UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
475 ALLENDALE ROAD
KING OF PRUSSIA, PA 19406-1415

November 23, 2009

Mr. Thomas P. Joyce
President and Chief Nuclear Officer
PSEG Nuclear LLC – N09
P.O. Box 236
Hancocks Bridge, NJ 08038

SUBJECT: HOPE CREEK GENERATING STATION - NRC COMPONENT DESIGN BASES INSPECTION REPORT 05000354/2009007

Dear Mr. Joyce:

On October 9, 2009, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at the Hope Creek Generating Station (HCGS). The enclosed inspection report documents the inspection results, which were discussed with Mr. John Perry and other members of your staff on October 9, 2009.

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. In conducting the inspection, the team examined the adequacy of selected components and operator actions to mitigate postulated transients, initiating events, and design basis accidents. The inspection involved field walkdowns, examination of selected procedures, calculations and records, and interviews with station personnel.

This report documents three NRC-identified findings which were of very low safety significance (Green). All of these findings were determined to involve violations of NRC requirements. However, because of the very low safety significance of the violations and because they were entered into your corrective action program, the NRC is treating the violations as non-cited violations (NCVs) consistent with Section VI.A.1 of the NRC Enforcement Policy. 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 U. S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001, with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at the Hope Creek Generating Station. In addition, if you disagree with the characterization of any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region I and the NRC Resident Inspector at the Hope Creek Generating Station.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for the public inspection in the NRC Public Docket Room or from the Publicly Available Records 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,

Lawrence T. Doerflein

Lawrence T. Doerflein, Chief
Engineering Branch 2
Division of Reactor Safety

Docket Nos: 50-354
License Nos: NPF-57

Enclosure: Inspection Report 05000354/2009007
w/Attachment: Supplemental Information

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In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for the public inspection in the NRC Public Docket Room or from the Publicly Available Records 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/

Lawrence T. Doerflein, Chief
Engineering Branch 2
Division of Reactor Safety

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U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No:	50-354
License No:	NPF-57
Report No:	05000354/2009007
Licensee:	PSEG Nuclear LLC
Facility:	Hope Creek Generating Station
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	September 14, 2009 – October 9, 2009
Inspectors:	F. Arner, Senior Reactor Inspector, Division of Reactor Safety (DRS), Team Leader J. Richmond, Senior Reactor Inspector, DRS D. Orr, Senior Reactor Inspector, DRS A. Ziedonis, Reactor Inspector, DRS C. Baron, NRC Mechanical Contractor G. Skinner, NRC Electrical Contractor
Approved by:	Lawrence T. Doerflein, Chief Engineering Branch 2 Division of Reactor Safety

Enclosure

SUMMARY OF FINDINGS

IR 05000354/2009007; 09/14/2009 – 10/09/2009; Hope Creek Generating Station; Component Design Bases Inspection.

The report covers the Component Design Bases Inspection conducted by a team of four NRC inspectors and two NRC contractors. Three findings of very low risk significance (Green) were identified, which were also considered to be non-cited violations. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using NRC Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). The cross-cutting aspects were determined using IMC 0305, "Operating Reactor Assessment Program." 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 4, dated December 2006.

NRC-Identified Findings

Cornerstone: Mitigating Systems

- Green. The team identified a finding of very low safety significance (Green) involving a non-cited violation of 10 CFR 50 Appendix B Criterion III, Design Control, in that PSEG had not properly verified that the safety-related 'B' 4 kV switchgear had adequate DC control voltage to operate under all design conditions. Specifically, PSEG did not use the maximum DC control current to the 'B' 4 kV switchgear to calculate the worst case voltage drop between the battery and the switchgear. PSEG relied on this calculation to verify the adequacy of their design and ensure the minimum voltage at the switchgear satisfied design requirements. In response, PSEG entered the issue into their corrective action program and performed a calculation to ensure that there was sufficient margin to assure operability of the 4kV switchgear.

  The finding was more than minor because it was associated with the design control attribute of the Mitigating Systems Cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The team determined the finding was of very low safety significance (Green) because it was a design deficiency subsequently confirmed not to result in a loss of operability or functionality. This finding did not have a cross-cutting aspect because the issue was not considered to be indicative of current licensee performance. (1R21.2.1.1)

- Green. The team identified a finding of very low safety significance (Green) involving a non-cited violation of 10 CFR 50 Appendix B Criterion III, Design Control, in that PSEG design control measures had not verified the adequacy of design with respect to ensuring adequate two-over-one seismic protection existed for the emergency diesel generators (EDG). Specifically, PSEG had not performed design reviews, calculations or testing to ensure the existing field crane configuration would not adversely impact the EDG function for a design basis safe shutdown earthquake (SSE) event. PSEG entered this issue into their corrective action program, performed Technical Evaluation (TE) 70102445-0050, Diesel Generator Underhung Crane Seismic II/I Evaluation, to calculate the seismic response of the diesel cranes and assess the as-found condition (e.g., crane seismic restraints not installed) and implemented appropriate compensatory measures.

The finding was more than minor because it was associated with the design control attribute of the Mitigating Systems Cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The team determined the finding was of very low safety significance (Green) because it was a design deficiency subsequently confirmed not to result in a loss of operability or functionality. This finding did not have a cross-cutting aspect because the issue was not considered to be indicative of current licensee performance. (1R21.2.1.2)

- Green. The team identified a finding of very low safety significance (Green) involving a non-cited violation of 10 CFR 50, Appendix B, Criterion III, Design Control, in that PSEG had not verified the adequacy of design with respect to establishing the bases for the degraded voltage relay (DVR) setpoint. Specifically, PSEG's calculation to verify the DVR setpoint utilized a non-conservative voltage input to analyze motor starting during accident load sequencing and assumed an inappropriate modeling technique for running motors that minimized the voltage dips during motor starting. Additionally, PSEG's analyses had not analyzed the capability of motor starting during steady state conditions following load sequencing. PSEG entered the issue into their corrective action program and prepared preliminary calculations to assess the cumulative effect of the non-conservative assumptions on the voltage available to motors starting during load sequencing. The calculations showed that although margins were substantially reduced, the motors would still be afforded their minimum required starting voltage.

  The finding was more than minor because it was associated with the design control attribute of the Mitigating Systems Cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The team determined the finding was of very low safety significance (Green) because it was a design deficiency confirmed not to result in a loss of the electrical distribution system operability or functionality. This finding did not have a cross-cutting aspect because the issue was not considered to be indicative of current licensee performance. (1R21.2.1.3)

REPORT DETAILS

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R21 Component Design Bases Inspection (IP 71111.21)

.1 Inspection Sample Selection Process

The team selected risk significant components and operator actions for review using information contained in the Hope Creek Probabilistic Risk Assessment (PRA) model and the U. S. Nuclear Regulatory Commission's (NRC) Standardized Plant Analysis Risk (SPAR) model. Additionally, the Hope Creek Significance Determination Process (SDP) Phase 2 Notebook (Revision 2.1a) was referenced in the selection of potential components and operator actions for review. In general, the selection process focused on components and operator actions that had a Risk Achievement Worth (RAW) factor greater than 1.3 or a Risk Reduction Worth (RRW) factor greater than 1.005. The components selected were located within both safety-related and non-safety related systems, and included a variety of components such as pumps, electrical buses, instrumentation controllers, transformers, and valves.

The team initially compiled a list of components and operator actions based on the risk factors previously mentioned. Additionally, the team reviewed the previous component design bases inspection report (05000354/2006015) and excluded the majority of those components previously inspected. The team then performed a margin assessment to narrow the focus of the inspection to 18 components, four operator actions and three operating experience items. The team's evaluation of possible low design margin included consideration of original design issues, margin reductions due to modifications, or margin reductions identified as a result of material condition/equipment reliability issues. The assessment also included items such as failed performance test results, corrective action history, repeated maintenance, maintenance rule (a)(1) status, operability reviews for degraded conditions, NRC resident inspector insights, system health reports, and industry operating experience. Finally, consideration was also given to the uniqueness and complexity of the design and the available defense-in-depth margins. The margin review of operator actions included complexity of the action, time to complete the action, and extent-of-training on the action.

The inspection performed by the team was conducted as outlined in NRC Inspection Procedure (IP) 71111.21. This inspection effort included walkdowns of selected components, interviews with operators, system engineers and design engineers, and reviews of associated design documents and calculations to assess the adequacy of the components to meet design basis, licensing basis, and risk-informed beyond design basis requirements. Summaries of the reviews performed for each component, operator action, and operating experience sample, and the specific inspection findings identified are discussed in the subsequent sections of this report. Documents reviewed for this inspection are listed in the Attachment.

.2 Results of Detailed Reviews

.2.1 Results of Detailed Component Reviews (18 samples)

.2.1.1 'B' 125 and 250 Vdc Batteries (2 samples)

a. Inspection Scope

The team reviewed the design, testing, and operation of the 'B' 125 and 250 Vdc station batteries to verify that they could perform their design function to provide reliable direct current (DC) power to connected loads under operating, transient and accident conditions. The team reviewed design calculations, including battery sizing, load flow studies, and voltage drop calculations, to verify that the battery capacity was adequate for the equipment load and duration required by design and licensing requirements. This included ensuring that adequate voltage was available to meet minimum voltage specifications for the electrical loads during worst case loading conditions. Battery maintenance and surveillance tests, including capacity and service discharge tests and quarterly surveillance tests, were reviewed to ensure the testing was sufficient and performed in accordance with established procedures, vendor recommendations, industry standards, and design and licensing requirements. The team compared the service test load profile to the load flow studies for the loss-of-coolant-accident (LOCA) with concurrent loss-of-offsite power (LOOP) and to the station blackout (SBO) design assumptions to verify that the load testing enveloped the predicted worst case loading conditions. In addition, the team compared as-found test and inspection results to established acceptance criteria to evaluate the as-found conditions and to verify that those conditions conformed to design basis assumptions and regulatory requirements.

The team performed field walkdowns of the 'B' 125 and 250 Vdc station batteries, the battery chargers, and associated distribution panels to independently assess the material condition of the battery cells and associated electrical equipment. Specifically, the team visually inspected the batteries for signs of degradation such as excessive terminal corrosion and electrolyte leakage. In addition, the team interviewed design and system engineers regarding the design, operation, testing, and maintenance of the battery.

b. Findings

'B' 125 Vdc Battery Voltage Drop Calculation Non-conservative

Introduction: The team identified a finding of very low safety significance (Green) involving a non-cited violation of 10 CFR 50, Appendix B, Criterion III, Design Control, in that PSEG had not properly verified that the safety-related 'B' 4 kV switchgear had adequate DC control voltage to operate under all design conditions. Specifically, PSEG did not use the maximum DC control current to the 'B' 4 kV switchgear to calculate the worst case voltage drop between the battery and the switchgear. However, PSEG relied on this calculation to verify the adequacy of design and ensure the minimum voltage at the switchgear satisfied design requirements.

Description: In order to verify that battery loads had adequate voltage under worst case conditions, PSEG used a minimum battery design voltage of 108 Vdc and a series of four separate calculations, as follows:

- E-4.1, 125 Vdc Battery & Charger Sizing, in part, determined the battery load profile for a loss of coolant accident coincident with a LOOP, and for a SBO event.
- E-1.4, 125 & 250 Vdc Systems Short Circuit and Voltage Drop Studies, in part, determined the voltage drops from the battery to the loads directly fed from the battery bus, such as DC distribution panel 1BD417.
- E-17D, 125 Vdc Voltage Drop from Distribution Panel to Load, determined the worst case voltage drop from a distribution panel to each connected load.
- E-4.2, DC Equipment & Component Voltage Study, tabulated data from other design documents, such as calculations and vendor equipment specifications, in order to verify that the DC components could perform their intended functions over the anticipated minimum and maximum voltages of their associated circuits.

Calculation E-4.2 compared a calculated minimum voltage of 106.6 Vdc at the 'B' 4 kV switchgear 10A402 (as calculated by E-17D) to a specified minimum requirement of 100.0 Vdc, and determined that the switchgear had adequate voltage to operate under worst case conditions. The team noted that the value of 106.6 Vdc used in E-4.2 did not agree with the calculated value of 106.79 Vdc documented in E-17D. PSEG design engineering reviewed this inconsistency and stated that E-4.2 had not been updated following the last revision to E-17D, and since the difference in voltages was conservative (e.g., value compared to the specification was less than the calculated value), no revision was required.

Calculation E-17D used a value of 6.2 amperes as the maximum current to the switchgear, and calculated a minimum voltage of 106.79 Vdc at the switchgear. The documented basis for the 6.2 ampere value was 5 amperes for one 4 kV breaker closing plus 1.2 amperes for switchgear steady state operation. However, calculation E-4.1 determined the 'B' battery load profile included 121.2 amperes to the 'B' switchgear during the first minute of a LOCA-LOOP event, and 61.2 amperes during the second minute.

The team determined that the design input value of 6.2 amperes, used in E-17D, was inconsistent with the maximum value of 121.2 amperes determined by calculation E-4.1. The team concluded that calculation E-17D used a non-conservative value of DC current to calculate the worst case voltage drop from the 125 Vdc distribution panel 1BD417 to the 'B' 4 kV switchgear. As a result of this non-conservative error, the associated calculations did not verify whether there would be adequate DC control voltage at the switchgear under all operating, transient, and accident conditions. Therefore, the team determined that an increase from 6.2 to 121.2 amperes was sufficiently significant to result in a reasonable doubt of operability for the switchgear. PSEG entered this issue into their corrective action program as notification 20434047 to revise the calculation. PSEG performed an informal calculation to evaluate this issue, and concluded that the minimum voltage at the switchgear would not drop below the specified minimum requirement of 100 Vdc with a worst case switchgear current of 121.2 amperes.

The team reviewed PSEG's informal evaluation and concluded it appeared reasonable to support operability.

Analysis: The team determined that the failure to use the most limiting design input values in design calculations and analyses was a performance deficiency. Specifically, PSEG did not use the expected maximum DC control current to the 'B' 4 kV switchgear to calculate the voltage drop between the battery and the switchgear. The result was that the design calculation did not verify that the safety-related switchgear would have adequate DC control voltage to operate under the most limiting conditions. The team concluded that this performance deficiency was reasonably within PSEG's ability to foresee and prevent prior to October 2009. The finding was more than minor because it was similar to Example 3j of NRC IMC 0612, Appendix E, Examples of Minor Issues, in that as a result of this error, the team had a reasonable doubt of operability with respect to the minimum voltage available at the switchgear. This was the result of the significant increase in the DC current used to calculate the minimum voltage at the switchgear. In addition, the finding was associated with the design control attribute of the Mitigating Systems Cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. 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 team performed a Phase 1 Significance Determination Process (SDP) screening, in accordance with NRC IMC 0609, Attachment 4, Phase 1 - Initial Screening and Characterization of Findings, and determined the finding was of very low safety significance (Green) because it was a design deficiency subsequently confirmed not to result in a loss of operability or functionality. The team did not identify a cross-cutting aspect associated with the finding because the cause of the performance deficiency occurred during the historical development of the 125 Vdc voltage drop analysis and the calculation had not been reviewed during recent engineering activities. Therefore, the issue was determined not to be indicative of current licensee performance.

Enforcement: 10 CFR 50 Appendix B Criterion III, Design Control, requires in part, that measures shall provide for verifying or checking the adequacy of design. Contrary to the above, as of October 9, 2009, PSEG had not properly verified that the safety related 'B' 4 kV switchgear had adequate DC control voltage to operate under all design conditions. Because this finding was of very low safety significance and was entered into the corrective action program as notification 20434047, this violation was treated as a non-cited violation (NCV), consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 05000354/2009007-01, Non-conservative Input Used in Design Calculation for DC Control Voltage for 4 kV Switchgear)**

.2.1.2 'B' Emergency Diesel Generator - Electrical

a. Inspection Scope

The team reviewed the electrical design, testing, and operation of the 'B' emergency diesel generator (EDG) to verify that it could perform its design function to provide reliable AC power to connected loads under transient and accident conditions. The team evaluated the EDG load flow study and voltage drop calculations to verify that adequate voltage was available to meet minimum voltage specifications for the safety-related electrical loads during worst case loading conditions. In addition, the team compared the load flow study uncertainties to the EDG's available margin to assess the load flow study adequacy. The team also reviewed static loading calculations to determine whether the maximum loading under accident conditions was within the generator ratings. The team reviewed EDG surveillance tests, including the integrated LOCA-LOOP load sequencer test, the 24 hour endurance run, and the 2 hour 110% rated load run, to verify that the testing was performed in accordance with established procedures and that the test conditions enveloped design basis and technical specification requirements. The team compared as-found test results to established acceptance criteria to evaluate the as-found conditions and to ensure that they were acceptable and conformed to design basis assumptions and regulatory requirements.

The team performed field walkdowns of the 'B' EDG to independently assess the material condition and the operating environment for the EDG and associated electrical equipment. During the walkdowns, the team observed installed local and remote EDG control switches, breaker position indicating lights, and system alignments, to verify that they were consistent with design and licensing basis assumptions. The team interviewed design and system engineers regarding the electrical design, operation, testing, and maintenance of the EDG. Additionally, the team reviewed system health reports and corrective action documents to determine if there were any adverse equipment operating trends.

b. Findings

'B' EDG Seismic Two Over One Protection

Introduction: The team identified a finding of very low safety significance (Green) involving a non-cited violation of 10 CFR 50, Appendix B, Criterion III, Design Control, in that PSEG design control measures had not verified the adequacy of design with respect to ensuring adequate two-over-one seismic protection existed for the emergency diesel generators. Specifically, PSEG had not performed design reviews, calculations or testing to ensure the existing field crane configuration would not adversely impact the EDG function for a design basis safe shutdown earthquake (SSE) event.

Description: During a field walkdown of the 'B' EDG, the team observed that bridge crane 1BH400 was located above the generator end of the EDG and did not appear to have any posted instructions or a local procedure for the crane's operation. The team asked the PSEG engineers for a description of the seismic qualifications and requirements for the EDG crane. All 4 EDG cranes (i.e., 1AH400 thru 1DH400) were in the same location above the EDG generators. In response to the team's question, PSEG determined that the bridge cranes in all four diesel rooms were required to be parked at the opposite end of the room (e.g., away from the EDG generator end) and seismically restrained by (1) bolting the crane bridge to the building rail, and (2) pinning the trolley to the bridge. PSEG walkdowns determined that neither the bridge nor the trolley had their seismic restraints installed. PSEG entered this issue into their corrective action program as notification 20431806, performed an immediate operability determination, and implemented appropriate compensatory measures.

The team determined that the seismic design of the non-safety related EDG bridge cranes had been appropriately considered and evaluated, as described in UFSAR Section 1.8.1.29, Conformance to Regulatory Guide (RG) 1.29, Seismic Design Classification, and UFSAR Table 9.1-10, Overhead Heavy Load Handling Systems Data Summary. The seismic evaluation documented in the UFSAR stated that the diesel cranes were required to be "Seismically secured (designed so that all parts remain in place under 7g horizontal and vertical seismic accelerations, and equipped with positive restraints and locking devices)." Design drawings specified the specific installation and configuration details for trolley seismic anchor pins and crane bridge seismic restraints.

PSEG performed Technical Evaluation (TE) 70102445-0050, Diesel Generator Underhung Crane Seismic II/I Evaluation, to calculate the seismic response of the diesel cranes and assess the as-found condition (e.g., crane seismic restraints not installed). The TE concluded the crane bridge and trolley configuration was structurally adequate in any configuration in the diesel rooms because the vertical acceleration value did not exceed the dead weight and the hoist and trolley were adequately held in-place against horizontal acceleration by the installed disc brakes, flanged wheels, and gearing mechanism. The team reviewed the TE and concluded PSEG adequately assessed the as-found condition and had taken appropriate compensatory actions.

PGEG performed extent-of-condition walkdowns to identify whether other plant cranes and trolleys were seismically restrained as required by plant design. PSEG entered multiple configuration discrepancies into their corrective action program as notifications 20433669 and 2043470.

Analysis: The team determined that the failure to verify the adequacy of design with respect to ensuring adequate two-over-one seismic protection existed for the EDGs was a performance deficiency. Specifically, the UFSAR and design drawings noted that seismic restraints were to be installed on the crane above an EDG, to ensure the EDG would remain functional following a design basis earthquake. PSEG had not installed the required restraints, had not placed the cranes at the correct end of the diesel rooms and had not evaluated the adequacy of this configuration. The team concluded that this performance deficiency was reasonably within PSEG's ability to foresee and prevent prior to October 2009.

This issue was more than minor because it was similar to NRC IMC 0612, Appendix E, Examples of Minor Issues, Example 3.c, in that multiple components (e.g., all four EDG cranes) were not in the correct position and configuration required by plant design. In addition, this finding was associated with the design control attribute of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. 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 team performed a Phase 1 SDP screening, in accordance with NRC IMC 0609, Attachment 4, Phase 1 - Initial Screening and Characterization of Findings, and determined the finding was of very low safety significance (Green) because it was a design deficiency subsequently confirmed not to result in a loss of operability or functionality. The team did not identify a cross-cutting aspect associated with the finding because the cause of the performance deficiency was historical in that design requirements had not been appropriately translated into procedures. The team determined that PSEG had not had a subsequent reasonable opportunity to identify the deficiency and therefore it was not indicative of current licensee performance.

Enforcement: 10 CFR 50, Appendix B, Criterion III, Design Control, requires, in part, that measures be provided for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program. Contrary to the above, as of October 9, 2009, PSEG's design control measures had not verified the adequacy of design with respect to ensuring adequate two-over-one seismic protection existed for the emergency diesel generators. Specifically, PSEG had not performed a design review, calculations or testing to ensure the existing field crane configuration would not adversely impact the EDG function for an SSE event. Because this finding was of very low safety significance and was entered into the corrective action program as notifications 20431806, 20433669, 20434370, and 20434477, this violation was treated as a non-cited violation (NCV), consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 05000354/2009007-02, EDG Overhead Cranes Not Seismically Restrained)**

.2.1.3 4.16 kV Emergency Bus 10A402

a. Inspection Scope

The team reviewed bus loading calculations to verify that the 4160V system had sufficient capacity to support its required loads under worst case accident loading and grid voltage conditions. The team reviewed the design of the 4160V bus degraded voltage protection scheme to ensure that it afforded adequate voltage to safety related devices at all voltage distribution levels. This included a review of degraded voltage relay (DVR) setpoint calculations, motor starting and running voltage calculations, and motor control center (MCC) control circuit voltage drop calculations. The team reviewed procedures and completed surveillances for calibration of the degraded voltage relays to verify that acceptance criteria was consistent with design calculations, and to determine whether the relays were performing satisfactorily. The team reviewed operating procedures to verify that the limits and protocols for maintaining offsite voltage were consistent with design calculations.

The team reviewed protective relaying schemes and calculations to verify that equipment such as motors and cables were adequately protected, and to ensure that protective devices featured proper selective tripping coordination. The team reviewed bus control logic to verify that bus transfer schemes were consistent with the design bases. The team reviewed system health reports, corrective action documents and maintenance records to determine whether there were any adverse operating trends.

In addition, the team performed a visual inspection of the 4160V safety buses to assess the material condition and the presence of hazards.

b. Findings

.1 Introduction: The team identified a finding of very low safety significance (Green) involving a non-cited violation of 10 CFR 50, Appendix B, Criterion III, Design Control, in that PSEG had not verified the adequacy of design with respect to establishing the bases for the degraded voltage relay setpoint. Specifically, PSEG calculation to verify the DVR setpoint utilized a non-conservative voltage input to analyze motor starting during load sequencing and assumed an inappropriate modeling technique for running motors that minimized the voltage dips during motor starting. Additionally, PSEG's analyses had not analyzed the capability of motor starting during steady state conditions following load sequencing.

Description: Calculation E-15.1 analyzed the voltage available to large ECCS motors during load sequencing at the onset of an accident. The motor starting evaluation was performed as part of the calculation intended to determine the capability of the electrical system to stay connected to offsite power following a trip of the unit. Offsite power availability is challenged during load sequencing because when large motors are started, bus voltage may dip below the degraded voltage relay dropout setpoint. In order to stay connected to the offsite power supply, bus voltage must then be able to recover to the upper tolerance relay reset setpoint prior to the expiration of the degraded voltage relay time delay. Calculation E-15.1 analyzed this scenario and applied a positive tolerance to the relay reset value, since this required a higher bus voltage (and higher corresponding switchyard voltage) for relay reset, and was the limiting case for offsite power availability. However, the relay reset setpoint could also exhibit a negative tolerance, which would permit a lower voltage on a safety bus, without transfer to the emergency diesel generator. The team determined this would represent a more limiting case for motor starting voltage that should have been analyzed separately. PSEG initiated Notification 20431969 within their corrective action system to evaluate the team's concern.

Calculation E-15.1, Section 2.2.5 stated that running motors (motors that were connected to the system prior to load sequencing or that had successfully started) were modeled as current sources. The team noted that this technique was appropriate for short circuit studies where the interval of interest was a few cycles, but was not appropriate for analyzing the voltage dips during starting of large motors where the interval of interest was a few seconds. This was because during voltage dips induction motors act only as current sources for a few cycles, after which they draw greater than full load current, because current to running motors is inversely proportional to their terminal voltage. Devices that exhibit this type of behavior are known as constant Kilo-Volt-Ampere (KVA) devices. Consequently, the loading on transformers supplying systems with large running motor loads will increase substantially during voltage dips associated with starting large motors. This additional loading further depresses system voltage resulting in lower voltage at the terminals of the starting motors. PSEG estimated that the use of this nonconservative technique resulted in approximately 2% to 5% greater system voltages than would be afforded by using the generally accepted technique of modeling running motors as constant KVA devices. PSEG initiated

Notification 20433513 to further evaluate the issue. PSEG also prepared preliminary calculations to assess the cumulative effect of the non-conservative assumptions described above on the voltage available to motors starting during load sequencing. The calculations showed that although margins were substantially reduced, the motors would still be afforded their minimum required starting voltage. Additionally, Calculation E-15.1 analyzed running voltage for individual motors during steady state operation following load sequencing, based on minimum voltage afforded by the degraded voltage relays. The calculation did not address starting voltage requirements for motors that may be started after load sequencing was completed. In response to the inspectors concerns, PSEG prepared preliminary calculations using the lowest voltages that could be allowed by the degraded voltage scheme. These calculations showed motors would still be able to start. The team reviewed PSEG's evaluation and concluded it appeared reasonable to support operability.

Analysis: The team determined that the failure to verify the adequacy of the design, through the performance of a design review, by the use of calculational methods, or by the performance of a suitable test program, was a performance deficiency that was reasonably within PSEG's ability to foresee and prevent. The finding was more than minor because it was similar to Example 3j of NRC IMC 0612, Appendix E, Examples of Minor Issues, because the condition resulted in reasonable doubt of the operability with respect to the adequacy of voltage supplied to downstream safety related components and additional analysis was necessary to verify operability. In addition, the finding was associated with the design control attribute of the Mitigating Systems Cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. 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.

In accordance with NRC Inspection Manual Chapter 0609, Attachment 4, Phase 1 – Initial Screening and Characterization of Findings, a Phase 1 SDP screening was performed and determined the finding was of very low safety significance (Green) because it was a design deficiency confirmed not to result in a loss of the electrical distribution system operability or functionality. The basis for this conclusion was that despite the lower than assumed voltage available at the motors and the loss of design margin, there was still adequate voltage for the motors to start during load sequencing and to perform their safety function. In addition, preliminary calculations showed that individual motors would have adequate voltage to start during steady state conditions with degraded voltage. The team did not identify a cross-cutting aspect associated with the finding because the cause of the performance deficiency occurred during historical development of the 4kV degraded voltage analyses and the calculation had not been reviewed during recent engineering activities. Therefore, the issue was determined to not be indicative of current licensee performance.

Enforcement: 10 CFR 50, Appendix B, Criterion III, Design Control, requires, in part, that measures be provided for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program. Contrary to the above, as of October 8, 2009, PSEG's design control measures had not verified the adequacy of design with respect to establishing the bases for the degraded voltage relay setpoint. Specifically, PSEG's calculation to verify the DVR setpoint utilized a non-conservative voltage input to analyze motor starting during load sequencing and assumed an inappropriate modeling technique for running motors that minimized the voltage dips during motor starting. Additionally, PSEGs analyses had not analyzed the capability of motor starting during steady state conditions following load sequencing. Because this violation is of very low safety significance and has been entered into PSEG's corrective action program as Notifications 20433513 and 20431969, it is being treated as a non-cited violation consistent with Section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000354/2009007-03, Inadequate Design Control for 4 kV Bus Degraded Voltage Relay Bases)**

.2 Unresolved Item: The team identified an unresolved item with respect to the HCGS degraded voltage protection scheme. The team noted that the existing scheme was not in conformance with the guidance provided in the office of Nuclear Reactor Regulation (NRR) Branch Technical Position (PSB-1), which established a technical position for the adequacy of station electric distribution system voltages. However, it was not clear at the time of the inspection what the approved licensing bases was for HCGS with respect to the guidelines contained in the BTP and postulated degraded voltage scenarios and therefore the issue was unresolved. The team noted that the existing scheme with a postulated degraded grid scenario, had the potential to automatically transfer a bus with a degraded source voltage to an alternate source that may also be degraded. Additionally, the team noted that the degraded voltage relay time delay was longer than the currently analyzed time in the accident analysis with respect to the assumption for cooling water injection to the core during a LOCA.

The HCGS electrical distribution system features four 4.16kV safety related buses, each of which can be powered by its dedicated emergency diesel generator or from either of two station service transformers connected to the offsite source. The buses are normally connected to one of the two station service transformers and the bus control logic features a transfer scheme where a safety bus is transferred to its alternate station service transformer in case of the following conditions:

- Failure of the normal source station service transformer, or
- Undervoltage on the primary source

The transfer is accomplished by opening the normal source breaker and closing the alternate source breaker for the affected 4.16 kV safety bus. Degraded voltage relays are connected on the source side of each breaker supplying a 4.16 kV safety bus from the station service transformers. These relays perform two functions in the transfer scheme; initiating the transfer on the normal source, and providing a voltage permissive on the receiving source. The relays have a nominal voltage setpoint of approximately 92% of bus rated voltage, and an acceptable time delay range of 15 to 35 seconds. If a degraded voltage condition occurs where the voltage at the 4.16 kV safety buses is near or just below 92%, a transfer of one of the buses may occur. For this scenario, the team was concerned that because the loading on the receiving transformer will increase and the loading on the sending source would decrease, this would tend to decrease voltage on the receiving source and increase voltage on the sending source, possibly enough to reset the degraded voltage relays at the supply breakers for each bus. The receiving source (now supplying three safety buses) would experience degraded voltage and one or two buses originally being supplied by that source would transfer to the source that was degraded first, thereby causing re-degradation. Once a transfer of a particular bus occurs, it would be prevented from transferring back to its original source, but the team noted that nothing prevents the transfer of other buses to that source. Therefore, each of the four safety buses could swap sources, prior to being transferred to the EDGs. The multiple starting of loads could challenge the thermal limits and overcurrent protective devices for some equipment and safety related equipment could be challenged due to damage or tripping of overload devices. This scheme does not appear to be consistent with the guidance in Branch Technical Position PSB-1, Position B.1.b)1), which states that the degraded voltage relay should disconnect the Class 1E system from the offsite power system in case of a degraded voltage condition that exceeds the voltage and time delay setpoints. It was not clear to the team if the design has to be able to withstand a postulated scenario where degraded voltage could occur for both offsite sources such that this condition would be a concern.

Additionally, the HCGS degraded voltage scheme employs only one time delay, with an allowable variation from 15 to 35 seconds instead of the two time delay scheme referenced within PSB-1. This time delay is effective whether an accident signal is present or not. The team noted that in June of 1977, the NRC had sent letters to holders of operating licenses at the time, providing guidance that the time delay for second level degraded voltage relays shall not exceed the time delay that was assumed in their FSAR accident analysis. In response to the team's inquiry, PSEG provided data that showed that even if there was no protective action function for the entire allowable 35 second time delay of the degraded voltage scheme, fuel peak cladding temperature (PCT) would remain well below the 2200°F acceptance criteria. The team noted that while the PCT would remain below the criteria, the calculated PCT would increase over the current licensing bases number. The team noted that the selection of the original 15 to 35 second time delay was apparently based on an attempt to coordinate bus overcurrent backup relays with the undervoltage scheme and not related to accident analysis core flood requirements. Additionally, a review of the licensing record did not provide any insight regarding the rationale for omitting the second time delay referenced in BTP PSB-1 Position B.1.b)2), which described a time delay of limited duration such that permanently connected Class 1E loads would not be damaged. The team concluded that the design of the existing degraded voltage protection scheme was an issue requiring further NRC review to determine if HCGS is in compliance with their licensing bases for degraded voltage protection. **(URI 05000354/2009007-04, Degraded Voltage Protection Scheme Design)**

.2.1.4 <u>480V Emergency Bus 10B420</u>

a. <u>Inspection Scope</u>

The team reviewed bus loading calculations to verify that the 480V bus had sufficient capacity to support its required loads under worst case accident loading and grid voltage conditions. The team reviewed the degraded voltage protection scheme to verify that the voltage setpoints were selected based on the voltage requirements for safety related loads at the 480V level. The team reviewed cable sizing calculations to ensure that cables were adequately sized for load and service conditions. The team reviewed 480V short circuit calculations to verify that protective devices were applied within their ratings and appropriate fault values were used in protective relaying calculations. The team reviewed breaker coordination studies to determine whether equipment was protected and protective devices featured selective coordination. The team reviewed maintenance procedures and schedules for the 480V load centers to ensure that equipment was being properly maintained. The team reviewed system health and corrective action documents to determine if there were any adverse operating trends. In addition, the team performed a visual inspection of the 480V safety buses to assess the material condition.

b. Findings

No findings of significance were identified.

.2.1.5 Station Service Transformer 1BX501

a. Inspection Scope

The team reviewed relay connection drawings and calculations to verify that protective schemes and settings were adequate to protect the transformer from overcurrent conditions and determine if the relaying was subject to spurious tripping under expected inrush and loading currents. The team reviewed the calculations and operating procedures to verify that bus voltages maintained by the automatic load tap changer were adequate to ensure successful bus transfers. The team reviewed sources of power for automatic control equipment to determine whether the transformer would operate properly during low voltage conditions and could be restored to service following an SBO. The team reviewed maintenance schedules, procedures, vendor manuals, and completed work records to determine if the transformer was being properly maintained. The team reviewed corrective action histories to determine whether there had been any adverse operating trends. In addition, the team performed a visual inspection of the 1BX501 transformer to assess material condition and the presence of hazards.

b. Findings

No findings of significance were identified.

.2.1.6 Service Water Pump A

a. Inspection Scope

The team reviewed the 'A' Service Water pump to verify that it was capable of meeting its design basis requirements. The service water pump was part of a once through cooling system designed to remove heat under both normal and post-accident conditions. The team reviewed the capability of the pump to perform its required function under limiting operating conditions. The review included flow analyses, net-positive-suction-head (NPSH) analyses, operating procedures, maintenance procedures, test procedures and recent pump test results. The team evaluated the capability of the system to provide adequate cooling water flow with the most limiting water temperatures to verify the capability of the pump to fulfill its required mission. The team interviewed the system and design engineers and performed a walkdown of the pump and associated equipment, including the traveling screens and strainers to assess the material condition of the equipment.

b. Findings

No findings of significance were identified.

.2.1.7 HPCI Exhaust Vacuum Breaker & Isolation Valves F077, F075, F079

a. Inspection Scope

The team reviewed vacuum breaker, F077, installed on the HPCI pump turbine exhaust piping as well as motor operated isolation valves F075 and F079 to verify they were capable of performing their design basis requirements. The design function of the vacuum breaker was to prevent unacceptable water-hammer transients in the exhaust piping when securing the HPCI turbine. The motor operated valves were designed to close and perform a primary containment isolation function under accident conditions. The team's review included verification that the vacuum breaker would have sufficient capacity to prevent an unacceptable water-hammer transient under both normal and post accident conditions. The team reviewed the closing time of the motor operated valves to verify that they would not isolate too quickly and interfere with the design function of the vacuum breaker. The team also reviewed analyses associated with the capability of the motor operated valves to verify they could operate under the most limiting conditions. The team reviewed the latest in-service testing (IST) results to ensure the valve capabilities were consistent with design assumptions. The team interviewed the system and design engineers regarding the design and evaluation of corrective action items associated with these valves.

b. Findings

No findings of significance were identified.

.2.1.8 Safety Auxiliaries Cooling System Pump 'A'

a. Inspection Scope

The team reviewed the 'A' safety auxiliaries cooling system (SACS) pump to verify that it was capable of meeting its design basis requirements. The SACS pump was part of a closed loop cooling system designed to remove heat under both normal and post-accident conditions. The pump was designed to provide cooling water to safety related equipment including the emergency diesel generators and room coolers.

The team reviewed the capability of the SACS pump to perform its required function under limiting operating conditions. The review included flow analyses, NPSH analyses, operating and test procedures along with recent pump IST results. The team also evaluated the basis of the pump IST acceptance criteria to verify that the testing ensured the capability of the pump to fulfill its required mission. The team interviewed the system and design engineers and performed a walkdown of the pump and associated equipment to assess the material condition of the equipment.

b. Findings

No findings of significance were identified.

.2.1.9 HPCI Turbine Governor Valve FV 4879 and Controls

a. Inspection Scope

The team reviewed the governor valve associated with the HPCI turbine driver to ensure it was capable of meeting its design basis function. The valve was designed to control the steam flowrate to the turbine which controls the pump speed and system flow. The review included operating and test procedures and recent IST results. The team evaluated the past performance of the HPCI pump during an actual injection event to verify that the governor valve responded as expected and that the HPCI system did not experience any flow instabilities. The team interviewed system and design engineers regarding the current condition of the valve and to discuss recent test results with respect to ensuring consistency with design requirements. The team also performed a walkdown of the valve and associated equipment to assess the material condition of the equipment.

b. Findings

No findings of significance were identified.

.2.1.10 Safety Auxiliaries Cooling System Valve EG-HV2395D

a. Inspection Scope

The team reviewed the design of valve EG-HV2395D and its associated controls to verify that it was capable of meeting its design basis function. The valve was designed to automatically admit cooling water flow to the 'D' EDG when it is operating and to isolate the cooling water flow when it is not required. The review included the design of the associated control system, valve performance calculations, operating procedures, maintenance and test procedures, and recent IST results. The team reviewed the past performance of the valve to verify it was capable of performing its function. The review included evaluations of past failures of the control system, and valve seats, and the associated operability determinations. The team interviewed the design and system engineers regarding the current condition of the valve and operational history. The team also performed a walkdown of the valve and associated equipment to assess the material condition of the equipment.

b. Findings

No findings of significance were identified.

2.1.11 Containment Pressure Suppression Chamber/Torus

a. Inspection Scope

The team reviewed the primary containment pressure suppression chamber (torus) to verify that it was capable of meeting its design basis function. The torus was designed to be maintained partially full of water and provide a heat sink for steam that may be released under transient or accident conditions. The torus was also designed to provide a supply of water to the emergency core cooling system (ECCS) under post-accident conditions. The review included operating and maintenance procedures. The team evaluated the criteria for inspecting and cleaning the torus to verify that the material condition was consistent with design analyses. Specifically, the team evaluated the acceptance criteria for debris in the torus, the condition of the internal coatings, and the inspection/cleaning interval. The team interviewed the system engineer regarding the condition of the torus and the latest inspection results. The team also interviewed operations personnel regarding the use of operating procedures to maintain the torus level during both normal and accident conditions.

b. Findings

No findings of significance were identified.

.2.1.12 Emergency Diesel Generator 'A' (Mechanical)

a. Inspection Scope

The team inspected a sample of mechanical support systems for the emergency diesel generator (EDG) to verify that the EDG was capable of performing its safety related function during design basis events. The team reviewed the Updated Final Safety Analyses Report (UFSAR), design basis documents, drawings, and procedures to identify the design basis requirements of the EDG and its mechanical support systems. Specifically, the team inspected the 'A' EDG fuel oil, lube oil, cooling water, starting air, and room ventilation systems to ensure they could successfully perform under design basis events. For the fuel oil system, the team reviewed fuel oil consumption calculations that were performed to ensure Technical Specification requirements were met. For the lube oil system, the team verified that the lube oil pressure, temperature and differential pressure across the lube oil filters would remain adequate to support extended EDG runs. The team also verified that proper maintenance was being performed on the fuel oil and lube oil filters. For the cooling water, the team reviewed calculations to verify that adequate coolant water was supplied to support operation under design basis conditions. The team reviewed the design specification for the starting air system, as well as air start test results, normal operating pressure band, alarm setpoint band, and Technical Specification limit for operability, to verify that the start air system was properly sized and could meet its design function for successive starts.

The room ventilation system calculations were reviewed to ensure room temperatures would remain within the equipment qualification limits during extended operation during design basis events. The team reviewed PSEG evaluations to verify that the EDG would be able to successfully perform its design basis function with ultra low sulfur fuel oil, as discussed in Information Notice 2006-22. The team conducted a walkdown of the EDG and its support systems to assess the material condition and to verify standby lineups were in accordance with the design and licensing bases. The team also observed the performance of a monthly surveillance test, and reviewed past surveillance test results, to ensure the EDG and its mechanical support systems were operating as designed. The team discussed the design, operation, and maintenance of the EDG and its support systems with the system engineer to gain an understanding of the performance history, maintenance and overall component health of the EDG and its mechanical support systems. Finally, condition reports and system health reports were reviewed to verify that deficiencies were appropriately identified and resolved, and that the EDG and associated mechanical support systems were properly maintained.

b. Findings

No findings of significance were identified.

.2.1.13 Reactor Core Isolation Cooling Injection (RCIC), BD-HV-F013, Core Spray Injection, BE-HV-F005A, and Residual Heat Removal (RHR) Heat Exchanger Bypass, BC-HV-F048B Motor Operated Valves (3 samples)

a. Inspection Scope

The team inspected the RCIC injection, core spray injection, and RHR heat exchanger bypass motor operated valves (MOV) to verify that they were capable of performing their design basis functions. The team reviewed the UFSAR, design basis documents, drawings, and procedures to identify the design basis requirements of each valve. The team also verified that the standby alignment of each MOV was consistent with the design and licensing bases assumptions. MOV testing procedures and specifications were also reviewed to verify the design basis requirements including assessment of worst case system conditions were incorporated into the test acceptance criteria and component design. The team reviewed periodic verification diagnostic test results and stroke-time test data to verify acceptance criteria were met.

The team verified the MOV safety functions, performance capabilities, torque switch configuration and design margins were adequately monitored and maintained for each MOV in accordance with Generic Letter (GL) 89-10 guidance. MOV diagnostic test frequency bases were reviewed to verify that they were properly established in accordance with GL 96-05. The team also reviewed evaluations and corrective actions performed on these MOVs to address thermal binding and pressure locking phenomena, as required by GL 95-07. The team reviewed MOV weak link calculations to ensure the ability of the MOVs to remain structurally functional during design basis events. The team reviewed motor data, degraded voltage conditions, thermal overload configuration, and voltage drop calculations to confirm that the MOVs would have sufficient voltage and power available to perform their safety function at worst case degraded voltage conditions. The team discussed the design, operation, and maintenance of the MOVs with engineering staff to gain an understanding of performance history, maintenance and overall component health. The team also conducted walkdowns of the core spray injection valve, as well as the RHR heat exchanger bypass valve, to assess the material condition of the MOVs, and to verify the installed configurations were consistent with the plant drawings, and the design and licensing bases. Finally, condition reports and system health reports were reviewed to verify that deficiencies were appropriately identified and resolved, and that the MOVs were properly maintained.

b. Findings

No findings of significance were identified.

.2.1.14 Main Steam Isolation Valve AB-HV-F022A

a. Inspection Scope

The team reviewed the 'A' inboard main steam isolation valve (MSIV) to verify that it was capable of performing its safety related function during design basis events. The team reviewed the UFSAR, design basis documents, drawings, and procedures to identify the design basis requirements of the MSIV. MSIV testing procedures and specifications were also reviewed to verify the design basis requirements were appropriately incorporated into the test acceptance criteria and component design. The team reviewed a sample of stroke-time test data and local leak rate test results to verify acceptance criteria were met. The team also reviewed leakage test data associated with the pneumatic accumulator check valves, to ensure that the check valves could successfully perform their design basis function. The team discussed the design, operation, and maintenance of the MSIV with engineering staff to gain an understanding of the performance history, maintenance and overall component health. Finally, condition reports and system health reports were reviewed to verify that deficiencies were appropriately identified and resolved, and that the MSIVs were properly maintained.

b. Findings

No findings of significance were identified.

.2.1.15 Standby Liquid Control Pump BH-P-208B

a. Inspection Scope

The team reviewed the 'B' standby liquid control (SLC) pump to verify that it was capable of performing its safety related function during design basis and anticipated transients without scram (ATWS) events. The team reviewed the UFSAR, design basis documents, drawings, and procedures to identify the most limiting requirements for the

SLC pump. SLC test procedures and specifications were also reviewed to verify that requirements for the most-limiting ATWS event were appropriately incorporated into the test acceptance criteria. The team reviewed a sample of surveillance test results to verify that acceptance criteria were met. The team also verified that proper maintenance was being performed on the SLC pump. The team reviewed calculations for net positive suction head (NPSH), discharge piping head loss, and SLC system transport time to ensure that the pump could successfully inject into the reactor vessel for the most limiting ATWS event. The team discussed the design, operation, and maintenance of the SLC pump with engineering staff to gain an understanding of the performance history, maintenance and overall component health. Additionally, condition reports and system health reports were reviewed to verify that deficiencies were appropriately identified and resolved and that the SLC pump was properly maintained.

b. Findings

No findings of significance were identified.

.2.2 Detailed Operator Action Reviews (4 samples)

The team assessed manual operator actions and selected a sample of four operator actions for detailed review based upon risk significance, time urgency, and factors affecting the likelihood of human error. The operator actions were selected from a probabilistic risk assessment (PRA) ranking of operator action importance based on risk reduction worth (RRW) and risk achievement worth (RAW) values. The non-PRA considerations in the selection process included the following factors:

- Margin between the time needed to complete the actions and the time available prior to adverse reactor consequences;
- Complexity of the actions;
- Reliability and/or redundancy of components associated with the actions;
- Extent-of-actions to be performed outside of the control room;
- Procedural guidance to the operators; and
- Amount of relevant operator training conducted.

.2.2.1 Operators Bypass the Main Steam Isolation Valves (MSIVs) Low Level Interlock at Level 1 (-129") During an Anticipated Transient Without Scram (ATWS)

a. Inspection Scope

The team inspected the operator actions associated with bypassing the MSIVs low level interlock at reactor pressure vessel (RPV) level 1 during an ATWS scenario consistent with PSEG's Hope Creek Human Reliability Analysis (HRA). The team reviewed applicable emergency operating procedures (EOPs) to verify that the procedure cues were as described in the Hope Creek HRA and observed an operating crew direct the actions to bypass the MSIV low level interlock at the appropriate procedure step during an ATWS simulator exercise. Additionally, the team observed operators and technicians walkthrough procedures HC.OP-EO.ZZ-0301, Bypassing MSIV Isolation Interlocks, and

HC.OP-EO.ZZ-0311, Bypassing Primary Containment Instrument Gas Isolation Interlocks. The team verified that PSEG maintained EOP equipment lockers to facilitate rapid EOP electrical jumper installation and in-field operations, and assessed the likelihood of success with respect to bypassing the MSIV low level interlock prior to RPV level falling below level 1.

b. Findings

No findings of significance were identified.

.2.2.2 Operators Inhibit the Automatic Initiation of the Automatic Depressurization System (ADS) During an ATWS

a. Inspection Scope

The team inspected the operator action to inhibit the automatic initiation of ADS during an ATWS scenario consistent with the Hope Creek HRA. The team reviewed applicable EOPs to verify that the procedure cues were as described in the Hope Creek HRA and observed an operating crew inhibit ADS during an ATWS simulator exercise. The team verified that simulator scenarios included inhibiting ADS as an objective task, verified that job performance measures included inhibiting ADS, and interviewed simulator instructors regarding operator performance related to inhibiting ADS during simulator evaluations. The team also verified that PSEG functionally tested the ADS inhibit switches at each refueling outage consistent with technical specification requirements. Finally, the team verified that PSEG maintained the ADS inhibit switch keys readily available at the main control room panel and provided a posted procedure for ADS/Safety Relief Valve operation during transient plant conditions which included procedure steps to manually inhibit ADS.

b. Findings

No findings of significance were identified.

.2.2.3 Operators Restore Vital Alternating Current (AC) Switchgear Room Cooling

a. Inspection Scope

The team inspected the operator actions to restore vital AC switchgear room cooling with alternate ventilation equipment. The team walked down the alternate ventilation lineup with an operator and observed the alternate ventilation equipment storage locations. The team verified that the fire protection and security departments were knowledgeable of their support and participation in establishing the alternate ventilation lineups. Finally, the team assessed alternate ventilation contingencies for other areas of the plant considered in calculation 317046, Hope Creek Generating Station Room Heatup Calculations.

b. Findings

No findings of significance were identified.

.2.2.4 Operators Emergency Depressurize the Reactor Pressure Vessel (RPV) and Align Both Safety Auxiliaries Cooling System (SACS) Heat Exchangers to a Single Service Water Pump

a. Inspection Scope

The team inspected the operator actions associated with a control room action to emergency depressurize (ED) the RPV for a loss of all high pressure injection makeup sources and a field action to align both loop A and loop B SACS heat exchangers to a single service water pump during a loss-of-power scenario. These operator actions were considered a dependent operator action in the Hope Creek HRA. The team reviewed applicable EOPs and abnormal operating procedures to verify that the procedure cues were as described in the Hope Creek HRA and observed an operating crew manually initiate ADS and ED during a loss of all high pressure injection simulator exercise. The team verified that simulator guides included a task objective to ED based on inability to maintain RPV level above level 1. The team also observed that PSEG maintained a posted procedure for ADS/Safety Relief Valve operation during transient plant conditions which included procedure steps to ED by manually initiating ADS or opening safety relief valves. Finally, the team walked down the SACS heat exchangers and assessed the feasibility to manually operate large service water motor operated valve handwheels and align a single service water pump to both SACS heat exchangers within the time constraints considered in the Hope Creek HRA.

b. Findings

No findings of significance were identified.

.2.3 Review of Industry Operating Experience and Generic Issues (3 samples)

The team reviewed selected operating experience issues for applicability at the Hope Creek Generating Station. The team performed a detailed review of the operating experience issues listed below to verify that PSEG had appropriately assessed potential applicability to site equipment and initiated corrective actions when necessary.

.2.3.1 NRC Information Notice 2001-13, Inadequate Standby Liquid Control Relief Valve Margin

a. Inspection Scope

The team reviewed PSEG's Standby Liquid Control (SLC) system relief valve margin to verify the ability of SLC to perform its required function under the most limiting anticipated transient without scram (ATWS) event, including the effects of Extended Power Uprate (EPU) conditions. The team reviewed the SLC pump vendor specifications, surveillance test performance history for the pump and relief valve, system relief valve setpoints, system discharge piping head loss calculations, and the EPU safety evaluation for the most limiting ATWS event, to verify the ability of the SLC pump to perform its required function. The team also reviewed relief valve bench test data to verify that the relief valve setpoints were properly adjusted, and that the relief valves were functioning as designed. Finally, the team discussed SLC pump and valve test performance history with engineering staff to assess the adequacy of the SLC relief valve margin.

b. Findings

No findings of significance were identified.

.2.3.2 NRC Information Notice 1997-90, Use of Nonconservative Acceptance Criteria in Safety-Related Pump Surveillance Tests

a. Inspection Scope

The team evaluated PSEG's applicability review and disposition of NRC IN 97-90. The NRC issued this IN to inform licensee's of instances where IST requirements had been satisfied for pumps without ensuring that design requirements were met. As a result, some plants had allowed safety related pumps to degrade below the performance assumed in the accident analyses. The team reviewed this potential condition for a sample of safety related pumps included in this inspection. The team reviewed specific calculations that addressed IST acceptance criteria and performed interviews with engineering personnel to verify that the testing criteria would ensure pump performance assumed in the design analyses.

b. Findings

No findings of significance were identified.

.2.3.3 Generic Letter (GL) 2006-02, Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power

The team reviewed PSEG's response to GL 2006-002 to assess its thoroughness and accuracy. The team compared the response to grid studies, operating procedures, interface agreements, and electrical distribution system calculations to determine whether the responses to the NRC were complete and consistent with station practices.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA2 Identification and Resolution of Problems (IP 71152)

The team reviewed a sample of problems that PSEG had previously identified and entered into the corrective action program. The team reviewed these issues to verify an appropriate threshold for identifying issues and to evaluate the effectiveness of corrective actions. In addition, notifications written on issues identified during the inspection were reviewed to verify adequate problem identification and incorporation of the problem into the corrective action system. The specific corrective action documents that were sampled and reviewed by the team are listed in the attachment.

b. Findings

No findings of significance were identified.

4OA6 Meetings, Including Exit

The team presented the inspection results to Mr. J. Perry, Site Vice President, and other members of PSEG's staff, at an exit meeting on October 9, 2009. The team verified that none of the information in this report is proprietary.

ATTACHMENT

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

A. Bhuta	Electrical Design Engineer
R. Binz	IST Program Manager
J. Boyer	Manager, Design Engineering
A. Bready	Risk Engineer
E. Casuilli	Shift Operations Superintendent
V. Chandra	Principal Nuclear Engineer
J. Dower	Senior Reactor Operator
P. Duca	Regulatory Assurance Engineer
A. Faulkner	Operations Training Instructor
M. Fowler	Senior Manager, Design Engineering
A. Ghose	Structural Engineer
A. Hak	Electrical Plant Engineer
M. Khan	Electrical Design Engineer
J. Lane	Electrical Design Engineer
J. Moss	Structural Engineer
K. Petroff	Electrical Plant Engineer
D. Schiller	Electrical Plant Engineer
K. Torres	System Manager

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened and Closed

NCV	05000354/2009007-01	Non-conservative input used in Design Calculation For DC Control Voltage for 4 kV Switchgear (1R21.2.1.1)
NCV	05000354/2009007-02	EDG Overhead Cranes Not Seismically Restrained (1R21.2.1.2)
NCV	05000354/2009007-03	Inadequate Design Control for 4 kV Bus Degraded Voltage Relay Bases (1R21.2.1.3)

Opened

URI	05000354/2009007-04	Degraded Voltage Protection Scheme Design

LIST OF DOCUMENTS REVIEWED

Calculations and Evaluations:

1EGHV-2395A,B,C,D Air Operated Valve (AOV) Capacity Evaluation, Rev. 2
A-5-500-E4C-0-1930, 500kV and 4.16kV Systems Voltage Drop Due to Unit Trip, Rev. 0
AP-0004, Condensate Storage Tank Level Set Points – EPU, Rev. 8
BC-0056, RHR Hydraulic Analysis, Rev. 5
BH-0002, Standby Liquid Control Suction Line System Pressure Drop, Rev. 3
BH-0003, SLC System Discharge Piping Pressure Drop and Transport Time, Rev. 3
D7.5, Hope Creek Generating Station Environmental Design Criteria, Rev. 21
E-1.1, Short Circuit Studies of 13.8, 7.2, and 4.16kV Systems, Revision 7A
E-1.3, Hope Creek Generating Station Short Circuit Study of 480V Systems, Revision 3B
E-1.4, 125 & 250 VDC Systems Short Circuit and Voltage Drop Studies, Rev. 5
E-2.6, Class 1E 4.16kV Switchgear, Revision 0
E-4.1, 125 VDC Battery & Charger Sizing, Rev. 16
E-4.2, DC Equipment & Component Voltage Study, Rev. 3
E-5.1, 250 VDC Battery & Charger Sizing, Rev. 7
E-7.13, Penetration Assembly Protection, Revision 4
E-7.13A, Short Circuit Study of Penetration Assembly & Pen. Conductor, Rev. 1
E-7.3, Station Service Transformer & 13.8kV Feeder Differential Protection, Rev. 2
E-7.4, Class 1E 4.16kV System Protective Relay Settings, Rev. 0
E-7.7, Class 1E480V System Protecting Relaying, Rev. 0
E-8.3, HCGS 13.8-7.2kV and 13.8-4.16kV Station Service Transformer Sizing, Rev.9
E-8.4, Hope Creek Transformer Tap-changer Settings, Rev. 1
E-9, Standby Diesel Generator Sizing, Rev. 8
E-10.1, Medium Voltage Cable Ampacity-Cable Sizing, Rev. 1
E-10.2, 600V Voltage Cable Ampacity, Rev. 1
E-15, Load Flow Study, Rev. 8
E-15.1, Hope Creek Degraded Voltage Analysis, Rev. 7
E-15.5, Hope Creek Fast Bus Transfer Analysis, Rev. 4
E-17B, Voltage Drop for 125V DC Control Circuit, Rev. 0
E-17C, 125 VDC Control Circuit lengths for DC MCC Starters, Rev. 1
E-17D, 125 VDC Voltage Drop from Distribution panel to Load, Rev. 4
E-17F, Hope Creek Generating Station Maximum Circuit Length for 120VAC Panel Control Circuits, Rev. 3
EA-0003, Station Service Water Hydraulic Analysis, Rev. 10
EG-0010, SACS Pump Runout Trip Setpoint/NPSH Evaluation, Rev. 3
EG-0020, SACS Required Flows and Heat Loads, EPU, Rev. 10
EG-0046, SACS Operation, Rev. 7
EG-0047, HCGS Ultimate Heat Sink Temperature Limits, EPU, Rev. 5
GM-0001, Aux Building EDG Area HVAC, Coil Selection and Power Requirements, Rev. 7
GM-0027, Diesel Generator Area HVAC Analysis, Rev. 1
H-1-AB-MDC-1312, MSIV Performance After a Postulated Pipe Break – EPU, Rev. 4
H-1-BC-MDC-0922, MOV Capability Assessment for 1BC-HV-FO48B, Rev. 0
H-1-BE-MDC-0924 Sh. 7, AC Motor Operated Gate Valve Calculation for 1BE-HV-F005A, Rev. 1

H-1-FD-MDC-0941 Sh. 6, AC Motor Operated Gate Valve Calculation for 1FD-HV-F075, Rev. 1
H-1-GX-NEE-0882, Room Heatup After Abnormal Loss of Cooling, Rev. 0
H-1-SA-MEE-1747 Attachment 1, Assessment of Hope Creek Suppression Pool Water Temperature During Anticipated Transient Without Scram Event, Rev. 0
H-1-PB-E4C-0-1832, Engineering Evaluation for Justification of Upper and Lower Voltage Limits at 4.16kV Vital Buses for Hope Creek Generating Station, Rev. 6
JE-0004, Diesel Fuel Oil Storage Tank Physical Capacity, Rev. 1
JE-0013, Volume of Diesel Fuel Oil Day Tank at Level Alarm and Control Setpoints, Rev. 4
JE-0015, Diesel Fuel Oil Storage Capacity Design Basis, Rev. 2A
NC.DE-AP.ZZ-0002, HCGS 13.8-7.2 and 13.8-4.16Kv Station Service Transformer Sizing, Rev. 9
SC-PB-0002, Hope Creek 4 kV Viltage Bus Degraded Grid Relay Setpoint/Accuracy, Rev. 2
MIDACALC Results, Core Spray Injection Valve BE-HV-F005A
MIDACALC Results, Reactor Core Isolation Cooling Injection Valve BE-HV-F013
317046, Hope Creek Generating Station Room Heatup Calculations, Rev. 0
677-0043, II/I Review of Lighting Fixture Supports, Rev. 3

<u>Completed Surveillance, Maintenance and Modification Testing:</u>

50109440, Class 1E 4.16 KV Feeder Degraded Voltage 18 Month Instrumentation Channel Calibration & Functional Test 10A-40208, (4/13/09)
50124059, Class 1E 4.16 KV Feeder Degraded Voltage Monthly Instrumentation Channel Functional Test, (7/15/09)
50124907, Class 1E 4.16 KV Feeder Degraded Voltage Monthly Instrumentation Channel Functional Test, (8/11/09)
50125562, Class 1E 4.16 KV Feeder Degraded Voltage Monthly Instrumentation Channel Functional Test, (9/08/09)
HC.IC-FT.PE-0006, Time Interval Test of Emergency Load Sequencer, (4/18/09)
HC.MD-ST.PK-0002, B 125 VDC Battery Quarterly Surveillance, (08/06/00, 4/11/09, and 7/12/09)
HC.MD-ST.PK-0006, B 125 VDC Battery Performance Discharge Test, (4/14/06)
HC.MD-ST.PK-0007, B 125 VDC Battery Service Test, (4/14/09)
HC.MD-ST.PJ-0002, B 250 VDC Battery Quarterly Surveillance, (4/19/09 and 10/12/07)
HC.MD-ST.PJ-0007, B 250 VDC Battery Performance Discharge Test, (4/20/09)
HC.MD-ST.PJ-0008, B 250 VDC Battery Service Test, (10/25/07)
HC.OP-IS.AB-0102, Main Steam System Valves, Cold Shutdown In-service Test, (4/26/09 and 11/06/07)
HC.OP-IS.AB-0103, MSIV Loss of Power Cold Shutdown In-service Test, (04/25/09, and 11/06/07)
HC.OP-IS.BC-0102, Residual Heat Removal Valves, In-service Test, (5/16/09)
HC.OP-IS.BD-0101, RCIC System Valves, In-service Test, (6/15/09)
HC.OP-IS.BE-0101, Core Spray Subsystem 'A' Valves, In-service Test, (8/06/09)
HC.OP-IS.BH-0004, Standby Liquid Control Pump BP208 In-service Test, (6/10/09 and 9/13/09)
HC.OP-IS.EA-0101, Service Water Subsystem 'A' Valves, In-service Test, (7/10/09)
HC.OP-IS.EA-0102, Service Water Subsystem 'B' Valves, In-service Test, (9/18/09)
HC.OP-ST.BC-0009, Residual Heat Removal System RHR Heat Exchanger Flow Measurement 18 Month, (4/08/09)

HC.OP-ST.HJ-0015, 'B' EDG 24 Hour Operability Run & Hot Restart Test, (10/16/08)
HC.OP-ST.KJ-0001, 'A' EDG Monthly Operability Test, (7/28/09 and 9/28/09)
HC.OP-ST.KJ-0006, Integrated EDG 1BG400 18 Month Test, (4/13/09)
HC.OP-ST.KJ-0014, 'A' EDG 24 Hour Operability Run and Hot Restart, (12/31/08)
STP-M-552-2, 21 Station Battery Service Test (2/8/00, 2/5/02, 5/27/04, 5/30/06, and 6/11/08)

Corrective Action Documents:

20173531	20288802	20434501*	20434625*
20326537	20306838	20433669*	20433754*
20327966	20357556	20434370*	20434350*
20332439	20367163	20431806*	20434346*
20346702	20430696	20431904*	20434337*
20348328	20430830	20432031*	20434047*
20355504	20431245	20433513*	20434032*
20360844	20431416	20433038*	20433727*
20374451	20432492*	20433040*	20433726*
20380141	20433162*	20433806*	20432023*
20381172	20434204*	20433948*	20416966
20381990	20434213*	20434052*	60080750
20405808	20434650*	20434241*	70058747
20407168	70062868	20434256*	70069859
20103992	80095526	20434517*	70071884
20273576	20434488*	20434520*	70074989
20282182	20434494*	20434541*	

* CR written as a result of inspection effort

Drawings:

731E779, Core Spray Sparger, Sht. 1 & 2, Rev. 6
93-14206, 6"-900 Flex Wedge Gate Valve (BD-HV-F013) with SMB-0-25 Operator, Rev. D
93-14363, 12"-900 Flex Wedge Gate Valve (BE-HV-F005A) with SB-3-100 Operator, Rev. C
C-0926-0, Containment Vessel Requirements, Rev. 14
C-0927-0, Containment Vessel Requirements, Rev. 14
C-0928-0, Containment Vessel Requirements, Rev. 11
D-11226-1, One Line Diagram 10 KVA Vital Bus UPS, Rev. E
DS-C-60902, Vacuum Relief Valve, Rev. D
E-3060-0, Logic Diagram Class 1E Station Pwr Swgr. – 4.16 kV System Main Circuit Breaker, Rev. 16
E-0001-0-24, Hope Creek Generating Station Single Line Diagram Station, Rev. 24
E-0002-1 Sht. 1, Single Line Meter & Relay Diagram Power System, Rev. 12
E-0005-1 Sht. 1 & 2, Single Line Meter & Relay Diagram 4.16 kV Station Power System, Rev. 9
E-0006-1 Sht. 1, Single Line Meter & Relay Diagram 4.16 kV Class 1E System, Rev. 11
E-0018-1 Sh. 1, Single Line Meter & Relay Diagram Class 1E Unit Substation 10B410, 10B420, 10B430, 10B440, 10B450, 10B460, 10B470, 10B480, Rev. 33
E-0047-1, Schematic Meter & Relay Diagram Station Power System Switchgears 10A402 & 10A404, Rev. 7

E-0068-0, Electrical Schematic Diagram Class 1E 4.16kV Sta Pwr Sys Swgr Main Circuit Breaker (1)52-40108, Rev. 10
E-0069-0, Electrical Schematic Diagram Class 1E 4.16kV Sta Pwr Sys Swgr Main Circuit Breaker (1)52-40101, Rev. 8
E-0070-0, Electrical Schematic Diagram Class 1E 4.16kV Sta Pwr Sys Swgr Main Circuit Breaker (1)52-40201, Rev. 8
E-0071-0, Electrical Schematic Diagram Class 1E 4.16kV Sta Pwr Sys Swgr Main Circuit Breaker (1)52-40108, Rev. 8
E-0077-0, Electrical Schematic Diagram Class 1E – 4.16kV Unit Substa. Xfmr. Feeder Circuit Breaker (1)52-40210, Rev. 5
E-0081-0, Electrical Schematic Diagram Class 1E – 4.16kV Unit Substa. Xfmr. Feeder Circuit Breaker (1)52-40203, Rev. 5
E-0085-0, Electrical Schematic Diagram Class 1E – 4.16kV Diesel Gen Circuit Brkr (1)52-40207, Rev. 11
E-0106-0 Sht. 3, Electrical Schematic Diagram Class 1E 4.16kV Station Power System Bus A40 & A402 Undervoltage Protection, Rev. 11
E-0208-0 Sht. 1, Electrical Schematic Diagram 4.16kV Circuit Breaker Control Station Service Water Pump, Rev. 13
E-0217-0 Sht. 1, Electrical Schematic Diagram 4.16kV Circuit Breaker Control Safety Auxiliaries Cooling Pump, Rev. 4
E-6025-0, Electrical Schematic Diagram Core Spray Reactor Isolation Valves, Rev. 4
E-6076-0 Sht.1, Electrical Schematic Diagram High Pressure Coolant Injection System Vacuum Breaker Isolation Valve, Rev. 3
E-6231-0 Sht. 2, Electrical Schematic Diagram Residual Heat Removal System HX Shell Side Bypass Valve 1HV-F048A, Rev. 5
E-6442-0, Electrical Schematic Diagram 4.16kV Circuit Breaker Control Core Spray Pumps, Rev. 6
E-6443-0, Electrical Schematic Diagram 4.16kV Circuit Breaker Control RHR Pump 1BP202, Rev. 8
J-00-0 Sht. 1, Logic Diagram Standard Symbols, Rev. 12
J-10-0 Sht. 4, Logic Diagram Station Service Water System, Rev. 14
J-51-0 Sht. 7, Logic Diagram Residual Heat Removal, Rev. 8
J-55-0 Sht. 3, Logic Diagram High Pressure Coolant Injection, Rev. 7
M-10-1, Sht. 1, Service Water, Rev. 52
M-12-1, Sht. 1, Safety Auxiliary Cooling, Rev. 31
M-30-1, Sht. 2, Diesel Engine Auxiliary Cooling, Rev. 20
M-48-1, Sht. 1, Standby Liquid Control, Rev. 11
M-49-1, Sht. 1 & 2, Reactor Core Isolation Cooling, Rev. 12
M-50-1, Sht. 1, Reactor Core Isolation Cooling Pump Turbine, Rev. 19
M-51-1, Sht. 1, Residual Heat Removal, Rev. 38
M-52-1, Sht. 1, Core Spray, Rev. 20
PM018-0354, Sht. 8, EDG Local PT & Exciter Control Panel 1AC420 Schematic, Rev. 14
PM018-0366, Sht. 1, EDG Engine Control Schematic, Rev. 18
PM065-0066, Diesel Generator Underhung Cranes, Rev. 1
PM065-0270, Sht.1, Installation & Utilization of Seismic Anchors, Rev. 0

Miscellaneous:

10855-D4.10, General Plant Design Criteria for Protective Relaying for the Hope Creek Generating Station, Rev. 3
NRC Branch Technical Position PSB-1, Adequacy of Station Electrical Distribution System, July 1981
Core Spray System Health Report, 4th Quarter 2007 – 2nd Quarter 2009
DEH-09-0141, Order 70060139, HPCI Steam Exhaust Piping Water Hammer Analysis, (10/06/09)
DEH-09-0141, Attachment 4, Evaluation of HPCI Turbine Exhaust FD-V004 Check Valve Disc (10/05/09)
EDG System Health Report, 1st Quarter 2009
Fairbanks Morse Letter to Hope Creek Re: Lube Oil Header Pressure and Strainer Differential Pressure, (3/26/09)
Hope Creek Open Low Margin Issues, (7/22/09)
IST Program Data Sheet, 1FDPSV-F076, HPCI Turbine Exhaust Vacuum Breaker
LR-N06-0132, Hope Creek Generating Station Response to NRC Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk And The Operability of Offsite Power"
LR-N07-007, Hope Creek, Response to the Request for Additional Information Regarding Resolution of NRC Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power"
Main Steam System Health Reports, 1st Quarter 2009, 2nd Quarter 2009
Midas MOV Periodic Verification Testing MOV Report per Generic Letter 96-05
NEDC-33076P, GE Safety Analysis Report for Hope Creek Constant Pressure Power Uprate, August 2006
NRC Information Notice 1987-10, Potential for Water Hammer During Restart of Residual Heat Removal Pumps
NRC Information Notice 1987-10, Supplement 1, Potential for Water Hammer During Restart of Residual Heat Removal Pumps
NRC Information Notice 2001-13, Inadequate Standby Liquid Control System Relief Valve Margin
NRC Information Notice 2006-26, Failure of Magnesium Rotors in MOV Actuators
NRC Regulatory Guide 1.9, Application and Testing of EDGs, March 2007
NRC Regulatory Guide 1.29, Seismic Design Classification, Rev. 3
NRC SRP Section 9.5.6, Diesel Generator Starting System, May 1975
Operability Evaluation 09-007, H1EG-EG-HV-2395A, (6/03/09)
SG-168, LOCA Level Control Training, (6/17/09)
SG-609, Variable ATWS, (7/21/09)
SG-613, LOCA Demonstration/Recirculation Pump Dual Seal Failure/LOCA with Downcomer Failure, (5/27/09)
SG-657, OHA Response, Circulating Water Pump Trip/Drywell Leakage Resulting in a LOCA, (7/30/09)
SLC Pump BH-1B-P-208 Oil Analysis Report, (5/26/06 and 9/25/09)
SLC System Health Reports, 1st Quarter 2009, 2nd Quarter 2009
Technical Evaluation 366472 Ultra Low Sulfur Diesel Fuel Evaluation, (6/27/07)
Technical Evaluation CRCA 70102449 OP 0010, Calculation E-15.1 Deficiency Evaluation
Technical Evaluation 70076510-0070 for RHR Heat Exchanger Bypass Valve Flow Coefficients

Technical Evaluation 80100085 for MSIV Stroke Time Issue
Technical Evaluation 70102445-0050, Diesel Generator Underhung Crane Seismic II/I, Evaluation, (9/29/09)
UFSAR Table 9.1-10, Overhead Heavy Load handling Systems Data Summary, Rev. 17
UFSAR Section 1.8.1.29, Conformance to Regulatory Guide (RG) 1.29, Seismic Design Classification, Rev. 0
UFSAR Section 8.3.1.1.3.10, Loading of EDGs, Rev. 17
Vendor Manual, PE002-0080, Station Service Transformer, Rev. 10

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DCR 80091864, RHR Hydraulic Analysis and Associated 50.59 Screening HC-07-192, Rev. 0
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80002367, Equivalency of GE Relay Types CR120B

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ER-AA-2030, Conduct of Plant Engineering, Rev. 8
ER-AA-302-1006, Generic Letter 96-05 Program Motor Operated Valve Maintenance and Testing Guidelines, Rev. 10
ER-HC-321-1101, Testing of Hope Creek ASME Code 1, 2 and 3 Safety/Relief Valves, Rev. 0
HC.MD-ST.PB-0003(Q), Class 1E 4.16 KV Feeder Degraded Voltage Monthly Instrumentation Channel Functional Test, Rev. 25
HC.MD-CM.BH-0001, Standby Liquid Control Injection Pump Overhaul, Rev. 10
HC.MD-CM.KJ-0001, Diesel Engine Overhaul, Rev. 19
HC.MD-PM.FD-0001(Q), High Pressure Coolant Injection (HPCI) Steam Turbine Inspection and PM, Rev. 23
HC.MD-ST.AB-0001, MSIV Closure Trip Channel 18 Month Calibration, Rev. 23
HC.MD-PM.ZZ-0001(Z), Oil Filled Transformer PM, Rev. 7
HC.MD-PM.ZZ-0008(Q), Preventive Maintenance of Dry-Type Transformers, Rev. 6
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HC.OP-AB.ZZ-0001, Transient Plant Conditions, Rev. 19
HC.OP-AB.COOL-0001, Station Service Water, Rev. 17
HC.OP-AB.COOL-0002, Safety Turbine Auxiliaries Cooling System, Rev. 5
HC.OP-AB.HVAC-0001, HVAC, Rev. 5
HC.OP-AB.ZZ-0171(Q), Loss of 4.16kV Bus 10A402 B Channel, Rev. 7
HC.OP-AR.KJ-0001, Jacket Water Temperature High, Rev. 20
HC.OP-AR.ZZ-0006, Condensate Storage Tank Level Lo, Rev. 25
HC.OP-AR.ZZ-0010, Temporary Battery Room Temperature/Hydrogen Control, Rev. 1
HC.OP-AR.ZZ-0023, HPCI Condensate Storage Tank Lo Lvl D3341, Rev. 6
HC.OP-EO.ZZ-0101, Reactor/Pressure Vessel (RPV) Control, Rev. 11
HC.OP-EO.ZZ-0101A, ATWS RPV Control, Rev. 3
HC.OP-EO.ZZ-0102, Containment Control, Rev. 12
HC.OP-EO.ZZ-0202, Emergency Depressurization, Rev. 7
HC.OP-EO.ZZ-0301, Bypassing MSIV Isolation Interlocks, Rev. 6
HC.OP-EO.ZZ-0311, Bypassing Primary Containment Instrument Gas Isolation Interlocks, Rev. 7

HC.OP-EO.ZZ-0319, Restoring Instrument Air in an Emergency, Rev. 2
HC.OP-SO.BC-0001, Residual Heat Removal System Operation, Rev. 45
HC.OP-SO.BH-0001, Standby Liquid Control System Operation, Revision 10
HC.OP-ST.BC-0005, LPCI Subsystem 'B' ECCS Time Response Functional Test, Rev. 14
HC.OP-SO.PB-0001(Q), 4.16kV System Operation, Rev. 25
HC.OP-ST.PB-0002(Q), AC Power Supply Transfer Functional Test -18 Months, Rev. 11
HC.OP-ST.BD-0003, RCIC Function Verification – 18 Months, Rev. 15
HC.OP-ST.BD-0004, RCIC Flow Verification – 18 Months, Rev. 4
HC.OP-ST.BE-0002, Core Spray Loop 'A' ECCS Time Response Test – 18 Months, Rev. 17
HC.OP-ST.KJ-0006, Integrated EDG 1BG400 18 Month Test, Rev. 35

Vendor Manuals & Specifications:

VTD 324671, C&D 125 VDC Battery, (8/14/00)
VTD 317103(25)-01, Weak Link Calculation for MOV BE-HV-F005A
VTD 323835, Hope Creek Containment Analysis with 100-degree-fahrenheit SACS Temperature
VTD 430024, Volume 1, EPU DIR T0400 – Containment System Response, (11/16/05)
VTD PM 018Q-0499, Vol. 3, drawing 11 909 835, Specification for EDG Lube Oil Pressure, Temperature, and Filter Differential Pressure, (1/30/79)
VTD PN1-B21-F022-0049, Main Steam Isolation Valve Vendor Manual, (12/10/92)
VTD PN1-C41-C001-0029, Standby Liquid Control Pump Vendor Manual, (11/29/95)

Work Orders:

50045161	50044510	50065569
50044548	50081102	50065762
50045233	50020906	990105160

LIST OF ACRONYMS

AC	Alternating Current
ADS	Automatic Depressurization System
ATWS	Anticipated Transient Without Scram
CFR	Code of Federal Regulations
CR	Condition Report
DC	Direct Current
DVR	Degraded Voltage Relay
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
EPU	Extended Power Uprate
HCGS	Hope Creek Generating Station
HPCI	High Pressure Coolant Injection
HRA	Human Reliability Analysis
IMC	Inspection Manual Chapter
IN	Information Notice

IP	Inspection Procedure
IST	In-service Testing
kVA	Kilo-Volt-Amperes
kV	Kilo-Volts
kW	Kilo-Watts
LOCA	Loss-of-Coolant Accident
LOOP	Loss-of-Offsite Power
MCC	Motor Control Center
MOV	Motor Operated Valve
MSIV	Main Steam Isolation Valve
NCV	Non-cited Violation
NPSH	Net Positive Suction Head
NRC	Nuclear Regulatory Commission
PRA	Probabilistic Risk Assessment
RAW	Risk Achievement Worth
RCIC	Reactor Core Isolation Cooling
RHR	Residual Heat Removal
RPV	Reactor Pressure Vessel
RRW	Risk Reduction Worth
SACS	Safety Auxiliaries Cooling System
SBO	Station Blackout
SDP	Significance Determination Process
SLC	Standby Liquid Control
SPAR	Standardized Plant Analysis Risk
SSE	Safe Shutdown Earthquake
TE	Technical Evaluation
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
Vac	Volts, Alternating Current
Vdc	Volts, Direct Current