**UNITED STATES**
**NUCLEAR REGULATORY COMMISSION**
REGION I
2100 RENAISSANCE BLVD., SUITE 100
KING OF PRUSSIA, PA 19406-2713

May 13, 2014

EA-14-050

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 UNIT 1 – NRC INTEGRATED INSPECTION REPORT AND EXERCISE OF ENFORCEMENT DISCRETION 05000354/2014002

Dear Mr. Joyce:

On March 31, 2014, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Hope Creek Generating Station (HCGS). The enclosed inspection report documents the inspection results, which were discussed on April 17, 2014, with Mr. P. Davison, Site Vice President of Hope Creek, and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

This report documents six violations of NRC requirements, all of which were of very low safety significance (Green). However, because of the very low safety significance, and because they are entered into your corrective action program, the NRC is treating these findings as non-cited violations, consistent with Section 2.3.2.a of the NRC Enforcement Policy. If you contest the non-cited violations in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at HCGS. In addition, if you disagree with the cross-cutting aspect assigned to any finding, or a finding not associated with a regulatory requirement 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 HCGS.

Additionally, as we informed you in the most recent NRC integrated inspection report, cross-cutting aspects identified in the last six months of 2013 using the previous terminology were being converted in accordance with the cross-reference in Inspection Manual Chapter 0310. Section 4OA5 of the enclosed report documents the conversion of these cross-cutting aspects which will be evaluated for cross-cutting themes and potential substantive cross-cutting issues in accordance with Inspection Manual Chapter 0305 starting with the 2014 mid-cycle assessment review. If you disagree with the cross-cutting aspect assigned, 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 HCGS.

Additionally, the inspectors reviewed Licensee Event Report 50-354/2013-005-00, which described the details associated with a failed solenoid operated valve associated with the pilot valve assembly for the 'P' Safety Relief Valve (SRV). The failed solenoid resulted in the inoperability of the relief valve function and the low-low set function of the 'P' SRV. This issue constitutes a violation of NRC requirements, in that PSEG operated HCGS with the 'P' SRV low-low set and relief valve functions inoperable without taking actions to restore it to operable status in accordance with Technical Specifications. However, the NRC concluded that the cause of the inoperability, a missing anti-rotation pin that secures the adjustable plunger in place, was due to a manufacturer's assembly error that could not have been identified during inspection and testing. Therefore, no performance deficiency associated with the violation was identified. The NRC performed a risk evaluation of the issue and determined it to be of very low safety significance. Based on these facts, I have been authorized, after consultation with the Director, Office of Enforcement, and the Regional Administrator, to exercise enforcement discretion and refrain from issuing enforcement for this violation.

In accordance with Title 10 of the *Code of Federal Regulations* (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 public inspection in the NRC's Public Document Room or from the Publicly Available Records component of the NRC's Agencywide Documents Access and Management System (ADAMS). ADAMS is accessible from the NRC website at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

**/RA/**

Ho K. Nieh, Director
Division of Reactor Projects

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

Enclosure: Inspection Report 05000354/2014002
w/Attachment: Supplementary Information

cc w/encl: Distribution via ListServ

in accordance with Inspection Manual Chapter 0305 starting with the 2014 mid-cycle assessment review. If you disagree with the cross cutting aspect assigned, 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 HCGS.

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Sincerely,
**/RA/**
Ho K. Nieh, Director
Division of Reactor Projects

Docket No. 50-354
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Enclosure: Inspection Report 05000354/2014002
w/Attachment: Supplementary Information

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| DATE | 05/08 /14 | 05/ 13 /14 | 05/13 /14 | 05/09 /14 | 05/ 13 /14 |

# U.S. NUCLEAR REGULATORY COMMISSION

REGION I

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|---|---|
| Docket No. | 50-354 |
| License No. | NPF-57 |
| Report No. | 05000354/2014002 |
| Licensee: | Public Service Enterprise Group (PSEG) Nuclear LLC |
| Facility: | Hope Creek Generating Station (HCGS) |
| Location: | P.O. Box 236<br>Hancocks Bridge, NJ 08038 |
| Dates: | January 1, 2014, through March 31, 2014 |
| Inspectors: | J. Hawkins, Senior Resident Inspector<br>S. Ibarrola, Resident Inspector<br>E. Burket, Emergency Preparedness Inspector<br>M. Orr, Reactor Inspector<br>B. Reyes, Project Engineer |
| Approved By: | Ho K. Nieh, Director<br>Division of Reactor Projects |

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**SUMMARY**

IR 05000354/2014002; 01/01/2014 – 3/31/2014; Hope Creek Generating Station; Maintenance Risk Assessments and Emergent Work Control, Operability Determinations and Functionality Assessments, Plant Modifications, Problem Identification and Resolution, and Follow-Up of Events and Notices of Enforcement Discretion.

This report covered a three-month period of inspection by resident inspectors and announced inspections performed by regional inspectors. Six findings of very low safety significance (Green) were identified, all of which were determined to be violations of NRC requirements. The significance of most findings is indicated by their color (i.e., greater than Green, or Green, White, Yellow, Red) and determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process (SDP)," dated June 2, 2011. Cross-cutting aspects are determined using IMC 0310, "Aspects Within the Cross-Cutting Areas," dated December 19, 2013. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy, dated July 9, 2013. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 5.

**Cornerstone: Initiating Events**

- Green. A self-revealing Green non-cited violation (NCV) of Technical Specification (TS) 6.8.1.a, "Procedures and Programs," was identified regarding PSEG failing to adequately establish, implement, and justify the initial replacement frequency for the 1DD481 inverter control circuit cards. As a result, an age-related failure of circuit cards for the safety-related 1E channel 'D' (1DD481) Inverter occurred on December 24, 2013, which caused PSEG to enter an unplanned 24 hour shutdown TS 3.8.3.1.a.4 for On-site Power Distribution Systems. PSEG's corrective actions include conducting an extensive extent of condition review of first-call preventive maintenances (PMs).

  The performance deficiency was determined to be more than minor because it was associated with the equipment performance attribute of the Initiating Events cornerstone, and adversely affected the cornerstone objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. The inspectors determined that this finding was of very low safety significance (Green) using NRC IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," Exhibit 1 – Initiating Events Screening Questions, dated June 19, 2012, because for findings involving support system initiators, i.e. the Loss of a DC [direct current] bus, the result did not involve the complete or partial loss of a support system that contributed to the likelihood of, or cause, an initiating event and affected mitigation equipment. The inspectors determined that there was no cross-cutting aspect associated with this finding because the cause of the performance deficiency occurred more than three years ago, and was not representative of present licensee performance. (Section 1R13)

**Cornerstone: Mitigating Systems**

- Green. A self-revealing Green NCV of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix B, Criterion XVI, "Corrective Actions," was identified because PSEG failed to assure that a condition adverse to quality (CAQ) was promptly identified and corrected. Specifically, PSEG did not initiate a timely notification for a potential design flaw in the operation of some 480 volt alternating current (VAC) Masterpact breaker's control logic scheme. PSEG's corrective actions included an extensive operability evaluation, compensatory measures conducted every shift by operators to ensure the operability and reliability of these breakers in the short-term, and a proposed design change to remove the design flaw in the breaker control logic by 2015.

The performance deficiency was determined to be more than minor because it was associated with the equipment performance and design control attributes of the Mitigating Systems cornerstone, and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). The inspectors determined that this finding was of very low safety significance (Green) using NRC IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," Exhibit 2 – Mitigating Systems Screening Questions, dated June 19, 2012, because although the breakers' design is affected, the operability of the breakers is maintained. The inspectors determined that the contributing cause that provided the most insight into the performance deficiency was associated with the cross-cutting aspect of Problem Identification and Resolution, Identification, because PSEG failed to identify issues completely, accurately, and in a timely manner in accordance with the corrective action program (CAP). [P.1] (Section 1R15)

- Green. A self-revealing Green NCV of TS 6.8.1.a, "Procedures and Programs," was identified for PSEG's failure to follow procedure HC.OP-SO.BH-0001, "Standby Liquid Control (SLC) System Operation," when restoring the SLC system after routine maintenance. Specifically, the licensee failed to adequately coordinate the restoration of the SLC system using the work control document (WCD) and the SLC system operating procedure which led to an incorrect SLC system lineup causing the inadvertent addition of demineralized (DI) water to the SLC storage tank. As a result, PSEG had to determine the immediate and prompt operability of the SLC system and enter the associated 8 hour SLC Technical Specification Action Statement (TSAS). PSEG's corrective actions include restoring the SLC tank concentration, briefing the operating crews on proper WCD turnover process, and addressing operator gaps in the SLC system operation that may have adversely affected the timeline and the inaccuracy of the immediate operability calculation method.

  The performance deficiency was determined to be more than minor because it was associated with the configuration control attribute of the Mitigating System cornerstone, and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, failing to follow procedure leading to configuration control issues could have rendered a safety-related system inoperable. This performance deficiency was also similar to examples 3.j and 3.k of NRC IMC 0612, Appendix E, in that the addition of 80 gallons of DI water to the SLC tank created a reasonable doubt of operability of the SLC system. The inspectors determined the finding to be of very low safety significance (Green) in accordance with IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," dated June 19, 2012." Using Exhibit 2, the inspectors determined that the finding screened as very low safety significance (Green) because although the SLC tank boron concentration was diluted, the SLC system was still capable of providing sufficient negative reactivity to shut down the reactor. The inspectors determined that the contributing cause that provided the most insight into the performance deficiency was associated with the cross-cutting aspect of Human Performance, Work Management, because PSEG failed to implement a process of planning, controlling, and executing work activities such that nuclear safety is the overriding priority. [H.5] (Section 1R15)

- <u>Green</u>. A self-revealing Green NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," was identified for PSEG's failure to adequately evaluate a modification to the design change package for replacement buckets on the Class 1E 10B232 480 VAC motor control center (MCC) in accordance with PSEG procedure CC-AA-103-1001, "Implementation of Configuration Changes." This resulted in damage to and de-energization of the 10B232 MCC during maintenance activities to install a new replacement bucket on October 28, 2013. PSEG's corrective actions included a full extent of condition inspection of all installed modified MCC buckets and removing instructions to install terminal block screws in future modifications.

  This issue was more than minor because it was associated with the design control attribute of the Mitigating Systems cornerstone, and adversely affected the cornerstone's objective to ensure the availability and reliability of systems that respond to initiating events to prevent undesirable consequences. Because this finding occurred while the plant was shut down, the inspectors used IMC 0609, Appendix G, "Shutdown Operations Significance Determination Process," dated February 28, 2005. The inspectors determined the finding to be of very low safety significance (Green) using Checklist 7 of Attachment 1, "Boiling Water Reactor Refueling Operation with Reactor Coolant System (RCS) Level Greater Than 23 Feet," because qualitative assessment concluded that PSEG maintained adequate mitigation capability and the event was not characterized as a loss of control. The inspectors determined that the finding had a cross-cutting aspect in Human Performance, Procedure Adherence, because PSEG personnel did not follow site procedures. [H.8] (Section 1R18).

- <u>Green</u>. The inspectors identified a Green NCV of 10 CFR 50.54(hh)(2), "Conditions of Licenses." Specifically, PSEG failed to adequately assess the functionality of the B.5.b portable gas generator on multiple occasions and implement adequate corrective actions in response to repeated failures of the B.5.b portable gas generator. This resulted in an unrecoverable and unavailable individual mitigating strategy associated with the remote operation of safety relief valves (SRV) with reactor pressure vessel (RPV) injection for approximately two and half months while the portable gas generator was unavailable. PSEG's corrective actions include repairing the B.5.b portable gas generator and returning it to an available, standby condition as well as performing a validation of all B.5.b equipment and associated mitigating strategies.

  The inspectors determined the performance deficiency was more than minor because it was associated with the equipment performance attribute of the Mitigating Systems cornerstone, and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e. core damage). The inspectors determined that this finding was of very low safety significance using NRC IMC 0609, Appendix L, "B.5.b Significance Determination Process," Table 2 - Significance Characterization, dated December 24, 2009, as specified for 10 CFR 50.54(hh) findings by IMC 0609, Attachment 4, "Initial Characterization of Findings," dated June 19, 2012, because the finding affected the Mitigating Systems cornerstone while the plant was at power and resulted in an unrecoverable unavailability of an individual mitigating strategy. Specifically, because the B.5.b portable gas generator was not functional for approximately 2.5 months with no compensatory actions in place, the Remote

Operation of SRVs with RPV Injection mitigation strategy per Hope Creek procedure HC.OP-AM.TSC-0024, Revision 8, was determined to be unrecoverable and unavailable during this time. The inspectors noted that the reactor core isolation cooling (RCIC) system remained functional during this time period and as such the finding did not represent an unrecoverable unavailability of multiple mitigating strategies such that injection to RPV could not have occurred. The inspectors determined that the contributing cause that provided the most insight into the performance deficiency was associated with the cross-cutting aspect of Problem Identification and Resolution, Evaluation, because PSEG failed to thoroughly evaluate equipment deficiencies related to the B.5.b portable gas generator to ensure that the resolutions addressed causes and extent of conditions commensurate with the B.5.b equipment's safety significance. [P.2] (Section 4OA2)

- Green. A self-revealing Green NCV of TS 6.8.1, "Procedures and Programs," was identified for PSEG's failure to use procedures during scram recovery on December 5, 2013. Specifically, PSEG failed to use an approved method of post-scram reactor pressure control, causing the main turbine bypass valves (BPVs) to cycle rapidly resulting in a reactor pressure transient, reactor water level transient, and reactor protection system (RPS) actuation. PSEG entered this issue into their CAP under notification (NOTF) 20632369 and chartered a quick human performance investigation. As part of PSEG's corrective actions, the operators involved in the event were removed from shift and retrained, and each shift manager (SM) reviewed post-scram reactor pressure control methods with their crew and received training on this event, decision making, and procedural adherence.

  The inspectors determined that the performance deficiency was more than minor because it is associated with the human performance attribute of the Mitigating Systems cornerstone and adversely affected its objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, PSEG's failure to implement procedures resulted in an unplanned reactor pressure transient, reactor water level transient, and ultimately resulted in RPS actuation and a trip signal to standby safety injection systems during scram recovery. Using IMC 0609, Appendix A, Exhibit 2, "Mitigating Systems Screening Questions," the finding was determined to be of very low safety significance (Green) because it was not a deficiency affecting the design or qualification of a mitigating structure, system or component; it did not represent a loss of system or function; it did not represent the loss of function for any TS system, train, or component beyond the allowed TS outage time; and it did not represent an actual loss of function of any non TS trains of equipment designated as high safety-significant in accordance with the PSEG's maintenance rule program. This finding was determined to have a cross-cutting aspect in Human Performance, Consistent Process, because PSEG failed to ensure that individuals use a consistent, systematic approach to make decisions and incorporate risk insights as appropriate. Specifically, operators did not use a systematic approach when making the decision to lower reactor pressure using the digital electro-hydraulic control (DEHC) system cooldown controller on December 5, 2013. [H.13] (Section 4OA3)

## REPORT DETAILS

Summary of Plant Status

The Hope Creek Generating Station began the inspection period at full rated thermal power (RTP). On February 7, 2014, Hope Creek conducted a planned down power to 70 percent of RTP to support offsite power line testing activities. The unit was returned to full RTP later the same day and remained at or near full RTP for the remainder of the inspection period

### 1. REACTOR SAFETY

**Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity**

1R01 Adverse Weather Protection (71111.01 – 2 samples)

Readiness for Impending Adverse Weather Conditions

a. Inspection Scope

The inspectors reviewed PSEG's preparations for the onset of impending adverse weather conditions, including heavy snow and high winds and a winter storm warning for Salem County, New Jersey on January 2, 2014, and extremely low outside temperatures experienced on January 7-8, 2014. The inspectors reviewed the abnormal operating procedure, HC.OP-AB.MISC-0001, "Acts of Nature," for responding to adverse weather conditions. The inspectors walked down the service water pump house and the fire pump house to ensure compliance with PSEG's cold weather procedures. The inspectors also verified that operator actions defined in PSEG's adverse weather procedure maintained the readiness of essential systems. Documents reviewed for each section of this inspection report are listed in the Attachment.

b. Findings

No findings were identified.

1R04 Equipment Alignment

.1 Partial System Walkdowns (71111.04 – 4 samples)

a. Inspection Scope

The inspectors performed partial walkdowns of the following systems:

- 'B' and 'D' safety auxiliaries cooling system (SACS) pumps during 'A' SACS pump maintenance on January 27, 2014
- Electric motor driven fire pump during troubleshooting and maintenance on the diesel driven fire pump on February 26, 2014
- 'A' SLC pump during 'B' SLC pump maintenance on March 12, 2014
- 'A' main control room chiller during 'B' main control room chiller maintenance on March 20, 2014

The inspectors selected these systems based on their risk-significance relative to the reactor safety cornerstones at the time they were inspected. The inspectors reviewed applicable operating procedures, system diagrams, the updated final safety analysis report (UFSAR), TSs, work orders, condition reports, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have impacted system performance of their intended safety functions. The inspectors also performed field walkdowns of accessible portions of the systems to verify system components and support equipment were aligned correctly and were operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no deficiencies. The inspectors also reviewed whether PSEG staff had properly identified equipment issues and entered them into the corrective action program for resolution with the appropriate significance characterization.

b. Findings

No findings were identified.

.2 Full System Walkdown (71111.04S – 1 sample)

a. Inspection Scope

On January 30, 2014, the inspectors performed a complete system walkdown of accessible portions of the SLC system to verify the equipment lineup was correct. The inspectors reviewed operating procedures, surveillance tests, drawings, equipment lineup procedures, and the UFSAR to verify the system was aligned to perform its required safety functions. The inspectors also reviewed electrical power availability, component lubrication and equipment cooling, hanger and support functionality, and operability of support systems. The inspectors performed field walkdowns of accessible portions of the systems to verify system components and support equipment were aligned correctly and operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no deficiencies. The inspectors also reviewed whether PSEG staff had properly identified equipment issues and entered them into the corrective action program for resolution with the appropriate significance characterization. Additionally, the inspectors reviewed a sample of related condition reports and work orders to ensure PSEG appropriately evaluated and resolved any deficiencies.

b. Findings

No findings were identified.

1R05 Fire Protection

Resident Inspector Quarterly Walkdowns (71111.05Q - 5 samples)

a. Inspection Scope

The inspectors conducted tours of the areas listed below to assess the material condition and operational status of fire protection features. The inspectors verified that

PSEG controlled combustible materials and ignition sources in accordance with administrative procedures. The inspectors verified that fire protection and suppression equipment was available for use as specified in the area pre-fire plan, and passive fire barriers were maintained in good material condition. The inspectors also verified that station personnel implemented compensatory measures for out of service, degraded, or inoperable fire protection equipment, as applicable, in accordance with procedures.

- FRH-II-561, Revision 7, Hope Creek Pre-Fire Plan, Control Equipment heating, ventilation, and air conditioning (HVAC) Inverter and Battery Rooms, Elevation 163'-6" on January 16, 2014
- FRH-II-562, Revision 5, Hope Creek Pre-Fire Plan, HVAC Equipment, Inverter, and Battery Rooms, Elevation 163'-6" on January 17, 2014
- FRH-II-413, Revision 3, Hope Creek Pre-Fire Plan, 'C' residual heat removal (RHR) pump room, Elevation 54' on February 27, 2014
- FRH-II-412, Revision 3, Hope Creek Pre-Fire Plan, 'D' RHR pump room, Elevation 54' on February 27, 2014
- FRH-II-541, Revision 7, Hope Creek Pre-Fire Plan, Class 1E Switchgear Rooms, Elevation 130'-0" on March 5, 2014

b. Findings

No findings were identified.

## 1R11 Licensed Operator Requalification Program and Licensed Operator Performance (71111.11Q – 2 samples)

### .1 Quarterly Review of Licensed Operator Requalification Testing and Training

a. Inspection Scope

The inspectors observed licensed operator simulator training on January 21, 2014, that included a failure of reactor recirculation pump (RRP) inboard and outboard seals, failure of an emergency diesel generator (EDG) causing loss of power to a vital bus, a large break loss of coolant accident (LOCA) and a safety and turbine auxiliaries cooling system pump fire caused by a bearing oil failure. The inspectors evaluated operator performance during the simulated event and verified completion of critical tasks, risk significant operator actions, including the use of abnormal and emergency operating procedures. The inspectors assessed the clarity and effectiveness of communications, implementation of actions in response to alarms and degrading plant conditions, and the oversight and direction provided by the control room supervisor. The inspectors verified the accuracy and timeliness of the emergency classification made by the shift manager. Additionally, the inspectors assessed the ability of the training staff to identify and document crew performance problems.

b. Findings

No findings were identified.

.2 Quarterly Review of Licensed Operator Performance in the Main Control Room

a. Inspection Scope

The inspectors observed a planned downpower to support an offsite power line outage for testing activities on February 7, 2014. The inspectors observed reactivity manipulations to verify that procedure use, and crew communications, met established expectations and standards. The inspectors also observed performance of a RCIC surveillance test on February 11, 2014. The inspectors observed pre-job briefings to verify that the briefings met the criteria specified in OP-AA-101-111-1004 "Operations Standards," Revision 4, and HU-AA-1211, "Pre-Job Briefings," Revision 11. Additionally, the inspectors observed test performance to verify that procedure use, crew communications, and coordination of activities between work groups similarly met established expectations and standards.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12 – 3 samples)

a. Inspection Scope

The inspectors reviewed the samples listed below to assess the effectiveness of maintenance activities on structure, system, and component (SSC) performance and reliability. The inspectors reviewed CAP documents (notifications), maintenance work orders (orders), and maintenance rule basis documents to ensure that PSEG was identifying and properly evaluating performance problems within the scope of the maintenance rule. As applicable, the inspectors verified that the SSC was properly scoped into the maintenance rule in accordance with 10 CFR 50.65 and verified that the (a)(2) performance criteria established by PSEG staff was reasonable; for SSCs classified as (a)(1), the inspectors assessed the adequacy of goals and corrective actions to return these SSCs to (a)(2); and, the inspectors independently verified that appropriate work practices were followed for the SSCs reviewed. Additionally, the inspectors ensured that PSEG staff was identifying and addressing common cause failures that occurred within and across maintenance rule system boundaries.

- 'C' EDG jacket water relief valve lifted on October 27, 2013 (Order 70161848)
- Failure of multiple RCIC relays during surveillance testing on December 12, 2013 (NOTF 20633364)
- 125 volts direct current (VDC) battery room fire damper failure after multiple failures of the same fire damper fusible link on January 8, 2014 (NOTF 20635785)

b. Findings

No findings were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13 – 5 samples)

a. Inspection Scope

The inspectors reviewed station evaluation and management of plant risk for the maintenance and emergent work activities listed below to verify that PSEG performed the appropriate risk assessments prior to removing equipment for work. The inspectors selected these activities based on potential risk significance relative to the reactor safety cornerstones. As applicable for each activity, the inspectors verified that PSEG personnel performed risk assessments as required by 10 CFR 50.65(a)(4) and that the assessments were accurate and complete. When PSEG performed emergent work, the inspectors verified that operations personnel promptly assessed and managed plant risk. The inspectors reviewed the scope of maintenance work and discussed the results of the assessment with the station's probabilistic risk analyst to verify plant conditions were consistent with the risk assessment. The inspectors also reviewed the TS requirements and inspected portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met.

- Corrective maintenance on the 'D' vital bus inverter on December 24, 2013 (Order 30192325)
- Unplanned yellow risk during a grid operator issued Maximum Emergency Generation Action and inoperable Salem Unit 3 on January 7, 2014
- Technical evaluation and operational risk assessment supporting the proposed normally de-energized relay replacement schedule as part of the high pressure coolant injection (HPCI) relay failure equipment apparent cause evaluation (EQACE) on January 28, 2014 (Order 70152218-0370)
- Planned maintenance on the 'B' EDG with the 'B' circulating water pump out of service on February 12, 2014 (Order 60103864)
- Planned maintenance on the 'D' SACS pump and RCIC system on February 19, 2014 (Orders 60114377 and 30098823)

b. Findings

Introduction. A Green self-revealing NCV of TS 6.8.1.a, "Procedures and Programs," was identified regarding PSEG failing to adequately establish, implement, and justify the initial replacement frequency for the 1DD481 inverter control circuit cards. As a result, an age-related failure of circuit cards for the safety-related 1E channel 'D' (1DD481) inverter occurred on December 24, 2013, which led to PSEG entering an unplanned 24 hour shutdown TS 3.8.3.1.a.4 for On-site Power Distribution Systems.

Description. On December 24, 2013 at 2:05 a.m., PSEG operators in the main control room (MCR) received abnormal alarms and indications indicating a failure with the normal power supply to the 1DD481 inverter. The inverter automatically swapped, as designed, to the backup alternating current power to continue to supply power to its associated safety-related 120 VAC loads. Through inspection and initial troubleshooting by the operators, PSEG determined there was a blown fuse in the inverter input which led to the power loss. The failure of the 1DD481 inverter did not cause any further equipment issues but did result in the inverter's safety-related function being inoperable and entry by PSEG operators into a 24 hour shutdown TSAS.

After initial troubleshooting and replacement of the blown fuse by PSEG, operators attempted to restore the normal power supply to the 1DD481 inverter but the fuse blew again at 9:30 a.m. PSEG determined that the blown fuses were due to a failed inverter control circuit card. PSEG replaced and tested six control circuit cards for the 1DD481 inverter and restored the inverter to service, thus exiting the 24 hour TSAS at 3:20 a.m., approximately 13 hours after the initial inverter failure.

PSEG initiated an EQACE (Order 70162737) to evaluate the failure of the 1DD481 inverter. This evaluation determined, in part, that the circuit card failed as a result of age. The EQACE determined that these circuit cards are recommended to be replaced on an 18 year frequency per PM and that the cards in the 1DD481 inverter were 27 years old (original construction). The EQACE also determined that PSEG's PM deferrals related to this and other similar inverters were not all completed in accordance with PSEG procedure MA-AA-716-210-1004, "First Call Preventative Maintenance (PM) Strategy."

As part of inspection follow-up, the inspectors reviewed the 1DD481 inverter EQACE and recent PSEG findings related to PM to ensure that PSEG's evaluation of the inverter failure and proposed corrective actions were appropriate.

During the inspector's review of PSEG's EQACE for the 1DD481 inverter, the inspectors noted that the evaluation focused on the PM deferral process inadequacies. The evaluation did not discuss the inverter performance centered maintenance (PCM), template recommended replacement frequency (10 years), and PSEG's justification and documentation of the initial replacement PM for the inverter circuit cards. The inspectors determined that the PCM template for "Inverters greater than or equal to 5 kilovolt-ampere" states in the component replacement section that, "*capacitors and circuit boards are expected to have a life of a few years up to about 10 years.*" The inspectors also determined that the PCM template recommends a 10 year replacement frequency for a component classified as critical, high duty and in a mild service environment as the 1DD481 inverter is classified by PSEG.

PSEG's EQACE cited that the basis for the 18 year inverter circuit card replacement frequency was located in Order 70090090 from 2009. This order states, in part, that "*Hope Creek has embarked on a one time replacement PM involving circuit cards. This discussion was presented to the Plant Health Committee and approved. Due to the high cost of circuit cards and number of cards installed versus the specific cards failures we have experienced, Hope Creek has decided at this time to replace a limited number of circuit cards in each inverter, versus all the circuit cards in each inverter. Hope Creek Engineering and Maintenance have determined that this PM should remain and the frequency is to be established at 18 years intervals.*" The inspectors noted another Order 80089525 (NOTF 20284604) that was created in 2006 and completed in 2009 to "*establish a PM task to replace inverter circuit cards based on age. The frequency should be 9-10 years and fit in refueling outages.*" This order created maintenance plans for each inverter but did not address the replacement frequency for inverter circuit cards. Because of this, the inspectors determined that the basis used for PSEG's initial inverter circuit card PM replacement frequency of 18 years was not adequately justified and documented per PSEG procedure MA-AA-716-210 for the Preventative Maintenance Process.

The inspectors concluded that PSEG failed to implement and appropriately revise the maintenance strategies associated with the replacement of control circuit cards for the safety-related 1E channel 'D' (1DD481) Inverter. Specifically, in 2009, PSEG failed to adequately justify the initial replacement frequency for the 1DD481 inverter control circuit cards. PSEG has entered the issues above into the CAP as NOTF 20642518. PSEG's corrective actions include conducting an extensive extent of condition review of first-call PMs.

Analysis. PSEG failing to adequately establish, implement, and justify the initial replacement frequency for the 1DD481 inverter control circuit cards represented a performance deficiency that was reasonably within the licensee's ability to foresee and correct and should have been prevented. The performance deficiency was determined to be more than minor because it was associated with the equipment performance attribute of the Initiating Events cornerstone, and adversely affected the cornerstone objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. The inspectors determined that this finding was of very low safety significance (Green) using NRC IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," Exhibit 1 – Initiating Events Screening Questions, dated July 1, 2012, because for findings involving support system initiators, i.e. the Loss of a DC bus, the result did not involve the complete or partial loss of a support system that contributed to the likelihood of, or cause, an initiating event and affected mitigation equipment.

The inspectors determined that there was no cross-cutting aspect associated with this finding because the cause of the performance deficiency occurred more than three years ago, and was not representative of current licensee performance.

Enforcement. TS 6.8.1.a, "Procedures and Programs," requires in part, that written procedures recommended in Appendix A of Regulatory Guide (RG) 1.33, Revision 2, shall be established, implemented, and maintained. Section 9.b of RG 1.33, Revision 2, Appendix A, requires that PM schedules should be developed to specify the inspection or replacement of parts that have a specific lifetime. PSEG procedure MA-AA-716-210 for the Preventative Maintenance Process details the implementation of maintenance strategies. Contrary to the above, PSEG failed to implement and appropriately revise the maintenance strategies associated with the replacement of control circuit cards for the safety-related 1E channel 'D' (1DD481) inverter. Specifically, in 2009, PSEG failed to adequately establish, justify, and implement an initial replacement frequency for the 1DD481 inverter control circuit cards. As a result, an age-related failure of circuit cards for the safety-related 1DD481 inverter occurred on December 24, 2013, which caused PSEG to enter an unplanned 24 hour shutdown TSAS. PSEG's corrective actions include conducting an extensive extent of condition review of first-call PMs. Because this violation was of very low safety significance (Green) and was entered into the licensee's CAP as NOTF 20642518, the violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000354/2014002-01, Inadequate Preventative Maintenance for Safety-Related Circuit Cards)**.

1R15 Operability Determinations and Functionality Assessments (71111.15 – 8 samples)

a. Inspection Scope

The inspectors reviewed operability determinations for the following degraded or non-conforming conditions:

- 'D' vital bus operability after the infeed breaker failure on December 19, 2013 (Order 70162724)
- Service water intake structure cabinet degraded anchors on January 7, 2014 (Order 80111107)
- HPCI pump operability with pump misaligned after maintenance during 1R18 on January 10, 2014 (NOTF 20635944)
- RCIC remote shutdown panel flow controller did not reach full flow in manual during surveillance testing on February 17, 2014 (Order 70163607)
- B.5.b portable gas generator functionality assessment for failing to start on February 18, 2014 (NOTF 20640369)
- Masterpact Breaker Model NW with Locked in Close Signal due to a Failure Analysis on February 21, 2014 (NOTF 20640696)
- 'C' EDG #7 cylinder cracked camshaft lobe on March 5, 2014 (NOTF 20642203)
- SLC Tank operability with increased tank volume due to the addition of demineralized water during 'B' SLC pump fill and vent on March 12, 2014 (NOTF 20643229)

The inspectors selected these issues based on the risk significance of the associated components and systems. The inspectors evaluated the technical adequacy of the operability determinations to assess whether TS operability was properly justified and the subject component or system remained available such that no unrecognized increase in risk occurred. The inspectors compared the operability and design criteria in the appropriate sections of the TSs and UFSAR to PSEG's evaluations to determine whether the components or systems were operable. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled by PSEG. The inspectors determined, where appropriate, compliance with assumptions in the evaluations.

b. Findings

.1 480 VAC Masterpact Breakers Condition Adverse to Quality

Introduction. A self-revealing Green NCV of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions," was identified because PSEG failed to assure that CAQs were promptly identified and corrected. Specifically, PSEG did not initiate a timely notification for a potential design flaw in the operation of some 480 VAC Masterpact breaker's control logic scheme. As a result, this CAQ was not addressed in a timely manner while a number of safety-related breakers were degraded. This CAQ required PSEG to perform an extensive operability evaluation and implement compensatory measures to ensure the operable but degraded status of these safety-related breakers.

Description. On February 21, 2014, PSEG engineering personnel were developing additional troubleshooting plans for a reactor building ventilation supply (RBVS) fan breaker failure that was experienced on December 10, 2013, and reviewed a failure analysis update letter sent from a breaker manufacturer, Nuclear Logistics Inc. (NLI), dated October 2, 2013, concerning issues with Masterpact breakers (Letter No. LD-042-MASTERPACT-1 Revision 1). This letter from NLI to PSEG cites that the logic scheme associated with some of the installed 480 VAC Masterpact breakers use a single relay to cycle between the constant close signal to the breaker and the trip signal. The use of a single relay in the breaker control logic scheme operating two sets of contacts for open and close potentially puts the breaker mechanism in a latch 'toggling' condition, causing the linkage for the 'ready to close' indicator to get caught between positions. Thus, if the breaker opens due to a trip, it may not be able to close again when required until being mechanically cleared by an operator locally resetting it.

PSEG initiated NOTF 20640696 on February 21, 2014, at 2:00 a.m., documenting the potential concern related to the Masterpact breaker logic scheme which initiated an operability evaluation (Order 70163760). This NOTF listed all of the Masterpact breakers currently installed in the plant (>60 safety-related and >130 non-safety related) that could be affected by this design issue.

PSEG's operability evaluation (OPEVAL) narrowed the list of affected breakers to a total of 21, which included only those breakers required for TS functions, to support TS requirements, or that are required to actuate during integrated emergency diesel generator testing. The evaluation determined these breakers to be operable but degraded because of the potential for the each breaker to fail to operate per design. The OPEVAL states "*the potential failure of a load to start because the Masterpact breaker is not ready to close would result in a time delay in starting the load. This delay is dependent on operator response time to inspect the 'ready to close' indicator and tripping the breaker locally. This places the breaker in a 'ready to close' position, and the load is restored using normal local or remote controls.*" In addition, PSEG determined the time delay did not impact the breakers trip function or LOCA load shed function. Because of this operable but degraded condition, PSEG has instituted compensatory measures to ensure all open breakers are 'ready to close' by having operators visually inspect the affected breakers once a shift to ensure the breaker indicator is not in an intermediate position.

The inspectors reviewed the weekend notifications from Friday, February 21, 2014, through Monday, February 24, 2014, on Monday morning during their normal daily plant status review. During this review, the inspectors questioned the timeliness of PSEG's review of the NLI failure analysis update letter received by PSEG engineering back in October 2013. PSEG initiated a second NOTF 20640964 on February 24, 2013 at 9:27 a.m., documenting an untimely review of the failure analysis.

The inspectors reviewed the history of Masterpact breakers issues at Hope Creek, related causal evaluations and other vendor provided failure analyses to determine when this Masterpact breaker logic scheme issue was a known issue. The inspectors also conducted walkdowns of the affected breakers, independently verifying that the 'ready to close' indicator on the front of the breaker provided clear indication that the breakers were available to close on demand. Based on this review, the inspectors noted that:

- From October 2, 2013, to February 24, 2014, Hope Creek experienced issues with multiple 480VAC Masterpact breakers failing to operate as designed, including:

  1. the 'B' RBVS exhaust fan breaker on October 27, 2013;
  2. the 'B' RBVS supply fan breaker on December 10, 2013, and;
  3. the 'C' Auxiliary Boiler breaker on February 21, 2014.

- On September 6, 2013, PSEG documented NOTF 20620439 for the 'A' stator water cooling pump failing to automatically start. PSEG performed a workgroup evaluation (WGE) (Order 70158162 approved by management review committee on December 12, 2013) documenting that "*there have been multiple situations where Masterpact circuit breakers have failed to close because they had not reset themselves when they were last opened; specifically the 'Ready/OK' flag was not fully visible, indicating that the breaker was not ready for the next closure operation*." As part of the corrective actions for this evaluation, PSEG instituted a Standing Order 2013-054, Field Validation of Masterpact Circuit Breakers, on December 24, 2013, to verify 62 of these Masterpact breakers every shift (once per 12 hours) are reset and ready for the next closure operation. Although the WGE recognized this issue and identified the extent of condition of the Masterpact breakers, no OPEVAL for these breakers was completed until February 26, 2014. This represented another missed opportunity by the site to ensure the continued reliability and operability of the affected breakers.

- On June 15, 2011, PSEG documented NOTF 20515029 for a RBVS supply fan breaker failing to close. Order 70125325 was created to track the failure analysis of the breaker which was received and uploaded into the order on August 20, 2012. The summarized failure analysis documented the design vulnerability with these Masterpact breakers failing to operate as designed. This order does not document corrective actions for this identified CAQ, but references another evaluation, Order 70140750, for corrective actions associated with the failure analysis. The inspectors determined that this evaluation did not have any corrective actions addressing the identified CAQ with the Masterpact breakers. This represented a missed opportunity by PSEG to evaluate the identified CAQ and take effective corrective actions to ensure the breakers' immediate operability and resolve the flaw in the designed breaker control logic.

The inspectors concluded that on multiple occasions PSEG failed to assure that CAQ related to a potential design flaw in the operation of some 480 VAC Masterpact breaker's control logic scheme were promptly identified and corrected. PSEG has entered the above concerns into the CAP as NOTF 20640964. PSEG's corrective actions include an extensive operability evaluation, compensatory measures conducted every shift by operators to ensure the operability and reliability of these breakers in the short-term, and a proposed design change to remove the design flaw in the breaker control logic by 2015.

Analysis. PSEG failed to assure that a CAQ was promptly identified and corrected. Specifically, PSEG failing to initiate a timely notification for a potential design flaw in the operation of some 480 VAC Masterpact breaker's control logic scheme represented a performance deficiency that was reasonably within their ability to foresee and correct and should have been prevented. The performance deficiency was determined to be more than minor because it was associated with the equipment performance and design control attributes of the Mitigating Systems cornerstone, and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). The inspectors determined that this finding was of very low safety significance (Green) using NRC IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," Exhibit 2 – Mitigating Systems Screening Questions, dated July 1, 2012, because although the breakers' design is affected, the operability of the breakers is maintained.

The inspectors determined that the contributing cause that provided the most insight into the performance deficiency was associated with the cross-cutting aspect of Problem Identification and Resolution, Identification, because PSEG failed to identify issues completely, accurately, and in a timely manner in accordance with the CAP. [P.1]

Enforcement. 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," states, in part, that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and non-conformances are promptly identified and corrected. Contrary to the above, from October 2, 2013, to February 24, 2014, PSEG failed to assure that CAQs were promptly identified and corrected. Specifically, PSEG did not initiate a timely notification for a potential design flaw in the operation of some 480 VAC Masterpact breaker's control logic scheme. As a result, this CAQ was not addressed while a number of safety-related breakers were potentially affected and required PSEG to perform an extensive operability evaluation and implement compensatory measures to ensure the operability of the affected safety-related breakers. Because this violation was of very low safety significance (Green) and was entered into the licensee's CAP as NOTF 20640964, the violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000354/2014002-02, Untimely Identification and Corrective Actions for a Condition Adverse to Quality related to 480 VAC Masterpact Breakers)**.

.2 Standby Liquid Control Inadvertent Dilution

Introduction. A Green self-revealing NCV of TS 6.8.1.a, "Procedures and Programs," was identified for PSEG's failure to follow procedure HC.OP-SO.BH-0001, "Standby Liquid Control (SLC) System Operation," when restoring the SLC system after routine maintenance. Specifically, the licensee failed to adequately coordinate the restoration of the SLC system using the WCD and the SLC system operating procedure which led to an incorrect SLC system lineup causing the inadvertent addition of DI water to the SLC storage tank. As a result, PSEG had to determine the immediate and prompt operability of the SLC system and enter the associated 8 hour SLC TSAS.

Description. The SLC system is designed as an independent backup reactivity control system capable of bringing the reactor from rated power to a cold shutdown at any time in core life by injecting sodium pentaborate. The SLC system is needed only in the event that not enough control rods are inserted into the reactor core to accomplish shutdown and cooldown in the normal manner. The minimum quantity of sodium pentaborate required by TSs is based on the required 660 parts per million (ppm) average boron concentration in the reactor coolant, including additional margin to account for dilution and imperfect mixing.

At 10:27 a.m. on March 12, 2014, PSEG was in the process of returning the SLC system to service following planned maintenance on the ‘B’ SLC pump when the MCR received a SLC tank high level alarm (>4880 gallons). The MCR informed the equipment operator conducting the SLC system restoration of the unexpected SLC tank high level alarm and the operator closed a valve that had just been opened which stopped the rise in SLC storage tank level at 4926 gallons. At 10:45 a.m. (18 minutes after the SLC tank high level alarm was received in the MCR), PSEG determined that approximately 80 gallons of DI water was added to the SLC storage tank before the valve lineup was restored.

A prompt investigation performed by PSEG determined that improper shift turnover of Hope Creek procedure HC.OP-SO.BH-0001, “Standby Liquid Control (SLC) System Operation,” caused a missed procedural step in the SLC system fill and vent lineup leading to a mispositioned valve allowing DI water to be unintentionally added to the SLC storage tank. PSEG’s prompt investigation also determined that there was inadequate coordination of the SLC restoration activities between the WCD release and the SLC operating procedure.

PSEG issued NOTF 20643229 for the SLC storage tank level increase which included the on-shift operator’s immediate operability screening for the degraded or non-conforming condition associated with the potential dilution of SLC storage tank boron concentration required by TS 3.1.5, “SLC System,” Surveillance Requirement 4.1.5.a.2., and Figure 3.1.5-1, Sodium Pentaborate Solution Volume/Concentration Requirements. The associated TSAS 3.1.5.a.2. states that “with both [SLC] subsystems inoperable, restore at least one subsystem to operable status within 8 hours or be in at least Hot Shutdown within the next 12 hours.”

PSEG’s immediate operability screening determined that the SLC tank volume was still within the required band established in TS Figure 3.1.5-1 (<5058 gallons) and that the SLC tank sodium pentaborate concentration had changed. The immediate operability determination utilized previous values for SLC tank volume, concentration, and chemical weight (4850 gallons, 13.93 weight-percent, 6064 pounds) collected on February 27, 2014, and determined through simple calculations ($C_1V_1=C_2V_2$; $V_2$ being the new SLC tank volume of 4926 gallons) that the projected SLC tank sodium pentaborate concentration was 13.71 weight-percent due to the addition of DI water. PSEG Operations, supported by Chemistry, decided around 11:05 a.m., that this calculation provided reasonable assurance that the SLC storage tank sodium pentaborate concentration was still within the required concentration band required by TSs (>13.6 percent and <14.4 percent) and that the SLC system remained operable and capable of performing its design function.

PSEG operations placed the SLC storage tank heaters and spargers (mixers) in service at 12:42 a.m. on March 13, 2014, in accordance with the SLC tank sampling procedure to obtain a SLC tank sample. This procedure requires a 30 minute wait between placing the heaters and spargers in service and obtaining a sample from the SLC tank. One of the on-shift chemistry technicians obtained the SLC tank sample at 1:52 a.m. and initial sample results of 13.65 weight-percent were communicated to the MCR around 6 a.m.

The sample results were validated by PSEG at 6:31 a.m. and the analysis of the SLC system tank yielded an actual sodium pentaborate concentration below the TS limit of 13.6 weight-percent, rendering both SLC subsystems inoperable. The sodium pentaborate concentration was determined to be 4 ppm low, at 13.598 weight-percent.

PSEG operations personnel entered the 8 hour TSAS for out of specification SLC tank concentration at 6:31 a.m. and commenced lowering the SLC tank level and adding additional boron to increase SLC tank concentration back to within TS limits. At 2:31 a.m., PSEG issued Event Notification (EN) # 49909 per 10 CFR 50.72(b)(3)(v)(D) for an event or condition that could have prevented the fulfillment of a safety function that are needed to mitigate the consequences of an accident. PSEG completed the boron addition to SLC tank at 2:46 a.m. and after sample analysis confirmed that the SLC tank concentration restored to TS limits (14.04 weight-percent) and exited the TS at 5:35 a.m. (~3 hours into the 12 hour action to be in Hot Shutdown).

The inspectors reviewed PSEG's prompt investigation and timeline associated with the SLC system restoration activities, the inadvertent addition of DI water to the SLC tank, the immediate operability determination for SLC, and numerous PSEG procedures. The inspectors also conducted interviews with on-shift operations and chemistry personnel. PSEG procedures OP-AA-109, "Safety Tagging Procedure," OP-AA-109-115, "Safety Tagging Operations," and CC-AA-10, "Configuration Control," require that the WCD and restoration activities associated with maintenance be controlled and independently verified to ensure proper system alignment and configuration control. The inspectors determined that PSEG failed to follow the required procedural steps in HC.OP-SO.BH-0001 to properly fill and vent the SLC system. Specifically, PSEG failed to adequately coordinate the restoration of the SLC system using the WCD and the SLC system operating procedure, which led to an incorrect SLC system lineup causing the inadvertent addition of DI water to the SLC storage tank.

Although the inspectors concluded there were no additional performance deficiencies related to PSEG's immediate operability determination and their actions to promptly collect additional information that was material to the SLC system operability determination, the inspectors determined that the calculation method used by PSEG to support immediate operability of the system was inaccurate and potentially non-conservative. PSEG initiated NOTF 20644515 and EQACE 70164536 in the corrective action program to restore the SLC tank concentration, brief the operating crews on proper WCD turnover process, and address operator gaps in the SLC system operation that may have adversely affected the timeline and the inaccuracy of the immediate operability calculation method.

Analysis. PSEG's failure to follow procedure HC.OP-SO.BH-0001, for SLC system operation, when restoring the SLC system after routine maintenance represented a performance deficiency that was reasonably within the licensee's ability to foresee and correct and should have been prevented. The performance deficiency was determined to be more than minor because it was associated with the configuration control attribute of the Mitigating System cornerstone, and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, failing to follow procedure leading to configuration control issues could have rendered a safety-related system inoperable. This performance deficiency was also similar to examples 3.j and 3.k of NRC IMC 0612, Appendix E, in that the addition of 80 gallons of DI water to the SLC tank created a reasonable doubt of operability of the SLC system. The inspectors determined the finding to be of very low safety significance (Green) in accordance with IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power, dated June 19, 2012." Using Exhibit 2, which contains the screening questions for the Mitigating Systems Cornerstone, the inspectors determined that the finding screened as Green because: it was not a deficiency affecting the design or qualification of the SLC system; it did not represent a loss of system or function; it did not represent the loss of function for any TS system, train, or component beyond the allowed TS outage time; and it did not represent an actual loss of function of any non TS trains of equipment designated as high safety-significant in accordance with the Hope Creek's maintenance rule program. Specifically, although the SLC tank boron concentration was diluted, the SLC system was still capable of providing sufficient negative reactivity to shut down the reactor.

The inspectors determined that the contributing cause that provided the most insight into the performance deficiency was associated with the cross-cutting aspect of Human Performance, Work Management, because PSEG failed to implement a process of planning, controlling, and executing work activities such that nuclear safety is the overriding priority. [H.5]

Enforcement. TS 6.8.1.a, "Procedures and Programs," requires in part, that written procedures recommended in Appendix A of RG 1.33, Revision 2, shall be established, implemented, and maintained. Section 9.a of RG 1.33, Revision 2, Appendix A, requires that maintenance that can affect the performance of safety-related equipment should be properly preplanned and performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstances. PSEG procedure HC.OP-SO.BH-0001, "Standby Liquid Control (SLC) System Operation," details proper restoration the SLC system after routine maintenance.

Contrary to the above, on March 12, 2014, PSEG failed to follow the requirements of this operating procedure. Specifically, PSEG failed to adequately coordinate the restoration of the SLC system using the WCD and the SLC system operating procedure, which led to an incorrect SLC system lineup causing the inadvertent addition of DI water to the SLC storage tank. As a result, PSEG had to determine the immediate and prompt operability of the SLC system and enter the associated 8 hour SLC TSAS. PSEG's corrective actions included restoring the SLC tank boron concentration to within TS limits and initiating an EQACE 70164536 to address potential operator knowledge gaps with the SLC system operation. Because this violation was of very low safety significance (Green) and was entered into the licensee's CAP as NOTF 20644515, the violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000354/2014002-03, Failure to Follow Procedure Resulting in the Potential Inoperability of a Safety-Related System).**

1R18 Plant Modifications (71111.18 – 3 samples)

.1 Temporary Modifications

a. Inspection Scope

The inspectors reviewed the temporary modifications listed below to determine whether the modifications affected the safety functions of systems that are important to safety. The inspectors reviewed 10 CFR 50.59 documentation and conducted field walkdowns of the modification to verify that the temporary modification did not degrade the design bases, licensing bases, and performance capability of the affected systems.

- Temporary configuration change package (TCCP) 4HT-14-002 – Install a Temporary Portable Heater in the Aux Building Corridor 5610
- TCCP 4HT-13-019 – Defeat the High Bearing Oil Temperature Trip for MCR chiller 1AK400

b. Findings

No findings were identified.

.2 Permanent Modifications

a. Inspection Scope

The inspectors evaluated a modification to the 10B232 480 VAC MCC implemented by design change package (DCP) 80098424, "MCC 10B232 Compartment Replacement." The DCP replaced the MCC buckets associated with the Class 1E 10B232 480 VAC MCC to resolve environmental qualification and obsolescence concerns. The inspectors verified that the design bases, licensing bases, and performance capability of the affected systems were not degraded by the modification. In addition, the inspectors reviewed modification documents associated with the upgrade and design change.

b. Findings

Introduction. A self-revealing Green NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," was identified for PSEG's failure to adequately evaluate a modification to the DCP for replacement buckets on the Class 1E 10B232 480 VAC MCC in accordance with PSEG procedure CC-AA-103-1001, "Implementation of Configuration Changes." This resulted in damage to and de-energization of the 10B232 MCC during maintenance activities to install a new replacement bucket on October 28, 2013.

Description. On October 28, 2013, electricians were installing a replacement bucket (10B232103) in the Class 1E 10B232 480 VAC MCC when an arc flash occurred, and caused extensive damage in the vertical section of the MCC and caused the supply breaker of the MCC to trip open on ground fault, de-energizing the MCC. De-energization of the 10B232 MCC resulted in the loss of power to the RHR and core spray jockey pump, room coolers, and filtration, recirculation, and ventilation system dampers. The replacement 10B232103 bucket was found with a hole drilled through the insulator support of the main power stab block in the back of the bucket. A root cause evaluation was performed (Order 70160636) and determined that less than adequate rigor existed in the implementation of the field change request (FCR) process, which led to using the modification acceptance test (MAT) to install this screw instead of installation instructions. The FCR process is used to document and resolve questions that arise during implementation or testing of the design change. A MAT is performed to demonstrate that modified components properly function and that other components are not adversely affected.

This bucket is part of a MCC bucket replacement project which includes the replacement of 287 buckets in the four Class 1E 480VAC MCCs to resolve environmental qualification and obsolescence concerns. The buckets are replaced with modern components that are precise drop-in replacements designed to duplicate the form, fit, and function of the existing buckets. The control power blocks and terminal blocks in the replacement buckets received from the vendor are designed to snap together. The decision to install screws in all terminal blocks originated as a corrective action upon finding a loose terminal block in a recently replaced bucket on October 29, 2011, by an equipment operator during tagging operations. A WGE (Order 70130783) concluded that either the friction connection design was an inadequate securing process or that the design was adequate and the technician mated the two sections of the connector together well enough to successfully complete post installation testing but not well enough to ensure the long term reliability of the connection.

In order to correct the condition of the loose pull apart section, FCRs were completed to specify that screws be installed in the existing holes in the pull apart connector sections. The screws provide a positive connection between the pull apart sections if the friction connection design is flawed, and makes the installation less susceptible to the human error of not fully mating the pull apart connector sections. Engineering determined the addition of the screw was considered an enhancement and stated the screws would be added to each new MCC bucket as needed.

Due to design differences, the male half of the 3-point terminal block contains countersunk screw holes which allow the screw head to be inserted approximately 3/4 inches into the block. The male half of the 8-point terminal block screw holes are not countersunk and contain brass sleeves so the screw head sits flush with the face of the block. The terminal block differences were understood and the decision was made for electrical maintenance to use longer screws, and trim any excess length protruding through the MCC pan as necessary, utilizing “skill-of-the-craft” and verbal communication only. Written instructions to trim the screws, specify screw length, or caution electrical safety concerns were not documented. The screw was long enough that when installed for the 10B232103 bucket, the screw protruded through the MCC bucket wall, insulation, stab block assembly, and touched the ‘A’ phase contact clip. The screw grounded the ‘A’ phase of the MCC bus through the bucket and caused the arc flash when the bucket was installed.

The replacement MCC buckets were seismically qualified with only the friction connection design. No screw was installed to connect the two halves of the control power blocks and terminal blocks. CC-AA-103-1001, “Implementation of Configuration Changes,” requires that major FCRs require re-verification. Because installation of the screws affected the MCC bucket seismic qualification, the decision warranted additional review and approval as a major FCR that was not performed. PSEG’s corrective actions included a full extent of condition inspection of all installed modified MCC buckets and removed instructions to install terminal block screws in future modifications. PSEG performed an evaluation of the installed replacement 480 VAC MCC buckets and determined that the terminal block mounting screws do not adversely affect the structural and seismic qualification of the MCC bucket. PSEG's planned corrective actions include restoring the MCC buckets to the tested configuration.

Analysis. The inspectors determined PSEG's failure to adequately evaluate a modification to the design change for replacement buckets on the Class 1E 10B232 480 VAC MCC in accordance with PSEG procedure CC-AA-103-1001, "Implementation of Configuration Changes," was a performance deficiency which was reasonably within PSEG's ability to foresee and prevent. The inspectors determined that the performance deficiency was more than minor because it is associated with the design control attribute of the Mitigating Systems cornerstone, and adversely affected the cornerstone objective to ensure availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the inadequate modification resulted in damage to MCC compartments and de-energization of the 10B232 MCC during maintenance activities to install the modification.

Because this finding occurred while the plant was shut down, the inspectors used NRC IMC 0609, Appendix G, "Shutdown Operations Significance Determination Process," dated February 28, 2005, to evaluate the finding for significance. Using Attachment 1, "Phase 1 Operational Checklists for Both Pressurized Water Reactors and Boiling Water Reactors," and specifically Checklist 7, "Boiling Water Reactor Refueling Operation with RCS Level Greater Than 23 Feet," the inspectors determined the finding to be of very low safety significance (Green), because qualitative assessment concluded that PSEG maintained adequate mitigation capability and the event was not characterized as a loss of control. The inspectors determined that the finding had a cross-cutting aspect in Human Performance, Procedure Adherence, because PSEG personnel did not follow site procedures. Specifically, PSEG personnel did not ensure that the decision to install screws to attach control power blocks and terminal blocks in replacement 480 VAC replacement buckets received sufficient review and approval. [H.8]

Enforcement. 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part, that design control measures shall provide for verifying or checking the adequacy of design, such as performance of design reviews. PSEG procedure CC-AA-103-1001, "Implementation of Configuration Changes," requires that major FCRs require re-verification." Contrary to this requirement, the decision to install screws to connect control power blocks and terminal blocks in 480 VAC replacement buckets did not receive sufficient review and approval on October 31, 2011. PSEG's corrective actions included a full extent of condition inspection of all installed modified MCC buckets and removing instructions to install terminal block screws in future modifications. Because of the very low safety significance (Green) and because the issue was entered into the CAP as NOTF 20627371, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000354/2014002-04, Inadequate Evaluation of 480VAC Motor Control Center Design Change).**

1R19 Post-Maintenance Testing (71111.19 – 6 samples)

a. Inspection Scope

The inspectors reviewed the post-maintenance tests for the maintenance activities listed below to verify that procedures and test activities ensured system operability and functional capability. The inspectors reviewed the test procedure to verify that the procedure adequately tested the safety functions that may have been affected by the maintenance activity, that the acceptance criteria in the procedure was consistent with the information in the applicable licensing basis and/or design basis documents, and that the procedure had been properly reviewed and approved. The inspectors also witnessed the test or reviewed test data to verify that the test results adequately demonstrated restoration of the affected safety functions.

- ‘B2’ RPS main steam isolation valve closure alarm troubleshooting on January 31, 2014 (Order 60115314)
- 125 VDC battery room fire damper fusible link replacement following low battery room temperature on February 6, 2014 (Order 60114765)
- RCIC check valve H1AP-1-AP-V050 repair following failed in-service test on February 6, 2014 (Order 60115118)
- ‘C’ EDG #7 cylinder camshaft lobe replacement on March 9, 2014 (Order 60113818)
- ‘B’ SLC pump following pump overhaul on March 14, 2014 (WCD 4351338)
- ‘A’ EDG lube oil make-up solenoid valve repair and camshaft lobe extent of condition inspections on March 28, 2014 (Orders 60114874 and 60116027)

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22 – 6 samples)

a. Inspection Scope

The inspectors observed performance of surveillance tests and/or reviewed test data of selected risk-significant SSCs to assess whether test results satisfied TSs, the UFSAR, and PSEG procedure requirements. The inspectors verified that test acceptance criteria were clear, tests demonstrated operational readiness and were consistent with design documentation, test instrumentation had current calibrations and the range and accuracy for the application, tests were performed as written, and applicable test prerequisites were satisfied. Upon test completion, the inspectors considered whether the test results supported that equipment was capable of performing the required safety functions. The inspectors reviewed the following surveillance tests:

- HC.OP-ST.BD-0001, RCIC Piping and Flow Path Verification monthly surveillance on January 29, 2014 (surveillance test)
- HC.OP-LR.BC-0002, Containment Isolation Valve (CIV) Type C Leak Rate Testing CIVs 1BCHV-F015A, F017A, F021A and F027A A RHR Penetrations #P4B, P6C, P24B and P214B (NOTF 20638412) reviewed on January 31, 2014 (containment isolation valve)

- HC.FP-ST.KC-0009, Diesel Driven Fire Pump Operability Test on February 4, 2014 (surveillance test)
- HC.OP-LR.FC-1004, Containment Isolation Valve Water Leak Rate Test CIVs 1FCHV-F060 and 1FCV-010 Penetration P210: RCIC Barometric Condenser Vacuum Pump Discharge on February 19, 2014 (containment isolation valve)
- HC.OP-ST.BH-0001, SLC Valve Operability Test – Monthly on March 13, 2014 (in-service test)
- HC.OP-IS.BE-0002, B & D Core Spray Pumps – BP206 and DP206 In-Service Test on March 21, 2014 (in-service test)

b. Findings

No findings were identified.

**Cornerstone: Emergency Preparedness**

1EP4 Emergency Action Level and Emergency Plan Changes (71114.04 - 1 sample)

a. Inspection Scope

PSEG implemented various changes to the Hope Creek Emergency Action Levels (EALs), Emergency Plan, and Implementing Procedures. PSEG had determined that, in accordance with 10 CFR 50.54(q)(3), any change made to the EALs, Emergency Plan, and its lower-tier implementing procedures, had not resulted in any reduction in effectiveness of the Plan, and that the revised Plan continued to meet the standards in 50.47(b) and the requirements of 10 CFR Part 50, Appendix E.

The inspectors performed an in-office review of all EAL and Emergency Plan changes submitted by PSEG as required by 10 CFR 50.54(q)(5), including the changes to lower-tier emergency plan implementing procedures, to evaluate for any potential reductions in effectiveness of the Emergency Plan. This review by the inspectors was not documented in an NRC Safety Evaluation Report and does not constitute formal NRC approval of the changes. Therefore, these changes remain subject to future NRC inspection in their entirety. The requirements in 10 CFR 50.54(q) were used as reference criteria.

b. Findings

No findings were identified.

1EP6 Drill Evaluation (71114.06 – 1 sample)

Training Observations

a. Inspection Scope

The inspectors observed a simulator training evolution for licensed operators on January 21, 2014, which required emergency plan implementation by an operations crew. PSEG planned for this evolution to be evaluated and included in performance indicator data regarding drill and exercise performance. The inspectors observed event classification activities performed by the crew. The inspectors also attended the post-evolution critique for the scenario. The focus of the inspectors' activities was to note any weaknesses and deficiencies in the crew's performance and ensure that PSEG evaluators noted the same issues and entered them into the CAP.

b. Findings

No findings were identified.

## 4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

Unplanned Scrams, Unplanned Power Changes, and Unplanned Scrams with Complications (3 samples)

a. Inspection Scope

The inspectors reviewed PSEG's submittal of the following Hope Creek Initiating Events Cornerstone performance indicators for the period of January 1, 2013 through December 31, 2013

- Unplanned (automatic and manual) Scrams per 7,000 critical hours
- Unplanned Power Changes per 7,000 critical hours
- Unplanned Scrams with Complications

To determine the accuracy of the performance indicator data reported during those periods, the inspectors used definitions and guidance contained in Nuclear Energy Institute (NEI) Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 7. The inspectors also reviewed Hope Creek's operator narrative logs, notifications, event reports, and NRC integrated inspection reports to validate the accuracy of the submittals.

b. Findings

No findings were identified.

4OA2 Problem Identification and Resolution (71152 – 3 samples)

.1 Routine Review of Problem Identification and Resolution Activities

a. Inspection Scope

As required by Inspection Procedure 71152, "Problem Identification and Resolution," the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that PSEG entered issues into the CAP at an appropriate threshold, gave adequate attention to timely corrective actions, and identified and addressed adverse trends. In order to assist with the identification of repetitive equipment failures and specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the CAP and periodically attended notification screening meetings.

b. Findings

No findings were identified.

.2 Annual Sample: Review of the Operator Workaround Program

a. Inspection Scope

The inspectors reviewed the cumulative effects of the existing operator workarounds, operator burdens, existing operator aids and disabled alarms, and open MCR deficiencies to identify any effect on emergency operating procedure operator actions, and any impact on possible initiating events and mitigating systems. The inspectors evaluated whether station personnel had identified, assessed, and reviewed operator workarounds as specified in PSEG procedures:

- OP-AA-102-103, “Operator Work-Around Program”
- OP-AA-102-103-1001, “Operator Burdens Program”
- OP-AA-102-103-1002, “Operator Burden Assessment”

The inspectors reviewed PSEG’s process to identify, prioritize, and resolve MCR distractions to minimize operator burdens. The inspectors reviewed the system used to track these operator workarounds and recent PSEG assessment of operator burdens. The inspectors also toured the control room and discussed the current operator workarounds with the operators to ensure the items were being addressed on a schedule consistent with their relative safety significance.

b. Findings and Observations

No findings were identified.

The inspectors observed that OP-AA-102-103-1001, Attachment 1, Section III discusses the aggregate impact assessment and states, “Results of the assessment shall be made available in the control room.” The inspectors noted that the hard copies of the Operator Challenges List and the quarterly aggregate impact assessment maintained in the control room were out-of-date, but that the most current revisions of those documents were available for review on the Hope Creek Operations internal webpage. However, because this issue was administrative and did not indicate a programmatic weakness, the inspectors determined that the issue was of minor significance and not subject to enforcement action in accordance with the NRC’s Enforcement Policy.

The inspectors determined that the issues reviewed did not adversely affect the capability of the operators to implement abnormal or emergency operating procedures. The inspectors also verified that PSEG entered operator workarounds and burdens into the CAP at an appropriate threshold and planned or implemented corrective actions commensurate with their safety significance.

.3 Annual Sample: Diesel-Driven Fire Pump, Repeated Failures to Start

a. Inspection Scope

The inspectors performed an in-depth review of PSEG's evaluations and the effectiveness of the corrective actions associated with the diesel driven fire pump (DDFP) deficiencies at the HCGS. Specifically, HCGS experienced four overspeed trips of the 00P521 DDFP in early 2013 when the DDFP failed to start for weekly operability testing and was declared inoperable. PSEG staff subsequently developed failure mode causal tables (FMCTs) for the failure scenarios and performed apparent cause and work group evaluations. This inspection was performed to evaluate whether PSEG was appropriately identifying and evaluating fire protection issues at the station and taking appropriate corrective actions to ensure the DDFP remained capable of performing the intended function.

The inspectors assessed PSEG's problem identification threshold, associated apparent cause analyses and evaluations, extent of condition reviews, and the prioritization and timeliness of actions to evaluate whether PSEG was appropriately identifying, characterizing, and correcting problems associated with the issue; and whether the planned or completed corrective actions were appropriate and met the requirements of their CAP. The inspectors reviewed the applicable notifications and associated documents, including work orders, maintenance procedures, and as-found test results. The inspectors reviewed PSEG's actions to address other possible or contributing causes. The inspectors interviewed operators and engineering personnel to assess the effectiveness of the implemented corrective actions. Finally, the inspectors walked down HCGS's DDFP and the motor-driven fire pump building to assess material condition of the systems.

b. Findings and Observations

No findings were identified.

PSEG determined that two separate component failures may have caused the overspeed trip failures to start in early 2013. In the case of the first component failure, the inspectors determined PSEG's determination that the fuel injector smoke limiter plunger may have been stuck during start-up to be reasonable. The plunger, upon freeing up after a few seconds of running, could have caused a sudden increase in fuel injection, resulting in the engine reaching the overspeed trip setting. In the second case, PSEG used FMCTs to determine that additional failures to start involved the mechanical speed switch on the diesel engine. PSEG concluded that the function of the original mechanical speed switch had weakened over time, and that the newer replacement switches were more susceptible to tripping due to vibration. The inspectors determined PSEG's conclusion to be reasonable, in part, because successful starts and surveillance tests were accomplished after PSEG removed the switch from the engine and mounted it on a platform external to the engine.

The inspectors determined PSEG's systematic approach to identifying the causes and corrective actions to be appropriate for those failures that occurred early in 2013. For instance, the smoke limiter plunger was cleaned and exercised to reduce sticking. The plunger and linkage remained free of any binding going forward. The inspectors noted that the smoke limiter plunger was factory-installed and there were no vendor-recommended PM tasks associated with the plunger. PSEG subsequently implemented a PM to inspect and ensure freedom of movement of the plunger and linkage. Secondly, the vibration-induced setpoint drift of the original and replacement speed switches was eliminated by relocating/remounting the speed switch off of the engine. The mechanical speed switch also was originally installed vendor equipment that had no recommended change-out frequency. PSEG further modified the DDFP engine controls by installing an electronic speed switch.

Further difficulties later in 2013 (additional failures to start or diesel engine trips shortly after starting) prompted additional troubleshooting which led to the installation of vendor-recommended reversed biased diodes. The inspectors observed that PSEG had been unaware of the recommendation for the reversed biased diodes at the time they developed the DCP and procured the electronic speed switch, despite a caution later found on the vendor's website. In addition, none of the three documents associated with the vendor-recommended Murphy model HD9063 speed switch (Sales Bulletin, HD9063 Installation Instructions, and the Magnetic Pickup Installation Instructions) discussed the need for installation of reversed biased diodes when connecting the switch to inductive loads. Furthermore, the vendor reported that there have been no actual failures of the HD9063 speed switch due to inductive interactions; however, PSEG installed the reversed biased diodes for the four relays connected to the output contacts of the Murphy HD9063 speed switch for the DDFP.

The observation of completely reviewing the written vendor documentation but not fully vetting information on the vendor website was discussed by the inspectors and acknowledged as a planned area for improvement by PSEG staff. The issue is being tracked as part of the licensee's organizational effectiveness initiatives and had already been entered into the CAP under a WGE (Order 70159026). At the time of this inspection, no additional DDFP start failures have occurred. Finally, the inspectors noted that PSEG staff have recently trended a potential degradation of the pump itself and are pursuing a modification for a replacement unit.

Taken collectively, the inspectors did not identify a performance deficiency that the licensee could have reasonably foreseen or corrected associated with the smoke limiter plunger, the speed switches, or the reversed biased diodes. Based on the documents reviewed and discussions with engineering personnel, the inspectors determined that PSEG's response to the issue was commensurate with the safety significance and that actions completed and planned were reasonable to address the probable and contributing causes of the fail-to-start problems with the DDFP at the station.

.4 Annual Sample: Recent B.5.b Equipment Deficiencies and Functional Assessments

a. Inspection Scope

The inspectors performed an in-depth review of PSEG's recent identification of B.5.b credited equipment deficiencies, functionality assessments, and corrective actions including:

- The B.5.b portable gas generator functionality (NOTF 20630529 – Hope Creek)
- The B.5.b portable gas generator failing to start (NOTF 20640369 – Hope Creek and 20630529 – Hope Creek)

- The replacement of the B.5.b temporary Spent Fuel Pool pump (NOTF 20630917 – Salem)
- The validation of B.5.b readiness at each site (NOTF 20633238 - Hope Creek and 20633239 - Salem)
- The B.5.b pump battery failed PM (NOTF 20635639 – Common)
- The B.5.b pump flat tire (NOTF 20636742 – Common)

The inspectors assessed PSEG's problem identification threshold, cause analyses, extent of condition reviews, compensatory actions, and the prioritization and timeliness of PSEG's corrective actions to determine whether PSEG was appropriately identifying, characterizing, and correcting problems associated with the B.5.b equipment and whether the planned or completed corrective actions were appropriate. The inspectors compared the actions taken to the requirements of PSEG's CAP.

b. Findings and Observations

Introduction. The inspectors identified a Green NCV of 10 CFR 50.54(hh)(2), "Conditions of Licenses." Specifically, PSEG failed to adequately assess the functionality of the portable generator on multiple occasions and implement adequate corrective actions to prevent reoccurrence of the B.5.b portable gas generator failure. This resulted in an unrecoverable and unavailable individual mitigating strategy associated with the remote operation of SRVs with RPV injection for approximately two and half months while the portable gas generator unavailable.

Description. During the inspection period, the inspectors conducted an in-depth review of PSEG's B.5.b mitigating strategies and recent equipment deficiencies as part of a Problem Identification and Resolution annual inspection sample. PSEG documented NOTF 20630529 for the B.5.b portable gas generator failing to start during quarterly PM on November 17, 2013. The operability screening and functionality assessment performed for this failure stated "*The portable generator is required for beyond design accident conditions per the Renewed Facility Operating License under (16) Mitigation Strategy (b) 5 - Identification of readily-available pre-staged equipment. The generator is also required per 10 CFR 50.54.h.h. The portable generator is INOPERABLE due to its inability to start. No compensatory actions are required, at present, due to the availability of redundant equipment.*"

PSEG's fix-it-now team attempted to address the notification by starting the generator, but the fix-it-now team started a different generator, the diesel trailer mounted generator, and determined this generator to be operable but failed to recognize the portable gas generator was the subject of the original NOTF 20630529. On February 4, 2014, PSEG documented NOTF 20639075 for the B.5.b portable gas generator not being worked in response to the original NOTF 20630529. The portable generator was started three times successfully on February 7, 2014, after cleaning the spark plug and replacing the fuel.

On February 18, 2014, the B.5.b portable gas generator again failed to start during its quarterly PM. The same operability screening and functionality assessment documented in NOTF 20630529 was documented in NOTF 20640369. The inspectors met with the Hope Creek B.5.b Operations Support Manager for equipment readiness on February 20, 2014, to discuss questions related to the B.5.b portable gas generator, the B.5.b pump battery, the B.5.b supporting equipment storage area, and the equipment used to transport the B.5.b pump. The inspectors reviewed the operability screening and functionality assessments associated with these notifications to understand the PSEG's evaluation of the impact that these deficiencies potentially had on the mitigating strategies implemented through 10 CFR 50.54(hh)(2). The inspectors questioned the operability screening and functionality assessment documented by operations in NOTFs 20630529 and 20640369 for the portable gas generator. The operations support manager for B.5.b equipment readiness indicated that there was no redundant B.5.b equipment available if and when the portable gas generator fails to start. Following this meeting, the B.5.b operations support manager initiated an action for engineering to review both failures of the portable gas generator to identify additional corrective actions to prevent reoccurrence.

The inspectors determined that the B.5.b portable gas generator is used for the Remote Operation of SRVs with RPV Injection mitigation strategy per Hope Creek procedure HC.OP-AM.TSC-0024, Revision 8. Specifically, the B.5.b portable gas generator is relied upon when normal SRV DC power supply from the 'B' and 'D' channels becomes unavailable and it is necessary to depressurize the RPV using the SRVs. Hope Creek's procedure provides guidance to equipment operators to operate the SRVs from three separate locations utilizing the portable gas generator as the credited power supply.

NRC Inspection Manual 0609, Appendix L, B.5.b Significance Determination Process, defines a strategy as an unrecoverable mitigation strategy if the licensee actions could neither reasonably correct nor compensate for the conditions creating the unavailability in time during a B.5.b event for the mitigating strategy to achieve its objective. The time limit is the time allowed by NEI 06-12, Revision 2, for establishment of the strategy where applicable, or a reasonable time. It also defines a mitigating strategy as unavailable if its hardware or components are not functional and ready for intended use, or personnel training and procedures are inadequate, as described in the licensee submittal and Safety Evaluation Report supporting the B.5.b license condition.

The inspectors noted that PSEG'S Testing and Reference Manual, OP-AA-106-103-1001, "B.5.b Mitigating Strategies Equipment Expectations," was developed to provide standardized guidance for selected elements of the Mitigation Strategy License Condition as required by 10 CFR 50.54(hh)(1) and (2), and was implemented by both Salem and Hope Creek on December 4, 2013. This procedure requires, in part, Section 3.3.1.3 states that "[B.5.b] equipment is maintained in a state of readiness to support B.5.b mitigation strategies." Also, Section 4.6 states, "Identified B.5.b equipment deficiencies shall be documented IAW LS-AA-125, "Corrective Action Program," and Equipment deficiencies that would prevent B.5.b equipment from performing its intended function shall be worked under the priority work list in accordance with the work management process." PSEG's CAP procedure requires the timely and effective completion of CAP assignment and documentation, including corrective actions and effectiveness reviews.

The inspectors concluded that PSEG failed to adequately assess the functionality of the portable gas generator on multiple occasions and implement adequate corrective actions to prevent reoccurrence of the portable gas generator failing to start per site procedures.

Based on this information, the inspectors determined that the B.5.b portable gas generator was unavailable and unrecoverable from November 17, 2013, through February 4, 2014 (approximately 2.5 months), without adequate compensatory measures in place to ensure the affected mitigation strategy remained recoverable and available. PSEG initiated NOTF 20641483 for this issue. PSEG's corrective actions include repairing the B.5.b portable gas generator and returning it to an available, standby condition as well as performing a validation of all B.5.b equipment and associated mitigating strategies.

Analysis. The inspectors determined that PSEG failing to adequately assess the functionality of the portable generator on multiple occasions and implement corrective actions to prevent reoccurrence of failure of the B.5.b portable gas generator was a performance deficiency that was reasonably within the licensee's ability to foresee and correct and should have been prevented. The performance deficiency was determined to be more than minor because it was associated with the equipment performance attribute of the Mitigating Systems cornerstone, and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e. core damage). The inspectors determined that this finding was of very low safety significance (Green) using NRC IMC 0609, Appendix L, "B.5.b Significance Determination Process," Table 2 - Significance Characterization, dated December 24, 2009, as specified for 10 CFR 50.54(hh) findings by IMC 0609, Attachment 4, "Initial Characterization of Findings," dated June 19, 2012, because the finding affected the Mitigating Systems cornerstone while the plant was at power and resulted in an unrecoverable unavailability of an individual mitigating strategy. Specifically, because the B.5.b portable gas generator was not functional for approximately 2.5 months with no compensatory actions in place, the Remote Operation of SRVs with RPV Injection mitigation strategy per Hope Creek procedure HC.OP-AM.TSC-0024, Revision 8, was determined to be unrecoverable and unavailable during this time. The inspectors noted that the RCIC system remained functional during this time period and as such the finding did not represent an unrecoverable unavailability of multiple mitigating strategies such that injection to RPV could not have occurred.

The inspectors determined that the contributing cause that provided the most insight into the performance deficiency was associated with the cross-cutting aspect of Problem Identification and Resolution, Evaluation, because PSEG failed to thoroughly evaluate equipment deficiencies related to the B.5.b portable gas generator to ensure that the resolutions addressed causes and extent of conditions commensurate with the B.5.b equipment safety significance. [P.2]

Enforcement. 10 CFR 50.54(hh)(2), "Conditions of Licenses," in part, requires that PSEG develop and implement guidance and strategies intended to maintain or restore core cooling to mitigate fuel damage under the circumstances associated with loss of large areas of the plant due to explosions or fire. Specifically, PSEG guidance OP-AA-106-103-1001, "B.5.b Mitigating Strategies Equipment Expectations," Revision 0, was developed to provide standardized guidance for selected elements of the mitigation strategies required by this license condition and was implemented by PSEG on December 4, 2013. This guidance required, in part, that "[B.5.b] equipment is maintained in a state of readiness to support B.5.b mitigation strategies," and that, "identified B.5.b equipment deficiencies shall be documented IAW LS-AA-125, "Corrective Action Program," and Equipment deficiencies that would prevent B.5.b equipment from performing its intended function shall be worked under the priority work list in accordance with the work management process." LS-AA-125 requires, in part, the timely and effective completion of CAP assignments and documentation, including corrective actions and effectiveness reviews.

Contrary to this, on three occasions between November 17, 2013, and February 18, 2014, PSEG failed to adequately assess the functionality of the portable generator on multiple occasions and implement adequate corrective actions to prevent reoccurrence of the B.5.b portable gas generator failure. This performance deficiency resulted in an unrecoverable unavailability of an individual mitigating strategy per PSEG's procedure HC.OP-AM.TSC-0024, "Remote Operation of SRVs with RPV Injection," Revision 8. PSEG's corrective actions included repairing the B.5.b portable gas generator as well as performing a validation of all B.5.b equipment and associated mitigating strategies. Because of the very low safety significance (Green) and because the issue was entered into its CAP as NOTF 20641483, it is being treated as an NCV, consistent with Section 2.3.2 of the NRC's Enforcement Policy **(NCV 05000354/2014002-05, Failure to Maintain B.5.b Equipment in a State of Readiness to Support Mitigation Strategies per 10 CFR 50.54(hh)(2)).**

4OA3 Follow-Up of Events and Notices of Enforcement Discretion (71153 – 3 samples)

.1 Plant Events

a. Inspection Scope

For the plant events listed below, the inspectors reviewed and/or observed plant parameters, reviewed personnel performance, and evaluated performance of mitigating systems. The inspectors communicated the plant events to appropriate regional personnel, and compared the event details with criteria contained in IMC 0309, "Reactive Inspection Decision Basis for Reactors," for consideration of potential reactive inspection activities. As applicable, the inspectors verified that PSEG made appropriate emergency classification assessments and properly reported the event in accordance with 10 CFR 50.72 and 50.73. The inspectors reviewed PSEG's follow-up actions related to the events to assure that PSEG implemented appropriate corrective actions commensurate with their safety significance.

- Turbine trip followed by a reactor trip on high moisture separator level due to an emergency level control failure on December 5, 2013 (EN 49608)
- Inadvertent dilution of SLC storage tank on March 12, 2014 (EN 49909)
- Potential GE-14 fuel defect resulting in abnormal weekly off-gas sample results and entrance by PSEG into procedure NF-AA-430, "Failed Fuel Action Plan," to increase chemistry sampling and convene the failed fuel monitoring team on March 24 (NOTF 20644437)

b. Findings

Introduction. A Green self-revealing NCV of TS 6.8.1, "Procedures and Programs," was identified regarding PSEG's operation of the system that controls steam flow to the main turbine and condenser, the DEHC system. Specifically, PSEG's failure to use procedures resulted in improper operation of the DEHC system during scram recovery which caused the main turbine BPVs to cycle rapidly resulting in a reactor pressure transient, reactor water level transient, and RPS actuation.

Description. On December 5, 2013, with reactor power at approximately 75 percent, a post-maintenance test to tune the 'A' moisture separator (MS) emergency level controller was in progress. At 3:25 a.m., the 'A' MS dump valve failed closed resulting in a high level in the 'A' MS, a main turbine trip, and subsequent reactor scram as a result of the turbine trip above 24 percent power. This scram also caused both RRPs to trip, as designed, on end-of-cycle recirculation pump trip.

Due to a delay in resetting the scram, thermal stratification of the reactor coolant in the reactor vessel occurred as a result of high flow through the control rod drive system. As a result, the differential temperature requirements to restart a RRP were no longer satisfied. In order to establish the conditions necessary to restart a RRP or facilitate the use of secondary condensate pumps to raise reactor water level and promote natural circulation, the control room supervisor (CRS) directed the nuclear control operator (NCO) to use the DEHC cooldown controller to lower reactor pressure. The NCO was implementing PSEG procedure HC.OP-AB.ZZ-0001, Attachment 15, "Post Scram Pressure Control," which does not include the DEHC cooldown controller as an approved method of post-scram reactor pressure control. The CRS believed HC.OP-AB.ZZ-0001, Attachment 15 contained direction for a reactor cooldown and therefore did not specify what procedure the NCO was to use. It was the NCO's belief that the CRS was ordering the reactor cooldown from emergency operating procedures and that entering another procedure was not required. As a result of this assumption between the CRS and NCO, no procedure was used for the reactor cooldown. At 4:28 a.m., a reactor cooldown was commenced using the cooldown controller at a rate of 80°F/hour without the use of a site procedure. PSEG's procedure HC.OP-IO.ZZ-0004, "Shutdown from Rated Power to Cold Shutdown," is required to be implemented when using the DEHC cooldown controller method for a reactor cooldown.

At 5:05 a.m., the combination of reactor water cleanup bottom head drain flow and a lowered steam dome pressure satisfied the requirements for RRP restart. The reactor cooldown using the DEHC cooldown controller was then secured without the use of a site procedure. Upon securing the cooldown controller without the use of a site procedure, a pressure mismatch between pressure set and throttle pressure resulted in all BPVs cycling open then closed. This rapid change in BPV position caused an initial swell of reactor water level above 54 inches (level 8, feedwater/HPCI/RCIC/ turbine trip setpoint) followed by a shrink below 12.5 inches (level 3, scram setpoint) and RPS actuation. HC.OP-IO.ZZ-0004 requires operators to match pressure set with throttle pressure prior to securing the cooldown controller. Implementing the steps provided in HC.OP-IO.ZZ-0004 ensures that a reactor pressure transient does not occur. Following the RPS actuation, the crew stabilized the plant in accordance with site procedures.

Inspectors reviewed the quick human performance investigation performed to evaluate the misoperation of the DEHC system. The inspectors also reviewed PSEG procedures concerning scram recovery, DEHC operations, and interviewed members of the operations staff involved in the event. PSEG has placed this event into their CAP as NOTF 20632369. The SM, CRS, and NCO were removed from shift and retrained per PSEG order 70162334. This order also requires each SM to review HC.OP-AB.ZZ-

0001, Attachment 15 with their crew and receive training on this event, decision making, and procedural adherence.

Analysis. The inspectors determined that PSEG's failure to follow procedures for reactor cooldown during scram recovery on December 5, 2013, was a performance deficiency that was within the capability of PSEG to foresee and correct and should have been prevented. Specifically, PSEG failed to use an approved method of post-scram pressure control in accordance with HC.OP-AB.ZZ-0001(Q) Attachment 15, and subsequently failed to secure from use of the DEHC cooldown controller in accordance with HC.OP-IO.ZZ-0004. The performance deficiency is more than minor because it is associated with the human performance attribute of the Mitigating Systems cornerstone and adversely affected its objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, PSEG's failure to implement procedures resulted in an unplanned reactor pressure transient, reactor water level transient, and ultimately resulted in RPS actuation and a trip signal to standby safety injection systems (HPCI and RCIC) during scram recovery.

The inspectors determined the finding to be of very low safety significance (Green) in accordance with NRC IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," dated June 19, 2012. Using Exhibit 2 of IMC 0609, Appendix A, which contains the screening questions for the Mitigating Systems cornerstone, the inspectors determined the finding to be of very low safety significance (Green) because: it was not a deficiency affecting the design or qualification of a mitigating SSC; it did not represent a loss of system or function; it did not represent the loss of function for any TS system, train, or component beyond the allowed TS outage time; and it did not represent an actual loss of function of any non TS trains of equipment designated as high safety-significant in accordance with the PSEG's maintenance rule program. IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," was used to screen this finding rather than Appendix G, "Shutdown Operations Significance Determination Process," because IMC 0609, Attachment 4, "Initial Characterization of Findings," states that "Appendix G is applicable during refueling, forced, and maintenance outages starting when the licensee has met the entry conditions for RHR and RHR cooling has been initiated and ends when RHR has been secured during plant heat-up."

The inspectors determined that this finding had a cross-cutting aspect in Human Performance, Consistent Process, because PSEG failed to ensure that individuals use a consistent, systematic approach to make decisions and incorporate risk insights as appropriate. Specifically, operators did not use a systematic approach when making the decision to lower reactor pressure using the DEHC cooldown controller on December 5, 2013. [H.13]

Enforcement. TS 6.8.1.a, "Procedures and Programs," requires in part, that written procedures recommended in Appendix A of RG 1.33, Revision 2, shall be established, implemented, and maintained. Section 2.c of RG 1.33, Revision 2, Appendix A, requires general plant operating procedures for recovery from a reactor trip. PSEG procedure HC.OP-AB.ZZ-0001 Attachment 15 lists approved methods of post-scram reactor pressure control and HC.OP-IO.ZZ-0004 outlines the steps for DEHC cooldown controller operation. Contrary to the above, on December 5, 2013, PSEG did not use an approved method of post-scram reactor pressure control and did not match pressure set to throttle pressure prior to securing the cooldown which resulted in an unplanned reactor pressure transient, reactor water level transient, and ultimately resulted in RPS actuation and a trip signal to standby safety injection systems (HPCI and RCIC) during scram recovery. As part of PSEG's corrective actions, the operators involved in the event were removed from shift and retrained, each SM has reviewed post-scram reactor pressure control methods with their crew and received training on this event, decision making, and procedural adherence. Because this finding was of very low safety significance (Green) and was entered into PSEG's CAP as NOTF 20632369, this violation is being treated as a NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy (**NCV 05000354/2014002-06, Failure to Use Approved Method of Post-Scram Reactor Pressure Control).**

2 <u>(Closed) Licensee Event Report (LER) 05000354/2013-005-00</u>, Low-Low Set Safety/Relief Valve Pilot Solenoid Operated Valve Failed As-Found Testing

a. <u>Inspection Scope</u>

On October 18, 2013, PSEG was notified by NWS Technologies that the solenoid operated valve (SOV) associated with the pilot valve assembly for SRV 1ABHV-F013P ('P' SRV) failed its required 'as-found' functional testing. The SOV failure affected the operability of the relief valve function and the low-low set function of the 'P' SRV as required by TS 3.4.2.2. Results of the 'P' SRV SOV failure analysis confirmed that the SOV failure occurred at some point during the operating cycle. Failure analysis determined that the cause of the inoperability was a missing anti-rotation pin that secures the adjustable plunger in place. The anti-rotation pin was never installed during manufacturer assembly.

TS 3.4.2.2 requires the relief valve function and the low-low set function for the SRV-H and SRV-P to be OPERABLE in Operational Condition 1, 2, and 3. With one SRV inoperable, the TS action requires that the valve be restored to operable within 14 days or be in Hot Shutdown within the next 12 hours and in Cold Shutdown in the following 24 hours. Therefore, the 'P' SRV was inoperable for a period longer than the TS allowed outage time. This condition was reportable in accordance with 10 CFR 50.73(a)(2)(i)(B) as an operation or condition which was prohibited by Hope Creek TS. The LER was reviewed for accuracy, the appropriateness of corrective actions, violations of NRC requirements, and generic issues. Additionally, the inspectors reviewed the associated work group evaluation and technical evaluation, and the adequacy of corrective actions. Corrective actions included replacing the solenoid.

b. <u>Findings</u>

This issue is considered within the traditional enforcement process because there was no performance deficiency identified and IMC 0612, Appendix B, "Issue Screening," directs disposition of this issue in accordance with the Enforcement Policy. The inspectors used the Enforcement Policy, Section 6.1 – Reactor Operations, to evaluate the significance of this violation. The inspectors concluded that the violation is more than minor and best characterized as Severity Level IV. In reaching this conclusion, the inspectors considered that the underlying technical finding would have been evaluated as having very low safety significance (i.e. green) under the Reactor Oversight Process using IMC 0609, Appendix G, “Shutdown Operations Significance Determination Process.” The inspectors screened the issue, and evaluated it using Checklist 7 of IMC 0609, Appendix G, Attachment 1. Based on these reviews, this issue would screen as very low safety significance (Green), because qualitative assessment concluded that PSEG maintained adequate mitigation capability and the event was not characterized as a loss of control.

The manufacturer assembly error could not be identified during inspection and testing. Because it has been determined that it was not reasonable for PSEG to foresee and prevent inadequate assembly of the SOV by the manufacturer, no performance deficiency exists. The NRC has decided to exercise enforcement discretion in accordance with Section 3.5 of the NRC Enforcement Policy and refrain from issuing enforcement action for the violation of TS (EA-14-050). Further, because licensee actions did not contribute to this violation, it will not be considered in the assessment process or the NRC’s Action Matrix. This LER is closed.

4OA5 Other Activities

Cross-Cutting Aspects

The table below provides a cross-reference from the 2013 and earlier findings and associated cross-cutting aspects to the new cross-cutting aspects resulting from the common language initiative. These aspects and any others identified since January 2014, will be evaluated for cross-cutting themes and potential substantive cross-cutting issues in accordance with IMC 0305 starting with the 2014 mid-cycle assessment review.

| Finding | Old Cross-Cutting Aspect | New Cross-Cutting Aspect |
|---|---|---|
| NCV 05000354/2013004-01, Failure to Follow PMT Procedure Prior to Returning the ‘B’ FRVS Recirculation Fan to Service | H.1(b) | H.14 |
| NCV 05000354/2013004-02, NCV Failure to Perform Maintenance in Accordance with Station Procedures Led to RCS Pressure Boundary Leakage | H.4(c) | H.2 |
| NCV 05000354/2013005-01, Failure to Follow Procedure for Configuration Control Activity Adversely Affected Unidentified Leakage in the Drywell | H.4(a) | H.12 |
| NCV 05000354/2013005-02, Failure to Follow the Primary Containment Closeout Procedure when Declaring the Drywell Ready for Power Operation | H.4(b) | H.8 |
| FIN 05000354/2013005-03, Inadequate Evaluation of Containment Vent Functionality | H.2(a) | H.6 |
| FIN 05000354/2013005-04 FIN Failure to Identify Adverse Trend Regarding Bailey Module and Auxiliary Card Failures | P.1(b) | P.4 |

4OA6 Meetings, Including Exit

Annual Sample Exit Meeting Summary

On April 17, 2014, the inspectors presented the inspection results to Mr. P. Davison, Site Vice President of Hope Creek, and other members of the Hope Creek staff. The inspectors verified that no proprietary information was retained by the inspectors or documented in this report.

**ATTACHMENT: SUPPLEMENTARY INFORMATION**

## SUPPLEMENTARY INFORMATION

## KEY POINTS OF CONTACT

Licensee Personnel

P. Davison, Site Vice President
E. Carr, Plant Manager
V. Acevedo, Operations Shift Supervisor
T. Agster, Senior Reactor Operator
C. Boxer, Reactor Operator
C. Banner, Emergency Preparedness Manager
S. Bier, Emergency Operating Procedures Coordinator
R. Black, Fire Marshall
J. Boyer, Design Engineering Supervisor
S. Brahma, Senior Design Engineer
D. Bush, System Engineer
M. Cardile, Fire Protection Supervisor
J. Carlin, Fire Protection Superintendent
S. Connelly, System Engineer
C. Garver, Senior Reactor Operator
A. Ghose, Senior Design Engineer
W. Hart, Fire Protection Operator
W. Hicks, Reactor Operator
R. Kelly, Reactor Operator
S. Kopsick, Operations Shift Supervisor
S. Lazorchak, Senior Design Engineer
S. Madden, Design Engineering Supervisor
E. Martin, Senior Program Engineer
J. Materazo, Senior Design Engineer
V. McPherson, Instrumentation and Controls Maintenance Superintendent
T. Morin, Senior Regulatory Compliance Engineer
J. Panagotopolous, Shift Manager
M. Peterson, Fire Protection System Manager
M. Reed, Shift Operations Superintendent
M. Rooney, System Engineer
V. Rubinetti, Design Engineer
W. Schmidt, Instrumentation and Controls Maintenance Supervisor
L. Sinclair, Electrical Maintenance Superintendent

## LIST OF ITEMS OPENED, CLOSED, DISCUSSED, AND UPDATED

Opened/Closed

| | | |
|---|---|---|
| 05000354/2014002-01 | NCV | Inadequate Preventative Maintenance for Safety-Related Circuit Cards (Section 1R13) |

| | | |
|---|---|---|
| 05000354/2014002-02 | NCV | Untimely Identification and Corrective Actions for a Condition Adverse to Quality related to 480 VAC Masterpact Breakers (Section 1R15) |
| 05000354/2014002-03 | NCV | Failure to Follow Procedure Resulting in the Potential Inoperability of a Safety-Related System (Section 1R15) |
| 05000354/2014002-04 | NCV | Inadequate Evaluation of 480VAC Motor Control Center Design Change (Section 1R18) |
| 05000354/2014002-05 | NCV | Failure to Maintain B.5.b Equipment in a State of Readiness to Support Mitigation Strategies per 10 CFR 50.54(hh)(2) (Section 4OA3) |
| 05000354/2014002-06 | NCV | Failure to Use Approved Method of Post-Scram Reactor Pressure Control (Section 4OA3) |

Opened
None

Closed

| | | |
|---|---|---|
| 05000354/2013-005-00 | LER | Low-Low Set Safety/Relief Valve Pilot Solenoid Operated Valve Failed As-Found Testing (Section 4OA3) |

## LIST OF DOCUMENTS REVIEWED

**Section 1R01: Adverse Weather Protection**

Procedures
HC.OP-AB.MISC-0001, Acts of Nature, Revision 23
HC.OP-AR.GQ-0001, Intake Structure HVAC Local Panel 1EC581, Revision 9
HC.OP-GP.ZZ-0003, Station Preparations for Winter Conditions, Revisions 28
HC.OP-SO.AP-0001, Condensate Storage and Transfer System Operation, Revision 37
HC.OP-SO.GD-0001, Fire Pump House Ventilation System Operation, Revision 0
HC.OP-SO.GM-0001, Diesel Area Ventilation System Operation, Revision 20
OP-AA-108-111-1001, Severe Weather and Natural Disaster Guidelines, Revision 9
OP-SO.GD-001, Fire Pump House Ventilation System Operation, Revision 0
SH.FP-TI.FP-0001, Freeze Prevention and Winter Readiness of Fire Protection Systems, Revision 4
WC-AA-107, Seasonal Readiness, Revision 12
WC-AA-107, Seasonal Readiness, Revision 13

Notifications

| | | | | | |
|---|---|---|---|---|---|
| 20463793 | 20479131 | 20523017 | 20576019 | 20585973 | 20620763 |
| 20622914 | 20625563 | 20630707 | | | |

Maintenance Orders/Work Orders

| | | | | | |
|---|---|---|---|---|---|
| 30244612 | 60105459 | 60109596 | 60110798 | 60111193 | 60112398 |
| 60112425 | 60112426 | 60112963 | | | |

Miscellaneous
2013 Hope Creek Winter Seasonal Readiness Affirmation dated October 1, 2013
Hope Creek Operator Narrative Logs, 1/1/14 – 1/3/14
Hope Creek Operator Narrative Logs, 1/7/14 – 1/8/14
Hope Creek POD, 1/7/14

**Section 1R04: Equipment Alignment**

Procedures
HC.CH-AD.BH-0001, Chemical Addition to the Standby Liquid Control System, Revision 21
HC.CH-CA.ZZ-0026, Boron by Mannitol Titration, Revision 18
HC.FP-ST.KC-0002, Electric Motor Driven Fire Pump Operability Test, Revision 7
HC.FP-ST.KC-0009, Diesel Driven Fire Pump Operability Test, Revision 19
HC.OP-DL.ZZ-0026, Surveillance Log, Revision 139
HC.OP-IS.BH-0004, Standby Liquid Control Pump-BP208 Inservice Test, Revision 12
HC.OP-SO.BH-0001, Standby Liquid Control System Operation, Revision 16
HC.OP-SO.GJ-0001, A(B)K400 Control Area Chilled Water System Operation, Revision 60
HC.OP-SO.GK-0001, Control Area Ventilation System Operation, Revision 22
HC.OP-ST.BH-0001, SLC Valve Operability Test – Monthly, Revision 8
HC.OP-ST.BH-0002, SLC Flow Test – 18 Months, Revision 28
HC.OP-ST.BH-0003, SLC System Tank Flow Test – 18 Months, Revision 10
HC.OP-ST.EG-0001, SACS Flow Path Verification – Monthly, Revision 9
HC-PRA-005.0003, Standby Liquid Control System Notebook, Revision 3
OP-AA-102-103, Operator Work-Around Program, Revision 2
OP-AA-102-103-1001, Operator Burdens Program, Revision 1
OP-AA-102-103-1002, Operator Burden Assessment, Revision 0
OP-AA-108-112, Definition and Measurement of Mispositioned Plant Components, Revision 3
OP-AA-108-115, Operability Determinations, Revision 3
OP-AA-108-115-1002, Supplemental Considerations for Immediate On-shift Operability Determinations, Revision 7

Notifications (*NRC-identified)

| | | | |
|---|---|---|---|
| 20201083 | 20596753 | 20627840 | 20643182 |
| 20201083 | 20597614 | 20627841 | 20643199 |
| 20237940 | 20607005 | 20628185 | 20643199 |
| 20237940 | 20611250 | 20628782 | 20643229 |
| 20484366 | 20616228 | 20629256 | 20643229 |
| 20484366 | 20617859 | 20632140 | 20643322 |
| 20536283 | 20619029 | 20638485* | 20643322 |
| 20589731 | 20621728 | 20640367 | 20643887* |
| 20592599 | 20626239 | 20641583 | |
| 20594838 | 20627837 | 20643182 | |

Drawings
M-11-1, Sheet 1, Safety Auxiliaries Cooling, Revision 31
M-11-1, Sheet 2, Safety Auxiliaries Cooling, Revision 42
M-11-1, Sheet 3, Safety Auxiliaries Cooling, Revision 28
M-41-1, Sheet 1, Nuclear Boiler, Revision 39
M-48-1, Sheet 1, Standby Liquid Control, Revision 16

Maintenance Orders/Work Orders

| | | | | | |
|---|---|---|---|---|---|
| 30194431 | 50163176 | 60115632 | 80111356 | 30218768 | 50164008 |
| 70155412 | 40022261 | 60114374 | 80069906 | | |

Miscellaneous
10855-D3.33, Design, Installation and Test Specification for Standby Liquid Control System, Revision 3
Calculation 626-0012, Foundations for Seismic Category II/I Mechanical Equipment
Hope Creek Event # 49909, Standby Liquid Control System Sample Concentration Outside
Hope Creek Operations Narrative Logs, March 11 – 14, 2014
Hope Creek Operations Shift Calculation for SLC Tank Concentration Immediate Operability, March 13, 2014
Hope Creek Standby Liquid Control System Design Spec Data Sheet (22A7641AA), Revision 8
Hope Creek Standby Liquid Control System Tank 1OT-204 Level – Calculation 1SC-BH-0001, Revision 0
Hope Creek UFSAR, Section 9.3.5 Standby Liquid Control System, Revision 0
LTA H-13-0075, Hope Creek Long Term Action for Fire pumps
Technical Specification Limits, March 13, 2014WCD 4351338

**Section 1R05: Fire Protection**

Procedures
FRH-II-412, RCIC Pump & Turbine Room, RHR Pump and Heat Exchanger Rooms & Electrical Equipment Room, Elevation 54’, Revision 3
FRH-II-413, HPCI Pump & Turbine Room, RHR Pump & Heat Exchanger Rooms, Elevation 54’, Revision 3
FRH-II-541, Revision 7, Hope Creek Pre-Fire Plan Class 1E Switchgear Rooms Elevation: 130’-0” on March 5, 2014
FRH-II-561, Hope Creek Pre-Fire Plan Control Equipment HVAC Inverter and Battery Rooms, Elevation 163’-6”, Revision 7
FRH-II-562, Hope Creek Pre-Fire Plan HVAC Equipment, Inverter, and Battery Rooms, Elevation 163’-6”, Revision 5
HC.FP-ST.ZZ-0031(F), Class 1 Fire Damper Functional Test, Revision 5
HC.FP-SV.ZZ-0028(F), Class 1 Fire Damper Visual Inspection, Revision 4

Notifications (*NRC identified)
20641586*

Drawings
M-85-1, Sheet 2, P&ID Auxiliary Building Diesel Area Air Flow Diagram, Revision 11
M-88-1, Sheet 2, P&ID Aux. Building / Diesel Area Control Diagram, Revision 13
P-9286-1, HVAC Area Drawing Aux. Building – Area 28 Plan, Elevation 163’-6”, Revision 1

Miscellaneous
HC Standing Order 2013-054, Field Verification of Masterpact Circuit Breakers, effective December 24, 2013

**Section 1R07: Heat Sink Performance**

Procedures
ER-AA-340-1002, Service Water Heat Exchanger (HX) and Component Inspection Guide, Revision 5
HC.OP-FT.EA-0001, Validating SSWS Flow Through SACS HXs, Revision 15

Notifications

| | | | | |
|---|---|---|---|---|
| 20625096 | 20626216 | 20631620 | 20625130 | 20626367 |

Maintenance Orders/Work Orders

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|---|---|---|---|---|---|
| 30158631 | 30214169 | 30249946 | 30256199 | 30158800 | 30214170 |
| 30251679 | 30259412 | | | | |

**Section 1R11: Licensed Operator Requalification Program and Licensed Operator Performance**

Procedures
H14-01, Hope Creek Onsite EP Drill Guide, 1/21/14
HC.OP-AB.IC-0001, Control Rod, Revision 16
HC.OP-IS.BD-0001, Reactor Core Isolation Cooling Pump – OP203 – Inservice Test, Revision 58
HC.OP-SO.BB-0002, Reactor Recirculation System Operation, Revision 98
HC.OP-SO.SE-0001, Nuclear Instrumentation System Operation, Revision 22
HC.OP-SO.SF-0001, Reactor Manual Control System Operation, Revision 32
HU-AA-1211, Pre-Job Briefings, Revision 11
OP-AA-101-111-1004, Operations Standards, Revision 4
OP-AA-300, Reactivity Management, Revision 6
OP-AB-300-1001, BWR Control Rod Movement Requirements, Revision 6
OP-AB-300-1003, BWR Reactivity Maneuver Guidance, Revision 11

Notifications

| | | |
|---|---|---|
| 20637842 | 20639185 | 20639756 |

Miscellaneous
H14-01, Hope Creek Onsite Drill Critique, 1/24/14
REMA 2014-0009, February 2014 Line Outage, Revision 0

**Section 1R12: Maintenance Effectiveness**

Procedures
ER-AA-10, Equipment Reliability Process Description, Revision 1
ER-AA-3001, Long Term Asset Management Strategies, Revision 4
ER-AA-310, Implementation of the Maintenance Rule, Revision 11
ER-AA-310-1003, Maintenance Rule – Performance Criteria Selection, Revision 5
ER-AA-310-1004, Maintenance Rule – Performance Monitoring, Revision 10

ER-AA-310-1005, Maintenance Rule – Dispositioning Between (a)(1) and (a)(2), Revision 9
ER-HC-310-1009, Maintenance Rule System Function and Risk Significant Guide, Revision 10
FRH-II-561, Hope Creek Pre-Fire Plan Control Equipment HVAC Inverter and Battery Rooms, Elevation 163'-6", Revision 7
FRH-II-562, Hope Creek Pre-Fire Plan HVAC Equipment, Inverter, and Battery Rooms, Elevation 163'-6", Revision 5
HC.FP-ST.ZZ-0031(F), Class 1 Fire Damper Functional Test, Revision 5
HC.FP-SV.ZZ-0028(F), Class 1 Fire Damper Visual Inspection, Revision 4
HC.IC-FT.BD-0005(Q), RCIC – Division 2 Channel E51-N035A, E51-N035E Condensate Storage Tank Low Level, Revision 9
HC.OP-GP.ZZ-0010(Q), Temporary Battery Room Temperature / Hydrogen Control, Revision 1
MA-AA-716-004, Conduct of Troubleshooting, Revision 12
MA-AA-716-210-1005, Predefine Change Process, Revision 3
WC-AA-111, Predefine Process, Revision 8

Notifications (*NRC identified)

| | | | | | |
|---|---|---|---|---|---|
| 20450057 | 20489633 | 20573863 | 20596497 | 20596499 | 20599917 |
| 20600071 | 20620147 | 20627200 | 20628047 | 20629947 | 20633364 |
| 20634962 | 20634982 | 20635136* | 20635785 | 20637873 | |

Maintenance Orders/Work Orders

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|---|---|---|---|---|---|
| 70043788 | 70065167 | 70117674 | 70129371 | 70151557 | 70152218 |
| 70153037 | 70160365 | 70161848 | 70162460 | | |

Drawings
M-85-1, Sht. 2 of 2, P&ID Auxiliary Building Diesel Area Air Flow Diagram, Revision 11
M-88-1, Sht. 2, P&ID Aux. Building / Diesel Area Control Diagram, Revision 13
M-30-1, Sheet 2, Diesel Engine Auxiliary Systems Intercooler and Injector Cooling, Jacket Water, Crankcase Vacuum Air Intake, Exhaust, and Vibration Monitoring System, Revision 23
P-9286-1, HVAC Area Drawing Aux. Building – Area 28 Plan, Elevation 163'-6", Revision 1

Miscellaneous
DEH-130281, Determine if Current Rely Testing / Replacement Schedule Ensures Reliable Performance (70152218-0370)

**Section 1R13: Maintenance Risk Assessments and Emergent Work Control**

Procedures
ER-AA-10, Equipment Reliability Process Description, Revision 1
HC.OP-SO.PN-0001, 120 VAC Electrical Distribution, Revision 24
LS-AA-125, Corrective Action Program, Revision 17
MA-AA-716-210, Preventative Maintenance (PM) Process, Revision 10
MA-AA-716-210-1001, Performance Centered Maintenance (PCM Templates), Revision 12
MA-AA-716-210-1004, First Call Preventative Maintenance (PM) Strategy. Revision 6
MA-AA-716-210-1005, Predefine Change Processing, Revision 3
OP-AA-101-112-1002, On-Line Risk Assessment, Revision 8
OP-AA-108-107-1001, Electric System Emergency Operations and Electric Systems Operator Interface, Revision 3
OP-AA-108-116, Protected Equipment Program, Revision 8

WC-AA-101, On-Line Work Management Process, Revision 22
WC-AA-105, Work Activity Risk Management, Revision 2
WC-AA-111, Predefine Process, Revision 8

Notifications (*NRC identified)

| | | | | | |
|---|---|---|---|---|---|
| 20458990 | 20459036 | 20467125 | 20573863 | 20614188 | 20633364 |
| 20634488 | 20637873 | 20639797* | 20639801* | 20639852* | 20639853* |
| 20639963* | 20639964* | 20643701* | 20642518 | | |

Maintenance Orders/Work Orders

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|---|---|---|---|---|---|
| 30098823 | 30192325 | 60103864 | 60114377 | 70065167 | 70080090 |
| 70109417 | 70111371 | 70152218 | 70162460 | 70162737 | 80089525 |
| 80107018 | | | | | |

Miscellaneous
DEH-130281, Determine if Current Rely Testing / Replacement Schedule Ensures Reliable Performance (70152218-0370)
E-0012-1, 120 VAC Instrumentation and Misc. Systems Diagram, Revision 14
HCGS PRA Risk Evaluation Form for February 9, 2014, through February 48, 2014, Revision 0
HCGS PRA Risk Evaluation Form for February 16, 2014, through February 22, 2014, Revision 2
HCGS PRA Risk Evaluation Form for December 24, 2013, Revision 0
Hope Creek Shutdown Risk Status Sheet, 1/7/14
Maintenance Plan 58782

## Section 1R15: Operability Determinations and Functionality Assessments

Procedures
CC-AA-11, Nonconforming Materials, Parts, or Components, Revision 4
ER-AA-2006, Lost Parts Evaluation, Revision 8
FRH-II-541, Revision 7, Hope Creek Pre-Fire Plan Class 1E Switchgear Rooms Elevation: 130’-0” on March 5, 2014
HC.CH-AD.BH-0001, Chemical Addition to the Standby Liquid Control System, Revision 21
HC.CH-CA.ZZ-0026, Boron by Mannitol Titration, Revision 18
HC.IC-CC.FC-0013, RCIC Turbine Steam – Division 2, Channel F-4158, S-4280, RCIC Pump Turbine Control (RSP), Revision 14
HC.MD-CM.BJ-0001, High Pressure Coolant Injection Main Pump Overhaul, Revision 8
HC.MD-CM.BJ-0002, High Pressure Coolant Injection Booster Pump Overhaul, Revision 12
HC.MD-CM.KJ-0009, Diesel Generator Fuel Oil System Maintenance, Revision 12
HC.MD-PM.BJ-0003, High Pressure Coolant Injection Gear Reducer Overhaul, Revision 4
HC.MD-ST.KJ-0001, Diesel Generator Technical Specification Surveillance and Preventative Maintenance, Revision 45
HC.OP-AB.ZZ-0135, Station Blackout/Loss of Offsite Power/Diesel Generator Malfunction, Revision 39
HC.OP-AM.TSC-0004, Alternate Power Supply to 1E 125/250 VDC, Revision 9
HC.OP-AM.TSC-0007, Fire Water Ring Header Make Up from the Delaware River, Revision 2
HC.OP-AM.TSC-0024, Remote Operation of SRVs with RPV Injection, Revision 8
HC.OP-DL.ZZ-0026, Surveillance Log, Revision 139
HC.OP-IO.ZZ-0008, Shutdown from Outside Control Room, Revision 34
HC.OP-IS.BH-0004, Standby Liquid Control Pump-BP208 Inservice Test, Revision 12
HC.OP-SO.BH-0001, Standby Liquid Control System Operation, Revision 16
HC.OP-SO.BJ-0001, High Pressure Coolant Injection System Operation, Revision 48

HC.OP-SO.PB-0001, 4.16 kilovolt (KV) System Operation, Revision 29
HC.OP-ST.BH-0001, SLC Valve Operability Test – Monthly, Revision 8
HC.OP-ST.BH-0003, SLC System Tank Flow Test – 18 Months, Revision 10
HC.OP-ST.KJ-0003, Emergency Diesel Generator 1CG400 Operability Test, Revision 76
HC.OP-ST.ZZ-0001, Power Distribution Lineup – Weekly, Revision 36
LS-AA-125, Corrective Action Program, Revision 17
LS-AA-125-F2, Long Term Corrective Action (LTCA) and Action Tracking (LTAT) Request, Revision 1
NC.FP-PM.ZZ-0007, Firefighting and Rescue Equipment Inventory, Revision 7
OP-AA-106-103-1001, B.5.b Mitigating Strategies Equipment Expectations, Revision 0
OP-AA-108-112, Definition and Measurement of Mispositioned Plant Components, Revision 3
OP-AA-108-115, Operability Determinations, Revision 3
OP-AA-108-115-1002, Supplemental Considerations for Immediate On-shift Operability Determinations, Revision 7
OP-HC-108-106-1001, Equipment Operational Control, Revision 4
SH.OP-AM.TSC-0001, Supplemental Severe Accident Management Guideline (SSAMG), Revision 8

Notifications

| | | | |
|---|---|---|---|
| 20201083 | 20565127 | 20633238 | 20640248 |
| 20237940 | 20577490 | 20633239 | 20640256 |
| 20385097 | 20577885 | 20634061 | 20640369 |
| 20446523 | 20590035 | 20634063 | 20640696 |
| 20467690 | 20594002 | 20635619 | 20640745 |
| 20478844 | 20594734 | 20635639 | 20640964 |
| 20484366 | 20595706 | 20635943 | 20642203 |
| 20509554 | 20604153 | 20635944 | 20642503 |
| 20515029 | 20606819 | 20636083 | 20642633 |
| 20515029 | 20613483 | 20636098 | 20642634 |
| 20521128 | 20620665 | 20636128 | 20642635 |
| 20554014 | 20621571 | 20636362 | 20643182 |
| 20554611 | 20627778 | 20636556 | 20643199 |
| 20555713 | 20630529 | 20636558 | 20643229 |
| 20558353 | 20630917 | 20636742 | 20643322 |
| 20558731 | 20633057 | 20639075 | |

Drawings
M-88-1, Sht. 2, P&ID Aux. Building / Diesel Area Control Diagram, Revision 13
M-41-1, Sheet 1, Nuclear Boiler, Revision 39
M-48-1, Sheet 1, Standby Liquid Control, Revision 16

Maintenance Orders/Work Orders

| | | | |
|---|---|---|---|
| 30194431 | 60113818 | 70153150 | 80085456 |
| 30210543 | 60115585 | 70153406 | 80096177 |
| 30218768 | 70072347 | 70158162 | 80109327 |
| 40022261 | 70107163 | 70162724 | 80110444 |
| 50163142 | 70125325 | 70163607 | 80111107 |
| 50163176 | 70137799 | 70163760 | 80111460 |
| 50164008 | 70140750 | 80065877 | |
| 60110728 | 70143910 | 80069906 | |
| 60111605 | 70151680 | 80078163 | |

Other Documents

10855-D3.38, Design, Installation and Test Specification for High Pressure Coolant Injection System for the Hope Creek Generating Station, Revision 9
HC Standing Order 2013-054, Field Verification of Masterpact Circuit Breakers, effective December 24, 2013
Hope Creek Event Notification # 49665 for Loss of Reactor Building Ventilation, December 19, 2013
Hope Creek Generating Station EDG A July 2013 Engine Signature Analysis Results, Revision 0
Hope Creek Generating Station EDG B August 2013 Engine Signature Analysis Results, Revision 0
Hope Creek Generating Station EDG C August 2013 Engine Signature Analysis Results, Revision 0
Hope Creek Generating Station EDG D September 2013 Engine Signature Analysis Results, Revision 0
KC-0035, Hydraulic Calculations for NRC B.5.b Security Order, Revision 0
LD-042-MASTERPACT-1, Masterpact Issues, Revision 1 dated October 2, 2013
LR-N07-0109, Att. 1, Table A.5-2, BWR Enhancement Strategy #2 – DC Power Supplies to Allow Depressurization of RPV & Injection with Portable Pump
LTAM H-13-0043, Reliability Improvement for Masterpacts from May 22, 2013
NEI 06-12, B.5.b Phase 2 and 3 Submittal Guidance, Revision 2
NRC Information Notice 2010-09, Importance of Understanding Circuit Breaker Control Power Indications dated April 14, 2010
PN1-E41-C001-0055, Instruction Manual HPCI Pump Assembly

Miscellaneous

10855-D3.33, Design, Installation and Test Specification for Standby Liquid Control System, Revision 3
Calculation 646-0008, Equip Foundations for Electrical Panels & Racks, Revision 5
D3.34, Design, Installation and Test Specification for Reactor Core Isolation Cooling System for the Hope Creek Generating Station, Revision 7
Hope Creek Event # 49909, Standby Liquid Control System Sample Concentration Outside
Hope Creek Operations Narrative Logs, March 11 – 14, 2014
Hope Creek Operations Shift Calculation for SLC Tank Concentration Immediate Operability, March 13, 2014
Hope Creek Standby Liquid Control System Design Spec Data Sheet (22A7641AA), Revision 8
Hope Creek Standby Liquid Control System Tank 1OT-204 Level – Calculation 1SC-BH-0001, Revision 0
Hope Creek UFSAR Section 9.3.5 Standby Liquid Control System, Revision 0
Technical Specification Limits, March 13, 2014
WCD 4351338

## Section 1R18: Plant Modifications

Procedures

CC-AA-103, Configuration Change Control for Permanent Physical Plant Changes, Revision 15
CC-AA-103-1001, Implementation of Configuration Changes, Revision 6
CC-AA-107, Configuration Change Acceptance Testing Criteria, Revision 11
CC-AA-112, Temporary Configuration Changes, Revision 13
CC-AA-112-1001, Temporary Configuration Change Implementation T&RM, Revision 3

HC.OP-AB.ZZ-0172, Loss of 4.16kV Bus 10A403, C Channel, Revision 7
HC.OP-AR.GJ-0003, Chiller 1AK400 Control Panel 1AC490, Revision 11
HC.OP-AR.ZZ-0015, Overhead Annunciator Window Box E1, Revision 27
HC.OP-FT.GJ-0001, AK400 Control Area Chilled Water System Venting – Monthly, Revision 4
HC.OP-SO.GJ-0001, A(B)K400 Control Area Chilled Water System Operation, Revision 60
FP-AA-002, Fire Protection Impairment Program, Revision 2
FP-AA-002-F3, Fire Protection Field Impairment Program, Revision 1
LS-AA-125, Corrective Action Program, Revision 17
LS-AA-125-1001, Root Cause Evaluation Manual, Revision 9

Notifications (*NRC identified)

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|---|---|---|---|---|---|
| 20532066 | 20600071 | 20624458 | 20626121 | 20627371 | 20629106 |
| 20630045 | 20634301 | 20634982 | 20635718 | 20635785 | 20639010 |
| 20639011 | 20643779* | 20646119* | | | |

Maintenance Orders/Work Orders

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|---|---|---|---|---|---|
| 60087251 | 60113270 | 60115147 | 70130783 | 70159686 | 70160636 |
| 70160820 | 80098304 | 80098424 | 80110470 | 80110510 | 80110958 |
| 80111090 | | | | | |

Drawings
A-206-0, Sht. 1, Level 6 – Elevation 153'-0" & 162'-0" Floor Plan, Revision 14
E-0014-1, Sht. 1, 480 Volt MCC Tabulation / 00B472 and 00B482 Aux. Building Control and D/G Area, Revision 25
E-1464-0, Sht. 1, Riser Diagram 480VAC Power Receptacles, Revision 13

Miscellaneous
10855-E-118, Technical Specification for Motor Control Centers for the Hope Creek Generating Station, Revision 7
E-118, Seismic Qualification of Safety-Related Equipment, 480 V. AC, Motor Control Centers, Revision 0
H-1-PH-EDS-0129, Hope Creek 480V MCC Compartment Replacement Specification, Revision 1
HC-14-008 - 50.59 Evaluation for TCCP 4HT-14-002, Install a Temporary Portable Heater in the Corridor 5610 to Support 'D' Battery Room 5609
QR 09-06, Seismic & Environmental Testing of Eaton A200 Starters, HFD Circuit Breakers, Ground Fault Relays & Sensors and Various Control Devices, Revision 1
TCCP 4HT-13-019, Defeat the High Bearing Oil Temperature Trip for 1AK400, Revision 0
Technical Specification Action Statement Log, LCO Index Number 13-295, dated October 28, 2013
Temporary Configuration Change Package Tracking Log, dated February 7, 2014

**Section 1R19: Post-Maintenance Testing**

Procedures
ER-AA-321, Administrative Requirements for Inservice Testing, Revision 11
HC.CH-AD.BH-0001, Chemical Addition to the Standby Liquid Control System, Revision 21
HC.CH-CA.ZZ-0026, Boron by Mannitol Titration, Revision 18
HC.FP-ST.ZZ-0031(F), Class 1 Fire Damper Functional Test, Revision 5

HC.FP-SV.ZZ-0028(F), Class 1 Fire Damper Visual Inspection, Revision 4
HC.IC-FT.AB-0020, Main Steam - Division 4 Channels B21-F022B, F022D, F028B, and F028D MSIV Closure Logic B2 Trip, Revision 9
HC.OP-AR.ZZ-0020, CRIDS Computer Points Book 1 A214 Thru D2270, Revision 18
HC.OP-DL.ZZ-0026, Surveillance Log, Revision 139
HC.OP-GP.ZZ-0010(Q), Temporary Battery Room Temperature / Hydrogen Control, Revision 1
HC.OP-IS.BD-0101, Reactor Core Isolation Cooling System Valves – In-service Test, Revision
HC.OP-IS.BH-0004, Standby Liquid Control Pump-BP208 Inservice Test, Revision 12
HC.OP-SO.BH-0001, Standby Liquid Control System Operation, Revision 16
HC.OP-SO.KJ-0001, Emergency Diesel Generators Operation, Revision 70
HC.OP-ST.BH-0001, SLC Valve Operability Test – Monthly, Revision 8
HC.OP-ST.BH-0003, SLC System Tank Flow Test – 18 Months, Revision 10
HC.OP-ST.KJ-0001, Emergency Diesel Generator 1AG400 Operability Test – Monthly, Revision 78
HC.OP-ST.KJ-0003, Emergency Diesel Generator 1CG400 Operability Test – Monthly, Revision 76
MA-AA-716-004, Conduct of Troubleshooting, Revision 12
OP-AA-108-112, Definition and Measurement of Mispositioned Plant Components, Revision 3
OP-AA-108-115, Operability Determinations, Revision 3
OP-AA-108-115-1002, Supplemental Considerations for Immediate On-shift Operability Determinations, Revision 7

Notifications (*NRC identified)

| | | | |
|---|---|---|---|
| 20201083 | 20606819 | 20635785 | 20642635 |
| 20237940 | 20618784 | 20639538 | 20643182 |
| 20484366 | 20623665 | 20642203 | 20643199 |
| 20495191 | 20630045 | 20642515 | 20643229 |
| 20549854 | 20630623 | 20642572 | 20643322 |
| 20558525 | 20633331 | 20642612 | 20644850* |
| 20590366 | 20633644 | 20642633 | |
| 20599917 | 20634973 | 20642634 | |

Maintenance Orders/Work Orders

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|---|---|---|---|
| 30194431 | 40022261 | 60076203 | 60116027 |
| 30218768 | 50159821 | 60113818 | 70061966 |
| 30218795 | 50163176 | 60114029 | 70151557 |
| 30222320 | 50164008 | 60114765 | 70163995 |
| 30222527 | 50164093 | 60114874 | 80069906 |
| 30225620 | 50164628 | 60115314 | 80111460 |

Drawings
E-6794, Sheet 1, Electrical Schematic Diagram Main Control Room Annunciators Reactor Protection System, Revision 2
M-08-0, Sheet 2, Condensate & Refueling Storage & Transfer, Revision 21
M-41-1, Sheet 1, Nuclear Boiler, Revision 39
M-48-1, Sheet 1, Standby Liquid Control, Revision 16
M-49-1, Sheet 1, Reactor Core Isolation Cooling, Revision 30
M-85-1, Sht. 2 of 2, P&ID Auxiliary Building Diesel Area Air Flow Diagram, Revision 11
M-88-1, Sht. 2, P&ID Aux. Building / Diesel Area Control Diagram, Revision 13
P-9286-1, HVAC Area Drawing Aux. Building – Area 28 Plan, Elevation 163’-6”, Revision 1

PN1-C71-1020-0006, Sheet 8A, Elementary Diagram Reactor Protection System, Revision 9
PN1-C71-1020-0006, Sheet 13, Elementary Diagram Reactor Protection System, Revision 18
PN1-C71-1020-0006, Sheet 20, Elementary Diagram Reactor Protection System, Revision 14

Miscellaneous
10855-D3.33, Design, Installation and Test Specification for Standby Liquid Control System, Revision 3
13-373, Technical Specification Action Statement Log
Hope Creek Event # 49909, Standby Liquid Control System Sample Concentration Outside P303A-HV-027, RCIC Turbine Steam Globe Valves, Revision 7
Hope Creek Operations Narrative Logs, March 11 – 14, 2014
Hope Creek Operations Shift Calculation for SLC Tank Concentration Immediate Operability, March 13, 2014
Hope Creek Standby Liquid Control System Design Spec Data Sheet (22A7641AA), Revision 8
Hope Creek Standby Liquid Control System Tank 1OT-204 Level – Calculation 1SC-BH-0001, Revision 0
Hope Creek UFSAR Section 9.3.5 Standby Liquid Control System, Revision 0
Technical Specification Limits, March 13, 2014
WCD 4351338

**Section 1R22: Surveillance Testing**

Procedures
ER-AA-380-1004, Qualification of Leak Rate Monitor Technicians Desktop Guide, Revision 0
F015A, F017A, F021A and F027A A RHR Penetrations #P4B, P6C, P24B and P214B, Revision 5
FP-AA-005, Fire Protection Surveillance and Periodic Test Program, Revision 0
FP-HC-004, Actions for Inoperable Fire Protection, - Hope Creek Station, Revision 1
FP-HC-004, Actions for Inoperable Fire Protection – Hope Creek Station, Revision 4
HC.CH-AD.BH-0001, Chemical Addition to the Standby Liquid Control System, Revision 21
HC.CH-CA.ZZ-0026, Boron by Mannitol Titration, Revision 18
HC.FP-ST.KC-0009, Diesel Driven Fire Pump Operability Test, Revision 19
HC.OP-DL.ZZ-0026, Surveillance Log, Revision 139
HC.OP-IS.BE-0002, B & D Core Spray Pumps – BP206 and DP206, Revision 50
HC.OP-IS.BH-0004, Standby Liquid Control Pump-BP208 Inservice Test, Revision 12
HC.OP-LR.BC-0002, Containment Isolation Valve Type C Leak Rate Testing CIVs 1BCHV-
HC.OP-LR.FC-1004, Containment Isolation Valve Water Leak Rate Test CIVs 1FCHV-F060 and 1FCV-010 Penetration P210: RCIC Barometric Condenser Vacuum Pump Discharge
HC.OP-SO.BH-0001, Standby Liquid Control System Operation, Revision 16
HC.OP-ST.BD-0001(Q), RCIC Piping and Flow Path Verification – Monthly, Revision 14
HC.OP-ST.BH-0001, SLC Valve Operability Test – Monthly, Revision 8
HC.OP-ST.BH-0003, SLC System Tank Flow Test – 18 Months, Revision 10
OP-AA-108-112, Definition and Measurement of Mispositioned Plant Components, Revision 3
OP-AA-108-115, Operability Determinations, Revision 3
OP-AA-108-115-1002, Supplemental Considerations for Immediate On-shift Operability Determinations, Revision 7
OP-HC-108-110-1001, Leak Rate Testing Generic Guidance, Revision 7
WC-AA-105, Work Activity Risk Management, Revision 2

Drawings
M-41-1, Sheet 1, Nuclear Boiler, Revision 39
M-48-1, Sheet 1, Standby Liquid Control, Revision 16

Notifications (*NRC identified)

| | | | | | |
|---|---|---|---|---|---|
| 20201083 | 20237940 | 20484366 | 20633644 | 20638412 | 20639006* |
| 20639094 | 20639311 | 20640738* | 20643182 | 20643199 | 20643229 |
| 20643322 | | | | | |

Maintenance Orders/Work Orders

| | | | | | |
|---|---|---|---|---|---|
| 30128241 | 30194431 | 30218768 | 40022261 | 50152390 | 50152394 |
| 50163176 | 50164008 | 50164017 | 50164803 | 70020669 | 70150479 |
| 70160814 | 70163833 | 80069906 | | | |

Miscellaneous
10855-D3.33, Design, Installation and Test Specification for Standby Liquid Control System, Revision 3
H-1-KC-NDC-1709, Minimum Fuel Supply for HC Diesel Fire Pump, Revision 1
Hope Creek Event # 49909, Standby Liquid Control System Sample Concentration Outside Technical Specification Limits, March 13, 2014
Hope Creek Operations Narrative Logs, March 11 – 14, 2014
Hope Creek Operations Shift Calculation for SLC Tank Concentration Immediate Operability, March 13, 2014
Hope Creek Standby Liquid Control System Design Spec Data Sheet (22A7641AA), Revision 8
Hope Creek Standby Liquid Control System Tank 1OT-204 Level – Calculation 1SC-BH-0001, Revision 0
Hope Creek UFSAR Section 9.3.5 Standby Liquid Control System, Revision 0
WCD 4351338

**Section 1EP4: Emergency Action Level and Emergency Plan Changes**

Procedures
Emergency Plan, Section 3, Revision 29
Emergency Plan, Section 16, Revision 23
NC.EP-EP.ZZ-0313, Advanced Dose Assessment (MIDAS) Instructions, Revision 06

**Section 1EP6: Drill Evaluation**

Procedures
HC.OP-AB.ZZ-0001, Transient Plant Conditions, Revision 27
OP-AA-101-111-1003, Use of Procedures, Revision 4
H14-01, Hope Creek Onsite EP Drill Guide, 1/21/14

Notifications
20637842

Miscellaneous
H14-01, Hope Creek Onsite Drill Critique, 1/24/14

**Section 4OA1: Performance Indicator Verification**

Procedures
HC.OP-AB.RPV-0003, Recirculation System/Power Oscillations, Revision 27
HC.OP-AB.RPV-0003, Recirculation System/Power Oscillations, Revision 28
HC.OP-AB.ZZ-0000FC, Reactor Scram Flow Chart, Revision 3
HC.OP-EO.ZZ-0101FC, Reactor Pressure Vessel Control Flow Chart, Revision 11
HC.OP-SO.BB-0002, Reactor Recirculation System Operation, Revision 97
HC.OP-SO.BB-0002, Reactor Recirculation System Operation, Revision 98
LS-AA-2001, “Collecting and Reporting of NRC Performance Indicator Data,” Revision 11
LS-AA-2003, "Use of the Institute of Nuclear Power Operations (INPO) Consolidated Data Entry Database for NRC and WANO Data Entry," Revision 6
LS-AA-2010, “Monthly Data Elements for NRC/WANO Unit/Reactor Shutdown Occurrences,” Revision 6
LS-AA-2030, “Monthly Data Elements for NRC Unplanned Power Changes per 7000 Critical Hours,” Revision 6
LS-AA-2190, Monthly Data Elements for NRC/INPO Consolidated Data Entry – Monthly Operating Report (MOR), Revision 3

Maintenance Orders/Work Orders
70155514 70161698 70162334

Miscellaneous
LER 2013-002-00(-01), Reactor Scram due to Degrading Condenser Vacuum
LER 2013-008-00, Automatic Actuation of the Reactor Protection System Due To A Main Turbine Trip
LER 2013-008-00, Automatic Actuation of the Reactor Protection System Due To A Main Turbine Trip
LS-AA-2010, Attachment 1, Monthly Data Elements for NRC/WANO Unit/Reactor Shutdown Occurrences, for January 2013
LS-AA-2010, Attachment 1, Monthly Data Elements for NRC/WANO Unit/Reactor Shutdown Occurrences, for February 2013
LS-AA-2010, Attachment 1, Monthly Data Elements for NRC/WANO Unit/Reactor Shutdown Occurrences, for March 2013
LS-AA-2010, Attachment 1, Monthly Data Elements for NRC/WANO Unit/Reactor Shutdown Occurrences, for April 2013
LS-AA-2010, Attachment 1, Monthly Data Elements for NRC/WANO Unit/Reactor Shutdown Occurrences, for May 2013
LS-AA-2010, Attachment 1, Monthly Data Elements for NRC/WANO Unit/Reactor Shutdown Occurrences, for June 2013
LS-AA-2010, Attachment 1, Monthly Data Elements for NRC/WANO Unit/Reactor Shutdown Occurrences, for July 2013
LS-AA-2010, Attachment 1, Monthly Data Elements for NRC/WANO Unit/Reactor Shutdown Occurrences, for August 2013
LS-AA-2010, Attachment 1, Monthly Data Elements for NRC/WANO Unit/Reactor Shutdown Occurrences, for September 2013
LS-AA-2010, Attachment 1, Monthly Data Elements for NRC/WANO Unit/Reactor Shutdown Occurrences, for October 2013
LS-AA-2010, Attachment 1, Monthly Data Elements for NRC/WANO Unit/Reactor Shutdown Occurrences, for November 2013

LS-AA-2010, Attachment 1, Monthly Data Elements for NRC/WANO Unit/Reactor Shutdown Occurrences, for December 2013
LS-AA-2030, Attachment 1, Monthly Data Elements for NRC Unplanned Power Changes per 7000 Critical Hours, for January 2013
LS-AA-2030, Attachment 1, Monthly Data Elements for NRC Unplanned Power Changes per 7000 Critical Hours, for February 2013
LS-AA-2030, Attachment 1, Monthly Data Elements for NRC Unplanned Power Changes per 7000 Critical Hours, for March 2013
LS-AA-2030, Attachment 1, Monthly Data Elements for NRC Unplanned Power Changes per 7000 Critical Hours, for April 2013
LS-AA-2030, Attachment 1, Monthly Data Elements for NRC Unplanned Power Changes per 7000 Critical Hours, for May 2013
LS-AA-2030, Attachment 1, Monthly Data Elements for NRC Unplanned Power Changes per 7000 Critical Hours, for June 2013
LS-AA-2030, Attachment 1, Monthly Data Elements for NRC Unplanned Power Changes per 7000 Critical Hours, for July 2013
LS-AA-2030, Attachment 1, Monthly Data Elements for NRC Unplanned Power Changes per 7000 Critical Hours, for August 2013
LS-AA-2030, Attachment 1, Monthly Data Elements for NRC Unplanned Power Changes per 7000 Critical Hours, for September 2013
LS-AA-2030, Attachment 1, Monthly Data Elements for NRC Unplanned Power Changes per 7000 Critical Hours, for October 2013
LS-AA-2030, Attachment 1, Monthly Data Elements for NRC Unplanned Power Changes per 7000 Critical Hours, for November 2013
LS-AA-2030, Attachment 1, Monthly Data Elements for NRC Unplanned Power Changes per 7000 Critical Hours, for December 2013
LS-AA-2190, Attachment 1, Monthly Data Elements for NRC/INPO Consolidated Data Entry – Monthly Operating Report (MOR), for January 2013
LS-AA-2190, Attachment 1, Monthly Data Elements for NRC/INPO Consolidated Data Entry – Monthly Operating Report (MOR), for February 2013
LS-AA-2190, Attachment 1, Monthly Data Elements for NRC/INPO Consolidated Data Entry – Monthly Operating Report (MOR), for March 2013
LS-AA-2190, Attachment 1, Monthly Data Elements for NRC/INPO Consolidated Data Entry – Monthly Operating Report (MOR), for April 2013
LS-AA-2190, Attachment 1, Monthly Data Elements for NRC/INPO Consolidated Data Entry – Monthly Operating Report (MOR), for May 2013
LS-AA-2190, Attachment 1, Monthly Data Elements for NRC/INPO Consolidated Data Entry – Monthly Operating Report (MOR), for June 2013
LS-AA-2190, Attachment 1, Monthly Data Elements for NRC/INPO Consolidated Data Entry – Monthly Operating Report (MOR), for July 2013
LS-AA-2190, Attachment 1, Monthly Data Elements for NRC/INPO Consolidated Data Entry – Monthly Operating Report (MOR), for August 2013
LS-AA-2190, Attachment 1, Monthly Data Elements for NRC/INPO Consolidated Data Entry – Monthly Operating Report (MOR), for September 2013
LS-AA-2190, Attachment 1, Monthly Data Elements for NRC/INPO Consolidated Data Entry – Monthly Operating Report (MOR), for October 2013
LS-AA-2190, Attachment 1, Monthly Data Elements for NRC/INPO Consolidated Data Entry – Monthly Operating Report (MOR), for November 2013
LS-AA-2190, Attachment 1, Monthly Data Elements for NRC/INPO Consolidated Data Entry – Monthly Operating Report (MOR), for December 2013

**Section 4OA2: Problem Identification and Resolution**

Procedures
ER-AA-2002, System Health Indicator Program, Revision 11
FP-AA-005, Fire Protection Surveillance and Periodic Test Program, Revision 0
HC.MD-PM.KC-0001(F), Diesel Fire Pump and Diesel Engine P.M., Revision 7
HC.OP-AM.TSC-0004, Alternate Power Supply to 1E 125/250 VDC, Revision 9
HC.OP-AM.TSC-0007, Fire Water Ring Header Make Up from the Delaware River, Revision 2
HC.OP-AM.TSC-0024, Remote Operation of SRVs with RPV Injection, Revision 8
LS-AA-125, Corrective Action Program, Revision 17
MA-AA-716-232-1001, Station Rework Reduction Process, Revision 2
NC.FP-PM.ZZ-0007, Firefighting and Rescue Equipment Inventory, Revision 7
OP-AA-102-103, Operator Work-Around Program, Revision 2
OP-AA-102-103-1001, Operator Burdens Program, Revision 1
OP-AA-102-103-1002, Operator Burden Assessment, Revision 0
OP-AA-106-103-1001, B.5.b Mitigating Strategies Equipment Expectations, Revision 0
SH.OP-AM.TSC-0001, Supplemental Severe Accident Management Guideline (SSAMG), Revision 8

Notifications

| | | | | | |
|---|---|---|---|---|---|
| 20597812 | 20598825 | 20599586 | 20611471 | 20613094 | 20613459 |
| 20614302 | 20614793 | 20616542 | 20623627 | 20624077 | 20624663 |
| 20638025 | 20639018 | 20630529 | 20630917 | 20633238 | 20633239 |
| 20635605 | 20635639 | 20636742 | 20637253 | 20639075 | 20640369 |

Maintenance Orders/Work Orders

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|---|---|---|---|---|---|
| 70107163 | 70150986 | 70155412 | 70159026 | 70159355 | 80070969 |
| 80096177 | | | | | |

Completed Surveillance Tests
HC.FP-ST.KC-0006(F), Fire Pump Capacity Test, performed 10/9/13 and 10/10/13
HC.FP-ST.KC-0009(F), Diesel-Driven Fire Pump Operability Test, performed 1/14/14 and 1/21/14

Miscellaneous
Adverse Condition Monitoring Plans Log, dated February 7, 2014
Alarm Bypass Log, dated February 7, 2014
DCP 80109924, Replace Overspeed Switch on Diesel-Driven Fire Pump, Revision 2
Hope Creek Performance Indicator OO.2, Main Control Room Distractions, dated January 2014
Hope Creek Performance Indicator OO.3, Operator Work-Arounds, dated January 2014
KC-0035, Hydraulic Calculations for NRC B.5.b Security Order, Revision 0
LR-N07-0109, Att. 1, Table A.5-2, BWR Enhancement Strategy #2 – DC Power Supplies to Allow Depressurization of RPV & Injection with Portable Pump
NEI 06-12, B.5.b Phase 2 and 3 Submittal Guidance, Revision 2
Operator Challenges List, dated February 7, 2014
Operator Work-Arounds List, dated April 28, 2013
OTDM Log, dated February 7, 2014
Plant Operations Review Committee Meeting Minutes, Meeting H2014-01, dated January 7, 2014

Temporary Configuration Change Package Tracking Log, dated February 7, 2014
Vendor Technical Document (VTD) PM-660-0055, Waukesha/Scania F673/F674D/DS, Revision 7

**Section 4OA3: Follow-up of Events and Notices of Enforcement Discretion**

Procedures
CY-AB-120-340, Offgas Chemistry, Revision 8
HC.IC-FT.SN-0009, ADS and Safety Relief Valve Operability Test, Revision 5
HC.MD-CM.AB-0006, Main Steam Safety/Relief Valve Removal and Installation, Revision 23
HC.OP-AB.IC-0001, Control Rod, Revision 16
HC.OP-AB-ZZ-0000(Q)-FC, Reactor Scram, Revision 3
HC.OP-AB-ZZ-0001(Q), Transient Plant Conditions, Revision 28
HC.OP-EO.ZZ-0101(Q), Reactor Pressure Vessel Control, Revision 12
HC.OP-EO.ZZ-0101(Q)-FC, Reactor/Pressure Vessel (RPV) Control, Revision 11
HC.OP-IO.ZZ-0004(Q), Shutdown from Rated Power to Cold Shutdown, Revision 98
HU-AA-1211, Pre-Job Briefings, Revision 11
LS-AA-125, Corrective Action Program, Revision 17
LS-AA-125-1003-F3, Quick Human Performance Investigation (QHPI) Purpose and Template, Revision 1
NF-AA-400-1000, Fuel Integrity Monitoring, Revision 4
NF-AA-400-1700, BWR Fuel Reliability Indicator (FRI) Calculation and Transmittal, Revision 1
NF-AA-430, Failed Fuel Action Plan, Revision 8
OP-AA-101-111-1004, Operations Standards, Revision 4
OP-AA-300, Reactivity Management, Revision 6
OP-AB-300-1001, BWR Control Rod Movement Requirements, Revision 6
OP-AB-300-1003, BWR Reactivity Maneuver Guidance, Revision 11

Lesson Plans
NOH01EHCLOG-08, EHC Control Logic, Revision 8

Notifications (*NRC identified)

| | | | | | |
|---|---|---|---|---|---|
| 20543906 | 20556518 | 20566308 | 20625612 | 20626677 | 20632369 |
| 20637563 | 20643757* | 20644437 | | | |

Drawings
E-1408-0, Sheet 11.1.8.1, Typical Connection for Environmentally Qualified Position Indicating Solenoid Valves Inside Drywell, Revision 3
E-1554-1, Sheet 1, Raceway Plan Reactor Bldg. – Area-17 Partial Plan El. 121’ 7½”

Maintenance Orders/Work Orders

| | | | | | |
|---|---|---|---|---|---|
| 40020014 | 50135999 | 50163804 | 60107199 | 70140638 | 70159875 |
| 70162334 | 70162663 | 80110856 | | | |

Other Documents
HC 14-008, ACM for Fuel Reliability Parameters used to Monitor Fuel Defect indicate potential fuel failure, March 25, 2014, Revision 0
Hope Creek Failed Fuel Monitoring Team Meeting on March 15, 2014
Hope Creek Long Term Trends – 2014 for Failed Fuel Monitoring (NOTF 20644437)
REMA 2014-0022, April 2014 TVT and PST Downpower REMA, Revision 0

Miscellaneous

Hope Creek Operations Narrative Logs, December 5, 2013
Hope Creek Reactor Pressure Trend, December 5, 2013
Hope Creek Reactor Temperature Trend, December 5, 2013
Hope Creek QHPI, Mis-Operation of the DEHC Controller, December 5, 2013
Hope Creek Technical Specification 6.8, Procedures and Programs, Amendment 97
LER 2013-005-00, Low-Low Set Safety/Relief Valve Pilot Solenoid Operated Valve Failed As-Found Testing
PSEG Event # 49608
Regulatory Guide 1.33, Quality Assurance Program Requirements, February 1978, Revision 2

## LIST OF ACRONYMS

| | |
|---|---|
| 10 CFR | Title 10 of the *Code of Federal Regulations* |
| BPV | bypass valve |
| CAP | corrective action program |
| CAQ | condition adverse to quality |
| CRS | control room supervisor |
| DCP | design change package |
| DDFP | diesel-driven fire pump |
| DEHC | digital electro-hydraulic control |
| DI | demineralized |
| EAL | Emergency Action Level |
| EDG | emergency diesel generator |
| EN | event notification |
| EQACE | equipment apparent cause evaluation |
| FCR | field change request |
| FMCT | failure modes causal table |
| HCGS | Hope Creek Generating Station |
| HPCI | high pressure coolant injection |
| HVAC | heating, ventilation, and air conditioning |
| IMC | Inspection Manual Chapter |
| LER | licensee event report |
| LOCA | loss of coolant accident |
| MAT | modification acceptance testing |
| MCC | motor control center |
| MCR | main control room |
| MS | moisture separator |
| NCO | nuclear control operator |
| NCV | non-cited violation |
| NEI | Nuclear Energy Institute |
| NLI | Nuclear Logistics Inc. |
| NOTF | notification |
| NRC | Nuclear Regulatory Commission |
| OPEVAL | operability evaluation |

| | |
|---|---|
| PCM | performance centered maintenance |
| PM | preventive maintenance |
| ppm | parts per million |
| PSEG | Public Service Enterprise Group Nuclear LLC |
| RBVS | reactor building ventilation system |
| RCIC | reactor core isolation cooling |
| RCS | reactor coolant system |
| RG | Regulatory Guide |
| RHR | residual heat removal |
| RPS | reactor protection system |
| RPV | reactor pressure vessel |
| RRP | reactor recirculation pump |
| RTP | rated thermal power |
| SACS | safety auxiliaries cooling system |
| SLC | standby liquid control |
| SM | shift manager |
| SOV | solenoid operated valve |
| SRV | safety relief valve |
| SSC | structure, system, or component |
| TCCP | temporary configuration change package |
| TS | technical specification |
| TSAS | technical specification action statement |
| UFSAR | Updated Final Safety Analysis Report |
| VAC | volts alternating current |
| VDC | volts direct current |
| VTD | Vendor Technical Document |
| WCD | work control document |
| WGE | work group evaluation |