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

August 30, 2017

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 – SUPPLEMENTAL INSPECTION REPORT 05000354/2017011 AND ASSESSMENT FOLLOW-UP LETTER

Dear Mr. Sena:

On August 11, 2017, the U.S. Nuclear Regulatory Commission (NRC) completed a supplemental inspection pursuant to Inspection Procedure 95001, "Supplemental Inspection Response to Action Matrix Column 2," at your Hope Creek Generating Station Unit 1 (Hope Creek). On August 11, 2017, the NRC inspection team and an NRC Region I Branch Chief discussed the inspection results and the implementation of your corrective actions with you and members of your staff during an inspection exit meeting and Regulatory Performance Meeting.

In accordance with the NRC Reactor Oversight Process Action Matrix, this supplemental inspection was conducted within the Regulatory Response Column of the NRC's Reactor Oversight Process (ROP) Action Matrix because one finding of White significance, associated with the Mitigating Systems Cornerstone, was identified in the third quarter 2016 integrated inspection report (ML16319A289) dated November 14, 2016. The finding was associated with PSEG Nuclear LLC's (PSEG) implementation of an adverse condition monitoring plan for a known adverse condition affecting a safety related component. Specifically, PSEG did not sample High Pressure Coolant Injection (HPCI) turbine lube oil for water intrusion due to a known steam leak. As a result, PSEG did not identify that HPCI had been inoperable for greater than its Technical Specification Allowed Outage Time due to this condition. The final significance determination and follow-up assessment letter (ML17033B541) for this finding issued on February 6, 2017, documented that Hope Creek transitioned to the Regulatory Response Column of the ROP Action Matrix retroactive to the third quarter of 2016. The NRC staff was informed on July 13, 2017, of your staff's readiness for this supplemental inspection.

The objectives of this supplemental inspection were to provide assurance that: (1) the root causes and the contributing causes of risk-significant performance issues were understood; (2) the extent of condition and extent of cause of risk-significant performance issues were identified; and (3) corrective actions, taken or planned, for risk-significant performance issues are sufficient to address the root and contributing causes and prevent recurrence. The inspection consisted of examination of activities conducted under your license as they related to safety, compliance with the Commission's rules and regulations, and the conditions of your operating license.

Based on the results of this inspection, the NRC concluded that, overall, the supplemental inspection objectives were met and no significant weaknesses were identified. Additionally, no findings of significance were identified.

Based on the guidance in Inspection Manual Chapter (IMC) 0305, “Operating Reactor Assessment Program,” and the results of this inspection, the White finding will be closed. Additionally, since Hope Creek has successfully completed this inspection, a Regulatory Performance Meeting has been held, and the finding had been open for at least four calendar quarters, Hope Creek will transition to the Licensee Response Column of the ROP Action Matrix effective the date of this report. However, in accordance with IMC 0305, Section 11.01.e, this finding will remain an Action Matrix input for the remainder of the third calendar quarter of 2017.

In accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any), will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records System component of the NRC's Agencywide Documents Access and Management System (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

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

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

Enclosure:
Inspection Report 05000354/2017011
w/Attachment: Supplementary Information

cc w/encl: Distribution via ListServ

SUBJECT: HOPE CREEK GENERATING STATION UNIT 1 – SUPPLEMENTAL INSPECTION REPORT 05000354/2017011 AND ASSESSMENT FOLLOW-UP LETTER DATED AUGUST 30, 2017

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REGION I

Docket No.	50-354
License No.	NPF-57
Report No.	05000354/2017011
Licensee:	PSEG Nuclear LLC (PSEG)
Facility:	Hope Creek Generating Station (Hope Creek)
Location:	Hancock’s Bridge, New Jersey
Dates:	August 7, 2017, through August 11, 2017
Inspectors:	A. Rosebrook, Senior Project Engineer, Team Leader M. Draxton, Project Engineer D. Beacon, Project Engineer (Observer)
Approved by:	Fred L. Bower, Chief Reactor Projects Branch 3 Division of Reactor Projects

Enclosure

SUMMARY

Inspection Report 05000354/2017011; 08/07/2017 – 08/11/2017; Hope Creek Generating Station (Hope Creek); Supplemental Inspection – Inspection Procedure (IP) 95001

A Senior Project Engineer from the Division of Reactor Projects, U.S. Nuclear Regulatory Commission (NRC) Region I and a Project Engineer from the Division of Reactor Projects, NRC Region I, performed this inspection. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 6.

Cornerstone: Mitigating Systems

The NRC staff performed this supplemental inspection pursuant to IP 95001, "Supplemental Inspection Response to Action Matrix Column 2 Inputs," because of one finding of White significance, associated with the Mitigating Systems Cornerstone, which was identified in the third quarter 2016 integrated inspection report (ML16319A289) dated November 14, 2016. The finding was associated with PSEG Nuclear LLC's (PSEG) implementation of an adverse condition monitoring plan (ACM) for a known adverse condition affecting a safety related component. Specifically, PSEG did not sample High Pressure Coolant Injection (HPCI) turbine lube oil for water intrusion due to a known steam leak. As a result, PSEG did not identify that HPCI had been inoperable for greater than its Technical Specification Allowed Outage Time due to this condition. The final significance determination and follow-up assessment letter (ML17033B541) for this finding, issued on February 6, 2017, documented that Hope Creek transitioned to the Regulatory Response Column of the Reactor Oversight Process (ROP) Action Matrix retroactive to the third quarter of 2016. The NRC staff was informed on July 13, 2017, of PSEG's readiness for this supplemental inspection.

Based on the results of the inspection, no significant weaknesses or findings were identified. The inspectors concluded that PSEG had adequately performed a root cause analysis of the event, and corrective actions, both completed and planned, were reasonable to address the related issues. Based on the guidance in Inspection Manual Chapter (IMC) 0305, "Operating Reactor Assessment Program," dated November 17, 2016, and the results of this inspection, the White finding will be closed. Additionally, a regulatory performance meeting was held immediately following the inspection exit meeting on August 11, 2017. Since Hope Creek has successfully completed this inspection, a Regulatory Performance Meeting has been held, and the finding had been open for at least four calendar quarters, Hope Creek will transition to the Licensee Response Column of the ROP Action Matrix effective the date of this report. However, in accordance with IMC 0305, Section 11.01.e, this finding will remain an Action Matrix input for the remainder of the third calendar quarter of 2017. (Section 4OA4)

REPORT DETAILS

4. OTHER ACTIVITIES

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

(Closed) Licensee Event Report (LER) 05000354/2016-002-01: High Pressure Coolant Injection System Inoperable.

On August 6, 2016, at 21:34, with the Hope Creek reactor operating at 100 percent power, the HPCI system turbine governor valve did not respond as expected during system surveillance testing. The system was declared inoperable and an 8-hour immediate notification was made under Title 10 of the *Code of Federal Regulations* (10 CFR) 50.72 (B)(3)(v)(d). Subsequent investigation found that the HPCI turbine governor was not functioning due to corrosion products in the governor, preventing movement of the pilot valve. Additional research determined that the turbine governor did not respond properly on July 3, 2016, during the collection of an oil sample. Based on this, the HPCI system was inoperable for a period of 39 days from July 3, 2016, until August 11, 2016, when repairs to the governor were completed. The HPCI system Technical Specification has an allowed outage time of 14 days. The report was submitted per 10 CFR 50.73(a)(2)(i)(B), as a condition which is prohibited by the plant's Technical Specifications, and per 10 CFR 50.73(a)(2)(v)(D), as an event or condition that could have prevented the fulfillment of a safety function of systems that are needed to mitigate the consequences of an accident. The cause of the event is the accumulation of corrosion products in the HPCI turbine governor due to excessive moisture content in the HPCI system control oil.

The inspectors performed an in-depth review of this LER and PSEG's evaluations, supporting documentation, station procedures, plant logs, and interviewed members of station staff. This issue was previously documented in NRC Inspection Report (IR) 05000354/2016003 (ML16319A289) dated November 14, 2016, and the enforcement aspects discussed in IR 05000354/2016008 dated February 6, 2017 (ML17033B541).

No additional issues were identified during this review. LER 50-354/2016-002-01 is closed.

4OA4 Supplemental Inspection (IP 95001)

.1 Inspection Scope

The NRC staff performed this supplemental inspection in accordance with IP 95001 to assess PSEG's evaluation of a White finding, which affected the Mitigating Systems cornerstone in the Reactor Safety strategic performance area. The inspection objectives were:

- To assure that the root causes and contributing causes of individual and collective significant performance issues are understood.
- To independently assess and assure that the extent of condition and extent of cause of significant individual and collective performance issues are identified.
- To assure that corrective actions taken to address and preclude repetition of significant performance issues are prompt and effective.
- To assure that corrective plans direct prompt actions to effectively address and preclude repetition of significant performance issues.

The NRC staff performed this supplemental inspection pursuant to IP 95001, “Supplemental Inspection Response to Action Matrix Column 2 Inputs,” because of one finding of White significance, associated with the Mitigating Systems Cornerstone, which was identified in the third quarter 2016 integrated inspection report (ML16319A289) dated November 14, 2016. The finding was associated with PSEG’s implementation of an ACM for a known adverse condition affecting a safety related component. Specifically, PSEG did not sample HPCI turbine lube oil for water intrusion due to a known steam leak. As a result, PSEG did not identify that HPCI had been inoperable for greater than its Technical Specification Allowed Outage Time due to this condition. The final significance determination and follow-up assessment letter (ML17033B541) for this finding issued on February 6, 2017, documented that Hope Creek transitioned to the Regulatory Response Column of the ROP Action Matrix retroactive to the third quarter of 2016.

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.

Upon identification of the HPCI system failure in August 2016, PSEG promptly declared the system inoperable, entered the appropriate technical specification action statement, drained, flushed, and refilled the HCPI turbine lube oil system, replaced degraded HPCI controls components, corrected improperly installed thermal insulation, and retested the HPCI system to restore operability. PSEG subsequently took the following actions: PSEG entered the issue into the corrective action program (CAP), conducted a root cause evaluation (RCE), revised station processes and procedures to address the root and contributing causes, and developed a plant modification to address the HPCI steam admission valve leakage. PSEG submitted letters dated December 14, 2016 (ML16349A604) and January 3, 2017 (ML17003A319) and conducted a phone conference on December 21, 2016 (ML17023A145), which documented the reason for the violation, corrective actions and corrective actions to prevent repetition planned and completed. Full compliance with NRC requirements was determined to have been restored on August 12, 2016. Therefore, as documented in the Final Significance Determination Letter dated February 6, 2017, no formal reply to the Notice of Violation (NOV) was required.

On July 13, 2017, Mr. D. Mannai, PSEG’s Senior Director of Regulatory Compliance, informed Mr. F. Bower, Chief, Region I, Division of Reactor Projects Branch 3, of PSEG’s readiness for the supplemental inspection.

During this supplemental inspection, the inspectors reviewed the causal evaluations, procedures, standing orders, and documents referenced above, in addition to other documents listed in the Attachment, which supported PSEG’s actions to address the White finding. The inspectors reviewed corrective actions, both completed and planned, to address the identified causes, extent of condition, and extent of cause. The inspectors also interviewed PSEG personnel to ensure that the root and contributing causes and the contribution of safety culture components were understood; and corrective actions taken or planned were appropriate to address the causes and prevent recurrence. Interviews were conducted with operators, engineering staff, chemistry technicians, and other personnel knowledgeable of the issue. Lastly, the inspectors conducted in-plant walk-downs, which included independent inspections of the HPCI and Reactor Coolant Isolation Cooling (RCIC) systems and the main control room.

.2 Evaluation of the Inspection Requirements

02.01 Problem Identification

a. IP 95001 requires that the inspection staff determine if PSEG's evaluation of the issue documents who identified the issue (i.e., licensee-identified, self-revealing, or NRC-identified) and under what conditions the issue was identified.

PSEG's RCE (Notification (NOTF) 20738402/ work order (WO) 70188669,) documented that on August 6, 2016, during the performance of HC.OP-ST.BJ-0003, "18- Month HPCI System Valve Actuation Functional Test," the HPCI governor control valve (FD-FV-4879) failed to stroke open as expected. This would be considered a self-revealing issue.

The cause was determined to be steam leakage past HPCI Steam Admission Valve (FOO1), and improperly installed thermal insulation in the vicinity of the HPCI gland seals, which allowed moisture to accumulate in the HPCI turbine lube oil system undetected. Over time, this moisture resulted in corrosion and degradation of the Woodward electric governor remote (EGR). This prevented the proper operation of the turbine governor control valve, rendering HPCI inoperable.

The inspectors determined this inspection objective was met.

b. IP 95001 requires that the inspection staff determine if PSEG's evaluation of the issue documents how long the issue existed and identified prior opportunities for identification.

PSEG's RCE contained an accurate timeline of the events which led up to the failed surveillance. The evaluation documented that the last successful run of the HPCI turbine occurred on June 23, 2016. It was also identified that a HPCI auxiliary oil pump run was performed on July 3, 2016. Detailed review of this run showed that the HPCI governor valve did not respond properly during this evolution as well. Therefore the exposure period was determined to be 44 days (T/2 for the period between June 23 and July 3 plus the entire period from July 3 to August 6 plus restoration period from August 6 until August 11 when HPCI was declared operable).

PSEG's RCE also indicated opportunities to identify the condition prior to the surveillance test failure. In accordance to ACM 15-08 Revision 3, HPCI turbine lube oil samples were to be taken and analyzed monthly to check for moisture in the oil. In March 2016, a sample showed in-specification results for water (15 ppm). Samples were taken in April, June, July, and August of 2016, however, these sample were not analyzed prior to the surveillance test failure. When analyzed, each of these samples tested above the fault limit for water in the oil (> 2000 ppm). Additionally, the May 2016 sample was not taken. Each of these samples represented a missed opportunity to identify the condition.

The inspectors determined this inspection objective was met.

c. IP 95001 requires that the inspection staff determine if PSEG's evaluation documents the plant specific risk consequences, as applicable, and compliance concerns associated with the issue.

PSEG's RCE, PSEG's response to the Preliminary White Finding, the addendum to PSEG's response to the White Finding, and the NRC's Preliminary and Final Significance Determination Letters adequately document the risk significance and regulatory compliance concerns for this issue. The issue was of low to moderate risk significance and represented a violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," due to PSEG staff not adequately implementing the ACM.

The inspectors determined this inspection objective was met.

The inspectors did have one observation in this area. During the enforcement process, PSEG revised Hope Creek's probabilistic risk assessment (PRA) model in order to remove conservatisms and challenge the NRC's preliminary risk assessment. This change was formally submitted to the NRC in PSEG's letter dated December 14, 2016 (ML16349A604). In that letter, PSEG stated they had implemented the new model at Hope Creek. This model is used on a routine basis for determining on-line plant risk due to planned maintenance activities and emergent equipment issues. In NRC IR 05000354/2016008, the NRC documented a technical concern with some assumptions in the revised model, including the assumptions that secondary condensate pumps would be available without cooling water to the pump. The letter stated that there was no technical justification to support this assumption; therefore, the secondary condensate pumps could not be credited when cooling water was lost. The inspectors questioned how this documented concern about the accuracy of the current model was being evaluated and tracked. PSEG was only tracking this via their station PRA modeling program, and per their program, the concern would not have a large enough impact on the plant risk model to require an immediate update to the PRA model. The inspectors questioned whether this should be in the CAP, since it represents a concern with the accuracy of the model currently in use. The inspectors determined that there were no specific NRC or licensee requirements for a modelling error to be placed in CAP; however, PSEG agreed with the inspectors' observation and wrote NOTF 20772420, to track and document PSEG's evaluation of this concern.

d. Findings

No findings were identified.

02.02 Root Cause, Extent of Condition, and Extent of Cause Evaluation

a. IP 95001 requires that the inspection staff determine if PSEG evaluated the problem using a systematic methodology to identify the root and contributing causes.

The inspectors determined that PSEG evaluated the White finding using a systematic methodology to identify root and contributing causes. The inspectors verified that PSEG staff implemented procedure LS-AA-125-1002, "Root Cause Analysis," as well as the guidance in procedure LS-AA-125, "Corrective Action Program (CAP)," in the conduct of the station's causal analyses to identify the root and contributing causes. The station utilized the following systematic methods to complete the RCE:

- data gathering through interviews and document review;
- barrier analysis;
- failure mode cause tables;
- event and causal factors chart;
- organizational and programmatic review;
- safety culture analysis;
- extent of cause review;
- extent of condition review;
- WHY staircase; and
- operating experience assessment.

The inspectors verified these methods were completed by reviewing the RCE and its attachments. The inspectors also verified that the root and contributing causal conclusions were consistently understood and supported by PSEG staff through the conduct of interviews, and review of third party reports.

The inspectors determined this inspection objective was met.

b. IP 95001 requires that the inspection staff determine if PSEG's root cause analysis was conducted to a level of detail commensurate with the significance of the problem.

The inspectors determined that PSEG conducted event follow up and cause evaluation reviews at the appropriate level of detail. PSEG staff conducted an Equipment Apparent Cause Evaluation (EACE) immediately after the HPCI Surveillance failure to address the material failures, and then elected to conduct a full RCE to address the human performance aspects of the event. During the review process for the RCE, PSEG Nuclear Oversite recommended expanding the scope of the RCE to cover both the material and human performance aspects of the event. The inspectors determined that all root, apparent, and contributing causes identified in the initial cause evaluations were either captured or updated in the final RCE. The final revision of the RCE identified two root causes and four contributing causes. The root causes were selected because if either of the root causes were eliminated, the event would have be prevented.

Causes	
Direct Cause	Over time, condensed steam in the oil system caused the governor valve (EGR) to corrode and become non-functional, causing HPCI to become inoperable.
Root Cause 1	The configuration of HPCI turbine casing insulation had less than adequate procedural guidance, work order guidance, and specifications. Plant personnel therefore lacked the information to correctly install, maintain, and monitor the insulation configuration.
Root Cause 2	The HPCI F001 flex wedge gate valve design is subject to recurring leakage. The strategy to address leakage through corrective maintenance was ineffective, and a mitigating strategy to manage recurring leakage was not implemented.
Contributing Cause 1	Station leadership and staff behaviors resulted in ineffective implementation of the Problem Identification and Resolution (PI&R) and CAP to address issues and adverse conditions associated with HPCI turbine oil moisture intrusion. Gaps were identified in the implementation of the following aspects: problem identification, evaluation, corrective actions, trending, operating experience (OE), and self-assessment.
Contributing Cause 2	Operations Shift Management's ownership of: assigning and communicating responsibility for required actions, providing oversight, and documenting trends was less than adequate (LTA) for HPCI Steam Admission Valve Leakage ACM HC-15-008.
Contributing Cause 3	Processes for implementing ACMs, lube oil program and industry working group participation were less than adequate to monitor, implement industry operating experience, or prevent HPCI oil system moisture intrusion.
Contributing Cause 4	System Engineering, Component Maintenance Optimization (CMO) and Operations Shift management failed to adequately challenge implementation of ACM HC-15-008 to ensure continued operability of the HPCI system.

The inspectors observed that the initial EACE incorrectly evaluated the apparent cause of the EGR failure as being an age related failure due to being in service for seven years (end of recommend service life period). The degradation of the EGR was actually due to the moisture in the HPCI turbine lube oil system which resulted in corrosion of the EGR internals. This degradation occurred over a period of months from when the moisture was introduced until the EGR was inoperable. However, the RCE's accurately reflected this as the direct cause of the event and the immediate corrective actions also adequately addressed the condition. The inspectors determined the final RCE was of adequate scope and conducted to an appropriate level of detail commensurate with a low to medium safety significant issue.

The inspectors determined this inspection objective was met.

c. IP 95001 requires that the inspection staff determine if PSEG's root cause evaluation included a consideration of prior occurrences of the problem and knowledge of operational experience.

   The inspectors determined that PSEG's RCE adequately identified prior occurrences of this condition and identified relevant operational experience that the station was aware of. Additionally, PSEG's staff used operational experience is the development of corrective actions.

   On four occasions (1994, 1995, 2012, and 2016), moisture levels in the HCPI turbine lube oil system were identified which resulted in the system being declared inoperable. LERs were issued for each of these events (LER 94-19, 95-21, 12-02, and 16-02). In 2012 improper response of the turbine governor valve was also noted when drawing the oil sample and inspection revealed degradation of the EGR similar to that observed in 2016, requiring the EGR to be replaced. The in-service testing program, which required quarterly samples of the turbine lube oil, identified these conditions prior to the system failing to meet a surveillance test. Additionally in 2015, the RCIC system was declared inoperable due to significant moisture accumulation in the turbine lube oil sump. This event resulted in a Green non cited violation documented in NRC IR 50-354/2015001 (ML15111A209). These events were identified as prior occurrences and missed opportunities to prevent the 2016 failure.

   The station had received industry, owner's group, and vendor information in 2001, 2013, and 2014 which address known concerns related to HPCI steam admission valve leakage and improper installation of HPCI insulation. This was identified as a missed opportunity.

   PSEG's RCE documented that the F001 valve had identified seat leakage on 12 occasions and the RCIC steam admission valve (F045) had documented seat leakage on multiple occasions. These were considered missed opportunities to address root cause number 2.

   These missed opportunities were captured in the PSEG RCE cause under contributing cause number 1.

   The inspectors determined this inspection objective was met.

d. IP 95001 requires that the inspection staff determine if PSEG's root cause analysis addressed the extent of condition and extent of cause of the problem.

   The inspectors determined that PSEG appropriately performed extent of cause and extent of condition reviews for each root cause and contributing cause as required by their procedure.

   For root cause 1 and 2, extent of cause and extent of condition reviews were conducted using a "Same-Similar Analysis Method" using the top 10 risk significant structures systems and components. Systems reviewed include HPCI, RCIC, Emergency Diesel Generator governors, Reactor Feed Pump Turbines, Reactor Recirculation Motor Generator Sets, and electro-hydraulic control oil for the main turbine valves. The inspectors also observed that a review of the installation of insulation associated with the Electromagnetic relief valves was reviewed separate from this Extent of Cause/Extent of Condition review, but done based on recent industry operating experience.

For each contributing cause an extent of condition review was conducted. For contributing causes 1 and 2, an extent of cause review was also conducted. Station management elected to go beyond the requirements of LS-AA-125.

The inspectors determined this inspection objective was met.

e. IP 95001 requires the inspection staff to determine if PSEG's root cause, extent of condition, and extent of cause evaluations appropriately considered the safety culture traits in NUREG-2165, "Safety Culture Common Language," referenced in IMC 0310, "Aspects Within Cross-Cutting Areas."

The inspectors determined that PSEG's RCE included a safety culture analysis which appropriately considered safety culture traits. The safety culture traits associated with for each root and contributing cause were identified. The results safety culture analysis was used to rank the importance of the contributing causes and to develop corrective actions. The results of the safety culture analysis were consistent with the cross cutting aspect documented in NRC IR 05000354/2016-003.

The inspectors determined this inspection objective was met.

f. Findings

No findings were identified.

02.03 Corrective Actions Taken and Corrective Action Plan

a. IP 95001 requires the inspection staff to determine if PSEG: (1) specified appropriate corrective actions for each root and/or contributing cause; or (2) had an adequate evaluation for why no corrective actions are necessary.

The inspectors determined that PSEG specified appropriate corrective actions for each root and contributing cause identified. A table of the key corrective actions to preclude repetition (CAPRs) and corrective actions is provided below.

Key Corrective Actions - Root Cause 1	
RC1 CAPR-1	Revise maintenance procedures for HPCI and RCIC to include insulation configuration pictures to ensure insulation does not enclose the steam gland cases and bearing pedestal cap. A supervisor hold point and signature is to be added to document proper insulation configuration.
RC1 CAPR-2	Revise insulation specification (M-161) Appendix D by adding notes in “area to be insulated” and “remarks” sections for equipment tag numbers 10S211 and 10S212, incorporating EPRI HPCI Terry Turbine Maintenance Guide note for insulation configuration.
RC1 CAPR-3	Revise HC.OP-SO.BJ-0001 & HC.OP-SO.BD-0001, HPCI/RCIC system operating procedures, to include a sign off for verification of correct insulation configuration during implementation of Section 5.2, Placing HPCI (RCIC) in Standby. A picture of “what good looks like” is to be included to ensure insulation does not enclose the steam gland cases and bearing pedestal cap.
RC1 CAPR-4	Review all active and on-condition maintenance plans for HPCI and RCIC that may perform work on the turbine that could impact the insulation configuration and verify that each references the appropriate insulation configuration specification (M-161) and respective procedures. If it does not, then revise the deficient maintenance plans to correct the deficiency.

Key Corrective Actions - Root Cause 2	
RC2 CAPR-5	Install a new HPCI steam admission valve F001 valve design (Crane Nuclear Sentinel gate valve) that is more appropriate for service conditions to prevent repetitive valve leakage. Expected completion date 05/30/18
RC2 CAPR-6	Implement an effective mitigation strategy similar to Boiling Water Reactor Owners Group (BWROG) TP-14-016 Section V Part C by re-stroking the HPCI steam admission valve F001 following pump IST testing in order to minimize the thermal stresses on the disc and seat. Note: CAPR-6 is an interim measure until CAPR-5 is implemented. Expected completion date 09/17/17
RC2 CAPR-7	Develop and issue a procedure similar to ER-AB-331-1006, include an example ACM, for a leakage monitoring and action plan that can be implemented when HPCI steam admission valve F001 leakage is identified. Incorporate guidance from BWROG TP-14-016 Section V parts A, B and D.

Key Corrective Actions - Contributing Cause 1	
CRCA-6	SOER 10-2 training (ACIT-2 assist in developing) Expected completion date 09/27/17
CRCA-7	Screening Oversight Committee (SOC) & Management Review Committee (MRC) case study PI&R/CAP issues
CRCA-8	LS-AA-115, OE procedure
CRCA-9	Lube oil database workshop
CRCA-27	Revise quarterly oil sample maintenance procedures for details on dept. interface responsibilities
CRCA-29	Review top ten core damage frequency contributing systems for recurring long standing open issues
CRCA-31	Revise Single Point Vulnerability (SPV) procedure for branch managers to be responsible for SPV coordinator responsibilities
CRCA-32	Process SPV review for HPCI/RCIC. Expected completion date 8/23/17
CRCA-33	Review SPV reviews completed under 2012 HPCI RCE and verify completion, if not create actions to complete. Expected completion date 08/23/17
CRCA-34	Issue engineering expectation letter reinforcing notifications initiation
CRCA-41	Include Hope Creek in the needs analysis being performed under Salem RCE 70189117
CRCA-42	Include Hope Creek MRC in the training implemented under Salem RCE. Expected completion date 09/15/17

Key Corrective Actions - Contributing Cause 2	
CRCA-13	Revise OP-AA-108-111 for tracking/data signature
CRCA-14	Revise OP-HC-112-101-1001-F1 shift manager relief checklist
CRCA-19	Performance management for ACM HC 15-008 gaps associated with failure to meet responsibilities of OP-AA-108-111, Revision 8

Key Corrective Actions - Contributing Cause 3	
CRCA-3	Perform gap analysis EPRI HPCI maintenance manual 11/29/17
CRCA-4	Perform gap analysis EPRI RCIC maintenance manual 11/29/17
CRCA-5	Perform gap analysis BWROG test procedure 14-006
CRCA-8	LS-AA-115, OE procedure
CRCA-9	Lube oil database workshop
CRCA-13	Revise OP-AA-108-111 for tracking/data signature
CRCA-15	Revise PHC Procedure ER-AA-2001 to REQUIRE quarterly review of all open plant vulnerabilities including high risk ACMs, Operability Evaluations, and OTDMs
CRCA-16	Revise OP-AA-108-111-F1 for operability screening
CRCA-22	Revise CC-AA-111, Industry Participation Process
CRCA-25	Revise Standard Operating Procedure to include governor valve response verification when abnormal operating procedure starts
CRCA-26	Revise lube oil sample traveler for improved communications between groups
CRCA-39	Revise HPCI/RCIC lube screens

Key Corrective Actions - Contributing Cause 4	
CRCA-6	SOER 10-2 training (ACIT-2 assist in developing) 09/27/17
CRCA-7	SOC & MRC case study PI&R/CAP issues
CRCA-13	Revise OP-AA-108-111 for tracking/data signature
CRCA-19	Performance management
CRCA-20	Performance management
CRCA-35	Realign CMO group

The inspectors determined this inspection objective was met.

b. IP 95001 requires that the inspection staff determine if PSEG's corrective actions taken and corrective action plans were prioritized by PSEG with consideration of risk significance and regulatory compliance.

The inspectors determined that the corrective actions taken and planned were appropriately prioritized by PSEG with consideration of risk significance and regulation.

Immediate corrective actions included:

- Immediately declaring HPCI inoperable and entering the appropriate Technical Specification Action Statement,
- entering the issue into the CAP,
- draining, refilling and flushing the oil system and gearbox,
- replacing oil filters,

- testing the lube oil cooler for tube leaks,
- replacement of the hydraulic controls (EGR and Remote Servo),
- reworked insulation around the HPCI turbine gland casing on the governor, and
- conducted time response testing and HPCI turbine surveillance run.

These immediate actions restored the HPCI system to an operable status on August 11, 2016. This would be a timely resolution for the risk significant safety issue since it was completed within the technical specification allowed outage time once the condition was discovered. ACM 15-08, Revision 4 was issued on August 12, 2016, and was properly implemented by PSEG staff. This corrective action restored compliance with the regulatory requirements.

The remaining corrective actions were prioritized and scheduled appropriately in accordance with the guidance of LS-AA-125 and LS-AA-125-1002.

The inspectors determined this inspection objective was met.

c. IP 95001 requires that the inspection staff determine if PSEG's corrective actions taken and corrective action plan to address and preclude repetition of significant performance issues are prompt and effective.

The inspectors determined that the PSEG's corrective actions taken and planned to address identification of root and contributing causes and development of corrective action which correct the identified root and contributing causes were prompt and appeared reasonable. Corrective actions addressed the associated causes, due dates were justifiable, and bridging strategies were developed as appropriate.

For example CAPR-5 for root cause (RC) 2 is a permanent plant modification to replace F001 with a newer valve design that is less susceptible to seat leakage. This modification is expected to be installed during the spring 2018 refueling outage. An evaluation was performed to assess the risk and impact of installing the modification on-line compared with installing the modification during the next refueling outage. During the fall 2016 refueling outage, the F001 seat was repaired and the valve re-lapped to address seat leakage in the short term, the ACM was revised and properly implemented, system engineer walk down sheets and operator rounds were revised to ensure the system was monitored more effectively, and a BWROG recommendation to cycle the auxiliary oil pump month and assess governor valve performance was incorporated to better mitigate and monitor the condition. The inspectors considered these risk mitigating activities to be an adequate bridging strategy.

This inspection objective was considered met.

d. IP 95001 requires that the inspection staff determine if the Notice of Violation related to the supplemental inspection was adequately addressed by PSEG, either in corrective actions taken or planned.

The issue was a low to moderate risk significance Notice of Violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," due to PSEG staff not adequately implementing the ACM. PSEG restored the HPCI system to an operable status on August 11, 2016, and issued ACM 15-08, Revision 4, on August 12, 2016. These actions restored full compliance with the NRC regulatory requirements, on August 12, 2016.

The inspectors determined this inspection objective was met.

e. IP 95001 requires that the inspection staff determine if PSEG developed quantitative and/or qualitative measures of success for determining the effectiveness of the corrective actions to prevent recurrence.

The inspectors determined that PSEG had developed and schedule interim and final effectiveness reviews (EFFR). Although not required per LS-AA-125, PSEG elected to conduct effectiveness reviews for contributing causes (CC) 1 and 2 and the oil sampling program element of contributing cause 3.

Effectiveness Measures	
RC1 - EFFR-1	Review documents to verify that the HPCI & RCIC maintenance procedures, maintenance plans and specification M-161 were revised, approved and implemented. If HPCI/RCIC maintenance has been performed, verify that the procedures were used, and that insulation is properly installed. If not, follow up with additional verification of procedure use. 08/31/17, 05/20/18
RC2 - EFFR-2	Review documentation associated with (1) LTAM issue H-13-0092; (2) the mitigation strategy for F001 valve stroking; (3) procedure issued for CAPR-7; (4) risk management and detection strategy to operate HPCI aux oil pump monthly to ensure the below attributed are met. Identify any problem areas and enter into the CAP. 06/30/18
CC1 - EFFR-3	Perform a Self-Assessment and verify that Station Leadership and staff behaviors produced effective implementation of the PI&R and CAP to address issues and adverse conditions associated with HPCI turbine oil moisture intrusion. 11/22/17 and 07/28/18
CC2 - EFFR-4	Verify that any ACMs generated following the issue of OP-AA-108-111, Revision 12, issued 12/09/16, have the appropriate attributes. Verify that the shift manager checklist is being used to review ACM data. Completed.
CC3 (Lube Oil Program Portion) - EFFR-5	Verify that lube oil samples are being obtained, processed, and analyzed without the need for supervisory intervention. Verify that system engineers and CMO have access to, and are utilizing, lube oil sample data in monitoring their systems' health. 08/11/17

The inspectors determined this inspection objective was met.

f. Findings

No findings were identified.

02.05 Evaluation of IMC 0305 Criteria for Treatment of Old Design Issues

PSEG did not request credit for self-identification of an old design issue; therefore, the risk-significant issue was not evaluated against the IMC 0305 criteria for treatment of an old design issue.

4OA6 Exit Meeting and Regulatory Performance Meeting

On August 11, 2017, the inspectors presented the inspection results to Mr. Peter Sena, PSEG Nuclear President and Chief Nuclear Officer, and other members of his staff, who acknowledged the inspection results. The inspectors verified that no proprietary information provided during the inspection was retained by the inspectors or documented in this report.

Upon completion of the exit meeting, the Region I Chief, Reactor Projects Branch 3, Mr. Fred L. Bower, conducted a Regulatory Performance Meeting, in accordance with IMC 0305 Section 10.01 (a), with Mr. Peter Sena, PSEG Nuclear President and Chief Nuclear Officer, and other members of his staff. The purpose of the meeting was to discuss PSEG's corrective actions in response to the White finding and NOV and to provide a forum in which to develop a shared understanding of the performance issues. Based on the guidance in IMC 0305, "Operating Reactor Assessment Program," and the results of this inspection, the White finding will be closed. Additionally, since Hope Creek has successfully completed this inspection, a Regulatory Performance Meeting has been held, and the finding had been open for at least four calendar quarters, Hope Creek will transition to the Licensee Response Column of the ROP Action Matrix effective the date of this report. However, in accordance with IMC 0305, Section 11.01.e, this finding will remain an Action Matrix input for the remainder of the third calendar quarter of 2017.

ATTACHMENT: SUPPLEMENTARY INFORMATION

SUPPLEMENTARY INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel
P. Sena, President and Chief Nuclear Officer
E. Carr, Hope Creek Site Vice President
E. Casulli, Plant Manager
T. Agster, Outage Manager
J. Atkison, Nuclear Chemistry Technician Specialist
A. Bauer, Lube Oil Program Manager
D. Cendo, Lead Engineer Nuclear (HPCI/RCIC)
M. Chimento, Communications Consultant
G. Demos, Principle Nuclear Engineer
E. Deppe, Nuclear Maintenance Nuclear Technician Mechanical
M. Dior, Manager Plant Engineering
R. Ficarra, Nuclear Shift Manager
G. Fisher, Nuclear Chemistry Technician Specialist
J. Garecht, Director Maintenance
J. Grey, Radiation Support Protection Superintendent
J. Johnson, Root Cause Consultant
T. Johnson, Root Cause Consultant
W. Kopchick, Director Engineering
S. Kugler, Manager Chemistry
K. Landis, Root Cause Consultant
T. MacEwen, Regulatory Compliance Engineer
J. Mallon, Director Regulatory Compliance
D. Mannai, Sr. Director Regulatory Compliance
A. Ochoa, Sr Engineer Nuclear Regulatory Affairs
K. O'Dowd, Principle Nuclear Engineer (HPCI/RCIC)
S. Poorman, Director Operations
J. Priest, Manager Nuclear Shift Operations
R. Rattigan, On-Line Work Manager
M. Reed, Nuclear Oversight Station Lead Assessor
M. Rooney, Nuclear Shift Supervisor Candidate
K. Torres, Hope Creek System Manager
A. Tramontana, Manager Programs Engineering
H. Trimble, Manager Radiation Protection

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Closed

05000354/2016003-01	NOV	Inadequate Implementation of Averse Condition Monitoring Actions for the High Pressure Coolant Injection System
05000354/2016-02-01	LER	High Pressure Coolant Injection System Inoperable.

LIST OF DOCUMENTS REVIEWED

Procedures
10855-M-161-13, Technical Specification for Nonmetallic Thermal Insulation for Piping, Equipment, and HVAC Ductwork, Revision 14
CC-AA-1111, PSEG Nuclear Industry Participation Process Control, Revision 2
ER-AA-10, Equipment Reliability Process Description, Revision 3
ER-AA-600-1015, FPIE PRA Model Update, Revision 8
ER-AA-2001, Plant Health Committee, Revision 17
ER-AA-2004, System Vulnerability Review Process, Revision 8
ER-AA-2030, Conduct of Plant Engineering Manual, Revision 14
ER-AB-1001, BWR HPCI Steam Admission Valve Leakage Monitoring and Action Plan, Revision 0
HC.MD-CM.FC-0001(Q), Reactor Core Isolation Cooling (RCIC) Steam Turbine Overhaul, Revision 15
HC.MD-CM.FD-0001(Q), High Pressure Coolant Injection (HPCI) Steam Turbine Overhaul, Revision 22
HC.MD-GP.ZZ-0056(Q), Insulation Removal and Installation, Revision 3
HC.MD-PM.FC-0001(Q), Reactor Core Isolation Cooling (RCIC) Steam Turbine Inspection and P.M., Revision 33
HC.MD-PM.FD-0001(Q), High Pressure Coolant Injection (HPCI) Steam Turbine Inspection and P.M, Revision 30
HC.OP-SO.BD-001(Q), Reactor Core Isolation Cooling System Operation, Revision 44
HC.OP-SO.BJ-0001(Q), High Pressure Coolant Injection System Operation, Revision 50
HC.OP-SO.BJ-001(Q), High Pressure Coolant Injection System Operation, Revision 49
LS-AA-115, Operating Experience Program, Revision 15
LS-AA-125-1001, Performance Improvement, Revision 13
MA-AA-716-210-1003, Preventive Maintenance Ownership Committee, Revision 4
MA-AA-716-230-1001, Oil Sampling Program, Revision 6
MA-AA-716-230-1004, Lubricant Sampling Guideline, Revision 5
MP 244305, LR-3M Sample HPCI Main and Booster PPs
MP 244306, LR-3M Sample RCIC Turbine
OP-AA-108-111, Adverse Condition Monitoring and Contingency Planning, Revision 12
OP-AA-108-111-F1, Adverse Condition Monitoring and Contingency Plan (ACMP), Revision 1
OP-HC-112-101-1001-F1, Shift Manager - Relief Checklist, Revision 2

Notifications (*means CR written as a result of this inspection)

20772420*	20680046	20765520
20500813	20696450	20765721
20550672	20736906	20765722
20551399	20758102	

Work Orders

60101966	70135925	70178523
60124249	70174237	70188669
60124249	70176529-0090	70191986
60130473	70176824	

Quality Assurance Audits, Peer Reviews, and Self Assessments
70183932, Op 0460, Benchmark on Industry Best Practices for the Corrective Action and Notification Screening Process, Dated 7/31/2017

Miscellaneous
Hope Creek 95001 Inspection Preparation Sheet
Hope Creek Corrective Action Line of Sight Diagrams for Order 70188669
Drawing 95415 C, EG-R Governor Hydraulic Control System-GE HPCI Units, Revision C
HPCI IST Data Recording worksheet
Hope Creek System Engineer Quarterly walk-down checklist for HPCI
HC-23, “HPCI Turbine Hydraulic Diagram,” Revised 4/22/88
026-01 HPCI System Operator Training Sheet, Revision 2
Plant Health Committee Meeting Agenda for 8/7/17
Hope Creek Daily Status Report for 8/8/17
Salem Daily Status Report for 8/8/17
Management Review Committee package for 8/9/17 and 8/10/17

LIST OF ACRONYMS USED

ACE	Apparent Cause Evaluation
ACM	adverse condition monitoring
ADAMS	Agencywide Documents Access and Management System
AOP	Abnormal Operating Procedure
BWR	boiling water reactor
BWROG	boiling water reactor owners group
CAP	Corrective Action Program
CAPR	corrective actions to preclude repetition
CC	contributing cause
CFR	Code of Federal Regulations
CMO	Component Maintenance Optimization
EACE	equipment apparent cause evaluation
EGR	electric governor remote
EPRI	Electric Power Research Institute
Hope Creek	Hope Creek Generating Station
HPCI	High Pressure Coolant Injection System
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	inspection report
LER	Licensee Event Report
LTA	less than adequate
LTAM	long term asset managment
MRC	Management Review Committee
NEI	Nuclear Energy Institute
NOTF	notification
NOV	Notice of Violation
NRC	U. S. Nuclear Regulatory Commission
OE	Operating Experience
PI&R	problem identification and resolution
PRA	probabilistic risk assessment
PSEG	PSEG Nuclear LLC
RC	root cause
RCE	Root Cause Evaluation
RCIC	Reactor Coolant Isolation Cooling System
ROP	Reactor Oversight Process
SOC	Screening Oversight Committee
SOP	Standard Operating Procedure
SPV	single point vulnerability
WO	work order