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

November 14, 2016

EA-16-184

Mr. Peter P. Sena, III
President and 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 05000354/2016003 AND PRELIMINARY WHITE FINDING

Dear Mr. Sena:

On September 30, 2016, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at Hope Creek Generating Station (HCGS). On October 27, 2016, the NRC inspectors discussed the results of this inspection with Mr. Eric Carr, Site Vice President, and other members of your staff. The results of this inspection are documented in the enclosed report.

The enclosed inspection report discusses a finding that the NRC has preliminarily determined to be White, a finding of low to moderate safety significance. As described in Section 1R15 of the enclosed report, the finding is associated with an apparent violation of Title 10 of the *Code of Federal Regulations* (CFR), Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," because PSEG did not adequately implement their adverse condition monitoring (ACM) procedure, specifically, the ACM plan action to perform monthly high pressure coolant injection (HPCI) turbine oil sampling and analysis for water contamination with known steam leakage by the HPCI steam admission valve (FD-F001). As a consequence, PSEG violated Technical Specification (TS) 3.5.1.c because, based on analysis of the HPCI governor control valve (FV-4879) and hydraulic actuator (EG-R) failures on August 6, 2016, the NRC determined that the HPCI system was inoperable for a period greater than its technical specification allowed outage time of 14 days.

The finding was assessed based on the best available information, using Inspection Manual Chapter (IMC) 0609.04, "Initial Characterization of Findings," and Exhibit 2 of IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," issued June 19, 2012. The basis for the NRC's preliminary significance determination is described in the enclosed report.

As an apparent violation of NRC requirements, this finding is being considered for escalated enforcement action in accordance with the Enforcement Policy, which appears on the NRC's Web site at http://www.nrc.gov/about-nrc/regulatory/enforcement/enforce-pol.html. The NRC will inform you, in writing, when the final significance has been determined. We intend to complete and issue our final safety significance determination within 90 days from the date of this letter. The NRC's SDP is designed to encourage an open dialogue between your staff and the NRC; however, the dialogue should not affect the timeliness of our final determination.

We believe that we have sufficient information to make a final significance determination. However, before we make a final decision, we are providing you an opportunity to provide your perspective on this matter, including the significance, causes, and corrective actions, as well as any other information that you believe the NRC should take into consideration. Accordingly, you may notify us of your decision within 10 days to: (1) request a regulatory conference to meet with the NRC and provide your views in person, (2) submit your position on the finding in writing, or (3) accept the finding as characterized in the enclosed inspection report.

If you choose to request a regulatory conference, the meeting should be held in the NRC Region I office within 40 days of the date of this letter, and will be open for public observation. The NRC will issue a public meeting notice and a press release to announce the date and time of the conference. We encourage you to submit supporting documentation at least one week prior to the conference in an effort to make the conference more efficient and effective. If you choose to provide a written response, it should be sent to the NRC within 30 days of the date of this letter. You should clearly mark the response as "Response to Preliminary White Finding in Inspection Report No. 05000354/2016003; EA-16-184," and send it to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with a copy to the Regional Administrator, Region I, and a copy to the NRC Senior Resident Inspector at HCGS.

You may also elect to accept the finding as characterized in this letter and the inspection report, in which case the NRC will proceed with its regulatory decision. However, if you choose not to request a regulatory conference or to submit a written response, you will not be allowed to appeal the NRC's final significance determination.

Please contact Fred Bower at (610) 337-5200 within 10 days from the issue date of this letter to notify the NRC of your intentions. If we have not heard from you within 10 days, we will continue with our significance determination and enforcement decision.

Because the NRC has not made a final determination in this matter, no notice of violation is being issued for this inspection finding at this time. In addition, please be advised that the number and characterization of the apparent violation may change based on further NRC review. The final resolution of this matter will be conveyed in separate correspondence.

The inspectors also documented two findings of very low safety significance (Green) in this report. Both of these findings involved violations of NRC requirements. Additionally, inspectors documented one Severity Level IV violation with no associated finding. 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 violations or significance of these NCVs, 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, and the NRC Resident Inspector at HCGS. In addition, if you disagree with the cross-cutting aspect assigned to any finding, or a finding not associated with a regulatory requirement in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region I, and the NRC Resident Inspector at HCGS.

This letter, its enclosure, and your response (if any) will be made available for public inspection and copying at http://www.nrc.gov/reading-rm/adams.html and the NRC Public Document Room in accordance with 10 CFR 2.390, "Public Inspections, Exemptions, Requests for Withholding."

Sincerely,

/RA/

Michael L. Scott, Director
Division of Reactor Projects

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

Enclosure:
Inspection Report 05000354/2016003
w/Attachments:
1) Supplementary Information
2) Detailed Risk Evaluation

cc w/encl: Distribution via ListServ

This letter, its enclosure, and your response (if any) will be made available for public inspection and copying at http://www.nrc.gov/reading-rm/adams.html and the NRC Public Document Room in accordance with 10 CFR 2.390, "Public Inspections, Exemptions, Requests for Withholding."

Sincerely,

/RA/

Michael L. Scott, Director
Division of Reactor Projects

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

Enclosure:
Inspection Report 05000354/2016003
w/Attachments:
1) Supplementary Information
2) Detailed Risk Evaluation

cc w/encl: Distribution via ListServ

DISTRIBUTION: (via email)
DDorman, RA
DLew, DRA
RLorson, DRS
JYerokun, DRS
MScott, DRP
DPelton, DRP
FBower, DRP
RBarkley, DRP
MDraxton, DRP
RVadella, DRP
FArner, DRS
JHawkins, DRP, SRI
JPatel, DRP, Acting RI
COtt, DRP, AA
RidsNrrPM Hope Creek Resource
RidsNrrDorlLpl1-2Resource
ROPreports Resource
JBowen, RI, OEDO

DOCUMENT NAME: G:\DRP\BRANCH3\Inspection Reports\Hope Creek\16Q3\HC IR 2016003 FINAL.docx
ADAMS Accession No. ML16319A289

☑ SUNSI Review		☑ **Non-Sensitive** ☐ Sensitive		☑ **Publicly Available** ☐ Non-Publicly Available	
OFFICE	RI/DRP	RI/DRP	RI/DRP	R1/DRS	R1/ORA
NAME	JHawkins/jh	RBarkley/rb	FBower/rb for	FArner/fa	BBickett/cjc for
DATE	11/8/2016	11/3/2016	11/10/16	11/09/16	11/14/16
OFFICE	R1/DRP				
NAME	MScott				
DATE	11/14/16				

OFFICIAL RECORD COPY

U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No.	50-354
License No.	NPF-57
Report No.	05000354/2016003
Licensee:	PSEG Nuclear LLC (PSEG)
Facility:	Hope Creek Generating Station (HCGS)
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	July 1, 2016 through September 30, 2016
Inspectors:	J. Hawkins, Senior Resident Inspector S. Haney, Resident Inspector F. Arner, Senior Reactor Analyst W. Cook, Senior Reactor Analyst S. Freeman, Senior Reactor Analyst R. Nimitz, Senior Health Physicist M. Draxton, Project Engineer R. Vadella, Project Engineer
Approved By:	Fred L. Bower, III, Chief Reactor Projects Branch 3 Division of Reactor Projects

TABLE OF CONTENTS

SUMMARY

IR 05000354/2016003; 07/01/2016 – 09/30/2016; Hope Creek Generating Station; Operability Determinations and Functionality Assessments, Problem Identification and Resolution, and Follow-Up of Events and Notices of Enforcement Discretion.

This report covered a three-month period of inspection by resident inspectors and announced inspections performed by regional inspectors. Inspectors identified one apparent violation of low to moderate safety significance (White). The inspectors also identified three non-cited violations (NCVs), all of which were of very low safety significance (Green and/or Severity Level IV). 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 NRC requirements are dispositioned in accordance with the NRC’s Enforcement Policy, dated August 1, 2016. The NRC’s program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, “Reactor Oversight Process,” Revision 5.

Cornerstone: Mitigating Systems

- Preliminary White. A self-revealing preliminary White finding and apparent violation (AV) of Title 10 of the *Code of Federal Regulations* (CFR), Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” and Technical Specification (TS) 3.5.1.c, “Emergency Core Cooling Systems - High Pressure Coolant Injection (HPCI),” was identified because PSEG did not detect and act upon an adverse trend of water intrusion into the HPCI oil system. Specifically, PSEG did not adequately implement procedure OP-AA-108-111, “Adverse Condition Monitoring (ACM) and Contingency Planning,” and the ACM HC 15-008 action to perform monthly HPCI turbine oil analysis for water contamination with known steam leakage by the Steam Admission Valve (FD-F001). Because these monthly oil samples were collected but were not analyzed for water content, PSEG did not identify significant moisture contamination in the HPCI oil system and thus take the necessary response actions. As a result, on August 6, 2016, the HPCI governor control valve (FV-4879) failed to stroke open as required due to moisture-induced corrosion that degraded its hydraulic actuator (EG-R). Consequently, PSEG violated TS 3.5.1.c because, based on failure of the FV-4879 and the EG-R to actuate on August 6, 2016, the NRC determined that the HPCI system was inoperable for a period greater than its technical specification (TS) allowed outage time of 14 days. PSEG’s immediate corrective actions included entering the issue into their Corrective Action Program (CAP) (NOTFs 20737383, 20738402 and 20738403); repairing the HPCI turbine insulation; replacing the HPCI EG-R; flushing the HPCI turbine oil system; and replenishing the system with new oil.

  This finding is more than minor because it adversely affected the equipment performance attribute of the Mitigating Systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, a loss of safety function occurred when elevated water concentration in the HPCI oil system corroded the EG-R, preventing the FV-4879 valve from opening and the HPCI system from starting/running. This resulted in HPCI system inoperability for greater than the 14 days allowed by TS. In accordance with IMC 0609.04, “Initial Characterization of Findings,” and Exhibit 2 of IMC 0609, Appendix A, “The Significance Determination Process for Findings At-Power,” the inspectors screened

the finding for safety significance and determined that a detailed risk evaluation (DRE) was required based on the HPCI system being inoperable for greater than the TS allowed outage time of 14 days. The DRE was performed by a Region I senior reactor analyst (SRA) and concluded that the condition resulted in an increase in core damage frequency (CDF) of low E-6/yr., or of low-to-moderate safety significance (White). The SRA determined the increase in Large Early Release Frequency (LERF) was low E-7/yr., consistent with the significance determined for the internal and external event CDF.

This finding had a cross-cutting aspect in the area of Human Performance, Conservative Bias, because PSEG did not use decision-making practices that emphasize prudent choices over those that are simply allowable. In addition, PSEG did not take timely action to address degraded conditions commensurate with their safety significance. [H.14] (Section 1R15)

- Severity Level IV. The Inspectors identified a Severity Level IV (SLIV) NCV of 10 CFR 50.73(a)(2)(v) for because PSEG did not submit a Licensee Event Report (LER) within 60 days of an event or condition that could have prevented the fulfillment of a safety function at any time within 3 years of the date of discovery. Specifically, while performing an in-service retest of the HPCI system, the turbine tripped on overspeed shortly after startup due to low spring force on the overspeed assembly reset spring. This condition allowed the overspeed tappet to trip the turbine without an actual overspeed condition present, rendering the system inoperable and unable to automatically initiate and inject at rated flow within 35 seconds as required per TSs and the design basis, thus preventing the fulfillment of a safety function. PSEG's corrective actions included documenting the missed LER in the corrective action program (CAP) in notification (NOTF) 20741046, and submitted LER 05000354/2016001-00 under 10 CFR 50.73(a)(2)(v)(D) on October 04, 2016.

  The inspectors evaluated this issue using the traditional enforcement process because the performance deficiency had the potential to impede or impact the NRC's regulatory process. Specifically, the failure to submit an LER under 10 CFR 50.73(a)(2)(v)(D) within 60 days of an event or condition that could have prevented the fulfillment of a safety function at any time within 3 years of the date of discovery could impact the NRC's regulatory process. The inspectors reviewed this issue in accordance with IMC 0612 and the Enforcement Manual; violations of 10 CFR 50.73 are dispositioned using the traditional enforcement process. The inspectors reviewed Section 6.9.d.9 of the NRC Enforcement Policy and determined this violation was a Severity Level IV violation because PSEG did not submit the LER as required by 10 CFR 50.73 did not cause the NRC to reconsider a regulatory position or undertake substantial further inquiry. The performance deficiency was screened against the Reactor Oversight Process (ROP) per the guidance of IMC 0612, Appendix B, "Issue Screening," and no associated ROP finding was identified. In accordance with IMC 0612, Appendix B, this traditional enforcement issue is not assigned a cross-cutting aspect. (Section 4OA2)

- Green. A self-revealing non-cited violation (NCV) of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," was identified for PSEG's inadequate corrective actions to address a condition adverse to quality (CAQ). Specifically, PSEG's corrective actions to address a December 2013 failure of the 'A' main control room (MCR) chiller pressure control valve (PCV) positioner were inadequate and did not ensure that the component was appropriately managed in their shelf life program. As a result, PSEG restored the 'A' MCR chiller with a PCV positioner that exceeded its specified shelf life by 10 years, and ultimately failed due to its age. PSEG's corrective actions included conducting an extensive extent of

condition (EOC) of similar positioners installed at the site (both Salem and Hope Creek), reviewing the shelf life program, and documenting an operability evaluation (70189201) for the currently installed positioners until they can be replaced.

This finding is more than minor because it was associated with the equipment performance attribute of the mitigating systems cornerstone, and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). The degraded positioners being installed in both MCR chillers affected the reliability and availability of the 'A' and 'B' MCR chillers, which provide cooling for the MCR, emergency switchgear rooms, and the safety auxiliaries cooling system pump rooms. Using Exhibit 2 of IMC 0609, Appendix A, the inspectors determined that this finding is of very low safety significance (Green) because, although the performance deficiency (PD) affected the design/qualification of the 'A' MCR chiller operability, it did not result in an actual loss of safety system function because the 'B' chiller was still available, and it did not represent a loss of function of one or more than one train for more than its TS allowed outage time or greater than 24 hrs. The 'B' MCR chiller remained available and the 'A' MCR chiller was restored to an operable status within 6 hours of failing.

This finding had a cross-cutting aspect in the area of Human Performance, Procedure Adherence, because PSEG did not follow the process and procedure that ensures the shelf life program for safety-related components is properly maintained. Specifically, PSEG did not ensure that the shelf life of the MCR chiller PCV positioners were adequately managed in the shelf life program by verifying the correct shelf life of 14 years was correctly assigned. [H.8] (Section 4OA3.2)

Cornerstone: Initiating Events

- Green. A self-revealing non-cited violation (NCV) of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," occurred when PSEG did not follow procedure during the transition from Cold Shutdown to refueling operations while filling up the reactor pressure vessel (RPV) to support RPV head cooling in preparation for reactor disassembly. This resulted in an automatic isolation of the operating residual heat removal (RHR) pump while it was providing decay heat removal in shutdown cooling. PSEG has entered this issue into their corrective action program (CAP) in notification (NOTF) 20684861, and corrective actions included performing a root cause evaluation for the event, revising the operating procedures to provide clarity, and conducting training with all operators on the lessons learned from the event.

  This issue was evaluated in accordance with IMC 0612, Appendix B, and determined to be more than minor since it was associated with the human performance attribute of the Initiating Events cornerstone and adversely affected its objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown, as well as power operations. The finding was evaluated using IMC 0609, Appendix G, "Shutdown Operations Significance Determination Process (SDP)," and per Attachment 1, Exhibit 2, required a Phase 2 risk evaluation which determined the safety significance of this performance deficiency to be in the mid E-8 range, or of very low safety significance (Green).

The inspectors determined this finding has a cross-cutting aspect in the area of Human Performance, Conservative Bias, in that the operator did not use decision-making practices that emphasized prudent choices over those that are simply allowable, and the operator's proposed action was not determined to be safe prior to proceeding with the action. Specifically, the operator did not ensure his actions were safe prior to aligning and operating the feedwater system to fill the RPV during plant cooldown using an uncommon method. [H.14] (Section 4OA3.1)

REPORT DETAILS

Summary of Plant Status

Hope Creek Generating Station (HCGS) began the inspection period at 100 percent of rated thermal power (RTP). On August 17, 2016, operators reduced power to approximately 80 percent power for a control rod pattern adjustment. On August 18, 2016, operators returned the unit to full RTP. On September 16, 2016, operators reduced power to approximately 60 percent to support planned turbine valve testing and control rod sequence exchange. On September 18, 2016, operators returned the unit to full RTP. 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)

External Flooding

a. Inspection Scope

During the week of September 2, 2016, the inspectors performed an inspection of the external flood protection measures for HCGS. The inspectors reviewed TSs, procedures, design documents, and the Updated Final Safety Analysis Report (UFSAR), which depicted the design flood levels and protection areas containing safety-related equipment to identify areas that may be affected by external flooding. The inspectors conducted a general site walkdown of all external areas of the plant, including the turbine building, auxiliary building, and berm to ensure that PSEG erected flood protection measures in accordance with design specifications. Where applicable, the inspectors determined installed flood seal service life and verified that adequate procedures existed for inspecting the installed seals. The inspectors also reviewed operating procedures, specifically, abnormal operating procedure, HC.OP-AB.MISC-0001, "Acts of Nature," for mitigating external flooding during severe weather, to confirm that, overall, PSEG had established adequate measures to protect against external flooding events and, more specifically, that credited operator actions were adequate.

b. Findings

No findings were identified.

1R04 Equipment Alignment

.1 Partial System Walkdown (71111.04Q – 4 samples)

a. Inspection Scope

The inspectors performed partial walkdowns of the following systems:

- ‘A’, ‘B’, and ‘D’ vital buses while the ‘C’ vital bus was inoperable due to the potential transformer failure on August 2
- Reactor core isolation cooling (RCIC) during HPCI inoperability caused by water intrusion on August 6
- Containment Atmosphere Control system during potential inoperability (NOTFs 20738376) caused by inaccurate purchase classification used for suppression chamber pressure indication the week of August 22
- ‘B’ emergency diesel generator (EDG) when the ‘A’ EDG failed to pick up load while synched to the grid for a 24 hour endurance surveillance test on August 25

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 UFSAR, TSs, 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 the system’s performance of its 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.

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

a. Inspection Scope

On July 13, 2016, the inspectors performed a complete system walkdown of accessible portions of the containment inerting and purge system to verify the existing equipment lineup was correct. The inspectors reviewed operating procedures, surveillance tests, drawings, equipment line-up check-off lists, and the UFSAR to verify the system was aligned to perform its required safety functions. The inspectors also reviewed electrical power availability, component lubrication and equipment cooling, hanger and support functionality, and operability of support systems. The inspectors performed field walkdowns of accessible portions of the systems to verify as-built system configuration matched plant documentation, and that system components and support equipment remained operable. The inspectors confirmed that systems and components were aligned correctly, free from interference from temporary services or isolation boundaries, environmentally qualified, and protected from external threats. The inspectors also

examined the material condition of the components for degradation and observed operating parameters of equipment to verify that there were no deficiencies. Additionally, the inspectors reviewed a sample of related condition reports and WOs to ensure PSEG appropriately evaluated and resolved any deficiencies.

b. Findings

No findings were identified.

1R05 Fire Protection

Resident Inspector Quarterly Walkdowns (71111.05Q – 6 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.

- Review of carbon dioxide storage tank failed pressure switch on July 8
- FRH-II-435, Room 4331, equipment access area during the week of July 15
- FRH-II-412, Room 4110, RCIC pump and turbine room during the week of July 22
- FRH-II-532, Room 5302, lower equipment room during the week of August 1
- FRH-II-512, Room 5105, battery room during the week of August 24
- FRH-II-713, service water intake structure during the week of September 21

b. Findings

No findings were identified.

1R06 Flood Protection Measures (71111.06 – 1 sample)

.1 Internal Flooding Review

a. Inspection Scope

The inspectors reviewed the UFSAR, the site flooding analysis, and plant procedures to identify internal flooding susceptibilities for the site. The inspectors review focused on the HPCI and RCIC rooms. It verified the adequacy of equipment seals located below the flood line, floor and water penetration seals, watertight door seals, common drain lines and sumps, sump pumps, level alarms, control circuits, and temporary or removable flood barriers. It assessed the adequacy of operator actions that PSEG had identified as necessary to cope with flooding in this area and also reviewed the CAP to determine if PSEG was identifying and correcting problems associated with both flood mitigation features and site procedures for responding to flooding.

b. Findings

No findings were identified.

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

Quarterly Review of Licensed Operator Requalification Testing and Training

a. Inspection Scope

The inspectors observed licensed operator simulator training on July 25, which involved a requalification examination a scenario covering the following major events: functional recovery of the HPCI system, a vital electrical bus fire, a loss of heat sink and main generator transient with an ATWS, and reactor core stratification, requiring emergency plan implementation by an operations crew. PSEG planned for this evolution to be evaluated and included in performance indicator data regarding drill and exercise performance. The inspectors observed event classification activities performed by the crew. The inspectors also attended the post-evolution critique for the scenario. The focus of the inspectors' activities was to note any weaknesses and deficiencies in the crew's performance and ensure that PSEG evaluators noted the same issues and entered them into the CAP.

The inspectors evaluated operator performance during the simulated event and verified completion of 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 and the technical specification action statements entered by the shift technical advisor. Additionally, the inspectors assessed the ability of the crew and training staff to identify and document crew performance problems.

b. Findings

No findings were identified.

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

a. Inspection Scope

The inspectors observed performance of 'B' and 'D' EDG unloaded runs completed as an EOC for 'C' EDG inoperability on August 4. The inspectors also observed performance of RCIC in-service testing on August 16. The inspectors verified 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 8, and HU-AA-1211, "Pre-Job Briefings," Revision 13. Additionally, the inspectors observed licensed operator 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 – 4 samples)

a. Inspection Scope

The inspectors reviewed the samples listed below to assess the effectiveness of maintenance activities on structure, system, and component (SSC) performance and reliability. The inspectors reviewed 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 SSCs classified as (a)(1), the inspectors assessed the adequacy of goals and corrective actions to return these SSCs 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 the reactor protection system (RPS) electrical protection assembly breaker failure on May 11
- Review of No. 2 main turbine control valve drain steam leak on June 5
- Review of the ’B’ and ‘C’ core spray minimum flow check valve adverse trend during in-service testing on June 30
- Review of the ‘D’ EDG lube oil keep warm pump spring on July 15 (Quality Control sample)

b. Findings

No findings were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13 – 4 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.

- Protected equipment and risk assessment for ‘F’ diesel fuel oil transfer pump failure during in-service testing the week of July 11
- Protected equipment and risk assessment for infrequently performed helicopter flyover inspections of the switchyard performed on July 11
- Protected equipment and risk assessment planned restoration of AX502 transformer following corrective maintenance on July 14
- Protected equipment and risk assessment for the failure of the ‘A’ EDG to pick up load on August 25

b. Findings

No findings were identified.

1R15 Operability Determinations and Functionality Assessments (71111.15 – 6 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 the ‘D’ EDG lube oil keep warm pump relief valve spring failure on July 5
- Review of operability evaluation for the spent fuel pool storage rack seismic qualification non-conservative calculation on July 19
- Review of ‘C’ 4 kilovolt (kV) vital bus potential transformer failure on August 2
- Review of the HPCI governor valve unexpected response on August 7
- Review of the ‘A’ EDG jacket water leak from number 11 cylinder on August 23
- Annual review of operator workarounds (OWAs) on September 19

The inspectors evaluated the technical adequacy of the operability determinations to assess whether TS operability was properly justified and the subject component or system remained available such that no unrecognized increase in risk occurred. The inspectors compared the operability and design criteria in the appropriate sections of the TSs and UFSAR to PSEGs 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 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

Introduction: A self-revealing preliminary White finding and AV of 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” and TS 3.5.1.c, “Emergency Core Cooling Systems - High Pressure Coolant Injection (HPCI),” occurred because PSEG did not detect and act upon an adverse trend of water intrusion into the HPCI oil system. Specifically, PSEG did not adequately implement procedure

OP-AA-108-111, “Adverse Condition Monitoring (ACM) and Contingency Planning,” and the ACM HC 15-008 action to perform monthly HPCI turbine oil sampling and analysis for water contamination with known steam leakage by the steam admission valve (FD-F001). As a consequence, PSEG violated TS 3.5.1.c because, based on analysis of the HPCI governor control valve (FV-4879) and hydraulic actuator (EG-R) failures on August 6, 2016, the NRC determined that the HPCI system was inoperable for a period greater than its TS allowed outage time (AOT) of 14 days.

Description: The HPCI turbine is a Terry Turbine intended to generate the motive force to turn the HPCI booster and main pumps and pump water into the reactor vessel for level control and core cooling during accident conditions. Steam flow to the turbine is controlled by a type “R” electro-hydraulic governor or EG-R that utilizes electrical signals to control hydraulic oil pressure and position the FV-4879 valve. The hydraulic medium for the governor control system is filtered oil taken from the turbine lube oil system.

On August 6, 2016, while performing an 18-Month HPCI System Valve Actuation Functional Test, the FV-4879 valve failed to stroke open as required. PSEG operators immediately declared the HPCI system inoperable, entered a 14-day shutdown TS action statement, and made an 8-hour report to the NRC as a result of the event due to a potential loss of safety function. PSEG also initiated troubleshooting to understand and correct the unexpected condition in the HPCI system.

PSEG’s initial prompt investigation and causal evaluations (PINV 20737383, EQACE 70188670, and RCE 70188669) determined that steam leakage past the HPCI turbine steam admission valve (FD-F001), combined with incorrectly installed insulation covering the HPCI turbine gland seal and bearing housing, led to steam leakage through the turbine casing and gland seals into the turbine outboard bearing housing. The FD-F001 valve had been leaking past its seat since March 2013 and the steam leakage became excessive in March 2015. Consequently, PSEG developed ACM HC 15-008 (NOTF 20600422) on July 29, 2015, which specified actions including performing monthly HPCI turbine oil sampling and analysis for water contamination, in response to known steam leakage by the FD-F001 valve. PSEG also determined that the HPCI turbine insulation became moisture laden and sagged down over a portion of the HPCI turbine shaft seal between March 1, 2016, when the HPCI oil system moisture content was measured at 15 ppm, and April 7, 2016, when it was measured at approximately 13,950 ppm. As described below, the oil sample taken on April 7 was not analyzed for water content until after the HPCI inoperability event on August 6, 2016.

The degraded insulation was not identified until August 7, 2016, and over the period from March 2016 to August 6, 2016, the condensed steam migrated and collected in the turbine oil reservoir. Oil from the reservoir is used to lubricate the turbine and provides oil to the EG-R to adjust FV-4879 position. Based on oil analysis conducted after the August 6, 2016 failure, the water content in the turbine oil was determined to have been above the ACM acceptable level (0.2 percent or 2,000 ppm) since April 7, 2016. This was based on the results of previously unanalyzed oil samples taken in April, May, June, July and analyzed after August 6, 2016. PSEG determined that the buildup of excessive moisture in the oil system caused corrosion that degraded the internals of the EG-R causing the FV-4879 valve to fail to operate. More timely analysis of the lube oil samples taken from HPCI on April 7 (~1.4 percent or 13,950 ppm), in June (~0.6 percent or 6,224 ppm) and in July 2016 (~0.8 percent or 8,193 ppm), may have identified the significant increase in the water content in the lube oil that occurred

between the in-spec March 1, 2016 oil sample (~0.002 percent or 15 ppm) and the failure of the HPCI governor control valve to open on August 6, 2016.

From August 7, 2016, through September 30, 2016, the inspectors conducted an in-depth review of PSEG's CAP NOTFs; EOC reviews; causal evaluations, and corrective actions associated with the water in the HPCI systems; and excessive leakage past the HPCI steam admission valve. The inspectors reviewed PSEG's event details, narrative logs, operating experience from the HPCI system, and the prioritization and timeliness of PSEG's corrective actions. The inspectors found that ACM HC 15-008, Revision 3, was established on July 29, 2015, and specified actions that included performing monthly HPCI turbine oil sampling and analysis for water contamination in response to known steam leakage by the FD-F001 valve. This ACM was developed in accordance with procedure OP-AA-108-111, "Adverse Condition Monitoring and Contingency Planning," that describes PSEG's process for creating a formal plan to monitor significant plant conditions and parameters outside of normal operating bands that have not yet reached plant operating procedure action levels. Specifically, Section 3.3.2, requires that PSEG Operations Shift Management review the current levels and trends of parameters associated with components being monitored under the ACM process to ensure all required actions are being met, and identify any adverse trends before they reach ACM threshold values for action. ACM HC 15-008, established in 2015, specified actions including performing monthly HPCI turbine oil sampling and analysis for water contamination in response to known steam leakage by the FD-F001 valve.

The inspectors reviewed the ACM and historical oil samples on the HPCI system, and found that PSEG staff inadequately implemented the ACM actions to perform monthly HPCI oil sampling and analysis for water contamination from July 29, 2015, through August 6, 2016. The inspectors noted that the HPCI oil system samples collected and analyzed in December 2015, March 2016, and June 2016 were quarterly samples required by the in-service testing (IST) surveillance procedure. The inspectors also concluded that PSEG did not analyze the monthly HPCI oil samples taken from April through July, until after August 7, 2016. The inspectors concluded that the untimely oil analysis contributed to the FV-4879 failure on August 6, 2016. In response, PSEG initiated NOTF 20738421 on August 16, 2016, for: 1) the missed ACM monthly samples; 2) the untimely creation of the HPCI oil sampling preventive maintenance (PM) plan to implement the ACM actions; and, 3) the untimely performance of the ACM monthly oil sample the first time it was actually performed (July 4, 2016).

Based on the information above, the inspectors concluded that between July 29, 2015, and August 6, 2016, PSEG did not adequately implement ACM HC 15-008 actions to perform monthly HPCI turbine oil sampling and analysis for water contamination in accordance with their procedure, OP-AA-111-108. As a result, PSEG did not identify significant moisture contamination in the HPCI oil system and consequently, on August 6, 2016, the HPCI FV-4879 valve failed to stroke open as required due a degraded EG-R, which was caused by the unmonitored moisture intrusion. The inspectors determined that an exposure time of 44 days for the time HPCI would have been challenged to meet its safety functions. This exposure time was based on the last successful HPCI surveillance test on June 23, 2016, failures of the HPCI FV-4879 valve to open during auxiliary oil pump starts on July 3, and August 7, 2016, and the return of HPCI system following repairs on August 11, 2016. The determination of the exposure time and risk analysis are included in Attachment 2 of this report. PSEG's immediate

corrective actions included entering the issue into their CAP (NOTFs 20737383, 20738402, and 20738403); repairing the HPCI turbine insulation; replacing the HPCI EG-R; flushing the HPCI turbine oil system; and replenishing the system with new oil.

Analysis: PSEG not adequately implementing their ACM procedure and the ACM HC 15-008 action to perform monthly HPCI turbine oil sampling and analysis for water contamination was a PD that was within PSEG's ability to foresee and correct, and should have been prevented. This finding is more than minor because it adversely affected the equipment performance attribute of the Mitigating Systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, a loss of safety function occurred when elevated water concentration in the HPCI oil system corroded the EG-R, preventing the FV-4879 valve from opening and the HPCI system from starting/running and resulting in HPCI system being inoperable and unavailable for greater than the 14 days allowed by TS. PSEG did not identify the elevated water concentration because PSEG staff inadequately performed the actions required by ACM HC 15-008 for monthly HPCI turbine oil sampling and analysis. This finding is also similar to IMC 0612, Appendix E, example 4.a, in that not following a procedural activity affecting quality led to a loss of safety function. In accordance with IMC 0609.04, "Initial Characterization of Findings," and Exhibit 2 of IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," the inspectors screened the finding for safety significance and determined that a DRE was required based on the HPCI system being inoperable for greater than the TS AOT.

A Region I SRA completed a DRE using the Hope Creek Standardized Plant Analysis Risk (SPAR) model, Version 8.18 and Systems Analysis Programs for Hands-On Integrated Reliability Evaluations (SAPHIRE). Based upon the DRE, the estimated total increase in CDF for this issue was 2E-6/yr., or of low to moderate safety significance (White). The dominant internal core damage sequences involved loss of condenser heat sink (LOCHS) and loss of main feedwater (LOMFW) initiating events with failure of operators to depressurize and the failure of the RCIC system. The risk was limited by the small probability of the operators failing to depressurize, where low pressure injection systems would be available to cool the core. The SRA used an exposure time of 44 days based on observing that the control oil system and start of the auxiliary oil pump did not result in governor valve movement during a routine oil sample performed on July 3, 2016, which was indicative of degradation at that time within the system. Upon the start of the auxiliary oil pump, the control valve (governor valve) will move in the open direction due to the normal hydraulic pressurization response within the system. Additionally, the inspectors noted that during the last surveillance test run of the turbine (June 23, 2016), the oil sample water content was more than 200 percent above the 2,000 ppm limit where the oil would be procedurally required to be flushed. The SRA noted that this oil sample was not analyzed for water content until after the August 6, 2016, HPCI functional failure. The SRA determined the increase in the Large Early Release Frequency (LERF) was in the low E-7/yr. range, consistent with the significance determination for the internal and external event CDF. The DRE is enclosed as Attachment 2 to this report.

This finding had a cross-cutting aspect in the area of Human Performance, Conservative Bias, because PSEG did not use decision making-practices that emphasize prudent choices over those that are simply allowable. In addition, PSEG did not take timely action to address degraded conditions commensurate with their safety significance.

Specifically, PSEG's decision making-practices associated with the implementation and timeliness of actions associated with the HPCI FD-F001 valve ACM plan and the station's oil sampling and analysis process did not emphasize the potential significance if the ACM actions were not implemented in a timely manner. [H.14]

Enforcement: 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," states, in part, that activities affecting quality shall be prescribed by documented instructions and procedures and shall be accomplished in accordance with these instructions and procedures. PSEG procedure OP-AA-108-111, "Adverse Condition Monitoring and Contingency Planning," describes the process for creating a formal plan to monitor significant plant conditions and parameters outside of normal operating bands that have not yet reached plant operating procedure action levels. Adverse Condition Monitoring and Contingency Plan (ACM) HC 15-008 requires that specified actions, including performing monthly HPCI turbine oil sampling and analysis for water contamination and, upon identification of a specified amount of contamination, to inspect the EG-R and flush the turbine oil system, be taken in response to the July 2015 identification of steam leak-by through the HPCI steam admission valve (FD-F001). Hope Creek Technical Specification 3.5.1.c requires that if the HPCI system becomes inoperable during power operation, the reactor may remain in operation for a period not to exceed 14 days.

Contrary to the above, from July 29, 2015, to August 6, 2016, PSEG did not appropriately accomplish activities affecting quality in accordance with a prescribed instruction. Specifically, PSEG inadequately accomplished their adverse condition monitoring (ACM) procedure, OP-AA-108-111, and the ACM HC 15-008 plan actions to perform monthly high pressure coolant injection (HPCI) turbine oil sampling and analysis for water contamination with known steam leakage by the HPCI steam admission valve. Because monthly oil samples were collected, but were not analyzed for water content, PSEG did not identify significant moisture contamination in the HPCI oil system and thus take the necessary response actions. As a result, on August 6, 2016, the HPCI governor control valve (FV-4879) failed to stroke open as required due to moisture-induced corrosion that degraded its hydraulic actuator (EG-R). Consequently, PSEG violated TS 3.5.1.c because, based on failure of the FV-4879 and the EG-R to actuate on August 6, 2016, the NRC determined that the HPCI system was inoperable for a period greater than its technical specification allowed outage time of 14 days. PSEG's immediate corrective actions included entering the issue into their CAP (NOTFs 20737383, 20738402, and 20738403); repairing the HPCI turbine insulation; replacing the HPCI EG-R; flushing the HPCI turbine oil system; and replenishing the system with new oil. This issue is being characterized as an AV in accordance with the NRC's Enforcement Policy, and its final significance will be dispositioned in separate future correspondence. **(AV 05000354/2016003-01, Inadequate Implementation of Adverse Condition Monitoring Actions for the High Pressure Coolant Injection System)**

1R19 Post-Maintenance Testing (71111.19 – 5 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 and post-job critique where possible, 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.

- Repair of the ‘C’ core spray minimum flow check valve disk nut pin after an adverse trend was identified during in-service testing on June 30 (WO 30189241)
- ‘D’ RHR minimum flow line check valve repairs on July 26 (Order 60130469)
- Repair of the ‘C’ vital bus (10A403) undervoltage relays after failure of the potential transformer on August 2 (WO 30178273)
- HPCI time response testing following control oil system maintenance on August 11 (Order 60130473)
- Repair of the ‘A’ EDG number 11 cylinder gasket and O-ring material after failure on August 24 (WO 60130794)

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:

- ‘D’ RHR pump 2 year comprehensive pump in-service test on July 19 (IST)
- RCIC pump quarterly in-service test on August 16 (IST)
- Review of the HPCI main and booster pump quarterly in-service test originally completed on April 7, reviewed August 29 (IST)
- Review of the ‘C’ EDG monthly in-service test and 24 hour endurance run on September 6

b. Findings

No findings were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06 – 1 samples)

Emergency Preparedness Training Observations

a. Inspection Scope

The inspectors observed a simulator training evolutions for licensed operators on August 2 which required emergency plan implementation by an operations crew. PSEG planned for this evolution to be evaluated and included in performance indicator data regarding drill and exercise performance. The inspectors observed event classification and notification activities performed by the crew. The inspectors also attended the post-evolution critique for the scenario. The focus of the inspectors' activities was to note any weaknesses and deficiencies in the crew's performance and ensure that PSEG evaluators noted the same issues and entered them into the CAP.

b. Findings

No findings were identified.

2. RADIATION SAFETY

Cornerstones: Occupational and Public Radiation Safety

2RS1 Radiological Hazard Assessment and Exposure Controls (71124.01) (1 sample)

a. Inspection Scope

The inspectors reviewed PSEG's performance in assessing and controlling radiological hazards in the workplace. The inspectors used the requirements contained in 10 CFR 20, TSs, applicable Regulatory Guides (RGs), and the procedures required by TSs as criteria for determining compliance.

Inspection Planning

The inspectors reviewed the performance indicators (PIs) for the occupational exposure cornerstone, radiation protection (RP) program audits, and reports of operational occurrences in occupational radiation safety since the last inspection.

Radiological Hazard Assessment

The inspectors conducted independent radiation measurements during walkdowns of the facility and reviewed the radiological survey program.

Instructions to Workers

The inspectors reviewed high radiation area work permit controls and use; observed containers of radioactive materials and assessed whether the containers were labeled and controlled in accordance with requirements.

Contamination and Radioactive Material Control (1 sample)

The inspectors observed the monitoring of potentially contaminated material leaving the radiological controlled area and inspected the methods and radiation monitoring instrumentation used for control, survey, and release of that material. The inspectors selected several sealed sources from inventory records and assessed whether the sources were accounted for and were tested for loose surface contamination. The inspectors evaluated whether any recent transactions involving nationally tracked sources were reported in accordance with requirements.

Radiological Hazards Control and Work Coverage

The inspectors evaluated in-plant radiological conditions and performed independent radiation measurements during facility walkdowns and observation of radiological work activities.

Risk-Significant High Radiation Area (HRA) and Very High Radiation Area (VHRA) Controls

The inspectors reviewed the procedures and controls for HRAs, VHRAs, and radiological transient areas in the plant.

Problem Identification and Resolution

The inspectors evaluated whether problems associated with radiation monitoring and exposure control (including operating experience) were identified at an appropriate threshold and properly addressed in the CAP.

b. Findings

No findings were identified.

2RS2 Occupational As Low As Is Reasonably Achievable Planning and Controls (71124.02)

a. Inspection Scope

The inspectors assessed PSEG's performance with respect to maintaining occupational individual and collective radiation exposures as low as is reasonably achievable (ALARA). The inspectors used the requirements contained in 10 CFR Part 20, applicable RGs, TSs, and procedures required by TSs as criteria for determining compliance.

b. Inspection Planning

The inspectors conducted a review of Hope Creek's collective dose history and trends; ongoing and planned radiological work activities; previous post-outage ALARA reviews; radiological source term history and trends; and ALARA dose estimating and tracking procedures.

Radiological Work Planning

The inspectors selected the following radiological work activities based on exposure significance for review:

- RWP Number 1, Reactor Water Clean Up
- RWP Number 8, Refuel Floor Activities
- RWP Number 13, Control Rod Drive (CRD) Activities
- RWP Number 20, Balance of Plant

For each of these activities, the inspectors reviewed ALARA work activity evaluations; exposure estimates; and exposure reduction requirements.

Verification of Dose Estimates and Exposure Tracking Systems

The inspectors reviewed the current annual collective dose estimate; basis methodology; and measures to track, trend, and reduce occupational doses for ongoing work activities.

Source Term Reduction and Control

The inspectors reviewed the current plant radiological source term and historical trend, plans for plant source term reduction, and contingency plans for changes in the source term as the result of changes in plant fuel performance or changes in plant primary chemistry.

Radiation Worker Performance

The inspectors observed radiation worker and RP technician performance during radiological work to evaluate worker ALARA performance according to specified work controls and procedures. Workers were interviewed to assess their knowledge and awareness of planned and/or implemented radiological and ALARA work controls.

Problem Identification and Resolution

The inspectors evaluated whether problems associated with ALARA planning and controls were identified at an appropriate threshold and properly addressed in the CAP.

b. Findings

No findings were identified.

2RS3 In-Plant Airborne Radioactivity Control and Mitigation (71124.03)

a. Inspection Scope

The inspectors reviewed the control of in-plant airborne radioactivity and the use of respiratory protection devices in these areas. The inspectors used the requirements in 10 CFR Part 20, RG 8.15, RG 8.25, NUREG/CR-0041, TS, and procedures required by TS as criteria for determining compliance.

Inspection Planning

The inspectors reviewed the UFSAR to identify ventilation and radiation monitoring systems associated with airborne radioactivity controls and respiratory protection equipment staged for emergency use. The inspectors also reviewed respiratory protection program procedures and current PIs for unintended internal exposure incidents.

Problem Identification and Resolution

The inspectors evaluated whether problems associated with the control and mitigation of in-plant airborne radioactivity were identified at an appropriate threshold and addressed by PSEG's CAP.

b. Findings

No findings were identified.

2RS4 Occupational Dose Assessment (71124.04 - 5 samples)

a. Inspection Scope

The inspectors reviewed the monitoring, assessment, and reporting of occupational dose. The inspectors used the requirements in 10 CFR Part 20, RGs, TSs, and procedures required by TSs as criteria for determining compliance.

Inspection Planning

The inspectors reviewed: RP program audits; National Voluntary Laboratory Accreditation Program (NVLAP) dosimetry testing reports; and procedures associated with dosimetry operations.

Source Term Characterization (1 sample)

The inspectors reviewed the plant radiation characterization (including gamma, beta, alpha, and neutron) being monitored. The inspector verified the use of scaling factors to account for hard-to-detect radionuclides in internal dose assessments.

External Dosimetry (1 sample)

The inspectors reviewed: dosimetry NVLAP accreditation; onsite storage of dosimeters; the use of "correction factors" to align electronic personal dosimeter (EPD) results with NVLAP dosimetry results; dosimetry occurrence reports; and CAP documents for adverse trends related to external dosimetry.

Internal Dosimetry (1 sample)

The inspectors reviewed: internal dosimetry procedures; whole body counter measurement sensitivity and use; adequacy of the program for whole body count monitoring of plant radionuclides or other bioassay technique; adequacy of the program

for dose assessments based on air sample monitoring and the use of respiratory protection; and internal dose assessments for any actual internal exposure.

Special Dosimetric Situations (1 sample)

The inspectors reviewed: PSEG's worker notification of the risks of radiation exposure to the embryo/fetus; the dosimetry monitoring program for declared pregnant workers; external dose monitoring of workers in large dose rate gradient environments; and dose assessments performed since the last inspection that used multi-badging, skin dose or neutron dose assessments.

Problem Identification and Resolution (1 sample)

The inspectors evaluated whether problems associated with occupational dose assessment were identified at an appropriate threshold and properly addressed in the CAP.

b. Findings

No findings were identified.

2RS5 Radiation Monitoring Instrumentation (71124.05 - 1 sample)

a. Inspection Scope

The inspectors reviewed performance in assuring the accuracy and operability of radiation monitoring instruments used to protect occupational workers and for effluent monitoring and analysis. The inspectors used the requirements in 10 CFR Part 20, 10 CFR Part 50, Appendix I; TSs; Offsite Dose Calculation Manual; RGs; applicable industry standards; and procedures required by TSs as criteria for determining compliance.

Inspection Planning

The inspectors reviewed: Hope Creek's 2014 and 2015 annual effluent and environmental reports; UFSAR; Offsite Dose Calculation Manual (ODCM); RP audits; records of in-service survey instrumentation; and procedures for instrument source checks and calibrations.

Calibration and Testing Program

For the following radiation detection instrumentation, the inspectors reviewed the current detector and electronic channel calibration, functional testing results and alarm set-points as appropriate: portal monitors; personnel contamination monitors; and small article monitors.

The inspectors reviewed the calibration standards used for portable instrument calibrations and response checks to verify that instruments were calibrated by a facility that used National Institute of Science and Technology traceable sources.

The inspectors reviewed the plant waste stream characterization to assess whether the calibration sources used were representative of the radiation encountered in the plant.

Problem Identification and Resolution (1 sample)

The inspectors verified that problems associated with radiation monitoring instrumentation were identified at an appropriate threshold and properly addressed in the CAP.

b. Findings

No findings were identified.

Cornerstone: Public Radiation Safety (PS)

2RS6 Radioactive Gaseous and Liquid Effluent Treatment (71124.06 - 1 sample)

a. Inspection Scope

Groundwater Protection Initiative (GPI) Implementation (1 sample)

The inspectors reviewed: groundwater monitoring results; changes to the GPI program since the last inspection; anomalous results or missed groundwater samples; leakage or spill events including entries made into the decommissioning files (10 CFR 50.75(g)); and PSEG's evaluation of any positive groundwater sample results including appropriate stakeholder notifications and effluent reporting requirements.

Problem Identification and Resolution

The inspectors evaluated whether problems associated with the radioactive effluent monitoring and control program were identified at an appropriate threshold and properly addressed in PSEG's CAP.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

.1 Mitigating Systems Performance Index (5 samples)

a. Inspection Scope

The inspectors reviewed PSEG's submittal of the Mitigating Systems Performance Index for the following systems for the period of October 1, 2015, through September 30, 2016.

- Emergency AC Power System (MS06)
- High Pressure Injection System (MS07)
- Heat Removal System (MS08)

- Residual Heat Removal System (MS09)
- Cooling Water Support System (MS10)

To determine the accuracy of the performance indicator data reported during those periods, the inspectors used definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 7. The inspectors also reviewed PSEG's operator narrative logs, CAP records, Mitigating Systems Performance Index (MSPI) reports, key performance indicator summary records, operating data reports and the MSPI basis document, event reports, and NRC integrated inspection reports to validate the accuracy of the submittals.

b. Findings

No findings were identified.

.2 Occupational Exposure Control Effectiveness (1 sample)

a. Inspection Scope

The inspectors reviewed PSEG's submittals for the occupational radiological occurrences PI for the first quarter 2015 through the second quarter 2016. The inspectors used PI definitions and guidance contained in NEI 99-02, Revision 7, to determine the accuracy of the PI data reported. The inspectors reviewed EPD accumulated dose alarms, dose reports, and dose assignments for any intakes that occurred during the time period reviewed to determine if there were potentially unrecognized PI occurrences. The inspectors conducted walkdowns of various locked high radiation area and very high radiation area entrances to determine the adequacy of the controls in place for these areas.

b. Findings

No findings were identified.

.3 Radiological Effluent TS/ODCM Radiological Effluent Occurrences (1 sample)

a. Inspection Scope

The inspectors reviewed PSEG's submittals for the radiological effluent TS/ODCM radiological effluent occurrences PI for the first quarter 2015 through the second quarter 2016. The inspectors used PI definitions and guidance contained in the NEI 99-02, Revision 7, to determine if the PI data was reported properly. The inspectors reviewed the public dose assessments for the PI for public radiation safety to determine if related data was accurately calculated and reported.

The inspectors reviewed the CAP database to identify any potential occurrences such as unmonitored, uncontrolled, or improperly calculated effluent releases that may have impacted offsite dose. The inspectors reviewed gaseous and liquid effluent summary data and the results of associated offsite dose calculations to determine if indicator results were accurately reported.

b. Findings

No findings were identified.

4OA2 Problem Identification and Resolution (71152 – 1 sample)

.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 PSEG entered issues into their CAP at an appropriate threshold, gave adequate attention to timely corrective actions, and identified and addressed adverse trends. In order to assist with the identification of repetitive equipment failures and specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into their 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: Review of Adverse Trend in HPCI Equipment Failures

a. Inspection Scope

The inspectors performed an in-depth review of PSEG's identified issues, system events, causal and MR evaluations, maintenance procedures, operability determinations, technical evaluations and CAP documents associated with the HPCI system since January 2016.

The inspectors assessed PSEG's problem identification threshold, problem analysis, EOC 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 HPCI system, and whether the planned or completed corrective actions were appropriate. The inspectors compared the actions taken to the guidance in PSEG's CAP.

The inspectors reviewed NOTFs and documents associated with the performance monitoring and corrective actions for HPCI system issues experienced from January through September 2016. The inspectors reviewed multiple causal evaluations associated with these events to determine whether an adverse trend in HPCI system equipment, performance and maintenance issues reflected a larger deficiency with PSEG's 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 issues.

b. Findings and Observations

One finding was identified and is documented below. Additionally, inspector-identified observations and minor performance deficiencies noted during this review are also documented below.

Introduction: The Inspectors identified a Severity Level IV NCV of 10 CFR 50.73(a)(2)(v) for not submitting an LER within 60 days of an event or condition that could have prevented the fulfillment of a safety function at any time within 3 years of the date of discovery. Specifically, while performing an in-service retest of the HPCI system, the turbine tripped on overspeed shortly after startup due to low spring force on the overspeed assembly reset spring. This condition allowed the overspeed tappet to trip the turbine without an actual overspeed condition present, rendering the system inoperable and unable to automatically initiate and inject at rated flow within 35 seconds as required per TSs and the design basis, thus preventing the fulfillment of a safety function.

Description: On April 5, 2016, the HPCI system was declared inoperable for the performance of a planned maintenance outage on the system. Operators entered the applicable 14 day shutdown TS 3.5.1, and commenced the schedule work. On April 7, 2016, HPCI was placed in-service for a retest following the system maintenance outage, and shortly after the HPCI turbine was started, operators received a HPCI turbine trip alarm, where the turbine was noted to trip at normal running speed of 4000 rpm, and then reset over the course of approximately 45 seconds. The HPCI governor was then able to recover and bring the turbine back up to rated speed, and the system retest was completed. Because of the unexpected system response, operators considered the HPCI system to remain inoperable, staying in the 14 day TS 3.5.1 for HPCI inoperability while PSEG commenced troubleshooting of the HPCI overspeed assembly. PSEG's troubleshooting determined that the cause of the trip was due to a low spring force on the overspeed assembly reset spring. The recommended force range for the reset spring per the HPCI vendor manual and PSEG's HPCI turbine overhaul procedure, HC.MD-PM.FD-0001, is 2.0 pounds force minimum to 5.0 pounds force maximum. This condition allowed the overspeed tappet to trip the turbine without an actual overspeed condition present.

The inspectors reviewed the requirements for reportability under 50.73(a)(2)(v)(D) for any event or condition that could have prevented the fulfillment of a safety function of SSCs that are needed to mitigate the consequences of an accident. The inspectors determined that the issue could have prevented the fulfillment of a safety function at any time within three years of the date of discovery, but not at the time of discovery, therefore only an LER was required to be submitted to the NRC within 60 days of the event.

The inspectors noted that reports are not required when systems are declared inoperable as part of a planned evolution for maintenance or surveillance testing when done in accordance with an approved procedure and the plant's TS (unless a condition is discovered that would have resulted in the system being declared inoperable). In this case, the inspectors found that after the unexpected HPCI system response at 3:52 AM on April 7, 2016, the operators considered the HPCI system to remain inoperable, causing HPCI to remain in the 14 day TS 3.5.1 for HPCI inoperability while PSEG commenced troubleshooting and system repairs. This caused HPCI to remain

inoperable for an additional 36 hours, until the system was restored to an operable status at 5:08 PM on April 8, 2016.

Because of this, the inspectors determined that the event required the submittal of an LER under 10 CFR 50.73(a)(2)(v)(D), and questioned PSEG about why an LER had not been submitted for the event. PSEG documented the missed LER in their CAP in NOTF 20741046, completed a causal evaluation (WGE 70189179) on September 29, 2016, and submitted LER 05000354/2016001-00 under 10 CFR 50.73(a)(2)(v)(D) on October 04, 2016. The inspectors determined that not submitting an LER under 10 CFR 50.73(a)(2)(v)(D) within 60 days of an event or condition that could have prevented the fulfillment of a safety function at any time within 3 years of the date of discovery was a performance deficiency that was within PSEG's ability to foresee and correct, and which should have been prevented. Specifically, PSEG found a condition that allowed the HPCI overspeed tappet to trip the turbine without an actual overspeed condition present, a condition that would have resulted in the system being declared inoperable. The inspectors reviewed this issue in accordance with IMC 0612 and the Enforcement Manual. Violations of 10 CFR 50.73 are dispositioned using the traditional enforcement process because they are considered to be violations that potentially impede or impact the regulatory process. The inspectors reviewed Section 6.9.d.9 of the NRC Enforcement Policy and determined this violation was a Severity Level IV violation because PSEG not submitting the LER as required by 10 CFR 50.73 did not cause the NRC to reconsider a regulatory position or undertake substantial further inquiry. No cross-cutting aspect was assigned because cross-cutting aspects are not assigned to traditional enforcement violations.

Enforcement: Title 10 CFR 50.73(a)(2)(v)(D) requires, in part, that licensees submit an LER within 60 days of an event or condition that could have prevented the fulfillment of a safety function needed to mitigate the consequence of an accident at any time within 3 years of the date of discovery. Contrary to the above, between June 8 and October 4, 2016, PSEG did not submit an LER within 60 days of an event or condition that could have prevented the fulfillment of a safety function at any time within 3 years of the date of discovery. Specifically, the condition which allowed the HPCI overspeed tappet to trip the turbine without an actual overspeed condition present, a condition that would have resulted in the system being declared inoperable and unable to automatically initiate and inject at rated flow within 35 seconds as required TSs and the design basis, thus preventing the fulfillment of a safety function needed to mitigate the consequences of an accident. In accordance with the Enforcement Policy, Section 6.9.d.9, the violation was classified as a Severity Level IV violation. Corrective actions included LER 05000354/2016001-00 under 10 CFR 50.73(a)(2)(v)(D) on October 4, 2016. Because this violation was of very low safety significance, was not repetitive or willful, and was entered into PSEG's CAP under NOTF 20741046, it is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000354/2016003-02: Untimely Submittal of an LER for a Condition that Could Have Prevented Fulfillment of a Safety Function)**.

Inspector-Identified Observations and CAP Performance Deficiencies

As a result of this review, the inspectors determined that while all of the issues noted below were performance deficiencies, they are minor because they were related to CAP procedural adherence and human performance issues that did not impact the operability of HPCI system or the ability of the system to perform its intended safety function.

However, all of these inspector identified performance deficiencies in PSEG's CAP related to the HPCI system events since January 2016, add perspective to the HPCI finding documented in Section 1R15 of this report and the finding documented above.

1. Event - HPCI Overspeed Reset Spring Found Low on April 7, 2016:

- (*Inadequate MR Evaluation in CAP*)
  On June 2, during the review of the HPCI system tripping unexpectedly upon system startup, the inspectors questioned PSEG about its assessment that the event on April 7, 2016, was not documented as a maintenance rule functional failure (MRFF) in CAP. The inspectors noted that during the event, the HPCI turbine took over a minute to come up to rated injection speed, and that PSEG's MR scoping document, ER-HC-310-1009, specifically, the MR function, H-BJ-13, states that this function is defined by a "*failure of any component that would prevent automatic initiation and rated injection of the HPCI system within 35 seconds*." After considering the inspector's questions, PSEG re-evaluated the event, determined the event to be a MRFF, and documented the incorrect MR screening in their CAP under NOTF 20731762.

- (*Untimely and Inadequate CAP Action for MRFF*)
  After PSEG determined this issue was a MRFF, PSEG's completion of a functional failure cause determination evaluation (FFCDE) was expected within 45 days of the event per their CAP procedure. Allowing for an additional 60 days for the creation of an order in PSEG's CAP tracking the completion of the MR required FFCDE, the inspectors then questioned PSEG why no FFCDE action had been created in their CAP. PSEG determined that the action to create an FFCDE order in CAP had been missed by both the station ownership committee (SOC) and management review committee (MRC) reviews. PSEG documented this missed evaluation in CAP under NOTF 20737173.

- (*Inadequate Operability/Causal Evaluations in CAP*)
  In early September, 2016, the inspector's noted that the spring had not been replaced when it was found out of tolerance on April 7, 2016, and that no operability evaluation (OpEval) existed for this potentially degraded or nonconforming condition. PSEG acknowledged the inspector's questions and documented NOTFs 20739418 and 20741187 in CAP, confirming that no cause had been identified for the reset spring being found out of tolerance and that the spring could have relaxed due to a potentially degraded or nonconforming condition existed. On September 12, 2016, PSEG troubleshooting determined that the reset spring tension was 3.0 pounds force, and had slightly relaxed since April 7, 2016, when it was reset to 3.5 pounds force.

  PSEG also documented actions for engineering to review the troubleshooting data and update WGE and FFCDE in CAP to determine why follow-up actions had not been established to verify the spring force sooner, and determine why a preventive maintenance item to replace the spring had not been completed.

2. Event - HPCI Water Intrusion Discovered on August 6, 2016:

- (*CAP and Maintenance Procedures Not Followed*)
  During the review of the HPCI system water intrusion event documented in Section 1R15 above, the inspectors determined that PSEG was not implementing their procedural requirements and standards, in that, MA-AA-716-230, Predictive Maintenance Program, Section 1.4.3, states to "*prevent equipment failure through*

accurate analysis and timely corrective action," and MA-AA-716-230-1004, Lubricant Sampling Guideline (A License Renewal Commitment), Section 4.1.2, which states "*if any abnormalities are observed during the collection of an oil sample (water in oil, particles in oil, oil discoloration, abnormal smell) then INITIATE an N1 notification to report abnormality.*" However, the inspectors found no N1 NOTFs were documented by PSEG in their CAP, as required by their maintenance and CAP procedures, for the oil samples drawn in April, June, and July 2016, all of which contained visible concentrations of water in them.

- (*Inadequate Corrective Action*): 1) The inspectors reviewed CAs for a similar water intrusion event on the RCIC turbine oil system that was identified by PSEG operators on February 26, 2015. This issue was also caused by a leaking steam admission valve, coupled with incorrectly installed insulation covering the gland seal and bearing housing, which allowed water to condense, migrate into, and collect in the turbine oil system. As part of the follow-up actions to this event, PSEG performed an EOC review of the HPCI turbine insulation to ensure it was installed correctly (WO 60122450) on May 1, 2015. PSEG also performed a causal evaluation (WGE 70174237) for this event as a result of an NRC documented Green self-revealing NCV 0500354/2015001-01, for not identifying and correcting a CAQ associated with the RCIC system insulation and oil trending, issued on April 21, 2015. The inspectors noted that although the HPCI turbine insulation was checked to be installed correctly after the RCIC event, no changes to the HPCI or RCIC maintenance procedures were completed, even though PSEG recognized that the Terry Turbine Maintenance Guide for HPCI and RCIC included a note stating, "*When insulating the turbine casing, verify that the insulation material stops at the turbine gland cases. If insulation material encloses the gland cases with the bearing pedestal caps, there is a high probability that steam and water will enter the turbine oil system*." On August 8, 2016, PSEG documented in CAP, NOTF 20736906 (Order 70188664), to update these maintenance procedures.

- 2) The inspectors noted that PSEG's evaluation for the 2015 RCIC water intrusion event recommended corrective actions which included an action to implement an upgraded oil analysis database by December 18, 2015. This action had an interim action to perform bi-monthly oil trend review meetings of all analyzed oil samples until the system is upgraded. The inspectors questioned PSEG about these bi-monthly oil trend review meetings on August 18, 2016, and discovered that only one meeting had occurred over a twelve-month period prior to the oil analysis database being upgraded in April 2016. PSEG documented this missed opportunity in its CAP.

(*Untimely Corrective Action):* The inspectors also reviewed multiple CAP NOTFs that supported PSEG's investigation, which stated that the lube oil sample and analysis process has previously been identified as a program improvement issue in the CAP. The inspectors determined that multiple NOTFs (20694025, 20715205, and 20720519) had been generated between June 16, 2015, and August 2016, citing oil sampling and analysis process inefficiencies, time delays, and lost or never completed oil sample analyses. All of these NOTFs recommended changing the process to ensure for the accountability and traceability of the oil samples from the time they were drawn from the system to the time the oil analysis results were received by engineering. The inspectors found that no corrective actions were taken to resolve any of the oil sampling and analysis process deficiencies, and that this inaction by PSEG contributed to multiple HPCI oil samples from April, June, and July 2016, going unanalyzed until after the HPCI water intrusion event on August 6, 2016. PSEG initiated NOTF 20737682 on

August 10, 2016, for a less than adequate oil sampling and analysis process and has issued a new traceability form in MA-AA-716-230-1004, Lubricant Sampling Guideline, required to be used for every oil sample from this point forward.

These performance deficiencies noted above were considered minor because they were related to CAP procedural adherence and human performance issues that did not impact the operability of HPCI system or the ability of the system to perform its intended safety function.

4OA3 Follow-Up of Events and Notices of Enforcement Discretion (71153 – 6 samples)

Plant Events

a. Inspection Scope

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

- The loss of shutdown cooling that occurred on April 10, 2015, while transitioning from cold shutdown to refueling operations
- The failure of the 'A' MCR chiller on May 6, 2016
- The improper helium backfilling of two loaded multi-purpose containers (MPCs 356 and 358) placed on the ISFSI for storage during Salem Unit 2 dry cask storage (DCS) campaign on July 8, 2016. As associated LIV is documented in NRC IR 50-272 & 311/2016003, Section 4OA7.
- The failure of the 'C' EDG speed switch during the performance of a 24 hour endurance surveillance test on August 5, 2016
- HPCI governor valve failed to reposition as expected during functional testing on August 6 (EN 52159)
- The failure of the 'A' EDG to pick up load while synched to the grid for a 24 hour endurance surveillance test on August 25, 2016

b. Findings

1. Inadequate Procedure Adherence Resulted in a Loss of Shutdown Cooling

Introduction. A self-revealing Green NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified when PSEG did not follow procedure during the transition from Cold Shutdown to refueling operations while filling up the RPV to support RPV head cooling in preparation for reactor disassembly. This

resulted in an automatic isolation of the operating RHR pump while it was providing decay heat removal in shutdown cooling.

Description. On April 10, 2015, PSEG commenced a normal reactor shutdown by manually scramming the reactor from 20 percent power in order to perform Hope Creek's planned 19th refueling outage (H1R19).

Hope Creek operations uses Integrated Operating Procedures (IOPs) HC.OP-IO.ZZ-0004, Shutdown from Rated Power to Cold Shutdown, and HC.OP-IO.ZZ-0005, Cold Shutdown to Refueling, which contain guidance to place the plant in a Cold Shutdown condition from rated power operation and align the plant to support refueling operations. Initial plant cool down per HC.OP-IO.ZZ-0004 is accomplished by rejecting steam to the main condenser via the main turbine bypass valves with forced circulation of the reactor coolant maintained by the Reactor Recirculation system. Once reactor pressure is stabilized at 50 PSIG, forced circulation is transitioned to the RHR system operating in the shutdown cooling mode, and plant cooldown to cold shutdown conditions is completed and maintained with the RHR system. Once the plant is stabilized in Cold Shutdown, HC.OP-IO.ZZ-0005 provides guidance for filling the RPV to between 270 to 300 inches to support RPV head cooling in preparation for reactor disassembly. This filling can be accomplished by using either the condensate and feedwater systems, condensate transfer to the shutdown cooling system suction piping, or the CRD system. After RPV level has been raised and the reactor head has been cooled, reactor disassembly is allowed to proceed.

On April 11, 2015, Hope Creek operators were utilizing HC.OP-IO.ZZ-0005 with the condensate transfer system aligned to the RHR pump suction in shutdown cooling to fill up the RPV. Operators secured this lineup due to the need to respond to unexpected conditions during routine RPS channel testing. After operators appropriately responded to these unexpected conditions, direction was given by the control room supervisor to the plant operator (a reactor operator) to use the feedwater system operation procedure, HC.OP-SO.AE-0001, in order to raise RPV water level to the required band for RPV head cooling.

Realignment to feed the RPV is controlled by HC.OP-SO.AE-0001, Section 5.1, Feeding the Reactor Vessel with the Condensate System and Start of Secondary Condensate Pumps. In this procedure, the feeding of the RPV is accomplished using the startup level control valve (SULCV) which provides for a throttlable method to precisely control reactor level during this evolution. Operators used the feedwater isolation valve, a 24 inch non-throttlable motor operated stop check valve, instead of the SULCV in order to feed the RPV causing the rate of RPV injection and RPV pressure to increase rapidly. This rapid RPV pressure increase caused automatic isolation of the RHR pump in shutdown cooling on high RPV pressure (>82 psig), resulting in a loss of decay heat removal until operators restored an RHR pump in the shutdown cooling lineup. HC.OP-SO.AE-0001 does not specify the use of the feedwater isolation valve in lieu of the SULCV.

PSEG's root cause evaluation (70175589) for this loss of shutdown cooling determined that shutdown cooling was lost for approximately 5 minutes and RPV temperature increased less than one degree during this event. PSEG's evaluation also determined the root cause of this event to be that operators did not use approved procedural guidance in HC.OP-SO.AE-0001 to properly align the condensate and feedwater

systems to fill up the RPV. PSEG entered this issue into their CAP in NOTF 20684861, and corrective actions included performing a root cause evaluation for the event, revising the operating procedures to provide clarity, and conducting training with all operators on the lessons learned from the event.

Analysis. PSEG not following its procedure for feedwater operations was a performance deficiency that was reasonably within their ability to foresee and correct and which should have been prevented. This issue was evaluated in accordance with IMC 0612, Appendix B, and determined to be more than minor since it was associated with the human performance attribute of the Initiating Events cornerstone and adversely affected its objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown, as well as power operations. Additionally, the finding was similar to IMC 0612, Appendix E, Example 4.b, which describes an operator not following procedure resulting in a reactor trip or plant transient as a condition that is more than minor. The finding was evaluated using IMC 0609, Appendix G, "Shutdown Operations Significance Determination Process (SDP)." Per Attachment 1, Exhibit 2, "Initiating Events Screening Questions," this loss of shutdown cooling event required a Phase 2 risk evaluation. A Region I SRA used Attachment 3, "Phase 2 SDP Template for BWR during Shutdown," to determine the safety significance of this performance deficiency. Using Worksheet 4, "Loss of Operating Train of RHR (LORHR) in Plant Operating State (POS) 1 (Head On)," the SRA made the following assumptions: Initiating Event Likelihood (IEL) equal to zero (0) based upon the actual loss of shutdown cooling having occurred on April 11, 2016; DHR recovery credit equal to three (3) based upon time to boil and subsequent re-pressurization to the RHR pump shutoff head; manual low pressure injection and RCS pressure control (MINJ&SRV) credit equal to two (2) based upon both trains of low pressure ECCS available; manual high pressure injection at pressure (MINJY) equal to one (1) based upon CRD, HPCI and SRVs being available, if needed; and Containment Venting (CV) credit equal to three (3) based upon available procedures and operator training. Lastly, the SRA gave an operator recovery credit of two (equivalent to an operator failure probability of 1E-2, one in a hundred chance of failure) based upon prompt identification and diagnosis of the event and prompt restoration of shutdown cooling per procedure (the actual loss of cooling was less than five minutes with essentially no RCS temperature increase). Based upon the Phase 2 Worksheet 4 core damage sequence results, the safety significance of this performance deficiency was estimated in the mid E-8 range, or of very low safety significance (Green).

The inspectors determined this finding has a cross-cutting aspect in the area of Human Performance, Conservative Bias, in that the operator did not use decision-making practices that emphasized prudent choices over those that are simply allowable, and the operator's proposed action was not determined to be safe prior to proceeding with the action. Specifically, the operator did not ensure his actions were safe prior to aligning and operating the feedwater system to fill the RPV during plant cooldown using an uncommon method. [H.14]

Enforcement. Title 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality shall be prescribed by documented instructions of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions. PSEG procedure for feedwater system operation, HC.OP-SO.AE-0001, is used to raise the RPV water level to the required band for RPV head cooling during shutdown operations. Contrary to the above,

on April 11, 2015, PSEG did not accomplish an activity affecting quality in accordance with documented instructions of a type appropriate to the circumstances. Specifically, personnel did not follow procedure, HC.OP-SO.AE-0001, during the transition from Cold Shutdown to refueling operations while filling up the RPV to support RPV head cooling in preparation for reactor disassembly. This resulted in an automatic isolation of the operating RHR pump while providing decay heat removal in shutdown cooling. PSEG's corrective actions included performing a root cause evaluation for the event, revising the operating procedures to provide clarity, and conducting training on the lessons learned from the event with all operators. Because this finding was of very low safety significance (Green) and entered into PSEG's CAP as NOTF 20684861, this finding is being treated as an NCV consistent with Section 2.3.2.a of the NRC Enforcement Policy. **(NCV 05000354/2016003-03, Inadequate Procedure Adherence Resulted in a Loss of Shutdown Cooling)**

2. <u>Inadequate Corrective Actions for a Main Control Room Chiller Failure</u>

<u>Introduction</u>. A Green, self-revealing NCV of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," was identified for PSEG's inadequate corrective actions to address a CAQ. Specifically, PSEG's corrective actions to address a December 2013 failure of the 'A' MCR chiller PCV positioner were inadequate and did not ensure that the component was appropriately managed in PSEG's shelf life program. As a result, PSEG restored the 'A' MCR chiller with a PCV positioner that exceeded its specified shelf life by 10 years, and subsequently failed due to its age.

<u>Description</u>. The control room envelope (CRE) heating, ventilation, and air conditioning (HVAC) systems are designed to ensure habitability during any design basis radiological accident. Redundant HVAC systems are provided to control the ambient conditions for safety-related equipment to ensure operating temperature limits are not exceeded. The 'A' and 'B' MCR chillers provide the accident function of maintaining the temperature of the CRE for equipment performance and operator comfort.

On May 6, 2016, while placing the 'A' MCR chiller in service, it tripped. PSEG's troubleshooting determined that the positioner for the PCV failed causing the valve to not open. This resulted in a loss of cooling to the 'A' MCR chiller and chiller inoperability. This positioner had been replaced previously on April 9, 2014, as a corrective action (70162284). PSEG performed a causal evaluation on May 31 (70186738), a failure analysis on September 19, and a maintenance rule functional failure cause determination evaluation on September 16, for the event. PSEG determined that internal relay diaphragms in the positioner had degraded due to age, leading to internal leakage of the diaphragm that prevented the PCV from opening. PSEG also found that the classification of the positioner was purchase classification 1 (PC1; safety-related). The PC1 classification was a corrective action from a December 2013, positioner failure.

The inspectors reviewed PSEG's causal evaluations, failure analysis, procurement procedures, and the recent failure history of the positioners. The inspectors noted the 'A' MCR chiller PCV positioner failed due to age on December 20, 2013, while the 'B' MCR chiller was out of service in support of maintenance, which caused a loss of both MCR chillers (LER 05000354/2013-010-00). This LER was closed by the inspectors in IR 2014003. A design control finding (NCV 05000354/2014003-05) was documented for not effectively implementing a design change that should have reclassified the positioner

from PC4 (nonsafety-related) to PC1, and for not appropriately tracking the shelf life of the positioner.

PSEG's 2013 causal evaluation (70162284) determined that if the PC of the positioner had been appropriately changed to PC1 during the design change, a positioner that had been on the shelf for more than 20 years should not have been installed into a safety-related system. However, because the PC was not changed, the shelf-life of the in-stock replacement positioners was not tracked, leading to the installation of a positioner in 2011 that had been manufactured 21 years before. PSEG determined that the MCR chiller PCV positioner failed to operate because of internal relay leakage caused by degraded diaphragms. These diaphragms failed due to the positioner's age exceeding the vendor recommended lifetime of 14 years. PSEG entered this issue into the CAP as NOTF 20642546 and as part of their corrective actions; they replaced the failed positioner and changed the PC for the chiller PCV positioners from PC4 to PC1.

The inspectors reviewed the December 2013, corrective actions which included an action (CRCA 70162284-0180) for procurement engineering to "*ensure the positioner is managed in the shelf-life program.*" PSEG completed this action by stating that, "*the original positioner has been purchased as PC1… It has been added to [the Bill of Materials]… and will be managed under the shelf-life program,*" and closed as complete in the CAP. PSEG's procurement procedures require that when a component is purchased as PC1, a new Material Master (MM) number is created which also requires a review to ensure the correct shelf life is assigned. This was not done. The inspectors found that while the positioner was replaced and the PC was appropriately changed, PSEG did not ensure that the positioner was managed in the shelf life program. Specifically, PSEG did not ensure that the correct shelf life had been assigned to the positioner (14 years vice 32 years). Because the shelf life was not managed appropriately, PSEG replaced the failed 'A' MCR positioner with a positioner that had been manufactured in 1990, making it 24 years old when it was installed on April 9, 2014, and 26 years old when it failed on May 5, 2016. The inspectors also found that PSEG's warehouse operations practice for the receipt process was to assign the receipt date (today's date) as the manufacturing date. In this case, the shelf life of the positioners was already expired upon receipt from a third party supplier and went unrecognized. PSEG is performing a separate evaluation and extent of condition of this issue (Order 70189201).

PSEG's In-Storage Shelf-Life Program procedure, SM-AA-300-1005, for PC1 components, requires that components containing nitrile rubber (Table 1 – Shelf life Criteria): 1) as a MECH/ELEC part be stored for no more than 14 years; or, 2) as a SEAL part be stored for no more than 32 years. PSEG found that the PC1 positioner uses nitrile rubber as a MECH/ELEC part, and that the failed MCR positioner had been incorrectly assigned a shelf-life of 32 years, when it should have only been assigned a shelf-life of 14 years. SM-AA-300-1001-F1, Form 1 – MM Classification Determination Checklist, requires shelf life of new MM number be verified in accordance with the shelf life criteria tables in SM-AA-300-1005. In addition, PSEG's procedure for shelf life start date and expiration dates, SM-AA-102-1001, Warehouse Operations, Section 5.9.3, directs the receiver to contact a manager if the manufacturer date is unknown or unavailable.

Because of this, the inspectors determined that PSEG's corrective action in 2014 to ensure the positioner was appropriately managed by the shelf life program was

ineffective because the shelf life was not verified to be accurate prior to installing the same type of positioner back into the system. PSEG's corrective actions for this included conducting an extensive EOC review of similar positioners installed at the site (both Salem and Hope Creek), reviewing the shelf life program and revising station procedures to ensure the receipt process is halted when the manufacturer's date is unknown, and documenting an operability evaluation (70189201) for the currently installed positioners until they can be replaced.

Analysis. PSEG's inadequate corrective actions to address a December 2013 failure of the 'A' MCR chiller PCV positioner was a performance deficiency that was within PSEG's ability to foresee and correct, and should have been prevented. Specifically, because of these inadequate corrective actions, PSEG restored the 'A' and 'B' MCR chillers with positioners that had exceeded its specified shelf life, and the 'A' MCR chiller positioner failed due to age. This resulted in a reduction of cooling capability for the control area chilled water system, and called into question the reliability of both chillers. The inspectors determined that the performance deficiency was more than minor because it was associated with the equipment performance attribute of the mitigating systems cornerstone, and adversely affected the cornerstone objective to ensure the availability and reliability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). The degraded positioners being installed in both MCR chillers affected the reliability and availability of the 'A' and 'B' MCR chillers, which provide cooling for the MCR, emergency switchgear rooms, and the safety auxiliaries cooling system pump rooms. Using Exhibit 2 of IMC 0609, Appendix A, the inspectors determined that this finding is of very low safety significance (Green) because, although the PD affected the design/qualification of the 'A' MCR chiller operability, it did not result in an actual loss of safety system function because the 'B' chiller was still available, and it did not represent a loss of function of one or more than one train for more than its technical specification allowed outage time or greater than 24 hrs. The 'B' MCR chiller remained available and the 'A' MCR chiller was restored to an operable status within 6 hours of failing.

This finding had a cross-cutting aspect in the area of Human Performance, Procedure Adherence, because PSEG did not follow the process and procedure that ensures the shelf life program for safety-related components is properly maintained. Specifically, PSEG did not ensure that the shelf life of the MCR chiller PCV positioners were adequately managed in the shelf life program by verifying the correct shelf life of 14 years was correctly assigned. [H.8]

Enforcement. Title 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires that measures be established to assure that conditions adverse to quality, such as failures, are promptly identified and corrected. Contrary to this, on April 11, 2014, PSEG's corrective actions to address a failure of the 'A' MCR chiller PCV positioner were not adequate, and did not ensure that the positioner was appropriately managed in their shelf life program. As a result, PSEG restored the 'A' MCR chiller with a positioner that had exceeded its specified shelf life by 10 years, and subsequently failed due to its age. PSEG's corrective actions for this included conducting an extensive EOC of similar positioners installed at the site (both Salem and Hope Creek), reviewing the shelf life program, and documenting an operability evaluation (70189201) for the currently installed positioners until they can be replaced. Because of the very low safety significance (Green) and because the issue was entered into the CAP as NOTF 20741967, this violation is being treated as an NCV, consistent with Section 2.3.2 of the

NRC Enforcement Policy. (**NCV 05000354/2016003-04, Inadequate Corrective Actions for Main Control Room Chiller Positioner Failure**)

4OA6 Meetings, Including Exit

On October 27, 2016, the inspectors presented the inspection results to Mr. Eric Carr, Hope Creek Site Vice President, and other members of the PSEG 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.

ATTACHMENT 1: SUPPLEMENTARY INFORMATION

SUPPLEMENTARY INFORMATION

KEY POINTS OF CONTACT

<u>Licensee Personnel</u>
P. Davison, Site Vice President
E. Carr, Site Vice President
E. Casulli, Hope Creek Plant Manager
L. Cary, Plant Chemist
R. Cary, Environmental Coordinator
R. Chan, Manager NOS
L. Clark, Instrument Supervisor
R. Emerick, Radiological Engineer
F. Grenier, Supervisor Radiation Protection
R. Grey, Superintendent Radiation Protection
M. Hassler, Salem Radiation Protection
A. Kraus, Manager, Nuclear Environmental Affairs
S. Kugler, Manager Chemistry
T. MacEwen, Principal Compliance Engineer
J. Mallon, Director, Regulatory Compliance
A. Ochoa, Senior Compliance Engineer
B. Ronan, Radiological Engineer
C. Thompson, Radiological Engineer
K. Timko, Radiation Protection Engineer
H. Trimble, Radiation Protection Manger

<u>Others</u>
J. Humphreys, Nuclear Engineer, Nuclear Engineering Section, NJ DEP BNE
K. Tuccillo, Supervisor, Nuclear Environmental Engineering Section, NJ, DEP, BNE
J. Vouglitois, Nuclear Engineer, Nuclear Environmental Engineering Section, NJ Department of Environmental Protection, Bureau of Nuclear Engineering (NJ DEP BNE)

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Open and Closed

05000354/2016003-01	AV	Inadequate Implementation of Adverse Condition Monitoring Actions for the High Pressure Coolant Injection System (Section 1R15)
05000354/2016003-02	NCV	Untimely Submittal of an LER for a Condition that Could Have Prevented Fulfillment of a Safety Function (Section 4OA2)
05000354/2016003-03	NCV	Inadequate Procedure Adherence Resulted in a Loss of Shutdown Cooling (Section 4OA3.1)
05000354/2016003-04	NCV	Inadequate Corrective Actions for Main Control Room Chiller Positioner Failure (Section 4OA3.2)

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection

Procedures
EP-AA-121-1003, Equipment Important to Emergency Response – Work Prioritization, Revision 0
EP-HC-111-107, Section H - Hazards & Other Conditions Affecting Plant Safety, Revision 0
EP-HC-111-207, HCGS ECG – EAL Technical Basis, Revision 0
HC.OP-AB.MISC-0001, Acts of Nature, Revision 29
HC.OP-AB.ZZ-0139, Acts of Nature, Revision 24
OP-AA-108-111-1001, Severe Weather and Natural Disaster Guidelines, Revision 14

Section 1R04: Equipment Alignment

Procedures
HC.OP-AB.ZZ-0172, Loss of 4.16 KV Bus 10A403 'C' Channel, Revision 7
HC.OP-GP.PB-0003, 4.16 KV Bus 10A403 Removal and Return to Service – 'C' Channel, Revision 15
HC.OP-IS.GS-0101, Containment Atmosphere Control System Valves – IST, Revision 50
HC.OP-SO.GS-0001, Containment Atmosphere Control System Operation, Revision 33
HC.OP-ST.PB-0007, 4.16 KV Bus 10A403 Undervoltage Test and Return to Service – 'C' Channel, Revision 16
LS-AA-125, Corrective Action Program, Revision 21
M-57-1, Containment Atmosphere Control, Revision 44
M-71-0, Liquid Nitrogen for Purge and Containment Inerting, Revision 11
MA-HC-716-004, Conduct of Troubleshooting, Revision 1
OP-AA-106-101-1001, Event Response Guidelines, Revision 16

OP-AA-108-115, Operability Determinations and Functionality Assessments, Revision 4
SM-AA-300, Procurement Engineering Support Activities, Revision 7

Notifications

20364215	20473349	20490237	20659652	20687215	20724437
20734340	20734685	20738367			

Maintenance Orders/Work Orders

30148569	30178273	50161947	50169137	50169770	50169797
50171955	60075973	70083735	70084736	70188135	70188401
70188668	80095996				

Other Documents
C-0002-0, Plot Plan, Revision 18
E-0046-1, Schematic Meter and Relay Diagram 4.16 KV Class 1E Station Power System Switchgears – 10A401 and 10A403, Revision 8
E-0106-0, Electrical Schematic Diagram Class 1E 4.16 KV Station Power System, Sht. 4, Revision 12
FSK-P-0-HA-662, Pipe Hanger Design Calculation and Aux Building Plant Heating Steam, Revision 4
HC Troubleshooting Log – 1, 10A403 Vital Bus Loss of Voltage Relays 27A1-403(B-C) and 27A2-403(B-C)
HC.MD-ST.PB-0011, 10A403 Class 1E 4.16 KV 18 Month Vital Bus Loss of Voltage Instrumentation Channel Calibration and Functional Test, Revision 15

Section 1R05: Fire Protection

Procedures
FP-AA-016, Conduct of Shift Turnover, Revision 3
FP-HC-004, Actions for Inoperable Fire Protection – Hope Creek Station, Revision 4
HC.IC-DC.ZZ-0070, Bailey Control Unit, Type 721, Revision 8
HC.MD-ST.SB-0005, RPS and PRNMS Electrical Protection Assembly Channel Functional Test for New Model Logic Card P/N 148C6118G001, Revision 7
HC.MD-ST.SB-0006, 18 Month Electrical Protection Assembly Channel Calibration New Model Logic Card P/N 148C6118G001, Revision 12
OP-AA-108-115, Operability Determinations and Functionality Assessments, Revision 4
SH.FP-TI.FS-0002, Venting and Draining CO2 Storage Tanks, Revision 0
SM-AA-300, Procurement Engineering Support Activities, Revision 7
FRH-II-713, Service Water Intake Structure, Revision 4
FP-HC-004, Actions for Inoperable Fire Protection – Hope Creek Station, Revision 4
HC.FP-ST.QK-0090(F), Service Water Intake Structure Incipient Fire Detector System Functional Test, Revision 8

Notifications (* Indicates NRC-identified)

20629910	20636724	20683816	20695722	20707982	20728186
20730391	20735140	20735304	20735405	20735977	20736527
20737513	20738367	20742747*	20742748*	20742749*	

Maintenance Orders/Work Orders

30185282	30227409	30282104	50161947	50169137	50169770
50169797	50171955	50180832	60130171	70020448	70134006
70155514	70161608	70162269	70168977	70173985	70175642
70186739	70188668				

Other Documents
PN1-C71-1030-0003, Elementary Diagram Reactor Protection System MG Set, Revision 16
PN1-C71-S003-0035, EPA Vendor Manual
PSE-61469, Failure Analysis of a Circuit Breaker – H1SB-1AN410, June 21, 2016

Section 1R06: Flood Protection Measures

Drawings
M-5066, Reactor Building Fire and Smoke Detectors Elev. 54’, Revision 5
P-2301-1, Piping Area Drawing Reactor Building Area 23 Elev. 54’, Revision 4

Section 1R11: Licensed Operator Requalification Program

Procedures
HC.OP-IS.BD-0001, Reactor Core Isolation Cooling Pump – OP203 – IST, Revision 60
HC.OP-ST.KJ-0019, Emergency Diesel Generator BG400 Operability Test – Unloaded, Revision 10
HC.OP-ST.KJ-0021, Emergency Diesel Generator DG400 Operability Test – Unloaded, Revision 10

Notifications

20734117	20734688	20736860	20736871	20736969	20737306
20738107	20738108				

Maintenance Orders/Work Orders
50186006
70176824

Other Documents
Scenario Guide (SG)-759, HPCI Retest/Electrical Fire/ATWS/Stratification, dated June 29, 2016

Section 1R12: Maintenance Effectiveness

Procedures
ER-AA-1004, Maintenance Rule – Performance Monitoring, Revision 14
HC.MD-GP.ZZ-0237, General Instructions for Dissassembly, Inspection, and Reassembly of Anchor-Darling Testable Check Valves, Revision 5
HC.MD-ST.SB-0005, RPS and PRNMS Electrical Protection Assembly Channel Functional Test for New Model Logic Card P/N 148C6118G001, Revision 7
HC.MD-ST.SB-0006, 18 Month Electrical Protection Assembly Channel Calibration New Model Logic Card P/N 148C6118G001, Revision 12
HC.OP-IS.BE-0101, Core Spray Subsystem A Valves – IST, Revision 29

HC.OP-IS.BE-0102, Core Spray Subsystem B Valves – IST, Revision 27

Notifications (* Indicates NRC-identified)

20446392	20447050	20567337	20632542	20640526	20683816
20712807	20728186	20733097	20733104	20734859	20736673*

Maintenance Orders/Work Orders

30189241	30282104	50180832	70020448	70058747	70134006
70140843	70155514	70161698	70162269	70168977	70173642
70173985	70175642	70183131	70186739	70187096	80088497

Other Documents
70179133
PN1-C71-1030-0003, Elementary Diagram Reactor Protection System MG Set, Revision 16
PN1-C71-S003-0035, EPA Vendor Manual
PSE-61469, Failure Analysis of a Circuit Breaker – H1SB-1AN410, June 21, 2016

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Procedures
ER-AA-321, Administrative Requirements for In-service Testing, Revision 13
HC.OP-AB.SEC-0002, Airborne Threat, Revision 9
HC.OP-IS.JE-0006, F Diesel Fuel Oil Transfer Pump – FP401 – IST, Revision 33
OP-AA-101-112-1002, Online Risk Assessment, Revision 9
OP-AA-108-116, Protected Equipment Program, Revision 12
WC-AA-105, Work Activity Risk Management, Revision 5

Notifications

20472339	20701963	20729113	20731785	20735353	20735391
20735549	20735553				

Maintenance Orders/Work Orders

50163676	60093725	60125556	70179969	70187287	70188084
70188163					

Other Documents
HCGS PRA Risk Evaluation Form for July 17, 2016, through July 23, 2016, Revision 0
Protected Equipment Log – 500kV 2-6 and 1-3 Breakers, dated July 13, 2016
Protected Equipment Log – AX502, dated July 13, 2016

Section 1R15: Operability Determinations and Functionality Assessments

Procedures
HC.MD-CM.KJ-0001, Diesel Engine Overhaul, Revision 23
HC.MD-CM.KJ-0017, Diesel Generator Keepwarm Pump Maintenance and Repairs, Revision 2
HC.MD-ST.KJ-0001, Diesel Generator Technical Specification Surveillance and Preventive Maintenance, Revision 46
HC.OP-AR.ZZ-0025, CRIDS Computer Points Book 6 D4303 Thru D4596, Revision 10

HC.OP-SO.KJ-0001, Emergency Diesel Generators Operation, Revision 72
HC.OP-ST.KJ-0004, Emergency Diesel Generator 1DG400 Operability Test – Monthly, Revision 76
HC.OP-ST.KJ-0014, EDG 1AG400 – 24 Hour Operability Run and Hot Restart Test, Revision 34
HC.OP-ST.ZZ-0001, Power Distribution Line-up – Weekly, Revision 36
SM-AA-410-1001, Nuclear Procurement Quality Material Receipt Inspection Process Guide, Revision 1
OP-AA-102-103, Operator Work-Around Program, Revision 3
OP-AA-102-103-1001, Operator Burdens Program, Revision 2
OP-AA-108-115, Operability Determinations & Functionality Assessments, Revision 4

Notifications

20593219	20732914	20732945	20732960	20734685	20735409
20735504	20736480	20736491	20736492	20736493	20737532
20737547	20738165	20738166	20738706	20738711	20738787
20738788	20738793				

Drawings
E-0006-1, Sheet 1, Single Line Meter & Relay Diagram 4.16kV Class 1E Station Power System, Revision 8
E-0046-1, 4.16kV Class 1E Station Power System Switchgears 10A401 & 10A403, Revision 8
E-0106-0, Sheet 4, Class 1E 4.16kV Station Power Bus A403 & A404 Undervoltage Protection, Revision 12

Maintenance Orders/Work Orders

30104071	30158457	30178273	30281241	30295245	50174288
60130794	70036674	70134049	70185463	70187533	70187695
70187873	70188045	80080425	80103518	80117792	

Other Documents
OP-HC-108-115-1001, Form 1, Technical Specification Action Statement Log, 16-158, C Core Spray/C RHR Pump start delay, dated August 2, 2016
DR-9028-2, Seismic Finite Element Model Analysis Design Report for the Spent Fuel Storage Modules for the HCGS, dated July 15, 1985, Revision 3
H-1-KJ-MGS-0199, Design Specification for Emergency Diesel Generator Lube Oil Keepwarm Pumps, Revision 1
PM178Q-0151, Special Module Seismic Static Analysis, Revision 2
PM49862
VTD 430856, EDG Keepwarm O&M Manual, Revision 2
Hope Creek Quarterly Operator Burden Assessment dated July 12, 2016

Section 1R19: Post-Maintenance Testing

Procedures
HC.MD-GP.ZZ-0237, General Instructions for Disassembly, Inspection and Reassembly of Anchor Darling Testable Check Valves, Revision 5
HC.OP-IS.BC-0104, Residual Heat Removal Subsystem D Valves – Inservice Test, Revision 27

HC.OP-ST.BJ-0002, HPCI System Functional Test (Low Pressure) – 18 Months and HPCI System Response Time Test (High Pressure), Revision 41
HC.MD-CM.KJ-0001, Diesel Engine Overhaul, Revision 23
HC.MD-ST.KJ-0001, Diesel Generator Technical Specification Surveillance and Preventive Maintenance, Revision 46
HC.MD-ST.PB-0011, 10A403 Class 1E 4.16 KV 18 Month Vital Bus Loss of Voltage Instrumentation Channel Calibration and Functional Test, Revision 15
HC.OP-AB.ZZ-0172, Loss of 4.16 KV Bus 10A403 'C' Channel, Revision 7
HC.OP-GP.PB-0003, 4.16 KV Bus 10A403 Removal and Return to Service – 'C' Channel, Revision 15
HC.OP-IS.BE-0101, Core Spray Subsystem A Valves – Inservice Test, Revision 29
HC.OP-IS.BE-0102, Core Spray Subsystem B Valves – Inservice Test, Revision 27
HC.OP-SO.KJ-0001, Emergency Diesel Generators Operation, Revision 72
HC.OP-ST.KJ-0014, EDG 1AG400 – 24 Hour Operability Run and Hot Restart Test, Revision 34
HC.OP-ST.PB-0007, 4.16 KV Bus 10A403 Undervoltage Test and Return to Service – 'C' Channel, Revision 16
HC.OP-ST.ZZ-0001, Power Distribution Lineup Weekly, Revision 36
LS-AA-125, Corrective Action Program, Revision 21
MA-HC-716-004, Conduct of Troubleshooting, Revision 1
OP-AA-106-101-1001, Event Response Guidelines, Revision 16

Notifications

20490237	20567337	20593219	20687215	20724437	20733097
20733104	20734665	20734685	20734859	20736471	20736480
20736491	20736492	20736493	20736556	20737547	20738165
20738166	20738706	20738711	20738787	20738788	20738793

Maintenance Orders/Work Orders

30104071	30158457	30178273	30189241	30281241	50174288
60130469	60130473	60130794	70036674	70058747	70134049
70140843	70188401	80088497	80103518		

Other Documents
E-0046-1, Schematic Meter and Relay Diagram 4.16 KV Class 1E Station Power System Switchgears – 10A401 and 10A403, Revision 8
E-0106-0, Electrical Schematic Diagram Class 1E 4.16 KV Station Power System, Sht. 4, Revision 12
HC Troubleshooting Log – 1, 10A403 Vital Bus Loss of Voltage Relays 27A1-403(B-C) and 27A2-403(B-C)
PM49862

Section 1R22: Surveillance Testing

Procedures
ER-AA-1200, Critical Component Failure Clock, Revision 6
ER-AA-310-1004, Maintenance Rule – Performance Monitoring, Revision 14
HC.MD-CM.FD-0001, High Pressure Coolant Injection Steam Turbine Overhaul, Revision 19

HC.MD-PM.FD-0001, High Pressure Coolant Injection Steam Turbine Inspection and Preventive Maintenance, Revision 27
HC.OP-IS.BC-0004, DP202, D Residual Heat Removal Pump In-Service Test, Revision 42
HC.OP-IS.BD-0001, Reactor Core Isolation Cooling Pump – OP203 – Inservice Test, Revision 60
HC.OP-IS.BJ-0001, HPCI Main and Booster Pump Set – OP204 and OP217 – Inservice Test, Revision 64
HC.OP-SO.BJ-0001, High Pressure Coolant Injection System Operation, Revision 6

Notifications
20724102 20731762 20737173

Maintenance Orders/Work Orders

30227966	30264538	30280116	30284644	50173730	50185402
50186006	60128823	70062699	70176824	70185851	

Other Documents
PN1-E41-C002-0054, HPCI Instruction Manual Changes for Turbine S/N 37122A Terry Turbine Instruction Manual, Revision 23

Section 1EP6: Drill Evaluation

Other Documents
Scenario Guide (SG)-759, HPCI Retest/Electrical Fire/ATWS/Stratification, dated June 29, 2016

Section 2RS1: Access Control to Radiologically Significant Areas

Procedures
RP-AA-463, High Radiation Area Key Control, Revision 4
RP-AA-460, Control for High and Very High Radiation Areas, Revision 17
RP-AA-605, 10 CFR 61 Program, Revision 1
RP-AA-605-1001, Evaluation of 10 CFR 61 Sample Results, Revision 1
RP-AA-211, Personnel Dosimetry Performance Verification, Revision 11
RP-AA-214, Area Surveillance
RP-AA-503, Unconditional Release Survey Methods, Revision 8
RP-AA-800, Control, Inventory, and Leak Testing of Radioactive Sources, Revision 11
LSA-SA-1000-1001, Salem Generating Station Unit 1 Surveillance Frequency Control Program List of Surveillance Frequencies, Revision 7
NC.RS-TI.ZZ-0582(Q), Operating Instruction for the Shepard Model 89 Calibrator, Revision 3
NC.RS-TI.ZZ-0561(Q), Calibration of the Canberra GEM 5 Gamma Monitor, Revision 0
NC.RS-TI-ZZ-0512(Q), Calibration of the Canberra CRONOS Small Article Monitor, Revision 0
NC.RS-TI.ZZ-0549(Q), Calibration of the Canberra ARGOS-5AB Whole Body Contamination Monitor, Revision 0

Other Documents
Source tracking data
Source leak check test data
Passive Whole-body Count Study

Calibration Records (various)
Current Source Term
Collective Dose Report
Corrective Action Documents (various)

<u>Section 2RS2: Occupational ALARA Planning and Controls</u>

<u>Procedures</u>
RP-AA-400, ALARA Program, Revision 6
RP-AA-401, Operational ALARA Planning, Revision 13
RP-AA-401-1002, Instructions for Establishing Electronic Alarming Dosimeter Setpoints Revision 3
HC.RP-TI.XX-0003(Q), Reactor Cavity, Fuel Pool and Drywell Special Evolution, Revision 25

<u>Other Documents</u>
Hope Creek ALARA Results 2016
Hope Creek Plan of Day Dose Report
Hope Creek Outage Task Breakdown and Dose Estimates
ALARA Plans (various)
Occupational Dose Reports
Corrective Action Documents (various)

<u>Section 2RS3: In-plant Airborne Radioactivity Control and Mitigation</u>

<u>Procedures</u>
RP-AA-605, 10 CFR 61 Program, Revision 1
RP-AA-605-1001, Evaluation of 10 CFR 61 Sample Results, Revision 1
RP-AA-300-1002, Electron Capture Isotope Control, Revision 1
RP-AA-300, Radiological Survey Program, Revision 1
RP-AA-301, Radiological Air sampling Program, Revision 5
RP-AA-302, Alpha Source Term Characterization, Revision 4
RP-AA-303, Personnel Air Sampling, Revision 1

<u>Other Documents</u>
Current Source Term
Collective Dose Report
Hope Creek Outage Task Breakdown and Dose Estimates
Occupational Dose Reports
Respirator Training Curricula
Air Sample Results (various)
Corrective Action Documents (various)

<u>Section 2RS4: Occupational Dose Assessment</u>

<u>Procedures</u>
RP-AA-350, Response to Potentially Contaminated personnel, Revision 12
RP-AA-220, Bioassay Program, Revision 9

RP-AA-222, Method for Estimating Internal Exposure from In Vivo or In Vitro Bioassay Data, Revision 6
RP-AA-211, Personnel Dosimetry Verification, Revision 7
RP-AA-214, Area Surveillance, Revision 4
RP-AA-221, Radiation Protection Whole-body Counter (WBC) and WBC Data Review, Revision 4
RP-AA-270, Prenatal Radiation Exposure, Revision 6
RP-AA-206, Dose Assessment for Airborne Radioactive Material Exposure, Revision 0
RP-AA-301, Radiological Air Sampling Program, Revision 6
RP-AA-203-1001, Personnel Exposure Investigation, Revision 7
RP-AA-303, Personnel Air Sampling, Revision 1
RP-AA-302, Alpha Source Term Characterization, Revision 4
RP-AA-350-1002, Managing Large Scale Contamination Events, Revision 0
RP-AA-281, Comparison of Personal Dosimetry Results, Revision 2
RP-AA-250, External Dose Assessment for Contamination, Revision 8
RP-AA-605, 10 CFR 61 Program, Revision 1
RP-AA-605-1001, Evaluation of 10 CFR 61 Sample Results, Revision 1
RP-AA-203-1001, Personnel Exposure Investigation, Revision 7
NC.RS-TI.ZZ-0514(Q), Calibration and Operation of the IDC-HF Electronic Dosimeter Calibrator and Calibration of the MGPI DMC 2000 Electronic Dosimeters, Revision 0
NC.RS-TI.ZZ-0592(Q), Radiation Protection Instrument (RPI) Laboratory Calibration and Quality Control, Revision 2
NC.RS-WC.ZZ-0402(Q), Whole Body Counter Calibration, Revision 4
RP-AA-270, Prenatal Radiation Exposure, Revision 6

Other Documents
NVLAP Certification
NVLAP Technical Bulletin NVLAP-LB-76-2013
PSEG Radiation Worker Training
Electronic Dosimeter Calibration Records (EPDs 053031, 055302, 057589, 063898, 054370)
MGP Calibrations (050827, 051402, 051683, 52071)
Salem and Hope Creek Neutron Study 2015
Outage Task Breakdown and Dose Estimates
Occupational Dose Reports
Audits (NOSA-HPC-15-08, NOSA–HPC-15-3C)
Annual Bioassay Program Review
Technical Bases Document- Hope Creek Alpha Characterization
Current Source Term
Collective Dose Report
Occupational Dose Reports
Corrective Action Documents (various)

Section 2RS5: Radiation Monitoring Instrumentation

Procedures
NC.RS-TI.ZZ-0514(Q), Calibration and Operation of the IDC-HF Electronic Dosimeter Calibrator and Calibration of the MGPI DMC 2000 Electronic Dosimeter, Revision 0
NC.RS-WC.ZZ-0402(Q), Whole-body Counter Calibration, Revision 4

NC.RS-TI.ZZ-0519(Q), Calibration of the Model SAC-4 Alpha Counter, Revision 4
NC.RS-TI.ZZ-0552(Q), Calibration of the Ludlum Model 3030P Alpha and beta counter, Revision 1
NC.RS-TI.ZZ-0551(Q), Calibration of the Eberline BC-4 Beta Counter, Revision 2
NC.RS-TI.ZZ-0549(Q), Calibration of the Canberra ARGOS-5AB Whole Body Contamination Monitor, Revision 0
CY-AA-130-205, Radiochemistry Quality Control, Revision 0
HC.CH-RC.ZZ-0002, Gross Beat and Tritium by Liquid Scintillation, Revision 22
RP-AA-503, Unconditional Release Survey Method, Revision 8

Other Documents
Supervisory Directive GEM 5
Tritium in Oil Evaluation (Document 7017855230040)
Calibration Reports (various – ARGOS, GEM 5, BC-4, SAC-4, CRONOS)
Corrective Action Documents (various)

Section 2RS6: Radioactive Gaseous and Liquid Effluent Treatment

Procedures
CY-AA-130-205, Radiochemistry Quality Control, Revision 0
EN-AA-170-4000, Radiological Groundwater Protection Program Implementation, Revision 0
EN-AA-170-4160, Station RGPP Controlled Sample Points, Revision 0

Other Documents
Hope Creek Offsite Dose Calculation Manual
PSEG Remediation Reports
Radiological Sampling Plans
2015 PSEG Hope Creek Effluent and Environmental Annual Reports
10 CFR 50.59 Screenings
2015 Ground Water Protection Program (RGPP) Report
Radioactive Release Analyses (liquid and gaseous discharges)

Section 4OA1: Performance Indicator Verification

Procedures
LS-AA-2001, Collecting and Reporting of NRC Performance Indicator Data, Revision 11
LS-AA-2140, Monthly Data Elements for NRC Occupational Exposure Control Effectiveness Revision 5
LS-AA-2150, Monthly Data Elements for RETS/ODCM Radiological Effluent Occurrences, Revision 6

Other Documents
Consolidated Data Entry MSPI Derivation Reports, Cooling Water System, June 2016
Consolidated Data Entry MSPI Derivation Reports, Emergency AC Power System, June 2016
Consolidated Data Entry MSPI Derivation Reports, Heat Removal System, June 2016
Consolidated Data Entry MSPI Derivation Reports, High Pressure Injection System, June 2016
Consolidated Data Entry MSPI Derivation Reports, Residual Heat Removal System, June 2016

Performance Indicator Data
Corrective Action Documents (various

Section 4OA2: Problem Identification and Resolution

Procedures
OP-AA-108-111, Adverse Condition Monitoring and Contingency Planning, Revision 11
OP-AA-108-115, Operability Determinations and Functionality Assessments, Revision 4
LS-AA-120, Issue Identification and Screening Process, Revision 13
EQ-HC-069, HCGS Environmental Qualification Binder for HPCI Turbine Assembly, Revision 0
HC.OP-ST.BJ-0002, HPCI System Functional Test (Low Pressure) – 18 Months and HPCI System Response time Test (High Pressure), Revision 41
HC.MD-CM.FD-0001, High Pressure Coolant Injection (HPCI) Steam Turbine Overhaul, Revision 19
ER-HC-310-1009, HCGS – Maintenance Rule Scoping, Revision 12
MA-AA-716-006, Control of Lubricants Program, Revision 12
MA-AA-716-230, Predictive Maintenance Program, Revision 9
HC.OP-IS.BJ-0001, HPCI Main and Booster Pump Set – 0P204 and 0P217 – Inservice Test, Revision 64

Notifications (* Indicates NRC-identified)

20300451	20537974	20600422	20680092	20694025	20715205
20720519	20724102	20725058	20726357*	20731762	20736683
20737006	20737173*	20737383	20737499	20737520	20737682
20738421					

Maintenance Orders/Work Orders

40025527	70062699	70135925	70173676	70174237	70179002
70184822	70188669	70188670	80105814	80107161	80114894

Other Documents
ACM HC 15-008, HPCI Steam Admission Valve Leakby, Revision 3
BWROG-TP-14-016, HPCI RCIC System Improvement Committee – HPCI Steam Admission Valve Leakage, Revision 0
LCO 16-077, Technical Specification Action Statement Log dated April 5, 2016
VTD 323602, EPRI Manual, Terry Turbine Maintenance Guide, HPCI Application

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

Procedures
HC.MD-ST.PB-0011, 10A403 Class 1E 4.16 KV 18 Month Vital Bus Loss of Voltage Instrument Channel Calibration and Functional Test, Revision 15
HC.OP-ST.BJ-0003, HPCI System Valve Actuation Functional Test, Revision 9
LS-AA-125, Corrective Action Program, Revision 21MA-HC-716-004
OP-AA-106-101-1001
SC.MD-FR.DCS-0006, Sealing, Drying and Backfilling of a Loaded MPC, Revision 8

HC.OP-AB.ZZ-0172, Loss of 4.16 KV Bus 10A403 ‘C’ Channel, Revision 7
HC.OP-GP.PB-0003, 4.16 KV Bus 10A403 Removal and Return to Service – ‘C’ Channel, Revision 15
HC.OP-ST.PB-0007, 4.16 KV Bus 10A403 Undervoltage Test and Return to Service – ‘C’ Channel, Revision 16
MA-HC-716-004, Conduct of Troubleshooting, Revision 1
OP-AA-106-101-1001, Event Response Guidelines, Revision 16

<u>Notifications</u>

20490237	20551399	20687215	20724437	20734685	20735208
20736904	20737006	20737383	20737459		

<u>Maintenance Orders/Work Orders</u>

30178273	30294830	30294831	50170959	70130358	70135925
70163676	70188401	80115180	80117971		

<u>Other Documents</u>

E-0046-1, Schematic Meter and Relay Diagram 4.16 KV Class 1E Station Power System Switchgears – 10A401 and 10A403, Revision 8
E-0106-0, Electrical Schematic Diagram Class 1E 4.16 KV Station Power System, Sht. 4, Revision 12
HC Troubleshooting Log – 1, 10A403 Vital Bus Loss of Voltage Relays 27A1-403(B-C) and 27A2-403(B-C)
OP-HC-108-115-1001, Form 1, Technical Specification Action Statement Log, 16-161, HPCI, dated August 7, 2016
VTD 400006, HI-STORM FSAR, Revision 7
H-1-BJ-MDC-1997, HPCI Lube Oil System Analysis, Revision 0

LIST OF ACRONYMS

10 CFR	Title 10 of the *Code of Federal Regulations*
ACM	adverse condition monitoring
ADAMS	Agencywide Documents Access and Management System
ALARA	as low as is reasonably achievable
AOT	allowed outage time
AV	apparent violation
CAP	corrective action program
CAQ	condition adverse to quality
CDF	core damage frequency
CFR	Code of Federal Regulation
CRD	control rod drive
CRE	control room envelope
CV	containment venting
DRE	detailed risk evaluation
EDG	emergency diesel generator
EOC	extent of condition
EPD	electronic personal dosimeter
FFCDE	failure cause determination evaluation
GPI	Groundwater Protection Initiative
HCGS	Hope Creek Generating Station
HPCI	high pressure coolant injection
HRA	High Radiation Area
HVAC	heating, ventilation and air conditioning
IEL	initiating event likelihood
IMC	inspection manual chapter
IR	inspection report
IST	in-service testing
kV	kilovolt
LER	licensee event report
LERF	large early release frequency
LOCHS	loss of condenser heat sink
LOMFW	loss of main feedwater
LORHR	loss of operating train of RHR
MCR	main control room
MM	material master
MR	maintenance rule
MRC	management review committee
MRFF	maintenance rule functional failure
MSPI	Mitigating Systems Performance Index
NCV	non-cited violation
NOTF	notification(s)
NRC	Nuclear Regulatory Commission
NVLAP	National Voluntary Laboratory Accreditation Program
ODCM	Offsite Dose Calculation Manual
OWA	operator workaround(s)
PCV	pressure control valve

PD	Performance Deficiency
PI	Performance Indicators
PM	preventive maintenance
POS	plant operating site
PSEG	Public Service Enterprise Group Nuclear LLC
RCIC	reactor core isolation cooling
RHR	residual heat removal
RG	Regulatory Guide
ROP	reactor oversite process
RP	radiation protection
RPS	reactor protection system
RPV	reactor pressure vessel
RTP	rated thermal power
SAPHIRE	systems analysis programs for hands-on
SDP	significance determination process
SLIV	severity level IV
SOC	station ownership committee
SPAR	standardized plant analysis risk
SRA	senior reactor analyst
SSC	structure, system, and component
SULCV	startup level control valve
TS	technical specification(s)
UFSAR	Updated Final Safety Analysis Report
VHRA	Very High Radiation Area
WO	work order(s)

ATTACHMENT 2: DETAILED RISK EVALUATION
Hope Creek Nuclear Generating Station
High Pressure Coolant Injection (HPCI) Failure to Start

Screening Logic

The inspectors evaluated the finding in accordance with IMC 0609.04, "Initial Characterization of Findings," and Exhibit 2 of IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," for the mitigating systems cornerstone. The finding screened to a DRE because the HPCI System was inoperable for greater than its allowed outage time of 14 days.

Detailed Risk Evaluation

The SRA evaluated the finding using the Hope Creek SPAR model version 8.18, and SAPHIRE version 8.1.4.

Internal Events Risk Contribution Key Assumptions:

HPCI Function

The HPCI pump/turbine was initially discovered to be inoperable on August 6, 2016, during scheduled HPCI valve functional testing. During the test, the HPCI governor control valve (FV-4879) failed to stroke open as expected.

During a HPCI start signal, the auxiliary oil pump starts in order to provide initial pressurization of the hydraulic system. The turbine oil relay system pressurizes first, which results in the governor valve beginning to open. Normal operation of the governor valve (control valve) is to open to a nominal 20-40 percent open position, before being moved in the closed direction due to the EG-R (hydraulic actuator) pressurizing and returning the valve to a further closed position. After hydraulic pressure builds up enough in the HPCI Stop Valve cylinder, this will open the stop valve and a limit switch will initiate the ramp generator circuit to allow the EG-R (governor) to ramp open the governor valve until the HPCI flow controller takes control of its position.

PSEG provided governor valve position traces for the August 6, 2016 event, which showed that upon a start of the auxiliary oil pump the governor valve initially went further closed instead of the expected initial opening. Therefore, the control valve would not have opened and the HPCI Turbine would not have started in an event.

The SRA also requested a computer trace for a routine oil sample taken on July 3, 2016, where the auxiliary oil pump was started. This trace showed a governor valve response similar to the failure that occurred on August 6. This indicated that the normal expected initial opening of the governor valve due to the pilot valve servo and pilot relay valve positioning had not occurred at that time as well. This was inconsistent with the normal expected movement of the control valve during initial pressurization and indicated that the control oil system was degraded at that time as the valve had not moved as expected. The SRA noted an anomaly had occurred back in the 2012 timeframe due to excessive friction in the EG-R when the governor valve initially moved open as expected, but never closed back down during the oil sample. This is the expected

response with the flow controller being positioned in the manually closed position. Therefore, the governor valve not initially opening on July 3 indicated there was some effect due to the water intrusion as far back as July 3, 2016. It was unknown whether this could have been caused by improper resetting of the pilot servo and EG-R during the last shutdown sequence of the turbine on June 23, 2016. The improper operation was not identified on July 3 because the auxiliary oil pump was operated only to take an oil sample and PSEG did not monitor the control valve position.

Exposure Time

The exposure time was determined to be 44 days. This was based on the last successful HPCI surveillance test start on June 23, 2016, failure of the HPCI governor valve to move as expected on July 3, and August 6, 2016, and the return of HPCI following repair on August 11, 2016. Using Section 2.0 of Volume 1 to the Risk Assessment of Operational Events (RASP) manual, the SRA used t/2 for exposure between June 23 and July 3 (5 days), t for exposure between July 3 and Aug 7 (35 days), and 4 days repair time. During the repair time, RCIC was protected (RCI-TDP-TM-TRAIN = False).

Due to the failure mechanism (water intrusion degradation of the internals of the hydraulic actuator (EG-R) and effect on the hydraulic control system), no recovery credit was applied.

SPAR Model Modifications

The SRA set the basic events for HPCI failure to start (HCI-TDP-FS-TRAIN) and operator failure to recover HPCI (HCI-XHE-XL-START) to TRUE. After an initial model run with the HPCI pump unable to start, the dominant sequences were driven by the failure of reactor depressurization and the failure of RCIC, and the most influential basic event was failure of the operator to depressurize the reactor.

For those sequences with basic events where RCIC failed to run (RCI-TDP-FR-TRAIN), the SRA adjusted the probability for operator failure to depressurize the reactor (ADS-XHE-XE-MDEPR). This adjustment was made because the RCIC failure to run probability is based on a 24-hour mission time and there is a probability that RCIC would run for some amount of time. Rather than adjust the RCIC failure probability, the SRA used the extra depressurization time provided by RCIC running to adjust the probability for operator failure to depressurize. Using the SPAR-H method with increased time available and high stress from the failure of both high pressure systems to function, the SRA adjusted the probability for operator failure to depressurize to 1E-4 (20 percent of normal value) and applied it to any core damage sequences that contained basic events for RCIC failure to run. This was performed by writing a post processing rule for the model.

Internal Risk Calculation

Internal Delta CDF for 44 days Exposure Time

The base case was determined to be 5.06E-6/yr. with the conditional case (HPCI failure to start) resulting in 2.05E-5/yr. The incremental increase in risk was 2.05E-5/yr. – 5.06E-6/yr. =

1.54E-5/yr. This was adjusted for 40-day exposure and 4-day repair time, which resulted in a change in risk of **<u>1.86E-6/yr</u>**.

<u>Analysis of Dominant Cutsets</u>

The dominant sequences consisted of:

- Loss of condenser heat sink, with failure to depressurize and failure of the RCIC MOV injection valve to re-openLoss of Main Feedwater with failure to depressurize and failure of the RCIC MOV injection valve to re-open
- Loss of condenser heat sink, with failure to depressurize and RCIC system in test and maintenance

<u>Sensitivity Case 5 was run due to sequences consisting of basic events with the RCIC MOV injection valve failing to re-open because by design once opened the injection valve should not automatically reposition closed even on high water level</u>

Additionally, the SPAR model calculated several loss of offsite power sequences that contained basic events for the salt service water 'B' (SSW) train in test and maintenance. These resulted from the calculation on reactor depressurization, which determined that the safety-relief valves (SRV) would fail to open due to loss of DC power to the solenoids. This can be explained by the power supply arrangement at Hope Creek for the SRV pilot solenoid valves, including the non-ADS valves. The 'B' EDG supplies 4kV Bus 10A402 and the 'D' EDG supplies 4kV Bus 10A404. These supply the distribution panels powering up the SRV pilot solenoids. Since SSW Train 'B' provides cooling to both the 'B' & 'D' emergency diesels, if a condition existed causing the 'B' SSW train to be out of service during the exposure time, the SPAR model calculates failure of the depressurization function due to the loss of 'B' Train AC power leading to loss of DC power to the SRV solenoids.

Sensitivity Cases 1 and 3 addressed the impact of the SSW 'B' in test and maintenance given PSEG procedures would permit this arrangement for only two hours before the EDG 'B' and/or 'D' coolers would have to be cross-tied, which would make one of the diesels available.

Uncertainty and Sensitivity Analysis

The SRA performed five sensitivity analyses as shown below. These were performed to determine the effect of exposure time, SSW 'B' Train out for maintenance, operator failure to depressurize and the effect of RCIC MOVs failing to re-open.

<u>Sensitivity 1, SSW 'B' Train Unavailable Due to Test & Maintenance</u>

The SRA wrote a post-processing rule that removed the basic event for SSW 'B' Train Test & Maintenance (SSW-SYS-TM-LOOPB) from developed cut sets. The results were as follows:

The Base Case was determined to be 4.9E-6/yr.
The Conditional Case was 1.87E-5/yr.
Delta 1.87E-5 – 4.9E-6 = 1.38E-5/yr.

After adjusting for a 40-day exposure and 4-day repair time, the total increase in risk came to **1.64E-6/yr.**

Sensitivity 2, Basic SPAR Run.

The SRA conducted a SPAR run with the post processing rules mentioned earlier turned off, such that no changes were made for SSW 'B' Train, operator failure to depressurize, or RCIC Test & Maintenance Events.

Base Case was 5.33E-6/yr.
Condition Case 2.48E-5/yr.
Delta = 1.95E-5/yr. x 44 days = **2.35E-6/yr**.

Sensitivity 3, Additional Changes to Depressurization Probability

For this run, the SRA put back the post processing rules for SSW 'B' Train and the operator failure to depressurize, but further reduced the failure probability to depressurize to 7.5E-5. After adjusting for a 40 day exposure and 4 day repair time the conditional increase in risk was **1.64E-6/yr**.

Sensitivity 4, Full Exposure Time

This sensitivity analysis addressed the exposure time. As mentioned in the assumptions, the exposure time was based on evidence of HPCI control valve failure on July 3, 2016. This resulted in a t/2 exposure between June 23, 2016 and July 3, 2016 and t exposure from July 4, 2016 until discovery on August 6, 2016. However, during the successful test of June 23, 2016, the governor valve opened much further than any other traces observed during tests with normal oil-water content. The control valve opened to around the 80 percent position on initial pressurization from the aux oil pump which was much more than what was observed on several other test runs and after its ramp open achieved an opening of 95 percent versus a normal 40-55 percent opening position observed in other test runs. The SRA determined that this could have been a result of the water intrusion into the oil control system and degradation of the internals of the system. Although the test was successful, the response of the system would be much more challenging during an actual event where the flow controller would come out of saturation at a later time due to not seeing flow until the discharge pressure exceeds backpressure and the system check valve opens. The dynamic response of the overall control system in an actual injection event is a different dynamic that that which is observed during normal in-service testing where flowrate has a gradual increase with turbine speed. While this anomaly existed, the SRA considered any additional exposure would not have elevated the risk into a higher threshold and determined this to be one of the major uncertainties involved within the entire risk evaluation for exposure time.

To check the longer exposure time, the SRA ran the model with an exposure time of 49 days, which equates to failure at completion of the previous successful in-service test start on June 23. This run included the post processing rules for failure to depressurize, but not for SSW B Train. The result was a change in core damage frequency of **2.03E-6/yr**.

<u>Sensitivity 5, changes to delete core damage sequences in question and adjust the operator depressurization failure probability for fast acting initiating event (Medium Break LOCAs)</u>
44 day exposure including repair time
A final sensitivity run was performed which performed the following:

- Deleted any cut sets which contained LOOP events with the salt service water train B in test and maintenance
- Revised the normal operator failure to depressurize basic event to 1E-4 (80 percent reduction) for any sequences which contained RCIC fail to run events
- Increased the normal operator failure to depressurize basic event probability to 2.75E-3 based on a SPAR-H calculation for MBLOCA events which result in much faster level loss (50 percent nominal time – 50 percent barely adequate time). This probability was more in line with several of the Licensees values for events such as (2 or more SRVs failing open, Medium LOCA in RHR system, MBLOCA RWCU system etc.)Set RCI-MOV-FC-FRO basic event to FALSE, this is the RCIC injection valve F013 failing to re-open. (Investigation revealed this valve once opened should remain open with no automatic closure signal upon the closure of the steam admission valve)

The base case value was 4.65E-6
Conditional case HPCI fail to start value was 1.31E-5
Repair time conditional value was 1.1E-5 with RCIC test and maintenance removed

Internal Event exposure time and repair time increase CDF/yr = **<u>9.92E-7/yr</u>**
<u>Analysis of Dominant Sequences</u>
The dominant sequences consisted of:

- Loss of condenser heat sink, with failure to depressurize and RCIC in Test and Maintenance
- Loss of Main Feedwater with failure to depressurize and RCIC in Test and Maintenance
- Loss of condenser heat sink, with failure to depressurize and RCIC failure to run
- Loss of condenser heat sink with failure to depressurize and failure of RCIC to start
- Loss of Main Feedwater with failure to depressurize and failure of RCIC to start

<u>All Sensitivity Cases resulted in the internal event plus external event contribution exceeding an increase in CDF/yr due to the degraded condition of 1E-6/yr.</u>

<u>Contributions and Risk Estimates from External Events</u>

<u>Fire</u>

The Hope Creek SPAR model does not include Fire External events.

PSEG maintains a fire PRA model. Using that model, PSEG originally calculated a change in core damage frequency from fire at approximately 5E-6/yr. given HPCI failure to start for an exposure of 27 days. After making adjustments for conservatisms, the result dropped to 1.1E-/yr. for 44 days. The higher number was influenced by fires in one EDG room. Because the cables that supply offsite power to the safety busses run along the ceiling in the room, the model originally included a contribution to loss of offsite power. PSEG concluded, after looking at the fire detection and suppression in the room, that only the EDG would be affected by a fire

in the room. From that, they removed the potential for a loss of offsite power from an EDG room fire. The SRA reviewed a summary of the changes made and concluded the revised assumptions were reasonable.

A few of the dominant fire scenario contributors to an increase in CDF due to the condition were:

- Full room burnout of HVAC equipment room causing inboard feedwater isolation with assumed failure of RCIC and subsequent loss of feedwater.
- Fire in Reactor Building at the 480V motor control center 10-B222 causing multiple RCIC MOVs to close, resulting in failure of RCIC and subsequent loss of feedwater

Fires in the Turbine Building and Control equipment room contributed a nominal 30 percent to the increase in CDF due to the large number of possible scenarios.

Nonetheless, even with various revisions to the model and removal of other conservative assumptions, the external event fire contribution for the condition remained greater than 1E-6/yr. for the 44 day exposure period.
External Risk **1.1E-6/yr**. 44 days

Seismic, External Flooding, and High Winds

The analyst reviewed the Hope Creek IPEEE and determined that the Fire risk contribution dominated the risk results and the contributions from Seismic, High Winds, and External Flooding were considered to have low risk contribution.

Large Early Release Frequency (LERF)
For issues involving an increase in CDF > 1E-7, IMC 0609 requires an evaluation of LERF using the guidance of NUREG-1765, "Basis Document for Large Early Release Frequency Significance Determination Process." The failure of the HPCI would be considered a Type A finding. NUREG-1765, Table 2, assigns a LERF factor of 1.0 for high-pressure sequences with a dry drywell, and 0.6 for high-pressure sequences with a flooded drywell. The former value is bounding, but not necessarily conservative, in that liner melt-through is expected to occur shortly after vessel failure if the drywell is dry. The latter value is affected by the type and size of reactor coolant system rupture, operator actions following the onset A3-4 Attachment 3 of core damage, and phenomenological issues related to direct containment heating and fuel-coolant interactions.

PSEG's model explicitly estimated the LERF contribution, and considered relevant high-pressure vessel breach phenomena (namely, fuel-coolant interaction, liner-melt-through, and direct containment heating). The multiplier for converting CDF to LERF was on the order of 0.1 after a review of the LERF contributing cut sets.

As noted by PSEG, recent evaluations (e.g., State of the Art Reactor Consequence Analysis at Peach Bottom) have indicated that the likelihood of severe accident-induced main steam line creep rupture or a stuck-open relief valve prior to vessel breach is potentially higher than typically estimated in PRAs. This same case was made in a 2003 report prepared for NRC Office of Research by Energy Research, Inc. These failure modes would lead to a more benign

containment response at the time of vessel breach, in terms of direct containment heating and fuel-coolant interaction-induced containment failure.

Other additional considerations in part were:

- Operator actions to depressurize the RPV during core melt progression and severe accident guidelines which direct primary containment spray

Consequently, the analyst determined that the PSEG's 0.1 LERF multiplier was a more reasonable and appropriate value, resulting in a LERF value of (0.1 x internal and external increase risk (1.86E-6/yr. + 1.1E-6/yr.) = 2.96E-7/yr. This delta LERF value represents a low to moderate safety significance, or White issue, consistent with the risk evaluation for internal and external event CDF.

<u>Total Estimated Increase in Risk</u>

Normal Model conditions **Delta CDF/yr = 2.96E-6/yr**. using the listed assumptions **(White**). **Using Sensitivity Case 5** with modeling changes to delete many core damage cut sets based on judgment to determine a refined best estimate **Delta CDF/yr = internal plus external, 2E-6/yr (White).** The total change above is the sum of internal and external risk contributions. The change in LERF estimate was consistent with the delta CDF White significance discussed above and does not dominate the risk conclusion.

<u>Licensee's Risk Evaluation</u>

PSEG performed sensitivity analyses based on different assumed exposure times. Their sensitivity analyses documented a range of total (internal and external) increase in CDF/yr. given the condition from 1.2E-6/yr. to 4.2E-6/yr. The analysts noted PSEG determined a reasonably conservative exposure time to be 44 days with a total increase in CDF/yr. of a nominal 2E-6 for both internal and external events. The analyst noted that this was the same number that Sensitivity 5 in this evaluation had calculated.

PSEG concluded that there are significant uncertainties in the operability of the HPCI system and significant conservatisms in the risk estimates from the Fire PRA.

The analysts did not believe significant uncertainties existed in determining the minimum exposure time of 44 days based on:

- The plant process computer showing no movement of the governor valve on July 3, 2016 during an auxiliary oil pump start indicative of a degraded control oil system.
- The water content in the control oil system was determined to be 200 percent (over 6000 ppm) above the conditions which warrant changeout of the oil (2000 ppm) during the June 23, 2016 surveillance test
- The control valve movement upon initial start of the HPCI system on June 23, 2016 showed anomalies from several other runs reviewed (computer traces) when the oil system was within normal specifications. This indicated uncertainty regarding how the system would have responded in an actual injection condition where the dynamics of the control system are much more challenging than normal in-service test runs from the condensate storage tank back to the CST.

Regarding the most influential basic event, the analysts noted that PSEG used a failure probability to manually depressurize of 3.7E-4, which was noted to be close to the nominal value used in the SPAR model of 5E-4. Additionally, the analyst decreased this failure probability given RCIC fail to run events.

LERF

PSEG's Level 2 PRA model credits the Emergency Operating Procedures and SAG direction to provide water makeup to the drywell floor prior to RPV failure to support quenching the ex-vessel debris and preventing shell failure, which results in the conclusion that the total delta LERF is less than 10 percent of the total delta CDF for the HPCI SDP. The analyst based on a review of their model output and documented bases determined this to be a reasonable conclusion.

Summary of Results and Impact

The NRC's quantitative risk assessment (internal and external delta CDF contributions) for this finding was determined to be in the low E-6 range (2E-6/yr to 2.96-6/yr.), or of low-to-moderate safety significance (White). Sensitivity analyses demonstrate a high confidence in this estimate.

PSEG values were calculated to be within the range of 1.2E-6/yr. to 4.2E-6/yr., all of which represented a low to moderate (WHITE) safety significant condition. The analyst noted that the higher number represented in the Licensee's range was based on a worst case exposure time of 94 days and was only performed due to the uncertainty concerns conveyed by the analyst in this evaluation and did not represent the Licensee had concluded this high end value to be valid. The low end number was based on a smaller exposure period.