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

May 10, 2016

Mr. Robert Braun
Chief Nuclear Officer
PSEG Nuclear LLC - N09
P.O. Box 236
Hancocks Bridge, NJ 08038

SUBJECT: HOPE CREEK GENERATING STATION UNIT 1 – INTEGRATED INSPECTION REPORT 05000354/2016001

Dear Mr. Braun:

On March 31, 2016, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Hope Creek Generating Station (HCGS). The enclosed report documents the inspection results, which were discussed on April 14, 2016, with Mr. P. Davison, Site Vice President of Hope Creek, and other members of your staff.

NRC inspectors 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.

The inspectors documented one finding of very low safety significance (Green) in this report. This finding involved a violation of NRC requirements. Additionally, inspectors documented one licensee-identified violation, which was determined to be of very low safety significance in this report. The NRC is treating these violations as non-cited violations (NCVs) consistent with Section 2.3.2.a of the 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 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.

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/

Fred L. Bower, III, Chief
Reactor Projects Branch 3
Division of Reactor Projects

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

Enclosure:
Inspection Report 05000354/2016001
w/Attachment: Supplementary Information

cc w/encl: Distribution via ListServ

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/

Fred L. Bower, III, Chief
Reactor Projects Branch 3
Division of Reactor Projects

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

Enclosure:
Inspection Report 05000354/2016001
w/Attachment: Supplementary Information

cc w/encl: Distribution via ListServ

DISTRIBUTION: (via email)
DLew, RA
SFlanders, DRA
RLorson, DRS
BSmith, DRS
MScott, DRP
DPelton, DRP
FBower, DRP
RBarkley, DRP
MDraxton, DRP
RVadella, DRP
JHawkins, DRP
SHaney, DRP
COtt, DRP, AA
JBowen, RI OEDO
RidsNrrPMHopeCreek Resource
RidsNrrDorlLpl1-2 Resource
ROPreports Resource

DOC NAME: G:\DRP\BRANCH3\Inspection Reports\Hope Creek\16Q1\HC IR2016001 final.docx
ADAMS Accession No. ML16131A095

☑ SUNSI Review		☑ **Non-Sensitive** ☐ Sensitive		☑ **Publicly Available** ☐ Non-Publicly Available
OFFICE	RI/DRP	RI/DRP	RI/DRP	
NAME	JHawkins per email	MDraxton/MSD	FBower/ FLB	
DATE	05/09/16	05/09 /16	05/10 /16	

OFFICIAL RECORD COPY

U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No.	50-354
License No.	NPF-57
Report No.	05000354/2016001
Licensee:	Public Service Enterprise Group (PSEG) Nuclear LLC
Facility:	Hope Creek Generating Station (HCGS)
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	January 1, 2016 through March 31, 2016
Inspectors:	J. Hawkins, Senior Resident Inspector S. Haney, Resident Inspector G. DiPaolo, Senior Reactor Inspector J. Schoppy, Senior Reactor Inspector
Approved By:	Fred L. Bower, III, Chief Reactor Projects Branch 3 Division of Reactor Projects

TABLE OF CONTENTS

SUMMARY

Inspection Report 05000354/2016001: 01/01/2016 – 03/31/2016; Hope Creek Generating Station; Problem Identification and Resolution.

This report covered a three-month period of inspection by resident inspectors and announced inspections performed by regional inspectors. The inspectors identified one self-revealing finding of very low safety significance (Green), which was a non-cited violation (NCV). 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 April 29, 2015. Cross-cutting aspects are determined using IMC 0310, “Aspects Within Cross-Cutting Areas,” dated December 4, 2014. All violations of Nuclear Regulatory Commission (NRC) requirements are dispositioned in accordance with the NRC’s Enforcement Policy, dated February 4, 2015. The NRC’s program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, “Reactor Oversight Process,” Revision 5, dated February 2014.

Cornerstone: Mitigating Systems

- Green. A self-revealing finding of very low safety significance (Green) and associated NCV of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix B, Criterion XVI, “Corrective Action,” were identified when PSEG did not correct a condition adverse to quality (CAQ). Specifically, despite identifying a potential CAQ on November 3, 2014, associated with high vibrations on the ‘C’ emergency diesel generator (EDG) jacket water (JW) braided flexible hose during a system walkdown, no notification (NOTF) was generated, no evaluation of the high vibration condition was conducted, and the CAQ was not promptly corrected as required by the corrective action program (CAP). Subsequently, during a monthly surveillance run conducted on January 4, 2016, the ‘C’ EDG was declared inoperable when a large JW leak developed in the aforementioned braided flexible hose. PSEG’s corrective actions included replacing the failed flexible hose and performing extent of condition walkdowns on the other EDG’s JW piping structural supports. PSEG also conducted simple troubleshooting on the piping and support structures of all the EDGs, and plans to initiate a vibration monitoring program of the EDGs and EDG support systems.

  The inspectors determined that the finding was more than minor because it was associated with the Equipment Performance attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective of ensuring the reliability of systems that respond to initiating events to prevent undesirable consequences. Specifically, not correcting the high vibrations on the JW piping resulted in an unplanned shutdown of the diesel, inoperability and unavailability when the leak worsened to a point where PSEG determined that the EDG could not meet its 24-hour mission time. In accordance with IMC 0609.04, “Initial Characterization of Findings,” dated June 19, 2012, and Exhibit 2 of IMC 0609, Appendix A, “The SDP for Findings At-Power,” dated June 19, 2012, the inspectors determined that this finding is of very low safety significance (Green) because the performance deficiency was not a design or qualification deficiency, did not involve an actual loss of safety function, did not represent the actual loss of a safety function of a single train for greater than its technical specification (TS) allowed outage time, and did not represent an actual loss of function of one or more non-TS trains of equipment designated as high safety-significant in PSEG’s maintenance rule program for greater than 24 hours.

This finding had a cross-cutting aspect in the area of Problem Identification and Resolution, Identification, because PSEG did not implement the CAP with a low threshold for identifying issues and did not identify issues completely, accurately and in a timely manner in accordance with the CAP. Specifically, the issue of high vibrations on the ‘C’ EDG JW braided flexible hose was identified by PSEG, but was not placed into CAP, leading to the issue not being properly documented or evaluated to ensure the cause of the high vibrations was addressed in a timely manner. [P.1] (Section 4OA2.4)

Other Findings

One violation of very low safety significance that was identified by PSEG was reviewed by the inspectors. Corrective actions taken or planned by PSEG have been entered into PSEG’s CAP. This violation and corrective action tracking numbers are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Hope Creek Generating Station began the inspection period at full rated thermal power (RTP). On February 4, operators reduced power to approximately 70 percent to support planned maintenance on the Red Lion offsite power line. Operators returned the unit to full RTP on the same day. On March 11, operators reduced power to approximately 60 percent to support planned turbine valve testing, condenser waterbox cleaning, moisture separator level transmitter troubleshooting, control rod scram time testing, and control rod sequence exchange. Operators returned the unit to full power on the following day. The unit 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 – 1 sample)

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 22 – 23. 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 intake structure (SWIS) 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

Partial System Walkdowns (71111.04 – 4 samples)

a. Inspection Scope

The inspectors performed partial walkdowns of the following systems:

- 'A' EDG fuel oil system on January 11
- 'B' and 'D' EDG starting air systems with the 'B' EDG starting air system cross-tied to the 'D' EDG starting air system on February 18
- 'C' EDG jacket water system on March 14

- ‘A’ main control room (MCR) chiller and ventilation system during ‘B’ MCR chiller planned maintenance on March 17

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), TS, work orders (WOs), NOTFs 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 CAP for resolution with the appropriate significance characterization.

b. Findings

No findings were identified.

1R05 Fire Protection

Resident Inspector Quarterly Walkdowns (71111.05Q - 4 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-531, EDG rooms on January 11
- FRH-III-714, fire water pump house on January 19
- FRH-II-421, control rod drive pumps and motor control center (MCC) areas on February 3
- Review of compensatory measure firewatch for SWIS fire protection panel failure on February 24

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program

.1 Quarterly Review of Licensed Operator Requalification Testing and Training (71111.11Q – 1 sample)

a. Inspection Scope

The inspectors observed licensed operator simulator training on January 25, that included a loss of the 'B' 1E MCC, loss of coolant accident, low power anticipated transient without scram, and emergency depressurization. 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 (71111.11Q – 1 sample)

a. Inspection Scope

The inspectors observed a planned down power to support offsite power line maintenance on February 4. The inspectors observed reactivity manipulations to verify that procedure use and crew communications met established expectations and standards. The inspectors observed pre-job briefings to verify that the briefings met the criteria specified in OP-AA-101-111-1004 "Operations Standards," Revision 6, and HU-AA-1211, "Pre-Job Briefings," Revision 13. Additionally, the inspectors observed performance of the high pressure coolant injection (HPCI) pump comprehensive test and in-service test on March 1. 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 (71111.12Q – 1 sample)

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 system health reports, CAP documents, maintenance WOs, and maintenance rule (MR) basis documents to ensure that PSEG was identifying and properly evaluating performance problems within the scope of the MR. For each sample selected, the inspectors verified that the SSC was properly scoped into the MR in accordance with 10 CFR 50.65 and verified that the (a)(2) performance criteria established by PSEG staff was reasonable. As applicable, for structures, systems, and components classified as (a)(1), the inspectors assessed the adequacy of goals and corrective actions to return these structures, systems, and components to (a)(2). Additionally, the inspectors ensured that PSEG staff was identifying and addressing common cause failures that occurred within and across MR system boundaries.

- Review of maintenance on the ‘A’ average power range monitor INOP inhibit switch after failing to operate and causing an unexpected reactor protection system logic trip on January 29

b. Findings

No findings were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13 – 6 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.

- ‘A’ EDG planned maintenance on January 27
- ‘B’ EDG planned maintenance on February 9
- Automatic voltage regulator troubleshooting activities on March 4
- Review of 4C feedwater heater extraction steam leak repair plan
- Reactor core isolation cooling (RCIC) outboard steam supply isolation (F008) valve planned maintenance on March 29
- RCIC remote shutdown panel transfer relay troubleshooting activities on March 31

b. Findings

No findings were identified.

1R15 Operability Determinations and Functionality Assessments (71111.15 – 5 samples)

a. Inspection Scope

The inspectors reviewed operability determinations for the following degraded or non-conforming conditions based on the risk significance of the associated components and systems:

- Review of delayed scram signal during testing of the #4 main turbine stop valve on December 18, 2015
- Review of degraded 'D' station service water (SSW) strainer motor coupling on January 15 (Order 70183533)
- Review of MCR heatup calculations for station blackout on February 9 (Order 70183913)
- Review of the use of non-safety-related lubrication in safety-related equipment on March 11 (Order 70184547)
- Review of RCIC outboard steam supply isolation (F008) valve steam leak on March 30 (NOTF 20722795)

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 TS and UFSAR to PSEG's evaluations to determine whether the components or systems were operable. The inspectors confirmed, where appropriate, compliance with bounding limitations associated with the evaluations. Where compensatory measures were required to maintain operability, such as in the case of operator workarounds (OWAs), the inspectors determined whether the measures in place would function as intended and were properly controlled by PSEG. Based on the review of the selected OWAs listed above, the inspectors verified that PSEG identified OWAs at an appropriate threshold and addressed them in a manner that effectively managed OWA-related adverse effects on operators and SSCs.

b. Findings

No findings were identified.

1R18 Plant Modifications (71111.18 – 1 sample)

Permanent Modifications

a. Inspection Scope

The inspectors evaluated a commercial grade item dedication evaluation of a SSW strainer motor and gearbox coupling implemented by dedication plan, DP-16-3239. The inspectors verified that the design bases, licensing bases, and performance capability of the affected systems were not degraded by the replacement component. In addition, the inspectors reviewed documents associated with the evaluation, validation, and installation of the replacement component.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19 – 7 samples)

a. Inspection Scope

The inspectors reviewed the post-maintenance tests for the maintenance activities listed below to verify that procedures and test activities adequately tested the safety functions that may have been affected by the maintenance activity, that the acceptance criteria in the procedure were consistent with the information in the applicable licensing basis and/or design basis documents, and that the test results were properly reviewed and accepted and problems were appropriately documented. The inspectors also walked down the affected job site, observed the pre-job brief, confirmed work site cleanliness was maintained, and witnessed the test or reviewed test data to verify quality control hold point were performed and checked, and that results adequately demonstrated restoration of the affected safety functions.

- ‘C’ EDG jacket water hose replacement on January 11 (Order 60127452)
- ’A’ EDG relay replacements on January 29 (Orders 60120344, 60120357, 60120394, 60120395, 60120400, 60120419, and 60120465)
- Reactor water cleanup system piping weld overlays and weld repairs on February 23 (Order 60127987)
- ‘B’ low pressure coolant injection valve retest following maintenance on February 26 (Order 50170269)
- ‘B’ CRD pump maintenance on March 16 (Order 30253734)
- ‘B’ control room ventilation damper maintenance on March 17 (Order 30209899)
- South plant ventilation stack radiation monitor detector and power supply replacement on March 25 (Order 60128473)

b. Findings

No findings were identified

1R22 Surveillance Testing (71111.22 – 4 samples)

a. Inspection Scope

The inspectors observed performance of surveillance tests and/or reviewed test data of selected risk-significant structures, systems, and components 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.GK-0003, ‘B’ control room emergency filtration system functional monthly testing on January 19
- HC.OP-ST.KJ-0003, ‘C’ EDG monthly operability testing on February 1
- HC.OP-IS.BD-0101, RCIC valve in-service testing on March 8
- HC.OP-IS.SK-0101, Plant leak detection system valves in-service testing on March 14

b. Findings

No findings were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06 – 1 sample)

Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors evaluated the conduct of a routine PSEG emergency drill on March 24 to identify any weaknesses and deficiencies in the classification, NOTF, and protective action recommendation development activities. The inspectors observed emergency response operations in the simulator, technical support center, and emergency offsite facility to determine whether the event classification, NOTFs, and protective action recommendations were performed in accordance with procedures. The inspectors also attended the facility critique to compare inspector observations with those identified by PSEG staff in order to evaluate PSEG’s critique and to verify whether the PSEG staff was properly identifying weaknesses and entering them into the CAP.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification (71151)

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

a. Inspection Scope

The inspectors reviewed PSEG’s submittals for the following Initiating Events Cornerstone PIs for the period of January 1, 2015 through December 31, 2015:

- 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 PI 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, NOTFs, 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 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 condition report screening meetings. The inspectors also confirmed, on a sampling basis, that, as applicable, for identified defects and non-conformances, PSEG performed an evaluation in accordance with 10 CFR Part 21.

b. Findings

No findings were identified.

.2 Annual Sample: Safety Relief Valve Set Point Drift

a. Inspection Scope

The inspectors reviewed PSEG's identification, evaluation, and corrective actions associated with longstanding main steam safety relief valve (SRV) set point drift issues at HCGS. Specifically, at HCGS, one or more SRVs have exceeded the TS allowable as-found lift set point acceptance criteria in 17 of the 19 operating cycles over the life of the plant (See Section 4OA3.1 for a review of Licensee Event Report (LER) 05000354/2015-004-01 related to as-found test results from refueling outage 19 (RF19)). PSEG contracted with NWS Technologies to perform SRV as-found testing, SRV pilot valve assembly inspection and repair, and SRV as-left testing at their offsite facility.

The inspectors assessed PSEG’s problem identification threshold, technical and cause analyses, operating experience (OE) and trend reviews, vendor oversight, and the prioritization and timeliness of corrective actions to evaluate whether PSEG was appropriately identifying, characterizing, and correcting problems associated with these issues and whether the planned and/or completed corrective actions were appropriate. The inspectors compared the actions taken in accordance with the requirements of PSEG’s and NWS’ maintenance procedures, PSEG’s CAP, 10 CFR 50 Appendix B, Hope Creek's TSs, and the Maintenance Rule. The inspectors interviewed Nuclear Oversight (NOS) and engineering personnel to gain an understanding of potential operational challenges, overpressure protection capability and margin management, NWS performance, planned and completed corrective actions, and SRV performance. The inspectors also reviewed NWS pilot assembly test and inspection documentation, including quality assurance (QA) acceptance and independent verifications, to ensure that NWS performed activities in accordance with prescribed procedures and industry standards. In addition, the inspectors performed several walkdowns of SRV related instrumentation (including the control room, the remote shutdown panel, and the alternate shutdown automatic depressurization system panel instrumentation and alarm panels) to independently assess the material condition, operating environment, SRV performance, and configuration control. [See also NRC Inspection Report 05000354/2012004, Section 4OA2.2, NRC Inspection Report 05000354/2013005, Section 4OA2.6, and NRC Inspection Report 05000354/2015003, Section 4OA2.4 for additional NRC assessment of the Hope Creek SRV issues.]

a. Findings and Observations

No NRC or self-revealing findings were identified. A licensee-identified violation associated with as-found set point test failures in RF19 is documented in Section 4OA7.

The Hope Creek main steam SRVs are 6" x 10" Target Rock Model 7567F, 2-stage SRVs consisting of a pilot stage, a main stage, and an air operator for remote operation. Hope Creek has 14 safety-related main steam SRVs that provide reactor pressure vessel overpressure protection and an automatic/manual depressurization function. Hope Creek TS 3.4.2.1, "Safety/Relief Valves," requires that 13 of the 14 SRVs be operable with the specified code safety valve function lift setting (+/- 3 percent). Hope Creek TS surveillance requirement 4.4.2.2 requires that at least half of the SRV pilot stage assemblies be removed and set pressure tested in accordance with the Surveillance Frequency Control Program (currently at the refueling outage (RFO) frequency of every 18 months). Since RF15 in April 2009, PSEG has performed as-found lift tests on all 14 SRV pilot valves every outage. PSEG conducts this surveillance testing during RFOs when the SRVs are accessible during reactor shutdown conditions. Historically, Hope Creek has experienced numerous as-found lift pressure failures during SRV testing. Most recently, in June 2015, PSEG identified that 10 of 14 SRVs lifted above the TS specified pressure band (see Section 4OA3.1).

The Target Rock 2-stage SRV has an industry-wide history of set point drift. Early documentation from General Electric (GE) identified that the Target Rock 2-stage SRV design was susceptible to corrosion bonding resulting in set point drift. The corrosion bonding failure mode occurs due to bridging oxides created between the pilot disc surface and the pilot valve body disc seating surface during service. The corrosion bonding trend results in the valve lifting at a higher pressure, failing to meet its set point criteria during the first lift attempt, but successfully lifting during consecutive tests (after the corrosion bond is broken during the first lift). Over the years, PSEG personnel reviewed failure mechanisms and implemented maintenance recommendations from industry OE, GE Service Information Letters (SILs), and Boiling Water Reactor Owners Group recommendations in an unsuccessful attempt to address Target Rock pilot set point drift failures. For example, the industry and PSEG have identified and implemented numerous mitigating strategies including: different pilot disc materials/coatings, addressing critical pilot disc and seat dimensions, correcting methods of insulation installation, and increased TS as-found set point margin (from +/- 1 percent to +/- 3 percent) in an attempt to improve Target Rock 2-stage SRV reliability. The inspectors noted that PSEG implemented a mitigation strategy to install new pilot discs in all 14 SRV pilot valves every RFO; however, based on the continued set point drift failures, this aggressive practice has not proven effective at mitigating the corrosion bonding failure mechanism.

During the review of Hope Creek LER 05000354/2010-002-01 in September 2011, NRC inspectors questioned whether multiple SRVs exceeding the TS allowable as-found lift set point acceptance criteria represented a significant CAQ (SCAQ). In response, on September 13, 2011, PSEG initiated corrective action NOTF 20525076 to address the inspectors' concern. PSEG reviewed their CAP procedure guidance and determined that the condition was not a SCAQ; however, it warranted a root cause evaluation (RCE). In February 2012, PSEG completed the RCE, "SRV Setpoint Drift Root Cause Evaluation" (70128407-010), to evaluate the longstanding SRV set point drift issues. PSEG's root cause analysis reviewed station preventative maintenance practices (rigging, storage, transportation, etc.), maintenance procedures, internal maintenance history, vendor maintenance history (including testing and inspection reports, replacement parts, and practices), industry OE, and the application of this OE at Hope Creek. The root cause team evaluated the Target Rock SRV pilot valve design, manufacturing, and application. The root cause team also reviewed effects of Extended Power Uprate, steam line vibration, and performance of each SRV by serial number. In February 2012, the multi-disciplined PSEG root cause team determined that the Target Rock 2-stage SRV pilot valve design was incapable of satisfying the set point drift design requirements on a consistent basis. PSEG's corrective actions to prevent recurrence of the above root cause included plans to replace the currently installed Target Rock 2-stage SRVs with a design that eliminates set point drift events exceeding +/-3 percent and improves SRV reliability. Based on several engineering studies (including industry OE), PSEG's Main Steam SRV Replacement Project (H-11-0009) recommended replacing the existing 2-stage Target Rock pilot valves with a SEBIM pilot operated design or with an upgraded Target Rock 3-stage pilot. During the first quarter of 2014, PSEG made the decision to no longer pursue the SEBIM model replacement valve due to difficulties meeting Hope Creek specifications. PSEG developed design change package (DCP) 80107006, "Safety Relief Valve (SRV) Replacement," and had planned to install seven Target Rock 3-stage pilots in May 2015 (RF19). However, in the early months of 2015 (just prior to RF19), PSEG decided to defer installing the new 3-stage Target Rock valves due to significant OE at Pilgrim Nuclear Power Station (including a Target Rock Part 21 report). At the time of this inspection, PSEG tentatively planned to install one new 3-stage Target Rock pilot valve in the Fall 2016 RFO (RF20), contingent on the satisfactory acceptance testing results. The inspectors noted that PSEG's decisions that resulted in delays in replacing the existing 2-stage Target Rock pilot valves were appropriate, conservative, and aligned with the principle of not moving forward in the face of uncertainty. From a historic perspective, leading up to RF19 in May 2015, the inspectors noted that PSEG's aggregate actions to address SRV pilot valve set point drift issues were aligned with industry initiatives, appropriate, and commensurate with the safety significance.

On June 3, 2015, based on initial post-RF19 test reports, PSEG initiated corrective action NOTF 20692390 documenting that four SRVs failed their as-found set point tests. Upon completion of the as-found testing on June 10, 2015, PSEG updated the NOTF documenting that 10 of 14 SRVs had failed their as-found set point tests. On July 30, PSEG submitted a LER (LER 2015-004-00) for the SRVs set point failures. On August 13, engineering completed two technical evaluations assessing the safety significance of the set point failures and determined that the set point drift did not impact or challenge the ability of the SRVs to perform their function of relieving reactor vessel overpressure (see Section 4OA3.1). On August 26, 2015, PSEG submitted a revision to the LER (LER 2015-004-01) to include the associated technical evaluations and impact on SRV operability. Based on a review of the LERs, technical evaluations, and associated corrective action NOTF, the NRC resident inspectors identified that PSEG did not identify and/or evaluate an apparent adverse trend in as-found set point testing results (see table below). Specifically, the resident inspectors noted that both the number and magnitude of the RF19 failures represented a step increase compared to the previous four operating cycles (RF15 – RF18). The resident inspectors discussed this observation with PSEG staff on several occasions and subsequently engaged PSEG senior managers and the PSEG engineering staff on a conference call on September 16, 2015. This conference call included NRC Region I Division of Reactor Projects and Division of Reactor Safety managers and technical staff. On November 5, 2015, following the resident inspectors' additional engagement on the potential adverse trend, PSEG initiated two corrective action NOTFs to: (1) evaluate a possible trend in SRV set point drift magnitude and/or number of valves affected (NOTF 20709653), and (2) evaluate a potential correlation between the number of as-found set point failures and the time interval between SRV removal and SRV testing (NOTF 20709757). Based on a review of corrective action NOTFs and NOS reports, the inspectors found no evidence that PSEG had identified and evaluated this potential trend prior to NRC engagement.

	RF15 04/09	RF16 10/10	RF17 04/12	RF18 10/13	RF19 05/15
SRV set point failures	6	6	6	5	10
Average set point drift (average of all 14 valves)	3.77%	3.64%	3.30%	2.34%	5.34%
Highest set point pressure (psig)	1212	1199	1202	1192	1240
Number of valves above 1200 psig	2	0	1	0	5
Approximate average delay in days between SRV removal & SRV test	N/A	N/A	20	25	50
Causal analysis Note: significance level (SL)2 RCE completed in 02/12	SL3 ACE (70096933)	SL3 ACE (70115711)	SL2 WGE (70138789)	SL2 WGE (70161353)	SL4 no evaluation

On February 17, 2016, engineering completed two evaluations (70181904-010 and 70181906-010). Engineering concluded that no definitive trend could be established based on a review of the as-found set point failures by cycle, SRV location, and set pressure group (i.e., valves set to lift at 1108 psig, 1120 psig, or 1130 psig), with one exception. Engineering noted that the data showed that the 1108 psig set pressure group had an increasing trend in failures after cycle 14. Engineering initiated an action item to perform a more detailed trend analysis of the 1108 psig group by specific pilot valve serial number and critical as-found dimensions (70181904-060). In the evaluation, engineering concluded, that although the H1R19 test results show a significant increase in failures compared to H1R18, the failure rate does not represent an adverse trend and the single H1R19 data set is not sufficient to declare a trend. The inspectors noted that engineering's evaluation did not fully evaluate the possible trend in SRV set point drift magnitude (note from the table above that the average set point drift more than doubled when compared to the RF18 data).

Engineering reviewed the test data for RF17 through RF19 from the table above and concluded that an extended time interval between SRV removal from the plant until as-found set point testing can adversely impact the results (number of set point failures). Engineering initiated an action item to expedite SRV as-found testing in RF20 to further evaluate and assess the potential adverse trend in the RF19 failure rate (70181904-050). The inspectors noted that the data supported engineering's conclusion regarding the impact of a time delay before testing. Based on an OE review, the inspectors also noted that a Pilgrim Nuclear Power Station LER (LER 2004-001-00) attributed three 2-stage SRV pilot valve failures due to a significant delay in performing as-found testing. The inspectors noted that the data suggests that significant delays prior to testing may result in more failures and a higher average set pressure. However, the data also showed that the corrosion bonding phenomenon adversely impacted SRV pilot valve set pressures during the operating cycle as some valves failed even when tested within a few days of removal. Thus, expediting the as-found testing would not eliminate corrosion bonding induced test failures; however, it may reduce the number and magnitude of the overall failures and result in as-found test results that more accurately reflect SRV pilot valve performance during the operating cycle.

The inspectors noted that engineering's evaluation did not assess a potential correlation between time delays on the front end of the cycle and the failure rate (including magnitude). Specifically, potential significant time delays between completing the required as-left +/- 1 percent testing and installing the pilot valves back into the plant and the potential impact on as-found failure rate at the end of the operating cycle. The inspectors reviewed the data for RF18 and RF19, and concluded that there was no correlation on the front end.

The inspectors noted that the significant step-change in SRV pilot valve as-found test results from the RF19 testing represented a CAQ. Based on interviews and document reviews, the inspectors determined that PSEG had not identified the condition until prompted by the resident inspectors. The inspectors determined that PSEG's not identifying and evaluating the CAQ was a performance deficiency that was reasonably within PSEG's ability to foresee and correct. The inspectors evaluated this PSEG performance deficiency in accordance with IMC 0612, Appendix B, "Issue Screening," and determined that the issue was minor. This issue was minor because the inspectors did not identify any PSEG and/or NWS deficiency that may have contributed to an increased failure rate, nor any actions that PSEG should take to preclude recurrence prior to RF20.

Based on a historical review of PSEG's causal evaluations initiated to evaluate SRV set point drift failures (see table above), the inspectors concluded that PSEG had high confidence in their 2012 RCE, which may have led to not questioning the RF19 as-found test results. Specifically, the inspectors noted that, following the RCE (completed in February 2012), PSEG initiated a significance level (SL) 2 work group evaluations (WGEs) after RF17 and after RF18, but initiated no causal evaluation after RF19. In

addition, the inspectors noted that on June 5, 2015, PSEG personnel did not provide adequate documentation supporting the CAP Management Review Committee (MRC) decision to screen NOTF 20692390 as SL4 with no associated evaluation, especially considering the number and magnitude of the as-found test failures. The inspectors noted MRC's decision, barring any documented justification, was not aligned with PSEG procedure LS-AA-120, "Issue Identification and Screening Process," Attachment 2 ("Significance Level Guidance") and Attachment 3 ("Guidance for Determining Evaluation Type"). The inspectors determined that PSEG's not following their CAP administrative procedure was a performance deficiency that was reasonably within PSEG's ability to foresee and correct. The inspectors evaluated this PSEG performance deficiency in accordance with IMC 0612, Appendix B, "Issue Screening," and determined that the issue was minor. Notwithstanding, the inspectors viewed the issue as another missed opportunity for PSEG to self-identify this trend.

Based on the RF19 as-found test results (all second lift tests were within 3 percent of the specified set point, with the average of 1.39 percent), engineering concluded that all ten SRV test failures were also due to the corrosion bonding phenomenon. The inspectors noted that, based on PSEG and industry OE and RF19 test results, engineering's conclusion was reasonable. However, at the time of this inspection, PSEG had not performed internal inspections of any of the SRV pilots removed during RF19 to confirm their theory. PSEG plans to perform inspections (including subsequent as-left set point testing) of all 14 SRV pilot valves commencing in June 2016 to support Hope Creek's next RFO (RF20).

Based on a review of as-left test documentation for all 14 SRVs pilot valves installed in RF17 and RF18 and a sample of SRV pilot assembly inspection records, the inspectors noted that NWS personnel maintained high-quality records that clearly documented the as-found condition, repairs and/or replaced components, the as-left condition, QA acceptance, and procedure compliance.

.3 Annual Sample: Instrument Air System Operation

a. Inspection Scope

The inspectors performed an in-depth review of PSEG's identification, evaluation, and resolution regarding several issues related to modifications made to the instrument air system during RF19 in the spring of 2015. The system is normally supplied with pressurized air from one of two service air compressors (one in automatic and one in standby). An emergency instrument air compressor (EIAC) is started automatically at low air pressure (85 psig) and is powered from an EDG upon a loss of offsite power. Pressurized air passes through one of three instrument air dryers. Prior to RF19, the installed EIAC had a design capacity of 700 standard cubic feet per minute (SCFM). Tracking and trending determined that the actual station usage of instrument air was normally 800 SCFM. In addition to the EIAC being undersized, two of the three instrument air dryers (00-F-104 and 10-F-104) were obsolete and not capable of meeting instrument air demand individually, which reduced system reliability. PSEG implemented DCP 80110744, “Emergency Instrument Air Compressor (EIAC) Replacement,” which, besides replacing the EIAC with a higher capacity compressor, also replaced the two undersized instrument air dryers with higher capacity units. For the third dryer (1-AF-104), the DCP eliminated the automatic start feature at a system pressure of 85 psig (lowering). Instead, automatic start of the third dryer was integrated into a combined automatic backup scheme (i.e., would start up automatically if selected as the backup dryer if the in-service dryer went out-of-service).

During the installation of the DCP, PSEG encountered several issues caused by design errors that required many field changes. PSEG documented the issue in NOTF 20688605 and performed an apparent cause evaluation (ACE). On September 22, 2015, operators entered the instrument air system abnormal operating procedure HC.OP-AB.COMP-0001(Q), “Instrument and/or Service Air,” due to lowering pressure when the in-service air dryer tripped offline and the standby air dryer failed to automatically go into service due to an equipment issue. PSEG wrote NOTF 20703343 to address the equipment issue. The third dryer did not automatically go into service because DCP 80110744 eliminated the automatic start feature at a system pressure of 85 psig (lowering). PSEG determined that the removal of the automatic start feature for the third air dryer was inappropriate because it created a single point vulnerability if the standby air dryer failed to go into service. PSEG wrote NOTF 20704884 to address the design error and performed an ACE.

The inspectors assessed PSEG’s problem identification threshold, causal analysis, extent of condition reviews, and the prioritization and timeliness of corrective actions to determine whether PSEG was appropriately identifying, characterizing, and correcting problems associated with these issues and whether the planned or completed corrective actions were appropriate. The inspectors compared the actions taken to the requirements of PSEG’s CAP and 10 CFR Part 50, Appendix B. In addition, the inspectors reviewed open WOs associated with the system, the system health report, the system MR Program (a)(1) action plan for the system, and reviewed the loss of instrument air abnormal operating procedure to verify that appropriate guidance is provided to operators. The inspectors performed a walk down of the installed equipment and interviewed engineering and operations personnel.

b. Findings and Observations

No findings of significance were identified. The inspectors concluded that PSEG’s problem identification threshold, causal analysis, extent of condition reviews, and the prioritization and timeliness of corrective actions for the above issues were appropriate. However, during the review of the issues, the inspectors identified several minor issues and observations discussed below.

During the review of abnormal operating procedure HC.OP-AB.COMP-0001(Q), “Instrument and/or Service Air,” the inspectors identified that the procedure did not address the effect of a loss of instrument air on the HPCI system. Upon the loss of instrument air, the system’s barometric condenser condensate return valve to radioactive waste fails closed. This does not have an effect on the flow of condensate when the system is in operation because condensate flow is routed to the suction of the HPCI booster pump. However, when the system is shutdown, the condensate flow path to the booster pump suction is removed. With the condensate return valve to radioactive waste failed closed, residual steam condensing in the barometric condenser will fill up the condenser and may affect the operation of the barometric condenser exhaust fan operation. PSEG wrote NOTF 20718803 to evaluate enhancing the abnormal operating procedure [HC.OP-AB.COMP-0001(Q)] to include the effect on the HPCI system following system shutdown during a loss of instrument air and to review the control room simulator model to ensure that the HPCI system was properly modeled. In addition, PSEG planned to perform an extent of condition review of the procedure and to determine whether prior reviews of the loss of instrument air abnormal operating procedure should have identified the effect on the HPCI system. This issue was determined to be minor because the barometric condenser exhaust fan is not required for HPCI system operability and condition would only occur after the HPCI pump has been secured. The inspector also noted that the condensate flow path would be re-established to the booster pump suction if the HPCI system was required to be restarted.

The inspector reviewed NOTF 20718072, written by the instrument air system manager on February 10, 2016, which documented high usage of instrument air. The high usage was caused by system leakage (32 documented active leaks) and by the instrument air dryers during the dryer desiccant regeneration cycle. Each air dryer consists of two desiccant towers. During the dryer tower regeneration cycle, air is purged from the out-of-service tower to remove moisture and contributes to air usage. The desired configuration of the system is to have only one dryer in service. However, because the dew point leaving the system was higher than desired, PSEG was testing the system with two dryers in service. With two air dryers operating the system usage was approximately 1350 SCFM, which was well within the capacity of the normally operating service air compressors. However, this usage was greater than the EIAC capacity of 1070 SCFM. The recommended planned action was to troubleshoot dryer high dew point issues and to prioritize and expedite repairs to the system leaks via the Plant Health Committee priority list.

The inspectors questioned whether the EIAC could be considered available with two instrument air dryers in service because system usage under this configuration was greater than the capacity of the EIAC. The inspector noted that, by system design, the EIAC is automatically started and all three instrument dryers go into service at a system air pressure of 85 psig. This configuration would result in an even higher system usage than 1350 SCFM because of the third tower regeneration cycle. System air usage exceeding the capacity of the station air compressors is unlikely during normal operation because there are two 100 percent capacity service compressors (one in operation and one in standby) in addition to the EIAC. However, under the condition where in service air compressor is tagged out for maintenance, usage of air could exceed the EIAC if the operating service air compressor failed unexpectedly. Based on the inspectors' question, PSEG wrote NOTF 20719021. PSEG planned to review operating strategies for the instrument air dryers, evaluate establishing a maximum allowed threshold of instrument airflow to initiate corrective action, and to consider risk mitigation measures during service air compressor outages. The inspector noted that the only compressor that is powered from an EDG is the EIAC. If a loss of offsite power were to occur, system air usage should be within the capacity of the EIAC because air dryer regeneration would not occur.

In July 2010, the PSEG added EIAC to the station's Margin Management Program because the calculated instrument air system usage was greater than the design capacity of the compressor. The Margin Management Program is used by PSEG to:

(1) evaluate the impact of changes on design and operating margin; (2) identify margin issues; and (3) track and resolve the identified margin issues. Placing the EIAC into the program was the main driver for the system upgrades implemented by DCP 80110744. Following the implementation of the DCP, the EAIC was taken out of the Margin Management Program because the modification resolved the design issues related to the EIAC capacity and the calculated instrument air system usage. At the time of closure, PSEG noted the on-going issues (design and operational) with the system dryer performance and other changes to improve system performance.

Based on the inspector's questioning, PSEG concluded that NOTF 20718072 should have been reviewed for inclusion in the Margin Management Program based on the instrument air usage being greater than the capacity of the EIAC. PSEG wrote NOTF 20719026 and planned to add the instrument air system to the Margin Management Program due to the high instrument air usage during normal operation. PSEG also planned to review whether the original margin management issue related to the EIAC capacity should have been removed from the program following the installation of DCP 80110774. The inspector determined that this issue was minor because adequate actions were planned by NOTF 2078072 to resolve system known leaks.

.4 Annual Sample: Review of Adverse Trend in 'C' EDG Failures

a. Inspection Scope

The inspectors performed an in-depth review of PSEG's identified issues, evaluations, and corrective actions associated with the 'C' EDG that were documented in the CAP over the last two years. Since January 2014, the 'C' EDG has experienced multiple equipment failures and operating issues.

The inspectors assessed PSEG's problem identification threshold, problem analysis, extent of condition reviews, compensatory actions, and the prioritization and timeliness of corrective actions to determine whether PSEG staff was appropriately identifying, characterizing, and correcting problems associated with the 'C' EDG and whether the planned or completed corrective actions were appropriate. The inspectors compared the actions taken to the guidance in PSEG's CAP.

b. Findings and Observations

The inspectors reviewed all NOTFs and documents associated with the performance monitoring and corrective actions for the 'C' EDG equipment and performance issues experienced from January 1, 2014, through January 31, 2016. The inspectors reviewed multiple causal evaluations associated with these events to determine whether an adverse trend in 'C' EDG equipment and performance issues reflected a larger deficiency in PSEG maintenance practices or equipment material condition, and whether the corrective actions developed through these causal evaluations adequately addressed the causes to reasonably prevent recurrence of similar equipment issues.

Below is a summary of issues reviewed by the inspectors that were associated with the 'C' EDG since March 1, 2014:

1. January 4, 2016 – experienced a large jacket water leak from a flexible braided hose line at the suction to the engine driven intercooler jacket water pump.

PSEG's apparent cause (70183330) determined the hose failure was due to cyclic loading fatigue cracking, as induced by a high vibration condition in the component. Two issues were identified by PSEG: 1) an installation deficiency (gap between the lug and bracket on a piping support bracket which allowed excessive movement of the line); and, 2) a manufacturing deficiency (related to pits on the external surface of the stainless steel bellows where the crack developed). During the review of this issue, the inspectors questioned why no NOTF was entered into CAP since the high vibration issue on the hose was a known issue and documented in a system walkdown on November 3, 2014. See the NCV documented below.

2. August 1, 2011 – During a historical review of EDG JW leaks in CAP, the inspectors reviewed a similar JW leak that developed on the 'A' EDG engine driven intercooler pump (EDIP) casing (ACE 70127265). Although outside the original intended scope of this inspection, the inspectors determined this leak to be potentially relevant to the hose failure experienced on January 4, 2016. This leak was the result of excessive vibrations on the suction piping for the EDIP due to pipe stress resulting from a 1/8 inch gap between the pump suction elbow and the piping. Contributing to this was a lack of procedural guidance on the appropriate gap between the suction elbow and piping flange during component installation. The inspectors reviewed the corrective actions for this leak which included:

    a. Replacement of the 'A' EDG EDIP. (corrective action (CA))
    b. Revising EDG maintenance procedures to include guidance for gap sizing. (long term CA)
    c. Extent of condition (EOC) inspections of the other EDG's EDIP and JW pump piping, and the installation of shims to correct any gaps that were found to be greater than allowed. (CA)
    d. A review of the EDG vendor recommended vibration monitoring points was completed and no changes made to the existing program. (action item (ACIT))
    e. A review of the EDG natural frequencies was requested but not performed. (ACIT)

    The inspectors noted that of the EOC inspections that were done above, the 'C' EDG EDIP and JW water pump had the two largest gaps, 0.093 inch and 0.142 inch respectively. Shims of different sizes were installed by PSEG via work order 60098256 on the 'C' EDG in November 2011. The inspectors reviewed the associated technical evaluations related to shim sizing and location, but could not find where PSEG evaluated the effect that these shims would have on the upstream and downstream piping. On February 29, 2016, the inspectors questioned whether there was a connection between these EOC corrective actions completed as a result of ACE 70127265 ('A' EDG EDIP Casing Failure) on the 'C' EDG, and the apparent cause of ACE 70183330 ('C' EDG JW Braided Hose Leak). The inspectors verified with the system engineer and regulatory assurance that the shims that were installed had little to no effect on the gap identified during the most recent 'C' EDG hose failure.

3. August 4, 2015 – experienced a failure of: 1) speed switch; and, 2) the jacket water heater breaker. (Apparent Cause: ACE 70179133 determined the speed switch failed due to a resistor failure deemed to be a manufacturing defect. The ACE determined the heater breaker failed due to an age-related failure of a ground fault

relay in the breaker cubicle. This component had never been replaced during the life of the plant, more than 35 years old.)

4. March 4, 2015 – experienced a slow start during a post-maintenance run. (Technical Evaluation: TE 80113940 determined that the slow start was most likely caused by increased viscosity in the governor oil due to low governor temperature due to the extended outage of all heaters (lube oil, jacket water, and generator) during the planned maintenance window. PSEG deemed this a process/procedural issue with respect to EDG system operation and maintenance.)

5. August 31, 2014 – experienced elevated vibration levels on the lubricating oil keepwarm pump. (Cause: WGE 70169061 determined the cause of the elevated lubricating oil keepwarm pump vibrations to be due to missing setscrews used to secure the pump ball bearing to the shaft.) Similarly, in June 2010, PSEG completed WGE 70110929 for the ‘C’ EDG motor-driven JW keepwarm pump high vibrations due to misalignment of the pump and motor due to inadequate procedural guidance for base bolt torqueing.

6. November 1, 2014 – In addition to the above-mentioned events, the ‘C’ EDG also experienced JW heater element failures requiring those elements to be jumpered out in accordance with a temporary modification.

7. March 5, 2014 – PSEG discovered a fractured fuel camshaft lobe and fuel injection pump drive assembly spring support plate on the #7 cylinder during a planned corrective maintenance work window. (Apparent Cause: ACE 70163995 determined the fractures in the fuel camshaft lobe and fuel injection pump to be due to poor manufacturing of the fuel camshaft lobe and improper installation of the key in the camshaft lobe keyway.)

8. Other Items Reviewed (2010 to Present) – The inspectors also reviewed other CAP documents that were outside the original time period of the review, but were referenced multiple times in the reviewed causal evaluations. One of these evaluations was a common cause evaluation (70134049) completed by PSEG in March 2012 for EDG leaks, determined that over a three year period from January 2009 through January 2012, 95 EDG leaks were identified as a result of: 1) design flaws/deficiencies; 2) loose bolted connections mainly due to improper torqueing; and, 3) deficient maintenance practices/rework. The inspectors also reviewed the EDG Gap Analysis performed by a vendor in 2010 for PSEG. No additional issues were noted during this review.

As a result of this review, the inspectors determined that an adverse trend in ‘C’ EDG equipment and performance issues reflecting a larger programmatic deficiency in PSEG maintenance practices, equipment material condition or operation of the equipment did not exist. However, the inspectors noted minor inadequacies with the evaluation and corrective actions associated with ACE 70183330, ACE 70127265, and ACE 70179133, as noted above. The inspectors also documented an NCV for the ‘C’ EDG JW braided hose connection failure experienced on January 4, 2016, below.

Introduction. A self-revealing finding of very low safety significance (Green) and associated NCV of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action,” were identified when PSEG did not correct a CAQ. Specifically, despite identifying a potential

CAQ on November 3, 2014, associated with high vibrations on the ‘C’ EDG jacket water (JW) braided flexible hose during a system walkdown, no NOTF was generated, no evaluation of the high vibration condition was conducted, and the CAQ was not promptly corrected as required by the CAP. During a monthly surveillance run conducted on January 4, 2016, the ‘C’ EDG was declared inoperable when a large JW leak developed on the aforementioned braided flexible hose.

Description. Hope Creek utilizes four EDGs to serve as the standby electrical power source in case both normal and alternate off-site power supplies to the safety-related emergency 4.16 kV buses are lost. These EDGs can supply all safety-related emergency loads that are required to safely shutdown the reactor, maintain the plant in a safe shutdown condition, and mitigate the consequences of an accident. Each of the generators is mounted on a skid and directly coupled to the engine, and is equipped with a safety-related JW cooling water subsystem. The JW system removes excess heat from the engine when running and keeps the EDG in a warmed condition when in a standby condition to ensure reliable starting.

On November 3, 2014, PSEG conducted a normal monthly surveillance run of the ‘C’ EDG. During this run, a system walkdown was conducted by PSEG engineering using procedure ER-AA-2030, Attachment 4, System Walkdown Standards. PSEG engineering documented twice on the ‘C’ EDG operational monitoring sheets that the braided flexible hose (H1KJ -1KJMH-105C), located between the JW expansion tank and EDIP suction piping, was experiencing high vibrations. PSEG did not initiate a NOTF documenting the high vibration condition determining that these flexible connections were installed in these pump surge lines to compensate for any line vibrations, although PSEG noted the vibrations in this particular line were observed to be greater than those found on the other three EDGs. PSEG engineering consulted the braided hose vendor about the component’s service life, and based on the vendor recommendations, replaced the hose on July 9, 2015, during the scheduled 24 month preventive maintenance work because the hose had never been previously replaced.

On January 4, 2016, during a monthly surveillance run, the ‘C’ EDG was declared inoperable when a large JW leak developed on the JW braided flexible hose. PSEG measured the JW leakage initially at approximately 275 milliliters per minute (ml/min), but the leakage rose significantly to 650 ml/min within 20 minutes. PSEG replaced the failed hose, which had been installed for less than six months, and conducted an ACE (70183330) which determined the JW leakage would have continued to degrade to greater than 1 liter per minute if the ‘C’ EDG had remained in service. This leakage rate would have exceeded the make-up capacity and the EDG would not have been able to meet its 24 hour mission time.

PSEG’s ACE determined that the apparent cause of the braided flexible hose failure was cyclic loading fatigue cracking, as induced by a high vibration condition in the component, coupled with an undetectable manufacturing defect. The failure analysis of the hose concluded that non-visible pitting - most likely from the manufacturing process - contributed to the cracking in the component. This hose was manufactured in 2011, whereas the one in place now and the one that was removed in July 2015 for preventive maintanence, were manufactured around 1981. All the other EDGs have hoses manufactured from 1981 vintage. PSEG conducted walkdowns of all four EDGs and observed notable differences between the frictional supports of the vertical hard piping on the JW expansion tank side of the failed hose connection on the ‘C’ EDG as compared to the other three EDG supports. Specifically, a gap between the welded lug on the piping and the U-shaped bracket provided no frictional support to the vertical piping allowing the hard piping to vibrate excessively, ultimately causing the high vibration condition experienced in the braided flexible hose. PSEG's ACE also identified that the cause of the high vibration condition had not been addressed in a timely manner through the CAP process.

PSEG's corrective actions included replacing the failed flexible hose and performing extent of condition walkdowns on the other EDG's JW piping structural supports. PSEG also conducted simple troubleshooting under NOTF 20721257 on March 7, 2016, consisting of rap testing (using a rubber hammer to determine the predominant natural frequency modes) on the piping and support structures of all the EDGs. As part of this troubleshooting, shims of different sizes were installed on the 'C' EDG JW piping to remove the identified support gap and resulting high vibrations on the JW line. PSEG also plan to initiate a vibration monitoring program for the EDGs and EDG support systems.

The inspector reviewed PSEG's ACE, the EDG preventive maintenance strategies, the EDG vibration monitoring program, and other EDG system related procedures and NOTFs. PSEG procedure, LS-AA-120, Issue Identification and Screening Process, defines a CAQ as "deficiencies including failures, malfunctions, deviations, defective material and equipment, and non-conformances associated with structures, systems, and components." This procedure also defines an issue as including "any equipment deficiency, equipment or document non-conformance, programmatic deficiency, human performance error, or enhancement (improvement)." An NOTF is "an electronic document, created in SAP, to identify a deficiency, repair, or action that requires tracking and resolution." Per PSEG procedure, ER-AA-2030, Conduct of Plant Engineering Manual, the system manager is expected to "initiate NOTFs for adverse system trends and conditions based on the results of system trending, analysis, and walkdowns. Attachment 4 of this procedure, states, in part, that when performing a system walkdown, evidence of vibration or excessive movement of piping should be considered, and NOTFs written on any identified deficiencies. Section 4.6.4 states that system walkdown provides the opportunity to identify potential problems resulting from vibration and dynamic effects during plant operations. Based on this review, the inspectors determined that PSEG appropriately identified a potential CAQ when associated with high vibrations on the 'C' EDG JW braided flexible hose connection, but failed to generate a NOTF in the CAP. Because no NOTF was generated, no evaluation of the cause of the high vibration condition was ever conducted by PSEG, and the CAQ was not corrected prior to the flexible braided hose connection degrading to a point that required shutdown of the EDG. Consequently, PSEG determined that the 'C' EDG was inoperable and unable to meet its 24-hour mission time.

On February 29, 2016, PSEG conducted a monthly surveillance run of the 'C' EDG and observed high vibrations still existed on the JW EDIP suction surge line and the intercooler water high point vent line. NOTFs 20720663 and 20720667 document the observed high vibration on the two hoses. Recommendations by the system engineer include taking vibration data on the 'C' EDG during the next available opportunity, as well as another EDG for comparison. Specifically, the recommendation includes vibration data points on the intercoolers, turbochargers, EDIP casing, and engine-driven JW pump casing.

Analysis. Not generating a NOTF for a potential CAQ and not implementing appropriate corrective actions to address the issue was a performance deficiency that was within PSEG's ability to foresee and correct and should have been prevented. Specifically, despite identifying a potential CAQ on November 3, 2014, associated with high vibrations on the 'C' EDG JW braided flexible hose during a system walkdown, no NOTF was generated, no evaluation of the high vibration condition was conducted, and the CAQ was not promptly corrected as required per the CAP. Subsequently, during a monthly surveillance run conducted on January 4, 2016, the 'C' EDG was declared inoperable when a large JW leak developed on the braided flexible hose connection. The Inspectors determined that the finding was more than minor because it was associated with the Equipment Performance attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective of ensuring the reliability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the failure to correct the high vibrations on the JW piping resulted in an unplanned shutdown of the diesel and declaration of inoperability when the leak worsened to a point where PSEG determined that the EDG could not meet its 24-hour mission time. In accordance with IMC 0609.04, "Initial Characterization of Findings," dated June 19, 2012, and Exhibit 2 of IMC 0609, Appendix A, "The SDP for Findings At-Power," dated June 19, 2012, the inspectors determined that this finding is of very low safety significance (Green) because the performance deficiency was not a design or qualification deficiency, did not involve an actual loss of safety function, did not represent the actual loss of a safety function of a single train for greater than its TS allowed outage time, did not represent an actual loss of function of one or more non-TS trains of equipment designated as high safety-significant in PSEG's maintenance rule program for greater than 24 hours. Specifically, the EDG was restored to operable status in approximately 16 hours.

This finding had a cross-cutting aspect in the area of Problem Identification and Resolution, Identification, because PSEG did not implement the CAP with a low threshold for identifying issues. PSEG did not identify issues completely, accurately and in a timely manner in accordance with the CAP. Specifically, the issue of high vibrations on the 'C' EDG JW braided flexible hose was identified by PSEG, but not placed into CAP, leading to the issue not being properly documented or evaluated by the CAP to ensure the cause of the high vibrations was addressed in a timely manner. [P.1]

Enforcement. 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," requires that measures 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 November 3, 2014 through January 4, 2016, implementation of PSEG's CAP did not assure that a CAQ associated with high vibrations on the 'C' EDG was promptly corrected. Specifically, despite identifying a potential CAQ on November 3, 2014, associated with high vibrations on the 'C' EDG JW braided flexible hose during a system walkdown, no NOTF was generated, no evaluation of the high vibration condition was conducted, and the CAQ was not promptly corrected. Subsequently, during the monthly surveillance run conducted on January 4, 2016, the 'C' EDG was declared inoperable when a large JW leak developed on the flexible braided hose. PSEG's corrective actions included replacing the failed flexible hose and performing extent of condition walkdowns on the other EDG JW piping structural supports. PSEG also conducted simple troubleshooting on the piping and support structures of all the EDGs, and plans to initiate a vibration monitoring program of the EDGs and EDG support systems. Because this violation was of very low safety significance (Green), and PSEG has entered this performance deficiency into the CAP as NOTF 20724655, the NRC is treating this as an NCV in accordance with Section 2.3.2.a of the NRC Enforcement Policy. **(NCV 05000354/2016001-01; Untimely Correction of a Condition Adverse to Quality (CAQ) Associated with High Vibrations on the 'C' Emergency Diesel Generator)**

4OA3 Follow-Up of Events and Notices of Enforcement Discretion (71153 – 1 sample)

(Closed) LER 05000354/2015-004-01: As Found Values for Safety Relief Valve Lift Set Points Exceed Technical Specification Allowable Limit

On June 2, 2015, PSEG received test results indicating that the as-found lift set points for two or more of the main steam SRVs failed to open within the required TS actuation pressure set point tolerance. TS 3.4.2.1 provides an allowable pressure band of +/- 3 percent for each SRV. Between June 2 and June 10, 2015, PSEG received the test results for the remainder of the SRV pilot valve assemblies. In all, 10 of the 14 SRVs lifted above the TS specified pressure band. This is a condition prohibited by TS. PSEG concluded that the apparent cause for the SRV set point failures was corrosion bonding between the pilot disc and seating surfaces, consistent with industry experience. PSEG entered these issues into the CAP as NOTF 20692390. PSEG replaced the pilot assembly for each of the 14 SRVs with a fully tested spare assembly. Additionally, this LER stated PSEG's corrective actions include evaluating options to replace the currently installed SRVs with a new design that eliminates set point drift events exceeding TS requirements and improves SRV reliability. Although this LER reports the inoperability of ten SRVs, this event did not result in a loss of system safety function based on engineering analyses. These analyses showed that the SRVs would have functioned to prevent a reactor vessel over pressurization and that postulated piping stresses would not exceed allowable limits. The enforcement aspects of this finding are discussed in Section 4OA7. In addition, PSEG CAP aspects are discussed in Section 4OA2.4. This LER is closed.

4OA6 Meetings, including Exit

On April 14, 2016, 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. PSEG management acknowledged and did not dispute the findings.

4OA7 Licensee-Identified Violations

The following violation of very low safety significance (Green) was identified by the licensee and is a violation of NRC requirements, which meets the criteria of the NRC Enforcement Policy, for being dispositioned as an NCV:

- In Modes 1, 2, and 3, Hope Creek TS 3.4.2.1, "Safety Relief Valves," requires that 13 of the 14 SRVs open within of +/- 3 percent of the specified code safety valve function lift settings or else be in Mode 3 within 12 hours and in Mode 4 within the next 24 hours. Contrary to this requirement, on June 2, 2015, PSEG identified that two or more SRVs had as-found set points in excess of the TS allowable tolerance. Subsequent testing revealed that 10 of 14 SRVs lifted above the TS specified pressure band, thus leaving 4 operable SRVs. PSEG entered this issue into their CAP as NOTF 20692390. PSEG corrective actions included replacing the pilot assembly for each of the 14 SRVs with a fully tested spare assembly, and evaluating options to replace the currently installed SRVs with a new design that eliminates set point drift events. The inoperability of the 10 SRVs did not result in a loss of system safety function based on engineering analyses that showed that the SRVs would have functioned to prevent a reactor vessel over-pressurization and that postulated piping stresses would not exceed allowable limits. The inspectors independently reviewed PSEG's associated technical evaluations and determined that PSEG used adequate engineering rigor and conservatively bounded the condition. The inspectors determined that this finding is of very low (Green) safety significance based on a SDP issue screening, because the SRVs would have functioned to prevent a reactor vessel over-pressurization (no loss of safety function). The closure of the LER associated with this event was documented in Section 4OA3.1.

ATTACHMENT: SUPPLEMENTARY INFORMATION

SUPPLEMENTARY INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel
P. Davison, Site Vice President
E. Carr, Plant Manager
D. Bedford, System Engineer
M. Biggs, Maintenance Rule Program Coordinator
C. Boxer, Reactor Operator
J. Boyer, Mechanical/Structural Design Manager, Design Engineering
B. Burgio, Risk Engineer
P. Chan, Manager, Nuclear Oversight
T. Gingerich, System Engineer
R. Hanna, Senior Reactor Operator
S. Kopsick, Senior Reactor Operator
T. MacEwen, Principal Engineer, Regulatory Assurance
E. Martin, Senior Engineer Nuclear, Hope Creek Programs Engineering
T. Morin, Balance of Plant Branch Manager
M. Murray, Senior Engineer Nuclear, Hope Creek Programs Engineering
A. Ochoa, Senior Engineer, Regulatory Affairs
B. Padworny, Senior Reactor Operator
M. Peterson, System Engineer
M. Pfizenmaier, Engineering Assessor, Nuclear Oversight
J. Priest, Nuclear Shift Operations Manager
N. Rock, Main Steam System Manager
J. Rothermel, Environmental Qualification Program Engineer
C. Serata, Operations Support Manager
S. Simpson, Director, Site Regulatory Compliance
G. Stith, Design Engineering Manager
J. Thompson, Procurement Program Manager
A. Tramontana, Manager, Hope Creek Programs Engineering

LIST OF ITEMS OPENED, CLOSED, DISCUSSED, AND UPDATED

Opened/Closed

05000354/2016001-01	NCV	Untimely correction of a Condition Adverse to Quality Associated with High Vibrations on the ‘C’ Emergency Diesel Generator (Section 4OA2.4)

Closed

05000354/2015-004-01	LER	As Found Values for Safety Relief Valve Lift Set Points Exceed Technical Specification Allowable Limit (Section 4OA3.1)

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection

Procedures
HC.OP-AB.MISC-0001, Acts of Nature, Revision 28
HC.OP-DL.ZZ-0026, Surveillance Log, Revision 152
OP-AA-108-111-1001, Severe Weather and Natural Disaster Guidelines, Revision 14

Notifications
20716456 20716561 20716766 20716769

Section 1R04: Equipment Alignment

Procedures
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-SO.KJ-0001, Emergency Diesel Generators Operation, Revision 72
HC.OP-SO.JE-0001, Diesel Fuel Oil Storage and Transfer System Operation, Revision 32

Notifications
20248181 20522528 20705513 20715784 20717692 20721175

Maintenance Orders/Work Orders
60127983 70180916 80083820

Drawings
PM-018Q-0048, Sheet 1, Starting & Control Air System, Revision 14
1-P-JE-01, Sheet 1, Aux Bldg Diesel Fuel Oil Storage and Transfer, Revision 24
M-20-0, Sheet 1, Auxiliary Boiler Fuel Oil System, Revision 17
M-30-1, Sheet 1, HCGS Diesel Engine Auxiliary Systems Fuel Oil PI&D, Revision 27

Section 1R05: Fire Protection

Procedures
FP-AA-015, Compensatory Measure Firewatch Program, Revision 6
FP-HC-004, Actions for Inoperable Fire Protection – Hope Creek Station, Revision 4
FRH-II-421, Hope Creek Pre-Fire Plan CRW Pumps Area & MCC Area, Revision 3
FRH-II-531, Hope Creek Pre-Fire Plan Diesel Generator Rooms, Elev. 102' of Aux. Building, Diesel Generator Area, Revision 8
FRH-II-713, Hope Creek Pre-Fire Plan, Service Water Intake Structure, Revision 4
FRH-III-714, Hope Creek Pre-Fire Plan Fire Water Pump House, Revision 4
HC.IC-SC.BJ-0005, HPCI – Division 1, Channel E41-N661A, Condensate Storage Tank Level (Suction Transfer), Revision 12

Notifications
20715619 20717280 20718667

Maintenance Orders/Work Orders
60097657

Miscellaneous
WCD # 4301107

Section 1R11: Licensed Operator Requalification Program

Procedures
EP-AA-120-1007, Maintenance of Emergency Response Organization, Revision 6
HC.OP-IS.BJ-0001, HPCI Main and Booster Pump Set – 0P204 and 0P217 – Inservice Test, Revision 64
HU-AA-101, Human Performance Tools and Verification Practices, Revision 10
HU-AA-1211, Pre-Job Briefings, Revision 13
OP-AA-101-111-1003, Use of Procedures, Revision 6
OP-AA-103-102, Watchstanding Practices, Revision 12

Notifications
20715870 20717024 20719601 20720792 20720794 20720795

Miscellaneous
Scenario Guide (SG)-748, EDG surveillance test/Loss of 10B222 MCC/Loss of Boiler/LOCA/Low Power ATWS/Emergency Depressurization, dated January 7, 2016

Section 1R12: Maintenance Effectiveness

Procedures
HC.IC-CC.SE-0013, Nuclear Instrumentation System Channel A Average Power Range Monitor, Revision 33
HC.IC-FT.SE-0013, Nuclear Instrumentation System, Division 1 – Channel A, Average Power Range Monitor, Revision 41
HC.OP-AB.IC-0004, Neutron Monitoring, Revision 8

Notifications
20631794 20682812 20689327 20696966 20716008

Maintenance Orders/Work Orders
50178653 60127031

Drawings
PN1-C51-1080-0025, Sheet 12, Elementary Diagram, Power Range Neutron Monitoring System, Revision 17

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Procedures
ER-AA-380, Primary Containment Leakrate Testing Program, Revision 9
ER-HC-1051, Leakage Reduction Program, Revision 2
ER-HC-380-1005, Hope Creek Specific Appendix J Program Information, Revision 2
MA-AA-716-004, Conduct of Troubleshooting, Revision 13
HC.MD-CM.ZZ-0013, Electrically Backseating MOV Remotely from a MCC
HC.MD-PM.PB-0001, 4.16 kV Breaker Cleaning and P.M., Revision 29
HC.MD-ST.PB-0003, Class 1E 4.16 kV Feeder Degraded Voltage Monthly Instrumentation Channel Functional Test, Revision 27

HC.OP-IS.BD-0101, Reactor Core Isolation Cooling System Valves – Inservice Test, Revision 62
HC.OP-LR.FC-0001, Containment Isolation Valve Type C Leak Rate Test, CIVs 1FCHV-F007 (1FCV-001), 1FCHV-F076 (1FCV-048) AND 1FCHV-F008 (1FCV-002), Penetration P11: RCIC Steam Supply, Revision 3
MA-AA-723-300, Diagnostic Testing and Inspection of Motor Operated Valves, Revision 11
OP-AA-101-112-1002, On-Line Risk Assessment, Revision 9
OP-AA-106-101-1006, Operational and Technical Decision Making Process, Revision 8
OP-AA-108-101-1002, Component Configuration Control, Att. 10 – Valve Operations, Revision 8
OP-AA-108-111, Adverse Condition Monitoring and Contingency Planning, Revision 11
OP-AA-108-115-1001, Operability Assessment and Equipment Control Program, Revision 31
OP-AA-108-116, Protected Equipment Program, Revision 10
WC-AA-105, Work Activity Risk Management, Revision 5

Notifications (*NRC-identified)

20525229	20603500	20617172	20620600	20625889	20625891
20647033	20651123	20652387	20672531	20686500	20710375
20716965	20717041*	20720236	20721726	20721841	20722795
20723901	20724724	20724758			

Maintenance Orders/Work Orders

30138744	40020600	50161885	60123025	60128619	70115394
70176260	80102665				

Drawings
1-P-FC-01, Sheet 1, Reactor Building RCIC Turbine Supply & Exhaust, Revision 19
E-6082-1, Sheet 1, RCIC System Pump Motors Vacuum & Condensate Pumps, Revision 6
E-6084-0, Sheet 1, Reactor Core Isolation Cooling System Steam Exhaust Isolation Valve, Revision 4
E-6084-0, Sheet 2, Reactor Core Isolation Cooling System Vacuum Pump Discharge Valve, Revision 4
E-6084-0, Sheet 3, Reactor Core Isolation Cooling System Pump Suction from CST Valve, Revision 4
E-6084-0, Sheet 4, Reactor Core Isolation Cooling System Pump Discharge Valve, Revision 4
E-6084-0, Sheet 5, Reactor Core Isolation Cooling System Feedwater Isolation Valve, Revision 6
E-6084-0, Sheet 6, Reactor Core Isolation Cooling System Minimum Flow Bypass Valve ISV-F019, Revision 6
E-6084-0, Sheet 7, Reactor Core Isolation Cooling System Main Steam Supply Valve, Revision 10
E-6084-0, Sheet 8, Reactor Core Isolation Cooling System Lube Oil Cooling Water Valve, Revision 6
E-6084-0, Sheet 9, Reactor Core Isolation Cooling System Pump Suction Valve, Revision 9
E-6084-0, Sheet 10, Reactor Core Isolation Cooling System Test By-Pass Valve, Revision 7
E-6084-0, Sheet 11, Reactor Core Isolation Cooling System Turbine Trip/Throttle Valve, Revision 8
E-6085-0, Sheet 2, Reactor Core Isolation Cooling System Steam Supply Isolation Valve F008, Revision 5
E-6085-0, Sheet 4, Reactor Core Isolation Cooling System Vacuum Breaker Isolation Valves, Revision 4

E-6089-0, Sheet 1, RCIC System Turbine Monitoring Circuits in RSP, Revision 13
E-6433-0, Sheet 1, RCIC Pump Turbine ECCS Jockey Pump 1BR228, Revision 4
E-6603-0, Sheet 1, Remote Shutdown Panel (10C399) Transfer Switch Contact Utilization, Revision 6
E-6604-0, Sheet 1, Remote Shutdown Panel (RSP) 10C300 Scheme Drawing Index, Revision 12
J-4049-0, Sheet 2, Reactor Core Isolation Cooling RCIC Pump Turbine Control, Revision 7
M-49-1, Sheet 1, P&ID Reactor Core Isolation Cooling, Revision 30
PJ201Q-0007, Sheet 14, Remote Shutdown Panel 10C399 Section A, Revision 20
PJ201Q-0007, Sheet 23, Remote Shutdown Panel 10C399 Section B, Revision 13
PJ201Q-0007, Sheet 32, Remote Shutdown Panel 10C399 Section C, Revision 7
PJ201Q-0007, Sheet 38, Remote Shutdown Panel 10C399 Section C, Revision 7

Miscellaneous
ACM HC 16-002, 4C FWH Extraction Line Steam Leak Adverse Condition Monitoring and Contingency Plan, dated March 22, 2016
HCGS PRA Risk Evaluation Form for January 24, 2016, through January 30, 2016, Revision 2
Hope Creek Standing Order 2016-05, Interim Operational Guidance for the Cross-Around Header to 4C Extraction Steam Header, effective March 17, 2016
OP-HC-108-115-1001, Form 1, Technical Specification Action Statement Log, 16-072, 1FC-FC-4158 RSP RCIC Flow Controller, dated March 30, 2016
OTDM 16-001, 4C FWH Extraction Line Steam Leak, dated March 21, 2016
Protected Equipment Log – ‘B’ EDG and 1E Switch Gear, dated January 26, 2016
Protected Equipment Log – ‘B’ FRVS Recirc Unit, dated January 26, 2016
Protected Equipment Log – ‘B’ FRVS Vent Fan, dated January 26, 2016
Protected Equipment Log – ‘B’ RHR in Suppression Pool Cooling, dated January 27, 2016
Protected Equipment Log – ‘C’ EDG and 1E Switch Gear, dated January 26, 2016
Protected Equipment Log – ‘C’ FRVS Recirc Unit, dated January 26, 2016
Protected Equipment Log – ‘D’ FRVS Recirc Unit, dated January 26, 2016
Protected Equipment Log – ‘D’ EDG and 1E Switch Gear, dated January 26, 2016
Protected Equipment Log – ‘F’ FRVS Recirc Unit, dated January 26, 2016
Protected Equipment Log – HPCI, dated January 26, 2016
Protected Equipment Log – RCIC, dated January 26, 2016
Salem Generating Station, Unit 1 Risk Assessment for January 24, 2016, through January 30, 2016, Revision 1

Section 1R15: Operability Determinations and Functionality Assessments

Procedures
ER-AA-380, Primary Containment Leakrate Testing Program, Revision 9
ER-HC-1051, Leakage Reduction Program, Revision 2
ER-HC-380-1005, Hope Creek Specific Appendix J Program Information, Revision 2
HC.DE-PS.ZZ-0041, Hope Creek Station Blackout Program, Revision 3
HC.IC-DC.ZZ-0329, Turbine Steam Control Valves Limit Switch Adjustment, Revision 13
HC.MD-CM.ZZ-0013, Electrically Backseating MOV Remotely from a MCC
HC.OP-AB.COOL-0001, Station Service Water, Revision 21
HC.OP-AB.ZZ-0135, Station Blackout // Loss of Offsite Power // Diesel Generator Malfunction, Revision 41
HC.OP-FT.AC-0005, Turbine Overspeed Protection System Operability Test – Quarterly, Revision 13
HC.OP-IS.BD-0101, Reactor Core Isolation Cooling System Valves – Inservice Test, Revision 62

HC.OP-LR.FC-0001, Containment Isolation Valve Type C Leak Rate Test, CIVs 1FCHV-F007 (1FCV-001), 1FCHV-F076 (1FCV-048) AND 1FCHV-F008 (1FCV-002), Penetration P11: RCIC Steam Supply, Revision 3
HC.OP-ST.AC-0002, Turbine Valve Testing – Quarterly, Revision 49
LS-HC-1000-1001, Hope Creek Generating Station Surveillance Frequency Control Program List of Surveillance Frequencies, Revision 7
MA-AA-716-006, Control of Lubricants Program, Revision 11
MA-AA-723-300, Diagnostic Testing and Inspection of Motor Operated Valves, Revision 11
OP-AA-108-101-1002, Component Configuration Control, Att. 10 – Valve Operations, Revision 8
SA-AA-111, Industrial Safety – Heat Stress Control, Revision 12

Notifications

20525229	20617172	20651123	20686500	20688841	20714431
20714727	20714903	20715078	20715188	20715610	20716094
20717497	20717688	20719597	20720796	20720916	20721224
20721511	20722795	20724724			

Maintenance Orders/Work Orders

30138744	40020600	50161885	50162571	50179731	60123025
60128619	70115394	70127346	70176260	70180302	70183074
70183288	70183533	70183913	70184400	70184547	70184719
80102665	80113610				

Drawings
1-P-FC-01, Sheet 1, Reactor Building RCIC Turbine Supply & Exhaust, Revision 19
M-49-1, Sheet 1, P&ID Reactor Core Isolation Cooling, Revision 30
PN1-C71-1020-0006, Sheet 8, Reactor Protection System Elementary Drawing, Revision 12
PN1-C71-1020-0006, Sheet 13, Reactor Protection System Elementary Drawing, Revision 16
PN1-C71-1020-0006, Sheet 20, Reactor Protection System Elementary Drawing, Revision 15

Miscellaneous
EA-0001, Station Service Water Hydraulic Model, Revision 6
H-1-FLX-MDC-4016, Hope Creek Auxiliary Building Extended Loss of AC Power FLEX Response, Revision 0
H-1-GK-MDC-0734, Loss of Ventilation during Station Blackout, Revision 3
OP-HC-108-115-1001, Form 1, Technical Specification Action Statement Log, 15-356, Main Turbine Stop and Control Valves, dated December 18, 2015

Section 1R18: Plant Modifications

Procedures
CC-AA-203, Environmental Qualification Program, Revision 8
CC-AA-203-1005, Environmental Qualification Program Implementation, Revision 2
SM-AA-300, Procurement Engineering Support Activities, Revision 7
SM-AA-300-1001, Procurement Activities and Responsibilities, Revision 12
SM-AA-410, Control or Purchased Material, Equipment and Services Program, Revision 7

Notifications

20714431	20715610	20716094	20716776

Maintenance Orders/Work Orders

70173533	70183614

Miscellaneous

D7.5, Hope Creek Generating Station Environmental Design Criteria, Revision 24

Dedication Plan DP-16-3239, Commercial Grade Item Dedication Evaluation for Service Water Strainer Motor and Gearbox Coupling, Revision 0

Section 1R19: Post-Maintenance Testing

Procedures

CC-AA-11, Nonconforming Materials, Parts, or Components, Revision 5

HC.CH-SO.BG-0001, Operation of the Reactor Water Cleanup System, Revision 46

HC.IC-FT.SP-0021, Process Radiation Monitoring – Non Divisional Channel H1SP-1SPRE-4875B South Plant Vent (WRGM), Revision 42

HC.IC-SC.SP-0014, Process Radiation Monitoring – Non Divisional Channel H1SP-1SPRE-4875B South Plant Vent Low Range Noble Gas, Revision 20

Notifications

20711433	20711715	20714395	20714986	20716196	20716197
20716199	20716200	20716290	20716811	20717125	20717150
20717177	20718663	20720487	20720846	20721100	20721499
20721502	20722406	20722472			

Maintenance Orders/Work Orders

30209899	30253734	50170269	50182478	60120344	60120357
60120394	60120395	60120400	60120419	60120465	60127987
60128473	70184544				

Drawings

M-44-1, Sheet 1, Reactor Water Clean-up, Revision 35

PN1-G33-B001-0125, Sheet 1, Regenerative and Non-Regenerative Clean-Up Heat Exchanger Instruction Manual, Revision 5

Miscellaneous

OP-HC-108-115-1001, Technical Specification Action Statement Log, 16-057, SPV Mid/High particulate and iodine, dated August 12, 2016

Section 1R22: Surveillance Testing

Procedures

HC.OP-IS.BD-0101, Reactor Core Isolation Cooling System Valves – Inservice Test, Revision 62

HC.OP-IS.SK-0101, Plant Leak Detection System Valves – Inservice Test, Revision 10

HC.OP-ST.KJ-0003, Emergency Diesel Generator 1CG400 Operability Test – Monthly, Revision 76

HC.OP-ST.GK-0003, B – Control Room Emergency Filtration System Functional Test – Monthly, Revision 11

Notifications

20717105

Maintenance Orders/Work Orders

20451368	50130822	50182595	50182704	60084878

Section 1EP6: Drill Evaluation

Procedures
EP-HC-111-F6, Attachment 6, Primary Communicator Log, Revision 14
EP-HC-111-F8, Attachment 8, Secondary Communicator Log, Revision 3
NC.EP-EP.ZZ-0404, Protective Action Recommendations (PARS) Upgrades, Revision 7

Notifications

20722397	20722403	20722765	20722768	20722769	20723315
20723427	20723840	20723913	20724248		

Section 4OA1: Performance Indicator Verification

Procedures
LS-AA-2001, “Collecting and Reporting of NRC Performance Indicator Data,” Revision 11
LS-AA-2003, "Use of the 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

Miscellaneous
LS-AA-2010, Attachment 1, Monthly Data Elements for NRC/WANO Unit/Reactor Shutdown Occurrences, for January 2015 – December 2015
LS-AA-2030, Attachment 1, Monthly Data Elements for NRC Unplanned Power Changes per 7000 Critical Hours, for January 2015 – December 2015

Section 4OA2: Problem Identification and Resolution

Procedures
CC-HC-1001, Technical Product Review Guideline, Revision 0
ER-AA-2001-1001, Evaluation of Equipment Reliability Strategies, Revision 1
ER-AA-2007, Evaluating Margins, Revision 2
ER-AA-2030, Conduct of Plant Engineering Manual, Revision 12
ER-AA-3001, Long Term Asset Management (LTAM) Strategies, Revision 5
ER-HC-321-1020, Hope Creek SRV Testing & Refurbishment Process, Revision 0
LS-AA-120, Issue Identification and Screening Process, Revision 13
LS-AA-125, Corrective Action Program, Revision 21
LS-AA-125-1001, Root Cause Evaluation Manual, Revision 10
LS-AA-125-1003, Apparent Cause Evaluation Manual, Revision 14
HC.MD-CM.AB-0006, Main Steam Safety/Relief Valve Removal and Installation, Revision 26
HC.MD-ST.KJ-0001, Diesel Generator Technical Specification Surveillance and Preventive Maintenance, Revision 46
HC.OP.AB.COMP-0001(Q), Instrument Air and/or Service Air, Revision 7
HC.OP-AR.ZZ-0002(Q), Overhead Annunciator Window Box AZ, Revision 24
HC.OP-SO.KB-0001(Q), Instrument Air Operation, Revision 25
HC.OP-SO.KJ-0001, Emergency Diesel Generators Operation, Revision 72

HC.OP-SO.SN-0001, Nuclear Pressure Relief and Automatic Depressurization System Operation, Revision 11
HC.OP-ST.KJ-0003, Emergency Diesel Generator 1CG400 Operability Test – Monthly, Revision 76
Hope Creek EDG Maintenance Program Gap Analysis dated September 12, 2010
LS-AA-120, Issue Identification and Screening Process, Revision 13
MA-AA-734-461, Bolt Torquing and Bolting Sequence Guidelines, Revision 2

Notifications (*NRC Identified)

20411328	20465649	20483383	20525076	20526178	20559112
20575763	20631351	20642203	20642572	20643745	20649599
20652520	20654742	20656862	20657179	20659174	20660927
20661336	20662250	20667792	20668682	20668742	20670717
20677676	20677792	20677948	20680249	20680743	20682164
20685772	20686811	20687177	20688605	20692390	20697032
20698578	20699154	20699154	20699440	20701294	20701295
20701297	20701299	20701300	20701301	20701303	20703343
20704884	20709449	20709653	20709757	20713234	20713234
20715733	20715869	20717108	20718803*	20718818*	20719021*
20719026*	20719152	20719361			

Maintenance Orders/Work Orders

30250278	60127452	70036674	70060872	70110929	70127265
70128976	70134049	70163995	70169061	70171837	70173612
70179133	70183330	80103510	80103518	80105131	80113940
80115131					

Drawings
VTD PM018Q-0050, Sheet 1, Jacket Water System, Revision 18

Audits and Assessments
NOH-15-007, Nuclear Oversight Performance Assessment Report Hope Creek Generating Station (HCGS) NOSPA-HC-15-1C, January 1 through April 30, 2015, dated May 28, 2015
NOH 15-020, Nuclear Oversight Performance Assessment Report Hope Creek Generating Station (HCGS) NOSPA-HC-15-2C, May 1 through August 31, 2015, dated October 9, 2015
NOH-16-002, Nuclear Oversight Performance Assessment Report Hope Creek Generating Station (HCGS) NOSPA-HC-15-3C, September 1 through December 31, 2015, dated January 29, 2016
NOV2015-083, Nuclear Oversight Vendor Auditor Surveillance Report (Target Rock Corp.), dated April 16, 2015
NUPIC Audit/Survey No. 23969, NUPIC Joint Audit of NWS Technologies, dated August 21, 2015

Calculations and Analyses
D-0106, Dynamic Analysis for Design Evaluation of Main Steam Safety Relief Valve Discharge Piping Inside the Drywell Main Steam B – MSRVD Line F, Revision 1 NEDC-32511P, Safety Review for Hope Creek Generating Station Safety/Relief Valve Tolerance Analyses, April 1996

VTD 430016, EPU DIR T0308 - Reactor Coolant Pressure Boundary Piping, Revision 2
VTD 431973 – Pielstick vibration guidance (P12608134)
PM018Q-0499, Operation and Maintenance Manual for Emergency Diesel Generator, Revision 25

Customer Equipment Anomalies Reports (CEARs)

13-228	13-244	14-182	14-215	15-118

Design and Licensing Bases Documents

Hope Creek License No. Amendment 64, Safety Relief Valve Testing Requirements, Hope Creek Generating Station (TAC No. M86525), dated January 27, 1994
NRC IMC 0326, Operability Determinations & Functionality Assessments for Conditions Adverse to Quality or Safety, dated January 31, 2014
NRC Regulatory Guide 1.124, Service Limits and Loading Combinations for Class 1 Linear-Type Supports, Revision 3

Engineering Evaluations

70096933-015, SRVs A, C, F, G, K, and L Failed Testing Technical Evaluation, dated April 24, 2009
70096933-070, Six (6) of 14 SRVs Exceed +3% As Found Setpoint Tolerance during RF15, Equipment Apparent Cause Evaluation, dated October 12, 2009
70115711-020, Six (6) of 14 SRVs Exceed +3% As Found Setpoint Tolerance during RF16, dated 12/23/10 70128407-010, SRV Setpoint Drift Root Cause Evaluation, dated February 17, 2012
70128407-165, SRV Equipment Reliability Strategy Evaluation, dated 8/15/12 70138789-010, RF17 - SRV As Found Setpoint Test Failures Work Group Evaluation, dated June 1, 2012
70144118, Main Steam (a)(1) Status in Question due to SRV Setpoint Drift Work Group Evaluation, dated October 23, 2012
70161353-010, RF18 - SRV As Found Setpoint Test Failures Work Group Evaluation, dated December 23, 2013
70161353-050, RF18 SRV As Found Setpoint Test Failures Assessment – SRV A, D, F, K, & L Technical Evaluation, dated 11/6/14 70177495-010, Impact of the RF19 As Found 'F' SRV Setpoint Pressure on the 'B' Main Steam Line and 'F' SRV Discharge Line, dated August 13, 2015
70177495-040, RF19 SRV Setpoint Test Failures Assessment Technical Evaluation, dated August 24, 2015
70181904-010, Possible Trend in SRV Setpoint Fail Rate Evaluation, dated February 17, 2016
70181906-010, SRV Testing Interval Evaluation, dated 2/17/16 Orders: 80082548, 80114506

Licensee Event Reports (LERs)

Browns Ferry Unit 1 LER 2010-005-01, Safety/Relief Valves As Found Setpoints Exceeded Technical Specification Lift Pressure Values, dated April 1, 2011
Browns Ferry Unit 1, LER 2014-006-00, Main Steam Relief Valves' Lift Settings Outside Technical Specifications Required Setpoint, dated January 26, 2015
Browns Ferry Unit 2 LER 2007-002-00, Main Steam Relief Valve As Found Setpoint Exceeded Technical Specifications Lift Pressure, dated July 16, 2007
Browns Ferry Unit 2 LER 2009-003-01, Safety/Relief Valve As Found Setpoint Exceeded Technical Specification Lift Pressure, dated July 28, 2011
Browns Ferry Unit 3 LER 2006-001-00, Main Steam Relief Valve Inoperability LCO Exceeded as a Result of Lift Setpoint Drift, dated June 23, 2006
Browns Ferry Unit 3 LER 2008-002-00, Main Steam Relief Valve As Found Setpoint Exceeded Technical Specification Lift Pressure, dated July 31, 2008

Browns Ferry Unit 3 LER 2010-001-00, Safety Relief Valves As Found Setpoints Exceeded Technical Specification Lift Pressure Values, dated June 21, 2010
Brunswick Unit 1 LER 2006-004-01, As Found Values for Safety/Relief Valve Lift Setpoints Outside Technical Specification Allowable Tolerance, dated November 17, 2006
Brunswick Unit 1 LER 2008-005-00, As Found Values for Safety/Relief Valve Lift Setpoints Outside Technical Specification Allowable Tolerance, dated September 10, 2008
Brunswick Unit 1 LER 2014-005-00, Setpoint Drift in Main Steam Line Safety/Relief Valves Result in Two Valves Inoperable, dated July 21, 2014
Brunswick Unit 2 LER 2007-003-01, As Found Values for Safety/Relief Valve Lift Setpoints Outside Technical Specification Allowable Tolerance, dated October 18, 2007
Brunswick Unit 2 LER 2015-002-01, Setpoint Drift in Main Steam Line Safety/Relief Valves Result in Three Valves Inoperable, dated June 26, 2015
Cooper LER 2015-001-01, Valve Test Failures in a Condition Prohibited by Technical Specifications and a Loss of Safety Function, dated November 5, 2015
FitzPatrick LER 2005-002-00, Safety Relief Valve Setpoints Outside of Allowable Tolerances, dated 6/3/05 FitzPatrick LER 2007-001-00, Safety Relief Valve Setpoints Outside of Allowable Tolerances, dated August 6, 2007
FitzPatrick LER 2009-005-00, Safety Relief Valve Setpoints Outside of Allowable Tolerances, dated June 22, 2009
FitzPatrick LER 2011-003-00, Safety Relief Valve Setpoints Outside of Allowable Tolerances, dated August 8, 2011
Hope Creek LER 97-024-00, As Found Values for Safety Relief Valve Lift Setpoints Exceed Technical Specification Allowable Limits, dated October 20, 1997
Hope Creek LER 2000-003-00, As Found Values for Safety Relief Valve Lift Setpoints Exceed Technical Specification Allowable Limits, dated June 5, 2000
Hope Creek LER 2001-007-00, As Found Values for Safety Relief Valve Lift Setpoints Exceed Technical Specification Allowable Limits, dated December 31, 2001
Hope Creek LER 2003-003-00, As Found Values for Safety Relief Valve Lift Setpoints Exceed Technical Specification Allowable Limits, dated June 25, 2003
Hope Creek LER 2004-009-00, As Found Values for Safety Relief Valve Lift Setpoints Exceed Technical Specification Allowable, dated January 17, 2005
Hope Creek LER 2006-003-00, As Found Values for Safety Relief Valve Lift Setpoints Exceed Technical Specification Allowable, dated June 15, 2006
Hope Creek LER 2009-002-01, As Found Values for Safety Relief Valve Lift Setpoints Exceed Technical Specification Allowable, dated August 18, 2009
Hope Creek LER 2010-002-01, As Found Values for Safety Relief Valve Lift Setpoints Exceed Technical Specification Allowable, dated April 7, 2011
Hope Creek LER 2012-004-01, As Found Values for Safety Relief Valve Lift Setpoints Exceed Technical Specification Allowable, dated December 10, 2012
Hope Creek LER 2013-007-00, As Found Values for Safety Relief Valve Lift Set Points Exceed Technical Specification Allowable Limit, dated January 16, 2014
Hope Creek LER 2015-004-00, As Found Values for Safety Relief Valve Lift Set Points Exceed Technical Specification Allowable Limit, dated July 30, 2015
Hope Creek LER 2015-004-01, As Found Values for Safety Relief Valve Lift Set Points Exceed Technical Specification Allowable Limit, dated August 26, 2015
Pilgrim LER 2004-001-00, Target Rock Relief Valves' Test Pressures Exceed Technical Specification Tolerance Limit, dated March 11, 2004
Pilgrim LER 2005-003-00, Target Rock Relief Valves' Test Pressures Exceeded Technical Specification Tolerance Limit, dated July 5, 2005
Pilgrim LER 2007-004-00, Target Rock Relief Valves' Test Pressure Exceeded Limit due to Corrosion Bonding and Setpoint Variance, dated August 13, 2007
Pilgrim LER 2012-001-00, Safety Relief Valves' Test Pressure Exceeded Setpoint Limits, dated May 29, 2012

Miscellaneous

DCP 80107006, Safety Relief Valve (SRV) Replacement, Revision 2
H2015-18, Plant Operations Review Committee Meeting Minutes, dated July 30, 2015
H2015-19, Plant Operations Review Committee Meeting Minutes, dated August 26, 2015
HC.OP-DL.ZZ-0003 Attachment 1, Log 3 Control Console Log Condition 1, 2 and 3, dated February 19, 2016
Hope Creek As Found Testing Data of Removed SRVs (RF17, RF18, & RF19), dated September 14, 2015
Hope Creek Plant Health Committee Meeting Minutes, dated November 2, 2015
LTAM H-11-0009, Main Steam SRV Replacement Project, dated June 5, 2014
NWS Hope Creek R18 SRV Tests & Refurbishments Engineering Trip report, July 2013
NWS Safety Valve Test Data, performed July 25, 2013 – August 26, 2013 and March 26, 2015 – April 24, 2015
NWS Traveler #12-144, Report of Repair of Nuclear pressure Relief Devices (S/N 363), dated September 24, 2013
NWS Traveler #12-150, Report of Repair of Nuclear pressure Relief Devices (S/N 1252), dated September 25, 2013
NWS Traveler #13-329, Report of Repair of Nuclear pressure Relief Devices (S/N 367), dated August 27, 2014
NWS Traveler #14-300, Report of Repair of Nuclear pressure Relief Devices (S/N 369), dated April 2, 2015
PSEG Nuclear Outlook, Update to Hope Creek SRV Project, dated March 27, 2015
Updated Final Safety Analysis Report, Section 9.3.1, Compressed Air Systems, Revisions 20 and 22
Instrument Air System Health Report, 1st Quarter 2016
DCP 80110774, Emergency Instrument Air Compressor Replacement, Revision 5, 10 CFR 50.59 Review for DCP 80110774, Emergency Instrument Air Compressor Replacement, Revision 0
NOH01INSAIR, Hope Creek Licensed/Non-Licensed Operator Training, Instrument Air, March 22, 2011
EVAL-H-KB-00063, Instrument Air Maintenance Rule (a)(1) Evaluation
IEEE Std. 387-1977, Standard Criteria for Diesel-Generator Units Applied as Standby Power Supplies for Nuclear Power Generating Stations

Operating Experience

GE SIL No. 196S3, Target Rock Safety/Relief Valve Simmer Margin, dated August 31, 1977
GE SIL No. 196S14, Target Rock 2-Stage SRV Set-Point Drift, dated April 23, 1984
NID#15155, 10 CFR Part 21 Interim Report Notification of a Potential Test Induced Defect in 0867F Series Main Steam Safety Relief Valves, dated March 16, 2015
NRC Information Notice 83-82: Failure of Safety/Relief Valves to Open at BWR - Final Report, dated December 20, 1983
NRC Information Notice 2003-01: Failure of a Boiling Water Reactor Target Rock Main Steam Safety/Relief Valve, dated January 15, 2003
NRC Information Notice 2006-24: Recent Operating Experience Associated with Pressurizer and Main Steam Safety/Relief Valve Lift Setpoints, dated November 14, 2006
NRC Regulatory Information Summary 00-012: Resolution of Generic Safety Issue B-55, "Improved Reliability of Target Rock Safety Relief Valves," dated August 7, 2000

System Health Reports, Walkdown Reports, & Trending
Main Steam System Health Report, Q3-2015 & Q4-2015
Maintenance Rule Function Scoping, Performance Criteria, and Current Performance Summary for the Main Steam Safety/Relief Valves, dated February 16, 2016

Vendor Documents and Specifications
21A9247, General requirements for Dual Function Safety/Relief Valve, Revision 4
VTD 324450, NWS-T-25 NWS Test Procedure for Hope Creek Nuclear Station Target Rock 7567F 2 Stage Main Steam Safety Relief Valves, Revision 7
VTD 328266, Evaluation of the Propensity for Pilot Disc and Seat Corrosion Bonding and Pilot Performance Correlation Analysis for Two-Stage Target Rock Main Steam Safety Relief Valves, Revision 3
VTD 328280, NWS-R-38 NWS Technologies Repair of Target Rock 2 Stage Main Steam Safety Relief Valves, Revision 2

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

Procedures
CC-AA-309-101, Engineering Technical Evaluations, Revision 10
ER-AA-430, Conduct of Flow Accelerated Corrosion Activities, Revision 8
ER-AA-430-1001, Guidelines for Flow Accelerated Corrosion Activities, Revision 10
HC.MD-CM.ZZ-0013, Electrically Backseating Motor-Operated Valve Remotely from a Motor Control Center, Revision 0
HC.OP-AB.BOP-0005, Main Steam Tunnel Temperature, Revision 2
HC.OP-FT.AC-0005, Turbine Overspeed Protection System Operability Test – Quarterly, Revision 13

Notifications

20642218	20652387	20681458	20683619	20702882	20703500
20705417	20709402	20716627	20716875	20718081	20719670
20721726	20721841	20724127			

Drawings
1-P-AF-02, Sheet 1, System Isometric/Turbine Building Extraction Steam to Feedwater Heater No. 4, Revision 16
M-02-1, Sheet 1, Extraction Steam, Revision 33
M-41-1, Sheet 2, Nuclear Boiler, Revision 29
P-0604-1, Sheet 1, Piping Area Drawing Turbine Building Area 05 Plan at Elevation 120’, Revision 3

Maintenance Orders/Work Orders

60087599	60123451	70166670	70181220	70182106	70183759
80116531	80116604				

<u>Miscellaneous</u>

1-AF-004-S08-L1, Ultrasonic Thickness Examination Record, dated December 4, 2004
1-AF-004-S08-L1, Ultrasonic Thickness Examination Record, dated October 20, 2010
CDI Non-conformance Report (2013), 03-43, 23 September
CDI Report No. 08-21P [Hope Creek letter F452/0943], Final Stress Assessment of Hope Creek Unit 1 Steam Dryer at 115% CLTP Conditions, Revision 1 October 2008
CDI Report No. 15-06P [Hope Creek letter F754/0015], Stress Re-Analysis of Hope Creek Dryer for EPU Conditions. Attached to this is stress re-evaluation of performed by CDI for the Hope Creek Unit 1 Steam Dryer at 115% CLTP, Revision 0
CDI Technical Note 07-29P, Revision 2, Limit Curve Analysis with ACM Revision 4 for Power Ascension at Hope Creek Unit 1
CDI Interim Report on Hope Creek's Steam Dryer Stresses at EPU Conditions [Hope Creek letter F754/0006], dated October 6, 2015
Hope Creek Unit 1 steam dryer data and evaluations performed as required per Att. 3, Dryer Data Collection, (Test No. 101) of HC.OP-FT.ZZ-0004, Extended Power Uprate Power Ascension Testing
HCG.5-0255, Product Assessment Uncleaned Springs Assembled in Control Rods, dated February 10, 2016

LIST OF ACRONYMS

10 CFR	Title 10 of the *Code of Federal Regulations*
ACE	apparent cause evaluation
ACIT	action item
ADAMS	Agencywide Documents Access and Management System
CA	corrective action
CAP	corrective action program
CAQ	condition adverse to quality
CFR	*Code of Federal Regulations*
DCP	design change package
EDG	emergency diesel generator
EDIP	engine driven intercooler pump
EIAC	emergency instrument air compressor
EOC	extent of condition
GE	General Electric
HCGS	Hope Creek Generating Station
HPCI	high pressure coolant injection
IMC	Inspection Manual Chapter
JW	jacket water
LER	licensee event report
MCC	motor control center
MCR	main control room
MR	maintenance rule
MRC	Management Review Committee (PSEG)
NCV	non-cited violation
NEI	Nuclear Energy Institute
NOS	Nuclear Oversight
NOTF	notification(s)
NRC	Nuclear Regulatory Commission
OE	operating experience
OWA	operator workaround(s)
PI	performance indicator(s)
PSEG	Public Service Enterprise Group Nuclear, LLC
QA	quality assurance
RCE	root cause evaluation
RCIC	reactor core isolation cooling
RF/RFO	refueling outage
RTP	rated thermal power
SCAQ	significant condition adverse to quality
SCFM	standard cubic feet per minute
SDP	Significance Determination Process
SIL	Service Information Letter
SL	significance level
SRV	safety relief valve
SSC	structure, system, and component
SSW	station service water
SWIS	service water intake structure
TS	technical specifications
UFSAR	Updated Final Safety Analysis Report
WGE	work group evaluation(s)
WO	work order(s)