. Schoppy, Senior Reactor Inspector S. McCarver, Reactor Inspector B. Welling, Senior Reactor Inspector Ram Bhatia, Reactor Inspector
Approved By:	Eugene W. Cobey, Chief Projects Branch 3 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

IR 05000354/2004004; 07/01/2004 - 09/30/2004; Hope Creek Nuclear Generating Station; Fire Protection, Licensed Operator Requalification, Maintenance Effectiveness, Other Activities.

The report covered a 13-week period of inspection by resident inspectors and an in-office review by a regional inspector. Five green non-cited violations (NCVs) were identified. 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: Mitigating Systems

C Green. The inspectors identified that fire protection procedure requirements were not met when seven drums of lubrication oil removed from the C emergency diesel generator were stored in the adjacent common corridor without the required transient combustible permit (TCP). The finding was of very low safety significance and constituted a non-cited violation of Technical Specification 6.8.1.

  Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements. This finding was greater than minor because it was associated with the protection against external factors attribute of the mitigating systems cornerstone and affected the objective to maintain the reliability of mitigating systems. The increased combustible loading from improperly stored lubrication oil potentially reduced the availability of mitigating systems in and adjacent to the emergency diesel generator common corridor in the event of a postulated fire. Additionally, this finding is similar to example 4.k in NRC Inspection Manual 0612, Appendix E. The finding was evaluated in accordance with NRC Inspection Manual 0609, Appendix F and determined to be of very low safety significance. The lubrication oil stored without a TCP had a high flashpoint and resulted in a low degradation of the combustible controls program. In addition, there were no in-progress maintenance tasks that resulted in a credible ignition source in the area where this oil was stored. (Section 1R05)

• Green. The inspectors identified that the Hope Creek simulator did not replicate the plant design during a station blackout (SBO) condition because the reactor core isolation cooling (RCIC) pump suction swapped from the condensate storage tank (CST) to the suppression pool. The finding was determined to be of very low safety significance and a non-cited violation of 10 CFR 55.46(c)(1), "Plant-Referenced Simulators."

Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements. This finding was more than minor because it was associated with the human performance attribute and affected the mitigating systems cornerstone objective to ensure the availability and reliability of mitigating systems equipment. The finding was evaluated using the Operator Requalification Human Performance SDP (MC 0609 Appendix I). The finding was determined to be of very low safety significance based upon the SDP contained in MC 0609, Appendix I. The discrepancy did not have an adverse impact on operator actions such that safety-related equipment was inoperable during normal operations or in response to a plant transient. (Section 1R11)

- Green. The inspectors identified that abnormal operating procedures contained errors in describing the expected reactor core isolation cooling (RCIC) and high pressure isolation cooling (HPCI) pump suction alignment during electrical equipment problems. The finding was determined to be a non-cited violation of 10 CFR 50, Appendix B, Criterion III, "Design Control."

  Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements. This finding was more than minor because it was associated with the procedure quality attribute of the mitigating systems cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems to respond to initiating events. These procedure errors would require operators to evaluate HPCI and RCIC pump suction alignments during electrical equipment problems because the alignments would be different than described in abnormal operating procedures. The finding was determined to be of very low safety significance because the finding was not a design or qualification deficiency, did not result in an actual loss of safety function, and the finding was not screened as a potentially risk significant for external events. (Section 1R11)

- Green. A self-revealing finding was identified regarding inadequate procedure guidance when the B station service water system (SSWS) pump packing failed on July 14, 2004. The finding was determined to be a non-cited violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings."

  Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements. The finding was more than minor, because it was associated with the mitigating systems cornerstone attribute for equipment performance and affected the objective to ensure the availability of the B station service water system (SSWS) pump. This issue also impacted the initiating events cornerstone objective because the unavailability of one train of SSWS increased the likelihood of a loss of service water (LOSW) event. The finding was determined to be of very low safety significance based upon a SDP Phase 3 analysis. (Section 1R12)

- Green. The inspectors identified that operating procedures allowed operation of the 4.16 kV vital electrical buses at voltage levels that would have caused the safety buses to separate from the offsite power source during the starting of emergency equipment loads following a loss of coolant accident. The finding was determined to be a non-cited violation of 10 CFR 50, Appendix B, Criterion III, "Design Control."

  Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements. This finding was more than minor because it affected the design control attribute of the mitigating systems cornerstone and the objective to ensure the availability, reliability, and capability of electrical systems to prevent undesirable consequences. The finding was determined to be of very low safety significance based on a SDP Phase 3 analysis. (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. The violation is listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

The Hope Creek plant began the period at full power operation. On July 14, 2004, operators reduced power to approximately 70 percent (%) to maintain turbine auxiliaries cooling system supply temperatures within limits after the B station service water system (SSWS) pump was removed from service for failed pump packing and a second SSWS pump was out of service for maintenance. The plant was returned to full power on July 16, 2004.

On August 2, 2004, operators decreased power in accordance with procedures to 80% after a high pressure feedwater heater isolated. The plant was returned to 98% power on August 3, 2004, and maintained essentially at that power level with the feedwater heater out of service. Plant power was reduced to 81% on August 7, 2004, for a planned down-power for control rod pattern adjustment and maintenance to a circulating water pump valve. The plant was returned to 98% power on August 8, 2004. Plant power was reduced to 60% on August 20, 2004 for a planned down-power to repair a steam leak from a non-safety related extraction steam valve flanged joint. However, the leak was not repaired due to problems with the repair device and the plant was returned to 98% power on August 22, 2004. On September 4, 2004, plant power was reduced to 70% and the extraction steam valve leak was repaired. The plant was returned to full power on September 5, 2004.

On September 16, 2004, operators reduced power from 100% to approximately 50% at the request of the electrical grid system operator. This down power was required to ensure system grid stability during an offsite line outage. The plant was returned to full power on September 19, 2004 after the line was returned to service and scheduled turbine valve testing was completed. The plant remained at or close to full power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope (3 samples)

The inspectors reviewed cold weather preparation activities and PSEG's response to two actual severe weather conditions. The inspectors reviewed applicable documents associated with adverse weather as listed in the Supplemental Information attachment to this report.

Seasonal Readiness. The inspectors reviewed the Hope Creek Updated Safety Evaluation Report for a description of risk significant systems that require protection from cold weather conditions. This review identified that the equipment in the service water intake structure (SWIS), the condensate storage tank, and the emergency diesel generator air intake and exhaust openings are protected from cold weather conditions by design features and/or procedural actions. The inspectors reviewed the design features and procedures required to protect these three risk significant systems from extreme cold weather conditions by a review of plant drawings, procedures and walkdown of the equipment. Applicable work orders were also reviewed to verify that winter preparation tasks were either completed or scheduled to be completed before potential winter conditions.

Severe Storm & Tornado Warnings For Adjacent Areas. On July 12, 2004, the National Weather Service reported tornado activity in Middletown, Delaware with a potential for the storm to track towards the plant site. The inspectors observed and reviewed the adequacy of the plant operators response in entering the abnormal procedure for acts of nature (HC.OP-AB.MISC-0001), closing watertight doors to the service water intake structure and auxiliary building, reviewing station blackout procedures, and terminating any in progress surveillance testing of emergency diesel generators or electrical equipment to ensure full system availability for a potential loss of offsite power condition. The inspectors also determined whether high wind conditions were adequately monitored against emergency action level criteria for classifying events. Finally, the inspectors determined whether the operators met reportability requirements for short term outages of some offsite sirens that were restored to service the same evening.

Severe Storm & Tornado Warnings For Salem County. On July 14, 2004, the National Weather Service issued a severe storm and a tornado warning affecting the Hope Creek site. The inspectors observed and reviewed PSEG's implementation of their abnormal procedure for acts of nature to verify the specified actions were completed. Additionally, external flood protection measures were observed and control room narrative logs were reviewed to assess PSEG's performance in preparing for potential high winds at the site. The inspectors also verified whether high wind conditions were adequately monitored against emergency action level criteria for classifying events.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

a. Inspection Scope

The inspectors performed four partial equipment alignment inspections and one complete alignment inspection. The partial alignment inspections were performed on the reactor core isolation cooling system, station service water system, standby liquid control system and safety auxiliary cooling system. The complete equipment alignment inspection was performed on the D emergency diesel generator fuel oil transfer and ventilation systems. The inspectors reviewed applicable documents associated with these equipment alignments as listed in the Supplemental Information attachment to this report. The inspectors also searched the corrective action program to identify a sample of equipment configuration problems. The evaluation and resolution of these problems were reviewed for effectiveness.

Partial System Alignments (IP 71111.04Q - 4 Samples). The high pressure coolant injection (HPCI) system was out of service for scheduled maintenance on July 1, 2004. The inspectors reviewed the operability of the reactor core isolation cooling (RCIC) system by verifying the system was aligned in accordance with its operating procedure. The inspectors also reviewed RCIC system drawings and operating procedures, performed field walkdowns of accessible portions of the RCIC system, and observed control room system indications to verify the alignment was correct.

On July 19, 2004, the inspectors reviewed applicable station service water system (SSWS) operating procedures and drawings to verify the system was correctly aligned and capable of performing its function following the emergent unavailability of the C SSWS pump. The inspectors verified by plant walkdowns and main control room tours that the maintenance activities on the C SSWS pump did not adversely affect redundant SSWS components. The inspectors also verified that PSEG restored the C SSWS pump to an operable condition following the associated maintenance.

On September 15, 2004, the A emergency diesel generator was removed from service for scheduled maintenance. The inspectors verified that the operability of the B standby liquid control system because this train was identified as risk significant with the A emergency diesel generator out of service. The inspectors verified that the B standby liquid control system train was protected in accordance with procedures and performed a partial alignment review by walking down accessible portions of the train and observing control room indications.

On September 23, 2004, the inspectors walked down risk significant portions of the A safety auxiliaries cooling loop to verify cooling was correctly aligned to safety-related heat loads. This system was selected because of its increased risk significance when the B station service water pump was out of service on this date for emergent corrective maintenance. The inspectors verified by walkdown that the cooling was correctly aligned to a sample of emergency diesel generator support equipment, residual heat removal pump seal coolers, and a sample of emergency core cooling system pump room coolers.

Complete System Alignment (IP 71111.04S - 1 Sample). The inspectors performed one complete system alignment inspection on the D emergency diesel generator (EDG) fuel oil storage and transfer system to determine whether the system was aligned and capable of providing fuel to the D EDG in accordance with design basis requirements. The D EDG fuel system was selected based on the risk significance of the D EDG while the C EDG was out of service in August 2004 for scheduled maintenance. The inspectors reviewed operating procedures, surveillance test procedure and equipment lineup lists to determine the required equipment alignment.

The D EDG fuel oil storage tanks, day tank, transfer pumps, piping and valves were subsequently walked down to observe whether the equipment was maintained as described in configuration documents to support D EDG operation during accident conditions. The inspectors observed whether valves were locked or maintained in the required position and reviewed local indications for tank fuel level and valve control to verify these components were maintained in accordance with procedures. Finally, engineering system health reports and corrective action notifications for the system were reviewed to determine that equipment alignment problems for the system were being identified and corrected at an appropriate threshold.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process (ROP) baseline inspections. In accordance with this deviation, the following additional inspection sample was performed. The inspectors reviewed PSEG's performance indicator for mis-positioned plant components to determine if an adverse trend exists and reviewed notifications 20188291, 201884378, and 20173625. Also, the inspectors reviewed additional corrective action program notifications identifying equipment alignment problems to ensure the problems were adequately evaluated and corrected. The additional notifications reviewed were 20179670, 20167384, 20151198, 20149395, 20133954 and 20179795.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope (8 Samples & 1 Fire Drill)

The inspectors observed one fire drill and performed eight fire area walkdowns. The inspectors observed a fire drill on September 14, 2004, to determine the readiness of PSEG's fire brigade to prevent and respond to fires. The drill scenario involved a simulated electrical fire in a 120 Vac inverter. The inspectors also observed the performance of operations personnel stationed in the control room during the drill. The inspectors attended PSEG's drill critique to evaluate its adequacy in assessing personnel performance to respond to the postulated fire.

During plant walkdowns the inspectors evaluated the adequacy of combustible material control, fire detection and suppression equipment availability and 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. The inspectors reviewed applicable documents associated with these equipment alignments as listed in the Supplemental Information attachment to this report. Additionally, the inspectors reviewed notifications documenting fire protection deficiencies to verify identified problems were being evaluated and corrected. The following plant areas were inspected:

- D fuel oil storage tank room on July 19, 2004;
- Control equipment room mezzanine on July 21, 2004;
- Cable spreading room on July 21, 2004;

- Service water intake structure on August 3, 2004;
- Main turbine lube oil reservoir room on August 17, 2004;
- A/B/C lube oil reservoir rooms on August 17, 2004;
- Common emergency diesel generator corridor (Room 5339) on August 23, 2004; and
- A Residual Heat Removal Heat Exchanger (Room 4113) on September 23, 2004.

b. Findings

Introduction. The inspectors identified that fire protection procedure requirements were not met when seven drums of lubrication oil removed from the C EDG were stored in the common corridor adjacent to the C EDG without the required transient combustible permit. The finding was of very low safety significance (Green) and a non-cited violation of Hope Creek Technical Specification (TS) 6.8.1 for the failure to correctly implement fire protection program procedures.

Description. During a walkdown of the auxiliary building on August 23, 2004, the inspectors observed seven 55 gallon drums of waste lubrication oil stored in the common electrical access area (room 5339) adjacent to the four EDG rooms. Operations personnel drained this oil from the C EDG the night before as part of planned maintenance on the C EDG. The inspectors discussed this with the on-duty fire protection supervisor and requested to review the transient combustible permit (TCP) for storing oil in this room. The fire protection supervisor determined that a TCP was not performed for the waste oil stored in this room.

On August 24, 2004, the oil drums were removed from room 5339 to the parallel common corridor (room 5315). The inspectors requested the transient combustible permit for storing the seven oil drums in room 5315 and were provided TCP# HTC-04 CD-10-002. However, the inspectors noted the TCP was incorrect because the amount of combustible liquid identified on this TCP was 0.5 gallons, not the seven drums of waste oil (385 gallons total) that were stored in the room. The fire protection supervisor subsequently determined this TCP had been issued to the maintenance supervisor for work on the C EDG and did not account for work activities by operations personnel to drain and dispose of the waste lubrication oil. On the evening of August 24, 2004, the drums of oil were removed from the auxiliary building to a location where a TCP was not required. PSEG initiated notification 20201300 to address this problem in their corrective action program.

Analysis. The performance deficiency involved a failure to comply with fire protection procedure requirements for controlling transient combustible material in the auxiliary building. On August 23 and 24, 2004, the inspectors identified seven drums (385 gallons) of lubricating oil stored in the auxiliary building without a TCP that evaluated and approved the storage of a combustible liquid in this area. Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements. This finding was greater than minor because it was associated with the protection against external factors attribute of the mitigating systems cornerstone and affected the objective to maintain the reliability of mitigating systems. The increased combustible loading from improperly stored lubrication oil potentially reduced the availability reliability of mitigating systems in and adjacent to the EDG common corridor in the event of a postulated fire. Additionally, the finding is similar to example 4.k in NRC IMC 0612, Appendix E.

The inspectors evaluated the finding in accordance with NRC IMC 0609, Appendix F and determined the finding was of very low safety significance (Green). The lubrication oil stored without a TCP had a high flashpoint (437F) and resulted in a low degradation of the combustible controls program. In addition, there were no in-progress maintenance tasks that resulted in a credible ignition source in the area where this oil was improperly stored. Accordingly, this finding was determined to be Green in the Phase 1, Qualitative Screening Analysis, Step 1.3.1 of NRC IMC 0609, Appendix F. This finding had a problem identification cross-cutting aspect because operations personnel supervisors responsible for draining the C EDG lubricating oil and fire watch personnel performing hourly fire watches in the area did not identify that the storage of these oil barrels required a transient combustible permit.

Enforcement. Hope Creek TS 6.8.1.g requires that written procedures be established, implemented, and maintained for the fire protection program. PSEG fire protection procedure NC.FP-AP.ZZ-0025, Step 5.8.2 requires that, for tasks that introduce transient combustible material into safety-related areas, the responsible supervisor initiate Form-1, "Transient Combustible Permit," to estimate the amount of combustible material that will be introduced into a safety-related area. Procedure Step 5.8.3 indicates that engineering personnel must approve transient combustible permits for loading estimated to exceed one half the established limit. Step 5.9.4.A describes the transient combustible load limit for Hope Creek as 4,480,000 BTUs over and above the limit assumed in the fire hazards analysis. Contrary to these requirements, on August 23 and 24, 2004, PSEG stored seven drums of lubrication oil, equivalent to 61,600,000 BTUs over and above the transient combustible limit allowed in the fire hazards analysis, in a safety-related area (room 5339) without an engineering approved transient combustible permit. However, because the violation was of very low safety significance and PSEG entered the deficiency into their corrective action system in notification 20201300, this finding is being treated as a non-cited violation, consistent with section VI.A of the NRC Enforcement Policy. **(NCV 50-354/2004004-01, Inadequate Control of Transient Combustible Material)**

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope (1 Sample)

The inspectors performed one external flood protection inspection activity of the service water intake structure (SWIS) and reactor and auxiliary building roof drainage systems. The SWIS was selected for review because the Hope Creek Updated Safety Analysis Report (UFSAR), Section 2.4.2.2 indicates that wave heights during the predicted maximum hurricane (PMH) could reach the height of the SWIS roofline facing the river. Flood design features described in the UFSAR for the SWIS and the roof drainage systems were reviewed by plant walkdowns to ensure these features were maintained.

Specifically, the inspectors walked down the SWIS structure internal and external walls and ventilation intake and exhaust openings to verify there were no penetrations that would allow water intrusion during a PMH that could affect service water system operation. The inspectors reviewed the design basis specifications for the watertight SWIS doors to confirm the doors would provide adequate leak tightness during a PMH. In response to inspector questions regarding preventive maintenance tasks, PSEG initiated notification 20202797 to document that preventive maintenance tasks had been discontinued for intake structure watertight doors 6 and 8. The inspectors followed up on this issue to determine whether the issue was minor by observing the door seals and locking mechanisms to verify the capability of the doors to perform their safety function. The inspectors further reviewed applicable procedures (HC.OP-AB.MISC-0001) to verify that SWIS and reactor building watertight doors would be closed in the event potential external flooding conditions were predicted. Additionally, the inspectors reviewed notification 20196823 which documented that a water tight door between the B/D SSWS pumps and the traveling screen room was found open and unmanned by the inspectors.

Finally, the inspectors walked down the reactor building and auxiliary building roofs to verify the drain systems were maintained as described in the UFSAR Section 3.4.1, Flood Protection. Documents associated with these reviews are listed in the Supplemental Information attachment to this report.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope (1 Sample)

Requalification Activities Review By Resident Staff. The resident inspectors observed one simulator training scenario to assess operator performance and training effectiveness on August 4, 2004. The scenario involved a loss of offsite power followed by a station blackout. 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 attachment to this report.

b. Findings

Simulator Incorrectly Replicates Plant Design

Introduction. The inspectors identified that the Hope Creek simulator did not replicate the plant design during a station blackout (SBO) condition because the reactor core isolation cooling (RCIC) pump suction swapped from the condensate storage tank (CST) to the suppression pool. The finding was determined to be contrary to 10 CFR 55.46(c)(1), "Plant-Referenced Simulators," and is being treated as a non-cited violation.

Description. On August 4, 2004, the inspectors observed licensed operator requalification training in the Hope Creek simulator. During a simulator scenario involving a SBO condition (loss of offsite and onsite alternating current (AC) power sources), the inspectors observed the suction valve from the condensate storage tank (CST) to the RCIC pump automatically closed and transferred pump suction to the suppression pool. The inspectors did not expect this to occur in the simulator because the plant design included batteries to maintain power to control circuits for RCIC system valves for a limited time and prevent automatic swaps such as this. After observing that PSEG personnel did not question the simulator performance during the post training critique, the inspectors discussed their observations with operator training personnel.

PSEG investigated and determined that during an emergency preparedness drill in September 2002 personnel in the simulator observed the RCIC pump suction did not swap from the CST to the suppression pool when the 4160 V vital bus (10A402) was de-energized. Personnel indicated this was contrary to abnormal procedure HC.OP-AB.ZZ-0171, Attachment 8, that indicated the RCIC pump suction would swap from the CST to the suppression pool on loss of this bus. The procedure specifically states the RCIC CST level switches (1LIS-E51-N035A and E) are powered from 120 V panel 10Y412.

During a follow-up review in October 2002 simulator personnel determined that drawings showed that 120 V panel 10Y412 was supplied power from vital bus 10A402; however, the power to the panel was not supplied through the battery backed inverter. Therefore, they reasoned the swap should have occurred. Simulator personnel confirmed this by referencing schematic drawing 791E421AC and panel circuit schedule E-1405-1, sheet 14A. Sheet 14A indicated the CST switches were powered from circuit 7 of Panel 10Y412 and the simulator was changed by action request H2002-160.

PSEG engineering personnel reconsidered this change in response to the inspectors questions and determined the simulator change made in October 2002 was in error. While circuit schedule E-1405-1, sheet 14A listed the level switches as powered from panel 10Y412, circuit 7, the cable schedule for this panel (sheet 14B) contradicted this by listing circuit 7 as not used. Furthermore, a database maintained by Design Engineering similarly showed circuit 7 as a spare. PSEG confirmed sheet 14 A was in error by visual inspection of the panel. Additionally, while schematic drawing 791E421AC was referenced as a basis for changing the simulator, this drawing did not show the power source to the level switch sensors. The power to these switches was correctly shown on drawing E-6089-0, that indicated 120 V panel 10C399 supplied power. This panel is battery backed and the RCIC pump suction would not swap on an SBO condition. PSEG revised the simulator model to reflect this and alerted operators to this problem in a night order entry. The inspectors concluded the simulator review did not establish the design basis because circuit schedule E-1405-1, sheet 14A was in error and other applicable drawings and databases were not reviewed.

Analysis. The inspectors identified a performance deficiency that involved a failure to ensure the Hope Creek simulator replicated the plant design during a SBO condition. Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements. This finding was more than minor because it was associated with the human performance attribute and affected the mitigating systems cornerstone objective to ensure the availability and reliability of mitigating systems equipment. The finding was evaluated using the Operator Requalification Human Performance SDP (MC 0609 Appendix I). The SDP, Appendix I, Block 12, requires the inspectors to determine if deviations between the plant and the simulator could result in negative training or could have a negative impact on operator actions. "Negative Training" is defined in ANSI/ANS 3.5-1993, "Nuclear Power Plant Simulators For Use in Operator Training And Examination," as "training on a simulator whose configuration or performance leads the operator to incorrect response or understanding of the reference unit." The Office of Nuclear Reactor Regulation (NRR), has clarified the requirement that negative training could have occurred to mean that there had to be a potential for negative training based on the difference between the simulator and plant. In this case the simulator incorrectly modeled the RCIC pump suction to swap from the CST to the suppression pool during a SBO condition, contrary to actual plant response.

This could potentially create negative training, in that, operators may not be trained to appropriately monitor CST level during SBO conditions. Therefore, the answer to Appendix I, Block 12 was affirmative and indicates the finding is of very low safety significance (Green) because the discrepancy did not have an adverse impact on operator actions such that safety-related equipment was inoperable during normal operations or in response to a plant transient.

Enforcement. 10 CFR 55.46(c)(1) requires a plant-referenced simulator used for the administration of the operating test or to meet experience requirements must demonstrate the expected plant response to operator input and to normal, transient, and accident conditions to which the simulator has been designed to respond. Contrary to the above, on August 4, 2004, the inspectors identified that PSEG failed to ensure that the simulator correctly replicated the expected plant response to transient conditions as a result of an improperly designed change to the simulator implemented per action request H2002-160 on October 10, 2002. Because the finding was of very low safety significance and entered into the corrective action program in notifications 20199406 and 20201509, this violation is being treated as a NCV, consistent with section VI.A of the NRC enforcement Policy. **(NCV 50-354/04-04-02, Simulator Incorrectly Replicated Plant Design)**

Inadequate Abnormal Procedures For Responding to Electrical Equipment Problems

Introduction. In responding to inspector questions, PSEG determined that two abnormal response procedures contained errors in describing the expected reactor core isolation cooling (RCIC) and high pressure isolation cooling (HPCI) pump suction alignment during electrical equipment problems. The finding was determined to be a non-cited violation of 10 CFR 50, Appendix B, Criterion III, "Design Control."

Description. On August 4, 2004, the inspectors observed licensed operator requalification training in the Hope Creek simulator. The inspectors identified that the simulator did not correctly replicate the RCIC pump suction remaining to the CST during a station blackout condition. This is described in the previous finding.

PSEG's investigation of the simulator fidelity issue identified two abnormal procedures that contained errors in describing the expected RCIC and HPCI pump suction alignment due to loss of power to 4.16 KV vital bus 10A402 or a loss of power to the associated 120V inverter. Specifically, PSEG determined that abnormal procedure HC.OP-AB.ZZ-0171, Attachment 8, incorrectly indicated that on a loss of 4.16 KV vital bus 10A402, the RCIC pump suction would swap from the CST to the suppression pool due to loss of power to RCIC CST level switch sensors. This was incorrect because the RCIC CST level switch sensors would remain powered through battery backed 120 V inverter 1BD481. PSEG also determined that abnormal procedure HC.OP-AB.ZZ-0136, Attachment 1, incorrectly indicated that on a loss of inverter 1AD481, the HPCI pump suction would remain aligned to the CST. However, the HPCI pump suction would be expected to realign to the suppression pool because the HPCI CST level switch sensors would lose power. Furthermore, PSEG determined abnormal procedure HC.OP-AB.ZZ-0136, Attachment 2, was in error because it did not describe the fact that on a loss of the inverter 1BD481, the RCIC pump suction would be expected to swap from the CST to the suppression pool. PSEG corrected these three procedure errors on September 14, 2004. Additionally, PSEG tracked an action to correct a drawing error identified during the investigation regarding panel circuit schedule E-1405-1, sheet 14A (showing panel 10Y412 as supplying power to the RCIC CST level switch sensors).

Analysis. The inspectors concluded the abnormal procedures for responding to a loss of the 4.16KV bus 10A402 and the loss of 120 VAC inverters 1AD481 and 1BD481 did not correctly reflect the plant design. Additionally, panel circuit schedule E-1405-1, sheet 14 A incorrectly listed panel 10Y412 as supplying power to the RCIC CST level switch sensors. Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and it was not the result of any willful violation of NRC requirements.

This finding was more than minor because it was associated with the procedure quality attribute of the mitigating systems cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems to respond to initiating events. These procedure errors would result in operators having to evaluate HPCI and RCIC pump suction alignments during electrical equipment problems that were different than described in abnormal operating procedures. Additionally, the drawing error contributed to an incorrect change to the Hope Creek simulator. The inspectors reviewed the finding using the Phase 1 SDP worksheet for mitigating systems and determined the issue was of very low safety significance (Green) because the finding was not a design or qualification deficiency, did not result in an actual loss of safety function, and the finding was not screened as a potentially risk significant for external events. While the errors in the abnormal procedures would require additional operator evaluation in response to electrical equipment malfunctions, the HPCI and RCIC pumps would by plant design remain aligned to a suction and perform their safety function.

Enforcement. 10 CFR 50, Appendix B, Criterion III, "Design Control", requires in part that measures shall be established to assure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures, and instructions. Contrary to the above, the plant design was not correctly translated into abnormal procedures HC.OP-AB.ZZ-0171, HC.OP-AB.ZZ-0136, and panel circuit schedule E-1405-1, sheet 14 A. However, because the violation is of very low safety significance (Green) and PSEG entered the deficiency into their corrective action system (notifications 20199406 and 20201509), this finding is being treated as a non-cited violation, consistent with section VI.A of the NRC Enforcement Policy. **(NCV 50-354/2004004-03, Inadequate Abnormal Procedures For Responding to Electrical Equipment Problems)**

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope (3 Samples)

The inspectors reviewed performance monitoring and maintenance activities for three systems or components to determine the effectiveness of maintenance activities to maintain equipment reliable. The neutron monitoring system was reviewed to verify the system was effectively monitored in accordance with maintenance rule (MR) program requirements. The inspectors compared documented functional failure determinations and unavailable hours to those being tracked by PSEG to evaluate the effectiveness of PSEG's condition monitoring activities and determine whether performance goals were being met. The inspectors reviewed work orders, corrective action notifications, preventive maintenance tasks and system health reports.

The inspectors also completed a review of PSEG's apparent cause evaluation (order 70040441) associated with the B station service water system (SSWS) pump packing failure on July 14, 2004. The inspectors reviewed the apparent cause evaluation, maintenance work history, corrective action notifications, vendor documents, maintenance rule classification review and maintenance procedures.

The inspectors further reviewed PSEG's apparent cause evaluation (order 70040356) associated with the C SSWS strainer keyway failure on July 12, 2004. The inspectors reviewed the apparent cause evaluation, maintenance work history, corrective action notifications, vendor documents, maintenance rule classification review and maintenance procedures.

b. Findings

Introduction. A self-revealing finding was identified regarding inadequate procedure guidance when the B SSWS pump packing failed on July 14, 2004. The finding was determined to be a non-cited violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings."

Description. On July 14, 2004, a PSEG equipment operator observed excessive packing leakage on the B SSWS pump. PSEG personnel determined that the nuts on the pump packing gland had backed off and disengaged on three of the four studs. The nut remained threaded on the fourth stud; however, the stud had backed out of the pump casing. As a result, the gland rotated approximately two inches from its bolted position and caused excessive packing leakage.

Operations personnel removed the B SSWS pump from service due to the high packing leakage. The C SSWS pump was out of service at the time for corrective maintenance to its associated strainer. Operations entered the applicable Technical Specification for two inoperable SSWS pumps. Additionally, operators decreased reactor power to 70% in accordance with procedures to maintain the non-safety related turbine auxiliary cooling system heat load supply temperatures within limits. Also, PSEG formed an operational challenge response (OCR) team to investigate and identify immediate corrective actions.

PSEG corrected the problem on July 15, 2004, and restored the B SSWS pump to service and subsequently completed an apparent cause evaluation under order 70040441. The evaluation identified that guidance contained in maintenance procedure HC.MD-CM.EA-0001 was inadequate because the procedure did not include vendor manual (VTD 322416) direction to verify the required packing height and ensure the gland follower could be inserted between 1/8 and 3/16 inches into the stuffing box.

The PSEG apparent cause evaluation identified two contributing causes. First, in December 2003 PSEG installed oversized packing in the B SSWS pump that caused the stackup of the packing rings in the pump gland to be greater than specified in the pump bill of material and prevented full thread engagement on the gland follower studs. Second, in June 2004 the inspectors identified and informed the system engineer that two nuts on the B SSWS pump packing gland were not fully threaded on the gland studs as required by PSEG's bolting and torquing procedure, SH.MD-GP.ZZ-0022, but the condition was not entered into the corrective action process for evaluation. The cause evaluation also determined that prior to June 2004, PSEG had two opportunities to self-identify the degraded condition of the B SSWS pump. In May 2004 maintenance personnel experienced problems installing packing in the A SSWS pump and PSEG determined (70039158) that the packing in the warehouse was too thick, but failed to identify the same problem on the B SSWS pump during its extent of condition review. On May 14, 2004, PSEG again failed to identify the degraded condition when maintenance personnel reinstalled oversized packing in the B SSWS pump following maintenance. These missed opportunities present a problem identification concern as referenced in Section 4OA2 of this report.

The inspectors concluded that PSEG identified the likely causal factors and corrective actions were appropriately broad to address the causal factors. The B SSWS pump was re-packed with normal sized packing. PSEG also tracked corrective actions to revise maintenance procedures with more detailed guidance and re-emphasize through training to maintenance personnel the thread engagement requirements.

Analysis. The performance deficiency associated with this self-revealing equipment problem involved inadequate procedure guidance. Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements. The inspectors determined that the issue was more than minor because it was associated with the mitigating systems cornerstone attribute for equipment performance and affected the objective to ensure the availability of the B SSWS pump. This issue also impacted the initiating events cornerstone objective to limit the likelihood of those events that affect plant stability and challenge critical safety functions during shutdown and power operations. The unavailability of one train of SSWS increased the likelihood of a loss of service water (LOSW) initiating event. The inspectors completed a SDP Phase 1 screening of the finding and determined that a more detailed Phase 2 evaluation was required to assess the safety significance because the finding affected two cornerstones (Initiating Event and Mitigating System).

The SDP Phase 2 evaluation used the loss of service water worksheet and the following assumptions:

- The B SSWS pump was unavailable during repairs of its associated strainer.
- The pump was determined to be unavailable during corrective maintenance activities which lasted 13.5 hours. Therefore, an exposure time of less then 3 days was used in the analysis.
- No operator recovery credit was assumed.
- The SSWS was considered to be a multi-train normally cross-tied support system. Therefore, the initiating event likelihood was increased by one order of magnitude for the associated special initiator.

The Phase 2 evaluation concluded the finding was of very low safety significance (Green) relative to internal events core damage frequence increase (ÎCDF). However, the internal event ÎCDF was greater than 1E-7 assuming less than a 3 day period. With a ÎCDF greater than 1E-7, the regional senior risk analyst (SRA) performed a Phase 3 analysis of ÎCDF and ÎLERF, which included the potential risk contribution due to external initiating events, in accordance with IMC 0609.

The Phase 3 analysis determined that the finding was of very low safety significance (Green) relative to: ÎCDF for internal and external events and ÎLERF. The analysis was conducted using the Hope Creek SPAR model, assuming the B SSWS pump failed and was not operable for 13.5 hours and an appropriate increase in the LOSW initiating event frequency given a SSWS pump unavailability. The analysis determined that the issue represented an internal events ÎCDF in the high E-7 range dominated by a loss of offsite power, common cause failure of the other remaining SSWS pumps (leading to a station blackout due to loss of EDG cooling water) and failure to recover offsite power in 5 hours, resulting in loss of the reactor core isolation cooling (RCIC) system. The SRA determined that this dominant sequence did not result in a contribution to LERF because it did not proceed to core damage until after the high pressure injection sources (RCIC) failed, due to battery depletion, several hours into the event. Further, based on a review of external events information provided by PSEG, the SRA determined that seismic and fire initiating events were not significant enough contributors to risk to increase the ÎCDF above 1E-6 given the 13.5 hour period involved.

Enforcement. 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires that activities affecting quality shall be accomplished in accordance with documented instructions, procedures, or drawings, which shall include appropriate qualitative and quantitative acceptance criteria to ensure that the task can be accomplished satisfactorily. Contrary to the above, PSEG procedure HC.MD-CM.EA-0001 did not provide qualitative and quantitative criteria described in the vendor manual for ensuring the correct number and height of packing rings and gland follower were installed properly in the B SSWS pump in December 2003. Additionally, on May 16, 2004, PSEG failed to engage the gland stud nut fully as required by procedure SH.MD-GP.ZZ-0022. However, because the finding was of very low safety significance and has been entered into the corrective action program in notification 20196881, this violation is being treated as a NCV, consistent with section VI.A of the NRC Enforcement Policy. **(NCV 50-354/2004004-04, Inadequate Procedures Resulted in B Service Water Pump Packing Failure)**

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

a. Inspection Scope (6 Samples)

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

C Planned outage of the B EDG and 1BD-414 battery charger on June 7, 2004;
C Unplanned unavailability of C SSW pump and the unavailability of the B primary containment instrument gas (PCIG) for scheduled maintenance on July 12, 2004;
• Unplanned unavailability of the B and C SSWS pump, and the unavailability of the B primary containment instrument gas (PCIG) for scheduled maintenance on July 14, 2004;
• HPCI declared inoperable due to design issues, and unplanned unavailability of C SSW pump due to emergent maintenance on strainer, and the unavailability of the D FRVS and B PCIG for scheduled maintenance on July 16, 2004;

- C emergency diesel generator inoperable for planned maintenance from July 22 to July 28, 2004; and
- D service water pump out of service for the week of September 6, 2004, for planned maintenance with C supply fan service water intake structure damper failed closed.

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. Finally, the inspectors reviewed notifications documenting problems associated with risk assessments and emergent work evaluations. Documents reviewed are listed in the Supplemental Information attachment to this report.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope (2 Samples)

The inspectors evaluated PSEG's performance and response during two non-routine evolutions to determine whether the operator responses were consistent 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 attachment to this report. Operator performance during the following two non-routine evolutions were reviewed.

B Service Water Pump Packing Failure. On July 14, 2004, PSEG discovered an excessive packing leak on the B SSW pump. At the time of this event, the C SSW pump was out of service for emergent repairs on its associated strainer. The loss of the B SSW pump resulted in the SACs loop supplying turbine auxiliary cooling system (TACS) having only one SSW pump. Reactor power was reduced to 80% to reduce TACS heat loads, and other plant heat loads on the B SACS loads on the B SACS loop were transferred to the A SACS loop. Rising TACS temperatures necessitated further power reduction to 70%.

Downpower Due to 5014 Line Outage. On September 16, 2004, operators reduced power from 100% to approximately 50% at the request of the electrical grid system operator. This down power was required to ensure system grid stability during an offsite line outage on the grid. The need for this downpower was not expected by plant operators. The inspectors observed operator actions in the control room to verify whether the response to abnormal generator output parameters was in accordance with procedures, power reductions were in accordance with procedures, and Technical Specification surveillance requirements related to power changes were completed as required.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope (2 Samples)

The inspectors reviewed two operability assessments or determinations for non-conforming conditions associated with:

- Lisega Snubber Equipment Qualification Nonconformance (70040861); and
- C Service Water Intake Structure Damper Failed Closed (20174801 and 20201824).

The inspectors reviewed the technical adequacy of the operability determinations to ensure the conclusions were technically justified. Additionally, the inspectors reviewed other PSEG identified safety-related equipment deficiencies during this report period and assessed the adequacy of their operability screens. Notifications and documents reviewed in this regard are listed in the Supplemental Information attachment to this report.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process (ROP) baseline inspections. In accordance with this deviation, the inspectors reviewed a recent operability assessment regarding a less than fully reliable master trip solenoid valve in the turbine emergency trip system (Order 70041261). The inspectors reviewed the technical adequacy of the operability determination to ensure the conclusions were justified and verified the short term corrective actions to exercise this solenoid valve daily were being completed until the next refueling outage.

b. Findings

No findings of significance were identified.

1R16 Operator Work-Arounds (71111.16)

a. Inspection Scope (1 Sample)

The inspectors evaluated the cumulative effects of operator workaround as related to (1) 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 events. The inspectors reviewed Hope Creek Operations Department lists of operator burdens/concerns, temporary modifications, and operability determinations to ensure there were not unidentified impacts due to combinations of issues. 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 attachment to this report.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope (1 Sample)

The inspectors reviewed the following design change installed during the inspection period:

C Resizing of the HPCI pump discharge flow orifice plates (80073096).

The design bases, licensing bases, modification instructions and post modification testing of the flow orifices were reviewed to verify the performance capability of the HPCI system was not adversely affected. The inspectors reviewed the applicable Technical Specifications for this equipment to ensure that operability requirements and allowable outage time limits were met when the design change was installed. The inspectors performed an independent inspection of the fabricated orifice plates to determine whether they were constructed in accordance with specifications provided in the design change package. The inspectors also reviewed notifications documenting deficiencies identified related to permanent plant modifications. The documents reviewed as part of these inspections are listed in the Supplemental Information attachment to this report.

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope (6 Samples)

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

- B SSWS pump on July 14, 2004;
- A control room emergency filtration unit on July 30, 2004;
- High pressure coolant injection pump on July 24, 2004;
- Reactor core isolation cooling pump room cooler (BVH208) on August 9, 2004;
- A EDG on September 17, 2004; and
- Replacement of residual heat removal shutdown cooling reset relay on September 22, 2004.

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, including an inspector identified minor procedure problem resolved under notification 20199396. The inspectors also reviewed applicable documents associated with PMTs as listed in the Supplemental Information attachment to this report.

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

a. Inspection Scope

New Fuel Activities. In preparation for Refueling Outage 12, PSEG received, transported, and inspected new fuel. The inspectors discussed fuel handling activities with reactor engineers and witnessed several shipping container inspections, fuel bundle inspections, and fuel moves from the refuel floor to the new fuel vault. The inspectors verified the fuel inspections and handling operations were performed in accordance with approved procedures and that foreign material exclusion was maintained in the refueling area. The inspectors also reviewed corrective action notifications concerning problems related to fuel handling activities or outage preparation.

Specifically, the inspectors reviewed PSEG’s evaluation of a fuel clip that was bent while inserting a new fuel bundle into the spent fuel pool. The inspectors also observed the new fuel bundle on the refueling floor and discussed the issue with involved personnel to understand the problem. The inspectors reviewed PSEG’s evaluation of this issue, documented in notification 20198581, to verify that the immediate actions to stop fuel movement activities, evaluate the causes of the problem, and make procedure changes and train personnel were adequate to prevent recurrence. Quarantine controls over the fuel bundle with a damaged clip were observed on the refueling floor to ensure they were adequate to prevent loading this bundle into the core until it was repaired by the fuel vendor. Documents reviewed for these inspections are listed in the Supplemental Information attachment to this report.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope (8 Samples)

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

- Recirculation jet pump operability on July 14 and 15, 2004;
- A-D 125 VDC (Class 1E) battery weekly surveillance tests on July 26, 2004;
- A 250 VDC battery (Class 1E) quarterly surveillance test on July 20, 2004;
- B Emergency diesel generator monthly surveillance test on August 2, 2004;
- Extraction steam check valve weekly functional test on August 8, 2004;
- A Standby Liquid Control pump inservice-test (IST) on August 19, 2004;
- Reactor core isolation cooling pump IST on September 2, 2004; and
- Reactor coolant system leakage detection system (drywell floor and equipment drain) surveillance test on September 6, 2004.

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 Technical Specification requirements and the Updated Final Safety Analysis Report (UFSAR). The inspectors also reviewed notifications documenting deficiencies identified during these surveillance tests. The reviewed documents associated with surveillance testing are listed in the Supplemental Information attachment to this report.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process (ROP) baseline inspections. In accordance with this deviation, the inspectors reviewed the reactor coolant system leakage detection system, drywell floor and equipment drain functional surveillance test completed on September 6, 2004, in greater detail to determine whether previous corrective actions completed early in plant life to modify sump alarm setpoints and sump configuration inputs into the microprocessor that calculates leak rates remained implemented in the plant.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope (2 Samples)

The inspectors reviewed the following two temporary plant modifications (T-mod):

- Bypass Position Indication for Control Rod 26-31 (T-mod 04-010); and
- Alarm Bypass Request for CD481 Inverter (T-mod 04-016).

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 Technical Specification operability requirements were met during installation and subsequent operation. The inspectors verified the modified equipment alignments through control room instrumentation reviews. Documents reviewed for these temporary plant modifications are listed in the Supplemental Information attachment to this report.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope (2 Samples)

The inspectors observed two licensed operator requalification scenario exams that were included as inputs into the emergency drill and exercise performance indicator. These observations were made in the simulator on August 19 and September 2, 2004. The inspectors observed the exams and PSEG's post-exam critique to verify that weaknesses and deficiencies were adequately identified. The inspectors specifically focused on ensuring PSEG identified operator performance problems with event classification and notification activities.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

a. Inspection Scope (3 Samples)

The inspectors reviewed PSEG's program to gather, evaluate and report information on the following three 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. The documents reviewed are listed in the Supplemental Information attachment to this report.

Reactor Coolant System Specific Activity PI. The inspectors verified the methods used to calculate the reactor coolant system (RCS) specific activity PI and reviewed the accuracy of the PI data submitted for the months of July 2003 to June 2004. The inspectors also reviewed PSEG's desktop guide (HC.CH-DG.PI-001) for this activity to understand the methodology and assumptions used by PSEG for reporting the PI data. The inspectors further reviewed notification 20200936 which documented minor discrepancies identified by PSEG's quality assurance department in PSEG's reported RCS specific activity PI data.

Reactor Coolant System Leakage PI. The inspectors verified the methods used to calculate the reactor coolant system leakage PI. The inspectors verified the accuracy of PI data submitted for the months of July 2003 to June 2004.

Safety System Functional Failures (PI). The inspectors assessed the accuracy and completeness of the data that PSEG used to calculate and report the safety system functional failure (SSFF) PI by reviewing Hope Creek licensee event reports (LERs) from July 1, 2003 to June 30, 2004 to determine whether issues meeting the SSFF definition were appropriately included in the data PI data reported by PSEG.

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 reviewing hard copies of condition reports, attending daily screening meetings, and/or accessing PSEG's computerized database.

Cross-References to PI&R Findings Documented Elsewhere

Section 1R05 describes that PSEG had identified a finding regarding the control of transient combustible material that had a problem identification cross-cutting aspect because operations personnel responsible for draining the C emergency diesel generator lubricating oil and fire watch personnel performing hourly fire watches in the area did not identify that seven barrels of oil were stored in the area without a transient combustible permit.

Section 1R12 of this report describes a finding where PSEG did not identify oversized packing was installed in the B SSWS pump when a similar problem was previously identified on another SSWS pump. Additionally, the inspectors identified to PSEG personnel that two nuts were not fully threaded onto the B SSWS gland studs prior to a packing failure; however, the condition was not entered into the corrective action process for evaluation and corrective action before the packing failed.

Section 4OA5.1 of this report discusses a finding at Hope Creek identified by the inspectors in April 2004 that was similar to a previous finding identified at Salem in August 2003. The inspectors determined that PSEG's extent of condition review and corrective actions for addressing the Salem finding did not find and correct a similar condition at Hope Creek.

4OA3 Event Followup (71153)

1. (Closed) LER 05000354/2004004-00, Non-Conservative 4160 Volt 1E Bus Operating Limits

This LER was reviewed during the closeout of URI 0500035420/0402-08. See Section 4OA5.1 of this report for the results of this review.

2. (Closed) LER 05000354/2004005-00, Control Room Emergency Filtration (CREF) System Train Inoperable for Greater Than 7 Days

On May 20, 2004, PSEG identified that the B chiller and associated CREF subsystem were inoperable from May 9 to May 20, 2004, and that this exceeded the seven-day allowed outage time that TS 3.7.2.a specified for one CREF subsystem. PSEG determined the cause to be inadequate maintenance procedures and post maintenance testing for maintenance performed from May 9 to May 15, 2004.

PSEG completed corrective actions to revise the applicable maintenance procedure to ensure the guide vane linkage was installed correctly. Additionally, applicable post maintenance test work instructions were modified to include monitoring requirements and acceptance criteria for chiller operating parameters such as evaporator pressure, that were not included in the operating procedure used to perform the post maintenance test. The inspectors reviewed the evaluation and confirmed the corrective actions were completed.

This finding was more than minor because it affected the mitigating systems cornerstone objective to ensure the availability and reliability of mitigating system equipment such as the B chiller and associated B CREF subsystem. This finding was of very low safety significance based on a SDP Phase 3 risk analysis previously performed for unavailability of the Hope Creek B CREF subsystem documented in Inspection Report 354/2003007, dated January 26, 2003. The risk analysis completed in January 2003 concluded that a performance issue that resulted in the B CREF subsystem being unavailable for thirteen days was of very low safety significance (green); therefore, the inadequate maintenance and post maintenance testing that resulted in eleven days of unavailability for the B CREF subsystem from May 9 to May 20, was similarly of very low safety significance. This licensee-identified finding involved a violation of TS 3.7.2.a, “Control Room Emergency Filtration System.” The enforcement aspects of this violation are discussed in Section 4OA7. This LER is closed.

4OA4 Cross Cutting Aspects of Findings

Section 1R11 of this report describes a finding regarding an inadequate change to the simulator which resulted in negative training that involved human performance as a contributing cause. A change was made without adequately determining the design basis by reviewing all applicable documents needed to validate proper simulator response.

4OA5 Other

1. (Closed) URI 05000354/2004002-08 4 kV Vital Buses Not Maintained at Voltages Supported by Design Basis Calculations

Introduction. The inspectors identified that operating procedures would have allowed the operation of the 4.16 kV vital electrical buses at voltage levels that would have resulted in the safety buses separating from the offsite power source during the starting of emergency equipment loads following a loss-of-coolant-accident. The finding was determined to be a non-cited violation of 10 CFR 50, Appendix B, Criterion III,”Design Control.”

Description. In April 2004, the inspectors identified that PSEG did not establish appropriate operating limits and translate these design parameters into plant procedures. This resulted in 4.16 kV vital buses being operated at voltages that were less than the minimum assumed in design calculations. Specifically, plant procedures HC.OP-DL.ZZ-0003(Q), “Log 3 Control Console Log Condition 1, 2 and 3,” Revision 46, and HC.OP-ST.ZZ-0001(Q), “Power Distribution Lineup - Weekly,” Revision 18, contained minimum voltage acceptance criteria that were non-conservative and not consistent with design basis calculations. Additionally, PSEG identified that the design calculations used to support minimum voltage acceptance criteria did not account for the uncertainties in the instrumentation loop that provided the voltage indication to the operators.

The inspectors identified this issue when the plant was in a cold shutdown condition. PSEG performed an engineering evaluation (H-1-PB-EEE-1832, Revision 3) to determine the proper bus voltage operating limits. As a result of this evaluation, the operating and surveillance procedures were revised. This event was reported to the NRC in Licensee Event Report (LER) 05000354/2004004-00 dated June 3, 2004.

The inspectors also reviewed operating data and found that the deficient procedures resulted in periods of operation with bus voltages less than design requirements. In the event of a loss-of-coolant accident (LOCA) coincident with low bus voltages, the buses would have separated from the offsite power source due to actuation of the degraded grid protection relays. The relays would actuate due to expected voltage drops during the starting of engineered safeguards equipment and, due to the low voltage at the start of the event, the bus voltage would not recover above the relay reset point. Following the separation from the offsite grid, the emergency diesel generators would start and power the buses and the engineered safeguards equipment would restart.

The inspectors also noted that a similar issue involving inadequate bus voltages was identified by the NRC at Salem Units 1 and 2 in August 2003 (NRC Inspection Report 50-272,311/2003008). The inspectors determined that PSEG's extent of condition review and corrective actions for that event were not rigorous and the similar condition at Hope Creek continued to exist until identified by the inspectors approximately nine months after the Salem finding.

Analysis. The inspector identified performance deficiency involved a failure to establish appropriate operational limits in the 4 KV electrical system operating procedures which resulted in the 4.16 kV vital buses being operated at voltages less than the minimum assumed in design calculations. Traditional enforcement does not apply because the issue did not have any actual safety consequence or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements. 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 consequences. The issue impacts the mitigation systems cornerstone only after a LOCA initiating event. This is because the LOCA safety injection signal results in the automatic sequencing of emergency core cooling system electrical loads onto the vital busses and causes the loss of offsite AC power sources via degraded grid voltage relay operation. Therefore the reliability of AC powered safety-related mitigating systems is reduced as only the EDGs are available. Based on review of plant logs a specific exposure time could not be determined, but the inspectors reasonably assumed that for more than 30 days of an operating year the bus voltages were below 4200V and the offsite power supplies were inoperable, relative to response to LOCA initiating events.

In accordance with IMC 0609 Appendix A, the issue required a Phase 2 evaluation, because it represented a condition where offsite power would have been unavailable for longer than its TS allowed outage time. The Region I Senior Risk Analyst conducted a bounding Phase 3 evaluation because this condition only applied to a LOOP resulting from a LOCA initiating event and the Phase 2 Site Specific notebook was not appropriate for evaluating this event.

The Phase 3 analysis determined that the finding was of very low safety significance (Green) relative to the increase in CDF for internal events. The analysis was conducted using the Hope Creek SPAR model. The assumptions were:

- A conservative one year exposure time.
- Any LOCA (small, medium or large) would result in safety-related electrical loads sequencing on to offsite power, with a subsequent loss of offsite power (LOOP).
- Offsite power non-recovery probability of 0.1 after 5 hours, based the Hope Creek LOOP event tree and NUREG 5496 offsite power recovery curves.

The analysis determined that the issue represented an increase in CDF in the low E-8 range per year. The dominant core damage sequence was a small LOCA, with the failure of the EDGs to supply power and non-recovery of offsite power, leading to a station blackout. High pressure injection was assumed to function, but all emergency core cooling systems that required AC power were assumed not to function. Late injection of cooling water from the fire water system was precluded by an inability to vent the containment.

Enforcement. 10 CFR 50, Appendix B, Criterion 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, PSEG failed to establish appropriate operating limits and failed to translate these design parameters into plant procedures. However, because this finding is of very low safety significance and has been entered into PSEG's corrective action program (notification 20184513), this violation is being treated as an NCV, consistent with Section V1.A of the NRC Enforcement Policy. **(NCV 05000354/2004004-05, Failure to Properly Establish and Translate Minimum Bus Voltage Limits Into Procedures)**

2. (Closed) URI 05000354/2003002-02: Degraded Grid Time Delay Relay Setting Relative to LOCA Analysis Assumptions

This item was open pending additional NRC review of the Hope Creek design basis off-site power initial condition assumptions during a LOCA. PSEG's position was that the design bases assumptions were that the LOCA would occur simultaneously with the complete loss of offsite power. The inspectors reviewed this position and concluded that it was appropriate and no issues with the degraded grid relay time delays were identified. This item is closed.

4OA6 Meetings, Including Exit

On August 12, 2004, a site visit was conducted by Mr. Ellis Merschoff, Deputy Executive Director of Operations - Reactor Programs for the NRC. During Mr. Merschoff's visit, he toured Hope Creek and Salem plants, and met with PSEG managers.

On September 30, 2004, the inspectors presented their overall findings to members of PSEG management led by Messrs. Mike Brothers and John Carlin. 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 3.7.2 requires two independent control room emergency filtration (CREF) subsystems to be operable. Included in each subsystem is a chilled water support system, required for CREF operability, that removes heat from the CREF airflow to maintain the control room temperature within limits required for habitability and equipment operation. TS action statement 3.7.2.a requires that if one CREF subsystem is inoperable and not restored to operable status within 7 days, the plant should be brought to a hot shutdown condition within the next 12 hours. Contrary to this requirement, the B chilled water support system, and therefore, the B CREF subsystem, were inoperable for greater than seven days from May 9 to May 20, 2004. This was identified in PSEGs corrective action program in notification 20190574. This finding is of very low safety significance based on a SDP Phase 3 SDP risk analysis documented in Inspection Report 354/2003007, dated January 26, 2003. This risk analysis concluded that a performance issue that resulted in a CREF being unavailable for thirteen days was of very low safety significance. The risk analysis is applicable for the B CREF subsystem being inoperable for eleven days and this performance issue is similarly of very low safety significance.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel

J. Anthes, Hope Creek System Engineer - Service Water
D. Boyle, Hope Creek Assistant Operations Manager
M. Brothers, Vice President - Site Operations
B. Buirch, Fire Protection Superintendent
T. Carucci, 12hr/WIN Maintenance Supervisor
M. Conroy, Hope Creek Maintenance Rule
J. Dower, Hope Creek Training Supervisor
J. Frick, Shipping Supervisor
C. Johnson, Valve Engineer
J. Hutton, Hope Creek Plant Manager
E. Parker, Hope Creek Operations Supervisor - Training
M. Pfizenmaier, Hope Creek System Engineering Supervisor - Primary Systems
L. Rajkowski, Hope Creek System Engineering Manager
J. Reid, Operations Training Leader
B. Sebastian, Radiation Protection Manager
G. Sosson, Hope Creek Operations Manager
B. Thomas, Sr. Licensing Engineer
J. Thompson, Hope Creek System Engineer - Neutron Monitoring
P. Tocci, Hope Creek Maintenance Manager
L. Wagner, Plant Support Manager

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened/Closed

05000354/2004004-01	NCV	Inadequate Control of Transient Combustible Material (Section1R05)
05000354/2004004-02	NCV	Simulator Incorrectly Replicated Plant Design (Section 1R11)
05000354/2004004-03	NCV	Inadequate Abnormal Procedures For Responding to Electrical Equipment Problems (Section 1R11)
05000354/2004004-04	NCV	Inadequate Procedures Resulted in B Service Water Pump Packing Failure (Section 1R12)

05000354/2004004-05	NCV	Failure to Properly Establish and Translate Minimum Bus Voltage Limits Into Procedures (Section 4OA5.1)

<u>Closed</u>

05000354/2004004-00	LER	Non-Conservative 4160 Volt 1E Bus Operating Limits (Section 4OA3.1)
05000354/2004005-00	LER	Control Room Emergency Filtration System Train Inoperable for Greater Than 7 Days (Section 4OA3.2)
05000354/2004002-08	URI	4 kV Vital Buses Not Maintained at Voltages Supported by Design Basis Calculations (Section 4OA5.1)
05000354/2003002-02	URI	Degraded Grid Time Delay Relay Setting Relative to LOCA Analysis Assumptions (Section 4OA5.2)

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
Hope Creek Operations Night Orders and Temporary Standing Orders

<u>Adverse Weather Protection (71111.01)</u>
Acts of Nature Abnormal Operating Procedure (HC.OP-AB.MISC-0001)
Station Preparations for Winter Conditions (HC.OP-GP.ZZ-0003)
Operator logs for July 12 and July 14, 2004
Emergency Classification Guide, Section 9.6, High Winds
Emergency Classification Guide, Reportable Action Level 11.7.1.b (Loss of Offsite Response Capability)

<u>Equipment Alignment (71111.04)</u>
Service Water System Operation (HC.OP-SO.EA-0001)
Service Water Traveling Screens System Operation (HC.OP-SO.EP-0001)
RCIC Piping and Flow Path Verification - Monthly (HC.OP-ST.BD-0001)
Reactor Core Isolation Cooling System Operation (HC.OP-SO.BD-0001)
Reactor Core Isolation Cooling Pump -OP203 - Inservice Test (HC.OP-IS.BD-0001)

Standby Liquid Control System Operation (HC.OP-SO.BH-0001)
Safety and Turbine Auxiliaries Cooling Water System Operation (HC.OP-SO.EG-0001)
Diesel Fuel Oil and Transfer System Operation (HC.OP-SO.JE-0001)
Diesel Fuel Oil System Health Report, 1st Quarter 2004
Diesel Fuel Oil Line-up Identification 127
P&ID - Diesel Engine Auxiliary Systems (M-30-1)
P&ID - Service Water System (M-10-1)
P&ID - Reactor Core Isolation Cooling Pump Turbine (M-50-1)
P&ID - Reactor Core Isolation Cooling (M-49-1)
P&ID - Safety Auxiliaries Cooling, Reactor Building (M-11-1)
P&ID - Safety Auxiliaries Cooling, Auxiliary Building (M-12-1)
P&ID M-48-1, Standby Liquid Control
Notifications: 20197272, 20197276, 20197390, 20197550, 20109190, 20201259, 20151198, 20167384, 20179670, 20179795, 20149395
Orders: 4064155

Fire Protection (71111.05)
Hope Creek Pre-Fire Plan (FRH-II-511)
Fire Protection Impairment Tracking Report, dated 7/19/04
Actions For Inoperable Fire Protection - Hope Creek Station (HC.FP-AP.ZZ-0004)
Precautions Against Fire (NC.FP-AP.ZZ-0025)
Fire Transient Combustible Permit HTC-04 CD-10-002
Notifications: 20201300, 20197116

Flood Protection Measures (71111.06)
Hope Creek Individual Plant Examination for External Events, Section 5.5, External Floods
Acts of Nature Abnormal Operating Procedure (HC.OP-AB.MISC-0001)
Drawing A-0549-0, Service Water Intake Structure
Drawing A-0702-0, Pressure Tight Doors Door and Hardware Schedule
Drawing C-0104-0, Service Water Intake Structure Wall Key Plans
Drawing A-C100-0, Service Water Intake Structure Door and Concrete Finish Schedule
Flood Levels: Intake Structure (Calc No. 24-4)
Notifications: 20058821, 20093028, 20115156, 20123015, 20141451, 20178521, 20185492, 20197234, 20196823, 20200574, 20200763, 20201921

Licensed Operator Requalification (71111.11)
Reactor Scram Hard Card (HC.OP-AB.ZZ-0001, Attachment 1)
Reactor Scram (HC.OP-AB.ZZ-0000)
Grid Disturbance (HC.OP-AB.BOP-004)
Loss of Power/Station Blackout (HC.OP-AB.ZZ-0135)
Reactor/Pressure Vessel (RPV) Control (HC.OP-EO.ZZ-0101)
Primary Containment Control (HC.OP-EO.ZZ-0102)
Loss of 120 VAC Inverter (HC.OP-AB.ZZ-0136)
Loss of 4.16KV Bus 10A402 B Channel (HC.OP-AB.ZZ-0171)
Simulator Action Requests (NC.TQ-TC.ZZ-0029)
Panel Circuit Schedule - 10Y412, Class 1E Channel B (Dwg E-1405-1, Sheet 14A)

Panel Cable Schedule - 10Y412, Class 1E Channel B (Dwg E-1405-1, Sheet 14B)
General Electric Dwg Reactor Core Isolation Cooling - 791E421AC (PN1-E51-1040-59(6))
General Electric Dwg Reactor Core Isolation Cooling - 791E421AC (PN1-E51-1040-59(7))
General Electric Dwg Reactor Core Isolation Cooling - 791E421AC (PN1-E51-1040-59(13))
General Electric Dwg High Pressure Coolant Injection - 791E420AC (PN1-E41-1040-62(5))
General Electric Dwg High Pressure Coolant Injection - 791E420AC (PN1-E41-1040-62(7))
General Electric Dwg High Pressure Coolant Injection - 791E420AC (PN1-E41-1040-62(11))
Electrical Schematic Diagram Reactor Core Isolation Cooling Sys Pump Suction Valve (Dwg E-6084-0, Sheet 3)
Electrical Schematic Diagram Reactor Core Isolation Cooling Sys Pump Suction Valve (Dwg E-6084-0, Sheet 9)
Electric Schematic Diagram High Pressure Coolant Injection Pump Suction Valve F042 (Dwg E-6075-0, Sheet 5)
Remote Shutdown Panel (RSP) 10C399 Scheme Dwg Index (Dwg E-6604-0, sheet 1)
Electric Schematic Diagram RCIC System Turbine Monitoring CKTS in RSP (Dwg E-6089-0)
Logic Diagram RCIC System (Dwg J-49-0, sheet 5)
Logic Diagram RCIC System (Dwg J-49-0, sheet 6)
Logic Diagram RCIC System (Dwg J-49-0, sheet 16)
Logic Diagram HPCI System (Dwg J-55-0, sheet 12)
P&ID - Reactor Core Isolation Cooling (M-49-1)
P&ID - High Pressure Coolant Injection (M-55-1)
Simulator Action Request (SAR#: H-2002-160)
Operations Department Night Order (HC-2004-082), dated September 14, 2004
Scenario Comments for SG-163, dated 8/4/04 (SAP ID 50949206)
Instruction Manual Operating, Installation, and Parts Catalog For Level Switch Model 8-66 (VTD J483Q-007-03)
Notification: 20199406, 20201509, 20173784

Maintenance Effectiveness (71111.12)

System Function Level Maintenance Rule VS Risk Reference (SE.MR.HC.02)
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
Technical Specification Action Statement Log - LCO Index Number 03-252
Technical Specification Action Statement Log - LCO Index Number 04-335
Technical Specification Action Statement Log - LCO Index Number 04-189
System Health Report - Neutron Monitoring, 1st Quarter 2003
System Health Report - Neutron Monitoring, 3rd Quarter 2003
System Health Report - Neutron Monitoring, 4th Quarter 2003
System Health Report - Neutron Monitoring, 2nd Quarter 2004
Service Water Pump & Motor Removal & Replacement (HC.MD-CM.EA-0001)
Service Water Strainer Clean and Inspect (HC.MD-PM.EA-0001)
Service Water Strainer Overhaul and Repair (HC.MD-CM.EA-0003)
Bolt Torquing, and Bolting Sequence Guidelines (SH.MD-GP.ZZ-0022)
Hayward Tyler Vertical Turbine Centrifugal Pump Installation & Operation Manual (VTD 322416)

Hayward Tyler Vertical Turbine Centrifugal Pump Bill of Materials (VTD 322422)
Service Water Self-Cleaning Strainer Vendor Technical Manual (VTD PM076-Q-0078)
Operational Challenge Report, dated July 14, 2004 (20196659)
Technical Issue Fact Sheet, dated July 14, 2004
Field Engineering Turnover Log, dated May 16, 2004
Dwg Hayward Tyler 24 VSN Pump - Sectional Arrangement (Dwg 01-600-033)
Notifications: 20075701, 20081475, 20082345, 20082965, 20082984, 20086640, 20104057, 20105504, 20130742, 20133915, 20135207, 20140072, 20140798, 20140742, 20140747, 20140072, 20140798, 20140747, 20141007, 20141467, 20141917, 20142300, 20143319, 20168090, 20170702, 20171042, 20173601, 20182367, 20185015, 20190365, 20196881, 20198535, 20168455, 20189538, 20196659, 20194090, 20196359
Orders: 60023559, 60026249, 60036419, 60036396, 60036401, 60042192, 60045432, 60041468, 60046307, 60038534, 70020848, 70021982, 70025819, 70029388, 70029893, 70030885, 70031003, 70031006, 70035285, 70035928, 70035718, 70037828, 70038174, 70040041, 70040640, 70039158, 70040356

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. 27, 28,34 36
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
Notifications: 20195650,20196359, 20196888

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

Notifications: 20196881, 20203787

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
Main Turbine Functional Test - Weekly (HC.OP-FT.AC-0001)
Chevron Technical Bulletin, Number 10 - Chevron NRR Lubricants, dated 12/20/83
Notifications: 20198346, 200200078, 20200227, 20200078, 20200292, 20199841, 20199919, 20197623, 20199758, 20174801, 20201824, 20203194, 20092231
Orders: 70040861, 70041261

Operator Workarounds (71111.16)
Condition Resolution Operability Determination Notebook
Inoperable Instrument/Alarm/Indicators/Lamps/Device Log
Inoperable Computer Point Log
Hope Creek Operator Workaround List

Hope Creek Operator Concerns List
Temporary Reading Log Index
Temporary Modification Log
Quarterly Operator Burden Assessment - 2[Nd] Quarter 2004
Notifications: 20197366, 20130227, 20155744, 20087812, 20013021, 20197712, 20104441, 20186941, 20129058, 20174733, 20128965, 20130227, 20202470
Orders: 70030919, 70029361, 70031449, 70022265, 70029169, 70030965, 70033464, 70038194, 70035928, 70038646, 70038787, 70038788

Permanent Plant Modifications (71111.17)
Vendor Document PM143Q-0077, Orifice Plate FD-D009 Liquid Flow Bore Calculation
Vendor Document PM143Q-0079, Orifice Plate FD-D008 Liquid Flow Bore Calculation
General Electric High Pressure Coolant Injection System Design Spec Data Sheet (PNO-E41-4010-0072)
Dwg No. N-901422-1, MK52 Orifice Plates
Dwg No. M-55-1, High Pressure Coolant Injection
Notifications: 20197067
Orders: 60047042, 60047102, 80073096

Post Maintenance Testing (71111.19)
Maintenance Testing Program Matrix (NC.NA-TS.ZZ-0050)
B Service Water Pump Vibration Results, dated July 14, 2004
Control Room Emergency Filtration System Functional Test (HC.OP-ST.GK-0001)
Control Area Ventilation System Operation (HC.OP-SO.GK-0001)
HPCI Main and Booster Pump Set Functional Test (HC.OP-FT.BJ-0001)
Bolt Torquing and Bolt Sequence Guidelines (SH.MD-GP.ZZ-0022)
Emergency Area Cooling System (EACS) Room Coolers Functional Test (HC.OP-FT.ZZ-0001)
Logic System Functional Test, NSSS - Inboard Valve Control Logic (HC.IC-FT.SM-0021)
Modify HPCI Discharge Flow Orifice FO-5051 (Order 60047042)
Modify HPCI Discharge Flow Orifice FO-6813 (Order 60047102)
SORC Presentation Materials (HPCI), dated 7/28/04
Engineering Change 80073096
HPCI System Leakage Test 60047042/0111
HPCI System Leakage Test 60047102/0071
Stress Calculation SC-0266, Evaluation of the Temporary Disconnect of Core Spray Piping
Notifications: 20196888, 20198472, 20199396, 20195549, 20201800
Orders: 50077485, 60047903

Refueling and Other Outage Activities (71111.20)
Fuel Handling Controls Procedure (HC.RE-FR.ZZ-0001)
New Fuel Inspection, Channeling, and Storage Procedure (HC.RE-FR.ZZ-0014)
Refueling Platform and Fuel Grapple Operation (HC.OP-SO.KE-0001)
Safe Load Path Drawing (Elevation 201), UFSAR Figure 9.1-32, Sheet 13
Notifications: 20197354, 20198581, 20200647

Surveillance Testing (71111.22)
Recirculation Jet Pump Operability - Daily (HC.OP-ST.BB-0001); dated 7/14/04, 7/15/04, 7/17/04, and 7/18/04.
125 Volt Weekly Battery Surveillance Test (HC.MD-ST.PK-0001)
250 Volt Weekly Battery Surveillance Test (HC.MD-ST.PJ-0001)
250 Volt Quarterly Battery Surveillance Test (HC.MD-ST.PJ-0002)
Emergency Diesel Generator 1BG400 Operability Test (HC.OP-ST.KJ-0002)
Extraction Steam Check Valve Exercise-Weekly (HC.OP-FT.AF-0001)
Standby Liquid Control Pump - AP208-Inservice Test (HC.OP-IS.BH-0003)
Operability Determination for B EDG, Order#70035290, Rev. 5, Dated 7/8/04
Technical Issue Fact Sheet - B EDG Spurious KW Load Wandering in Full Load Band, dated 4/7/04 and 8/4/04
Drywell Leak Detection Sump Monitoring System (HC.IC-FT.SK-0016)
Radiation Monitoring System Database, entries for monitor identification 1SKLY-4930
FSAR Section 10.2.3.6, Extraction System Check Valves
Notifications: 20197023, 20197025, 20198832, 20199226, 20194664, 20198631, 20198633, 20198550, 20198632
Orders: 50075642, 50078004, 50078629, 70040163

Temporary Plant Modifications (71111.23)
T-mod 04-010, Bypass Position Indication for Control Rod 26-31
T-mod 04-016, Alarm Bypass Request for CD481 Inverter
Notifications: 20181218, 20192342
Orders: 60045365, 60047380

Drill Evaluation (71114)
PSEG Nuclear Emergency Plan
PSEG Emergency Plan Implementing Procedure

Performance Indicator Verification (71151)
Notifications: 20200936, 20200553

LIST OF ACRONYMS

AC	Alternating Current
CFR	Code of Federal Regulations
CREF	Control Room Emergency Filtration
CST	Condensate Storage Tank
EDG	Emergency Diesel Generator
HCGS	Hope Creek Generating Station
HPCI	High Pressure Coolant Injection
IMC	Inspection Manual Chapter
IPEEE	Individual Plant Examination For External Events
IST	Inservice Test

kV	Kilo-Volt
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
LOSW	Loss of Service Water
MR	Maintenance Rule
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
OCR	Operational Challenge Response
PARS	Publicly Available Records
PCIG	Primary Containment Instrument Gas
PIs	Performance Indicators
PMH	Predicted Maximum Hurricane
PMT	Post Maintenance Testing
PSEG	Public Service Electric Gas
RCIC	Reactor Core Isolation Cooling
RCS	Reactor Coolant System
RF12	Refueling Outage No. 12
ROP	Reactor Oversight Process
SACS	Safety Auxiliaries Cooling System
SBO	Station Blackout
SDP	Significance Determination Process
SRA	Senior Risk Analyst
SSFF	Safety System Functional Failure
SSWS	Station Service Water System
SWIS	Service Water Intake Structure
T-Mod	Temporary Modification
TAC	Turbine Auxiliary Cooling System
TCP	Transient Combustible Permit
TS	Technical Specifications
UFSAR	Updated Final Safety Analysis Report
V	Volt