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

March 26, 2015

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

SUBJECT: HOPE CREEK GENERATING STATION – NRC PROBLEM IDENTIFICATION AND RESOLUTION INSPECTION REPORT 05000354/2015008

Dear Mr. Joyce:

On February 13, 2015, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Hope Creek Generating Station (Hope Creek). The enclosed report documents the inspection results, which were discussed on February 13, 2015, with Mr. Paul Davison, Site Vice President, and other members of your staff.

This inspection examined activities conducted under your license as they relate to identification and resolution of problems and compliance with the Commission's rules and regulations and conditions of your license. Within these areas, the inspection involved examination of selected procedures and representative records, observations of activities, and interviews with personnel.

Based on the samples selected for review, the inspectors concluded that PSEG was generally effective in identifying, evaluating, and resolving problems. PSEG personnel identified problems and entered them into the corrective action program at a low threshold. PSEG prioritized and evaluated issues commensurate with the safety significance of the problems and corrective actions were generally implemented in a timely manner.

This report documents two NRC-identified findings of very low safety significance (Green). The inspectors determined that each of these findings also involved a violation of NRC requirements. Additionally, this report documents one Severity Level IV violation with no associated finding. Because all three violations have been entered into your corrective action program, the NRC is treating these as non-cited violations, consistent with Section 2.3.2 of the NRC Enforcement Policy. If you contest these non-cited violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC

Resident Inspector at Hope Creek. In addition, if you disagree with the cross-cutting aspect assigned to either of the findings 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 Hope Creek.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of the NRC's document system (ADAMS). ADAMS is accessible from the NRC website at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Glenn T. Dentel, Chief
Reactor Projects Branch 3
Division of Reactor Projects

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

Enclosure: Inspection Report 05000354/2015008
w/Attachment: Supplementary Information

cc w/encl: Distribution via ListServ

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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket Nos.:	50-354
License Nos.:	NPF-57
Report Nos.:	05000354/2015008
Licensee:	PSEG Nuclear LLC
Facility:	Hope Creek
Location:	Hancocks Bridge, NJ
Dates:	January 26 – February 13, 2015
Team Leader:	Nicole Warnek, Allegation/Enforcement Specialist
Inspectors:	Justin Hawkins, Senior Resident Inspector Mark Draxton, Project Engineer Matthew Fannon, Reactor Engineer
Approved by:	Glenn Dentel, Chief Reactor Projects Branch 3 Division of Reactor Projects

SUMMARY

IR 05000354/2015008; 01/26/2015 – 02/13/2015; Hope Creek Generating Station; Biennial Baseline Inspection of Problem Identification and Resolution. The inspectors identified two findings and one Severity Level IV violation in the areas of Effectiveness of Prioritization and Evaluation of Issues and Effectiveness of Corrective Actions.

This NRC team inspection was performed by three regional inspectors and one resident inspector. The inspectors identified two findings of very low safety significance (Green) during this inspection and classified these findings as non-cited violations (NCVs). Additionally, a Severity Level IV violation with no associated finding was identified and classified as an NCV. The significance of most findings is indicated by their color (i.e., greater than Green, or Green, White, Yellow, Red) and determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process," dated June 2, 2011. Cross-cutting aspects are determined using IMC 0310, "Components Within Cross-Cutting Areas," dated December 4, 2014. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy, dated July 9, 2013. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 5.

Problem Identification and Resolution

The inspectors concluded that PSEG was generally effective in identifying, evaluating, and resolving problems. PSEG personnel identified problems, entered them into the corrective action program (CAP) at a low threshold, and prioritized issues commensurate with their safety significance. The inspectors concluded that, in general, PSEG adequately identified, reviewed, and applied relevant industry operating experience to Hope Creek operations. In addition, the inspectors determined that PSEG's self-assessments and audits were thorough, and identified deficiencies were entered into the CAP for follow up.

In most cases, PSEG appropriately screened issues for operability and reportability, and performed causal analyses that appropriately considered extent of condition, generic issues, and previous occurrences. The inspectors also determined that PSEG typically implemented corrective actions (CAs) to address the problems identified in the CAP in a timely manner. However, the inspectors identified three violations of NRC requirements; two in the area of effectiveness of prioritization and evaluation of issues and one in the area of effectiveness of corrective actions.

Based on interviews the inspectors conducted over the course of the inspection, observations of plant activities, and reviews of individual CAP and employee concerns program issues, the inspectors did not identify any indications that site personnel were unwilling to raise safety issues nor did they identify any conditions that could have had a negative impact on the site's safety conscious work environment.

Cornerstone: Initiating Events

- Green. The inspectors identified a Green NCV of TS 6.8.1.a, "Procedures and Programs," regarding PSEG's failure to adequately establish, implement, and justify a replacement frequency for the Residual Heat Removal (RHR) system optical isolators AT14 and AT18. These optical isolators were the most likely cause of an October 2013 RHR pump trip that resulted in a loss of shutdown cooling (SDC) during Hope Creek's R18 refueling outage. PSEG determined that the optical isolators did not have an established replacement frequency, and they had been installed since original plant construction. PSEG replaced the optical isolators and established a replacement preventive maintenance (PM) task going forward. The inspectors determined that PSEG had previous opportunity to identify the deficient PM strategy and replace the optical isolators prior to the October 2013 loss of SDC. In response to this finding, PSEG plans to conduct a causal evaluation and document the basis for their new PM frequency.

This issue is more than minor because it was associated with the equipment performance attribute of the initiating events cornerstone, and adversely affected the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, the RHR optical isolators were determined to be the most likely cause of the 'B' RHR pump trip and associated loss of SDC on October 17, 2013. The inspectors, with the assistance of a Region I Senior Reactor Analyst (SRA), used IMC 0609, Appendix G, "Shutdown Operations Significance Determination Process," to evaluate the safety significance of this issue. Based upon Appendix G, Attachment 1, Exhibit 2, this issue required a Phase 2 analysis, because the performance deficiency resulted in an actual loss of decay heat removal event. Using Attachment 3, "Phase 2 Significance Determination Process Template for BWRs During Shutdown," Worksheet 5, the SRA determined this issue was of very low safety significance (Green). The inspectors determined that the finding has a cross-cutting aspect in the area of Problem Identification and Resolution, Evaluation, which states that licensees thoroughly evaluate issues to ensure that resolutions address causes and extent of conditions commensurate with their safety significance. In this case, when the PCM template process was initially implemented in 2008, PSEG failed to evaluate AT14 and AT18 against the applicable PCM template (Signal Conditioner – Electronic) and generate replacement PMs. Although this performance deficiency dates back to 2008, the inspectors determined the issue is reflective of current licensee performance, because PSEG's root cause evaluation (RCE) and the associated PM change request (PCR), conducted in 2013, constituted a second missed opportunity for PSEG to evaluate the applicable PCM template against the PM strategy for AT14 and AT18. [P.2] (Section 4OA2.1.c(1))

Cornerstone: Mitigating Systems

- Severity Level IV. The inspectors identified a Severity Level IV NCV of 10 CFR Part 50.73(a)(2)(i)(B) because PSEG did not provide a written Licensee Event Report (LER) to the NRC within 60 days of identifying a condition prohibited by the plant's technical specifications (TS). Specifically, PSEG personnel did not submit a 50.73 report for the inoperability of the 'B' Filtration, Recirculation and Ventilation System (FRVS) recirculation fan that exceeded its TS allowed outage time. PSEG entered this issue into the corrective action program as notification 20678572. Planned actions include submitting an LER and performing a causal evaluation.

  Because the failure to submit a required LER impacts the regulatory process, this violation was evaluated using Section 2.2.4 of the NRC's Enforcement Policy, dated July 9, 2013. The issue was determined to be a Severity Level IV violation in accordance with the example listed in Section 6.9.d.9, "a licensee fails to make a report required by 10 CFR 50.72 or 10 CFR 50.73." The inspectors reviewed the issue for reactor oversight process significance and concluded there was no associated finding. Because this violation involves the traditional enforcement process and does not have an underlying technical violation that would be considered more-than-minor, a cross-cutting aspect is not assigned to this violation in accordance with IMC 0612. (Section 4OA2.1.c(2))

- Green. The inspectors identified a Green NCV of 10 CFR 50.65(a)(1) due to inadequate maintenance rule monitoring of the Reactor Manual Control System (RMCS). Specifically, PSEG did not properly evaluate and account for 52 maintenance preventable functional failures (MPFFs) across various systems, which were discovered by PSEG during a 2013 self-assessment of the Maintenance Rule Program. The inspectors determined that the multiple functional failures and a repeat MPFF experienced by RMCS demonstrated that the performance of RMCS was not being effectively controlled through appropriate preventive maintenance, and additional monitoring actions were required by 10 CFR 50.65(a)(1) and the PSEG Maintenance Rule Program. In response to this finding, PSEG plans to re-evaluate the 52 MPFFs for potential repeat MPFFs, generate a new notification for any repeat MPFFs identified, and conduct a work group evaluation to determine the cause of the improperly evaluated MPFFs.

  This issue was determined to be more than minor in accordance with IMC 0612 Appendix B, “Issue Screening,” 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. Specifically, because PSEG did not identify the repeat MPFF and implement required (a)(1) corrective actions and goals, PSEG missed an opportunity to assure reliability of RMCS by preventing additional failures. The inspectors determined that this finding was of very low safety significance (Green) using Exhibit 2 of IMC 0609, Appendix A, “The Significance Determination Process (SDP) for Findings At-Power,” dated June 19, 2012, because the finding did not 1) affect a single reactor protection system (RPS) trip signal to initiate a reactor scram and the function of other redundant trips or diverse methods of reactor shutdown; 2) involve control manipulations that unintentionally added positive reactivity; or, 3) result in mismanagement of reactivity by operators. The inspectors determined that the finding has a cross-cutting aspect in the area of Problem Identification and Resolution, Resolution, which states that licensees are expected to take effective corrective actions to address issues in a timely manner commensurate with their safety significance. In this case, PSEG failed to take effective corrective actions to resolve a known maintenance rule program deficiency with respect to non-conservative functional failure cause determination evaluations (FFCDEs). This directly led to inadequate reliability monitoring of RMCS under the maintenance rule, and potentially affected other maintenance rule systems as well. [P.3] (Section 4OA2.1.c(3))

REPORT DETAILS

4. OTHER ACTIVITIES (OA)

4OA2 Problem Identification and Resolution (71152B)

This inspection constitutes one biennial sample of problem identification and resolution as defined by Inspection Procedure 71152. All documents reviewed during this inspection are listed in the Attachment to this report.

.1 Assessment of Corrective Action Program Effectiveness

a. Inspection Scope

The inspectors reviewed the procedures that describe and implement PSEG's corrective action program at Hope Creek. To assess the effectiveness of the corrective action program, the inspectors reviewed performance in three primary areas: problem identification, prioritization and evaluation of issues, and corrective action implementation. The inspectors compared performance in these areas to the requirements and standards contained in 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action,” and PSEG procedure LS-AA-125, "Corrective Action Program." For each of these areas, the inspectors considered risk insights from the station’s risk analysis and reviewed notifications selected across the seven cornerstones of safety in the NRC's Reactor Oversight Process. Additionally, the inspectors attended multiple Plan-of-the-Day, Station Ownership Committee (SOC), and Management Review Committee (MRC) meetings. The inspectors selected items from the following functional areas for review: engineering, operations, maintenance, physical security, emergency preparedness, radiation protection, chemistry, and oversight programs.

(1) Effectiveness of Problem Identification

In addition to the items described above, the inspectors reviewed system health reports, completed corrective and preventative maintenance work orders, completed surveillance tests, and periodic trend reports. The inspectors completed field walkdowns of various systems on site, including the Standby Liquid Control (SLC) system, Redundant Reactivity Control System (RRCS), Auxiliary Building Heating Ventilation and Control System, and the Instrument and Service Air Systems. Additionally, the inspectors reviewed a sample of notifications written to document issues identified through internal self-assessments, audits, emergency preparedness drills, and the operating experience program. The inspectors completed this review to verify that PSEG entered conditions adverse to quality into their corrective action program as appropriate.

(2) Effectiveness of Prioritization and Evaluation of Issues

The inspectors reviewed the evaluation and prioritization of a sample of notifications issued since the last NRC biennial Problem Identification and Resolution inspection completed in February 2013. The inspectors also reviewed notifications that were assigned lower levels of significance that did not include formal cause evaluations to ensure that they were properly classified. The inspectors’ review included the appropriateness of the assigned significance, the scope and depth of the causal analysis, and the timeliness of resolution. The inspectors assessed whether the evaluations identified likely causes for the issues and developed appropriate corrective actions to address the identified causes. Further, the inspectors reviewed equipment operability determinations, reportability assessments, maintenance rule functional failure determinations, and extent-of-condition and extent-of-cause reviews for selected problems to verify these processes adequately evaluated equipment operability, reporting of issues to the NRC, maintenance rule impacts, and the extent of the issues.

(3) Effectiveness of Corrective Actions

The inspectors reviewed PSEG's completed corrective actions through documentation review, interviews, and, in some cases, field walkdowns to determine whether the actions addressed the identified causes of the problems. The inspectors also reviewed notifications for adverse trends and repetitive problems to determine whether corrective actions were effective in addressing the broader issues. The inspectors reviewed PSEG's timeliness in implementing corrective actions and PSEG's effectiveness in precluding recurrence for significant conditions adverse to quality. The inspectors also reviewed a sample of notifications associated with previous NCVs and findings to verify that PSEG personnel properly evaluated and resolved these issues. In addition, the inspectors performed an expanded, five year corrective action review to evaluate PSEG's actions related to SLC system issues.

b. Assessment

(1) Effectiveness of Problem Identification

Based on the selected samples, plant walkdowns, and interviews of site personnel in multiple functional areas, the inspectors determined that PSEG identified problems at a low threshold and entered them into the corrective action program as appropriate. PSEG staff at Hope Creek initiated approximately 23,500 notifications between February 2013 and January 2015. The inspectors observed supervisors at SOC and MRC meetings appropriately questioning and challenging notifications to ensure clarification and proper classification of the issues. Based on the samples reviewed, the inspectors determined that PSEG trended equipment, human performance, and programmatic issues, and entered identified problems into the CAP as appropriate. However, the inspectors did note one observation regarding PSEG's problem identification.

Temperature Switch Potential Part 21 Issue

Notification (NOTF) 20626121 documented an October 2013 trip of the 'A' main control room chiller. PSEG performed an apparent cause evaluation (ACE) and determined that the trip was due to the bearing oil temperature switch momentarily pegging high. The ACE cited electromagnetic interference (EMI) as the most likely cause, and the switch was sent to a vendor for failure analysis. In an August 2014 report, the vendor confirmed EMI as a likely cause of the switch failure. The ACE included an action item (ACIT) to evaluate the switch for Part 21 reportability, if EMI was found to be the cause and was determined to be within the switch specifications. This ACIT was initially due in January 2015, but, at an MRC meeting attended by the inspection team in late January 2015, the due date was extended to June 2015. The inspectors noted that, if the issue were ultimately determined to warrant reporting under 10 CFR Part 21, the station would have 60 days from the time of discovery to submit the required Part 21 report.

The inspectors determined that Hope Creek has not taken timely action to determine whether the temperature switch EMI issue is reportable under the Part 21 process. As of the time of the inspection, it had been 16 months since the switch initially failed, and six months since the failure analysis report was received, and the station had not yet determined if the switch had operated within its design, or if the failure constituted a deviation or non-conformance subject to the Part 21 process. The inspectors determined the performance deficiency was minor, because the issue is most likely not required to be reported under 10 CFR 21. Specifically, the inspectors noted that the vendor's failure analysis determined the switch was only subject to EMI at levels below those typically present in the nuclear power plant environment, and below the levels that NRC requires electrical components to be designed and tested to NRC Regulatory Guide 1.180, "Guidelines for Evaluating Electromagnetic and Radio-Frequency Interference in Safety-Related Instrumentation and Control Systems."

(2) Effectiveness of Prioritization and Evaluation of Issues

The inspectors determined that, in general, PSEG appropriately prioritized and evaluated issues commensurate with the safety significance of the identified problem. PSEG screened notifications for operability and reportability, categorized the notifications by significance, and assigned actions to the appropriate department for evaluation and resolution. The notification screening process considered human performance issues, radiological safety concerns, repetitiveness, adverse trends, and potential impact on the safety conscious work environment.

Based on the sample of notifications reviewed, and the SOC and MRC meetings attended, the inspectors noted that the guidance provided by PSEG's corrective action program implementing procedures was sufficient to ensure consistency in the categorization of issues. Operability and reportability determinations were generally performed when conditions warranted, and, in most cases, the evaluations supported the conclusion. Causal analyses appropriately considered the extent of condition associated with the problem, generic issues, and previous occurrences of the issue. However, the inspectors identified two NCVs in the area of prioritization and evaluation of issues, which are discussed in sections 4OA2.1.c(1) and 4OA2.1.c(2). Additionally, the inspectors noted the following two observations.

Standby Liquid Control (SLC) Troubleshooting

The inspectors reviewed NOTF 20658033, which was written for a SLC auto-initiation that occurred on July 30, 2014. The inspectors also reviewed the associated ACE 70168161 and complex troubleshooting documentation. The inspectors identified that the troubleshooting documentation for the event was incomplete and inaccurate, and in several places it contradicted the MRC-approved ACE. Most notably, the ACE cited the Bailey Logic Module as the most probable cause of the SLC initiation, yet the complex troubleshooting documentation listed this cause as "refuted." Additionally, the ACE considered the RRCS to be an unlikely cause of the SLC initiation, yet the troubleshooting documentation listed this leg as "open."

The inspectors determined that the failure to maintain accurate troubleshooting records was contrary to PSEG procedure MA-AA-716-004, "Conduct of Troubleshooting," and was a performance deficiency. The performance deficiency is minor because, after multiple interviews with PSEG personnel involved in the troubleshooting effort, the inspectors concluded that, although the complex troubleshooting documentation contradicted the conclusions in the ACE, the actual complex troubleshooting results were aligned with the ACE. PSEG documented this observation in NOTF 20677632.

Narrow Extent of Condition and Extent of Cause for an ACE

The inspectors reviewed ACE 70170877, which examined a service water ventilation system damper that failed to close due to a linkage issue. The ACE identified that the PM procedure for the damper did not include inspection of the damper linkage, despite the fact that this inspection was recommended by the PCM template. The inspectors determined that the extent of condition documented in the ACE was too narrowly focused. PSEG conducted an extent of condition review on 8 of 16 similar dampers in the service water ventilation system. However, there was not adequate justification for not looking at the other eight dampers in the system. Additionally, the inspectors noted that there had been recent damper failures in other systems, and the extent of condition should have considered all dampers that follow the same PCM template, regardless of system.

The inspectors also identified weaknesses with the ACE's extent of cause. Specifically, the ACE charter directed the team to look at all MPFFs documented in the last 24 months with similar causes (i.e., a damper failing due to a linkage problem.) The ACE identified and evaluated 3 similar MPFFs. However, the inspectors noted several additional MPFFs related to damper failures in other ventilation systems, and it was unclear why these were not evaluated. Additionally, a 2014 self-assessment had recently been conducted by PSEG and identified several additional MPFFs. Based on the timing of the self-assessment, the inspectors determined these additional MPFFs should have been reviewed by PSEG to determine if any involved similar causes and should have been included in the extent-of-cause review.

The NRC determined that PSEG's failure to perform thorough extent of condition and extent of cause reviews was a performance deficiency. However, it was determined to be minor because the team did not find any instances where subsequent damper failures may have been prevented by a more thorough extent of condition or extent of cause evaluation. Based on NRC's observation, PSEG generated NOTF 20678412 to determine whether the extent of cause should be re-performed.

(3) Effectiveness of Corrective Actions

The inspectors concluded that corrective actions for identified deficiencies were generally timely and adequately implemented. For significant conditions adverse to quality, PSEG identified actions to prevent recurrence. The inspectors concluded that corrective actions to address selected NRC NCVs and findings since the last problem identification and resolution inspection were generally timely and effective. The inspectors identified one finding in the area of corrective action implementation, which is documented in section 4OA2.1.c(3). Additionally, the team identified one observation.

Timeliness of Corrective Actions for a Previous NRC Finding

The inspectors reviewed a previous NRC finding on the 1DD481 inverter, which was documented in NRC Inspection Report 05000354/2013005, issued February 2014. PSEG had completed a work group evaluation (WGE) in response to the finding, and assigned four corrective actions with a due date of July 30, 2014. The inspectors noted that the corrective actions had been extended four times and, as of February 13, 2015, were still not completed. Per PSEG procedure LS-AA-125, "Corrective Action Program," the expectation for corrective actions is they should typically be done within 90 calendar days of issue identification. The corrective actions associated with this NRC finding were over 160 days old at the time of this inspection.

The inspectors determined that PSEG's failure to implement timely corrective actions in response to a previous NRC finding was a performance deficiency. However, the issue was determined to be minor because there were no other examples identified that would suggest this was a programmatic concern, and the inspectors determined there was no impact as a result of extending these specific corrective actions.

c. Findings

(1) Inadequate Preventive Maintenance for Safety-Related Optical Isolators in the Residual Heat Removal System

Introduction. The inspectors identified a Green NCV of TS 6.8.1.a, "Procedures and Programs," regarding PSEG's failure to adequately establish, implement, and justify a replacement frequency for the residual heat removal (RHR) system optical isolators AT14 and AT18. These optical isolators were listed as the most likely cause of an October 2013 RHR pump trip that resulted in a loss of shutdown cooling (SDC) during Hope Creek's R18 refueling outage. PSEG determined that the optical isolators did not have an established replacement frequency, and they had been installed since original plant construction. PSEG replaced the optical isolators and established a replacement PM task going forward. The inspectors determined that PSEG had previous opportunity to identify the deficient preventive maintenance (PM) strategy and replace the optical isolators prior to the October 2013 'B' RHR pump trip and associated loss of SDC.

Description. On October 17, 2013, Hope Creek was in a refueling outage with the 'B' RHR pump in SDC mode when the pump tripped unexpectedly. Operators in the main control room re-started the 'B' RHR pump and restored SDC within 18 minutes. A root cause evaluation (RCE) was performed to determine the cause of the trip and establish corrective actions to prevent reoccurrence. The RCE determined that the cause of the trip was indeterminate; however, the RHR system optical isolators AT14 and AT18 were the most likely cause. The RCE determined that the optical isolators had been installed and in service since initial plant construction (nearly 27 years) and had signs of age-related degradation. PSEG replaced AT14 and AT18 and created a new PM task to replace these optical isolators on a 24 year frequency.

The inspectors' review of the RCE noted that there was no PM in place for the optical isolators prior to their failure. The RCE also stated that the optical isolators had never been evaluated under a performance centered maintenance (PCM) template. A PCM template is a licensee document that lists recommended PM tasks for various plant equipment. PCM templates were first introduced at Hope Creek in 2008. When the PCM templates were initially implemented, PSEG engineers were tasked with evaluating the current PM strategy for equipment in their systems against the PCM template and creating new PM tasks as needed, under order 80100224. The inspectors noted that, according to the RCE, "no documentation could be located that the optical isolators were ever evaluated under any PCM template." The inspectors determined that there was a

PCM template applicable to AT14 and AT18 and, therefore, they should have been evaluated. Specifically, the PCM template, “Signal Conditioner - Electronic,” was directly associated with the component identification numbers for AT14 and AT18, and this PCM template recommended a 15 year replacement frequency. Per PSEG procedure MA-AA-716-210, "Preventive Maintenance Program," all PCM template recommendations do not need to be implemented as PMs; however, “all PMs that deviate from the PCM template recommendations require a justification documented in the PM Change Process.” The inspectors determined that PSEG did not have a documented justification for deviating from the “Signal Conditioner – Electronic” PCM template for AT14 and AT18.

The inspectors determined that PSEG had a reasonable opportunity to identify that the PM strategy was not aligned with the applicable PCM template in 2013, during conduct of the RCE. Specifically, one of the CAs from the RCE was to implement a PM Change Request (PCR) to establish new PMs for the optical isolators. The PCR stated there was no applicable PCM template for the optical isolators and established a 24 year replacement PM. The inspectors determined that both the PCR and RCE failed to recognize that the “Signal Conditioner – Electronic” PCM template was associated with the optical isolators and recommended a 15 year replacement frequency. PSEG entered this issue into the CAP as NOTF 20679076. Planned corrective actions include conducting a causal evaluation and documenting the basis for the 24 year replacement PM, given the 15 year recommended frequency in the PCM template.

Analysis. The inspectors determined that PSEG’s failure to establish a replacement PM for the RHR system optical isolators AT14 and AT18 was a performance deficiency that was within PSEG’s ability to foresee and correct and could have been prevented. This issue is more than minor because it was associated with the equipment performance attribute of the initiating events cornerstone, and affected the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, the RHR optical isolators were determined to be the most likely cause of the ‘B’ RHR pump trip and associated loss of SDC on October 17, 2013. The inspectors, with the assistance of a Region I SRA, used IMC 0609, Appendix G, “Shutdown Operations Significance Determination Process,” to evaluate the safety significance of this issue. Based upon Appendix G, Attachment 1, Exhibit 2, this issue required a Phase 2 analysis, because the performance deficiency resulted in an actual loss of decay heat removal event. Using Attachment 3, “Phase 2 Significance Determination Process Template for BWRs During Shutdown,” Worksheet 5, the SRA determined this issue was of very low safety significance (Green), based on the following inputs and assumptions. The SRA assumed maximum equipment and operator mitigation credit because the reactor coolant system was vented, the cavity was flooded, the spent fuel pool gates were open, the time-to-boil was in excess of 17 hours, and the actual loss of RHR cooling was of short duration (18 minutes). Accordingly, the dominant core damage sequences involved failure of the operators to recover shutdown cooling and the subsequent failure to provide long term make-up for boiling losses.

The inspectors determined that the finding has a cross-cutting aspect in the area of Problem Identification and Resolution, Evaluation, which states that licensees thoroughly evaluate issues to ensure that resolutions address causes and extent of conditions commensurate with their safety significance. In this case, when the PCM template process was initially implemented in 2008, PSEG failed to evaluate AT14 and AT18 against the applicable PCM template (Signal Conditioner – Electronic) and generate replacement PMs. Although the original performance deficiency dates back to 2008, the inspectors determined the issue is reflective of current licensee performance, because PSEG's RCE and associated PCR, conducted in 2013, constituted a second missed opportunity for PSEG to evaluate the applicable PCM template against the PM strategy for AT14 and AT18. [P.2]

Enforcement. TS 6.8.1.a, "Procedures and Programs," requires in part, that written procedures recommended in Appendix A of Regulatory Guide (RG) 1.33, Revision 2, shall be established, implemented, and maintained. Section 9.b of RG 1.33, Revision 2, Appendix A, requires that PM schedules should be developed to specify the inspection or replacement of parts that have a specific lifetime. Contrary to this requirement, from 2008 until February 13, 2015, PSEG failed to develop and implement appropriate preventive maintenance for the replacement of the RHR system optical isolators AT14 and AT18. PSEG entered this issue into the CAP as NOTF 20679076. Planned corrective actions include conducting a causal evaluation and documenting the basis for the 24 year replacement PM, given the 15 year recommended frequency in the PCM template. Because this violation was of very low safety significance (Green) and was entered into the licensee's CAP, the violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000354/2015008-01, Inadequate Preventive Maintenance for Safety-Related Optical Isolators in the Residual Heat Removal System)**.

(2) Failure to Submit a Licensee Event Report for a Condition Prohibited by Technical Specifications

Introduction. The inspectors identified a Severity Level IV NCV of 10 CFR Part 50.73(a)(2)(i)(B) because PSEG did not provide a written Licensee Event Report (LER) to the NRC within 60 days of identifying a condition prohibited by the plant's technical specifications (TS). Specifically, PSEG personnel did not submit a 50.73 report for the inoperability of a 'B' Filtration, Recirculation and Ventilation System (FRVS) recirculation fan that exceeded its TS allowed outage time.

Description. The FRVS is a mitigating system that maintains a slight vacuum in the Reactor Building during normal operations, and also circulates and cleans-up the atmosphere within the building during abnormal (accident) conditions. On June 2, 2013, the 'B' FRVS recirculation fan successfully completed its monthly TS surveillance test. However, on June 3, 2013, PSEG discovered the flow controller indication was pegged high, and PSEG replaced the flow-indicating controller service module. Following this replacement, instrument technicians performed a calibration and a functional test. The functional test included the verification of signal continuity through the controller. However, it did not involve a functional test of the FRVS recirculation fan itself (i.e., starting the recirculation fan) to ensure that the controller could actually control the fan. The operations personnel credited the continuity verification as the post maintenance test (PMT) for the 'B' FRVS recirculation fan, and proceeded to restore the fan to operable status.

Approximately 3 weeks later, on June 24, 2013, Hope Creek operations personnel were performing the monthly surveillance test of the 'B' FRVS recirculation fan in accordance with surveillance procedure HC.OP-ST.GU-0005, "FRVS Fan Operability Test." The fan tripped on a low flow signal approximately 10 seconds after starting. This was the first time the fan was run since the June 3, 2013 maintenance. The instrumentation technicians re-performed the signal continuity check that was done after the controller's installation on June 3, and the testing passed. PSEG then performed an inspection of the fan's control system, and discovered that a pin in the connector for the flow-indicating controller was not locked in place, which was resulting in intermittent connectivity. As a result of the loose connection, the flow-indicating controller would intermittently lose the ability to operate the fan damper, which caused the 'B' FRVS fan to trip on low flow.

PSEG chartered an ACE to evaluate the failed surveillance test. The ACE determined that not all required post maintenance operability testing had been conducted on June 3. Specifically, PSEG determined that the fan should have been placed in service before declaring it operable. (Note: An NRC finding was documented in NRC Inspection Report 05000354/2013004 (ML13322B251) regarding the inadequate PMT.) The ACE included an action to evaluate the issue for 10 CFR 50.73 reportability. PSEG's evaluation determined the issue was not reportable, crediting the continuity test performed following the maintenance of June 3, 2013 as adequate to prove operability. However, the evaluation also acknowledged that the flow indicating controller would have functioned intermittently since installation on June 3.

NRC inspectors determined that this issue was incorrectly evaluated and should have been reported per 10 CFR 50.73, because the intermittent connectivity existed since the controller was replaced on June 3, 2013, and the fan could not be considered operable with this condition. Although PSEG had initially determined (on June 3) that the controller was operable, the inspectors determined that the discovery (on June 24) of the intermittent connection provided new information that rendered the initial operability determination inaccurate. Of note, the signal continuity check that was credited to prove operability on June 3, 2013 was unsuccessful on identifying the failure on June 24, 2013 after the 'B' FRVS recirculation fan had tripped on low flow.

The inspectors determined that the 'B' FRVS recirculation fan was not operable for 21 days, from June 3 to June 24, 2013, which is longer than the FRVS recirculation TS allowed outage time of 7 days. NUREG-1022, "Event Report Guidelines 10 CFR 50.72 and 50.73," Revision 3, section 3.2.2, "Operation or Condition Prohibited by Technical Specifications" states, in part, that "an LER is required if a condition existed for a time longer than permitted by the TS even if the condition was not discovered until after the allowable time had elapsed and the condition was rectified immediately upon discovery." PSEG entered this issue into the CAP as NOTF 20678572. Planned actions include submitting a LER per 10 CFR 50.73 and performing a causal evaluation.

Analysis. The inspectors determined that PSEG's failure to provide a written LER within 60 days was a performance deficiency that was reasonably within PSEG's ability to foresee and correct, and should have been prevented. Because the failure to submit a required LER impacts the regulatory process, the violation was evaluated using Section 2.2.4 of the NRC's Enforcement Policy, dated July 9, 2013. The issue was determined to be a Severity Level IV violation in accordance with the example listed in Section 6.9.d.9, "a licensee fails to make a report required by 10 CFR 50.72 or 10 CFR 50.73." The inspectors reviewed the issue for reactor oversight process significance and concluded there was no associated finding. Because this violation involves the traditional enforcement process and does not have an underlying technical violation that would be considered more-than-minor, a cross-cutting aspect is not assigned to this violation in accordance with IMC 0612.

Enforcement. As stated in 10 CFR 50.73(a)(2)(i)(B), "Operation or Condition Prohibited by Technical Specifications," requires, in part, that licensees submit an LER for any operation or condition which was prohibited by the plant's Technical Specifications, within 60 days of discovering the event. Contrary to this requirement, on June 24, 2013, PSEG did not submit an LER for a condition that was prohibited by the plant's Technical Specifications within 60 days of discovering the event. Specifically, PSEG failed to submit a report within 60 days when PSEG personnel identified that during maintenance on June 3, 2013, a defective FRVS flow indicating controller service module was installed that was not identified during post maintenance testing. This resulted in an inoperable FRVS recirculation fan for approximately 21 day; a condition which was determined to be prohibited by the plant's Technical Specification. PSEG entered this issue into the CAP as NOTF 20678572. Planned actions include submitting a LER per 10 CFR 50.73 and performing a causal evaluation. Because this SLIV violation was not repetitive or willful, and was entered into PSEG's CAP, the issue is being treated as a Severity Level IV NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy (**NCV 05000354/2015008-02, Failure to Submit a Licensee Event Report for a Condition Prohibited by Technical Specifications**).

(3) Inadequate Maintenance Rule Monitoring of the Reactor Manual Control System

Introduction. The inspectors identified a Green NCV of 10 CFR 50.65(a)(1) due to inadequate maintenance rule monitoring of the Reactor Manual Control System (RMCS). Specifically, PSEG did not properly evaluate and account for 52 maintenance preventable functional failures (MPFFs) across various systems, which were discovered by PSEG during a 2013 self-assessment of the Maintenance Rule Program. The inspectors determined that the multiple functional failures and a repeat MPFF experienced by RMCS demonstrated that the performance of RMCS was not being effectively controlled through appropriate preventive maintenance, and additional monitoring actions were required by 10 CFR 50.65(a)(1) and the PSEG Maintenance Rule Program.

Description. As part of the NRC Problem Identification and Resolution team inspection, the inspectors reviewed the PSEG Focused Area Self-Assessment (FASA 70162305) for the Fleet Maintenance Rule Program that was completed in July 2014. The purpose of this FASA was to assess the implementation of the maintenance rule program at Hope Creek and Salem. This FASA identified multiple deficiencies within the maintenance rule program, including deficiency 3 (NOTF 20657565) which found that a majority of completed functional failure cause determination evaluations (FFCDEs) at both sites had used improper justification in determining whether equipment failures should be considered MPFFs.

As part of PSEG's corrective actions to address this deficiency, the FFCDE form (ER-AA-310-1004-F1) was revised to be more conservative in determining whether functional failures were maintenance preventable. An extent of condition review was performed under order 70167903-0030 to re-evaluate all FFCDEs completed over the past 3 years. This review found that 52 of the 75 completed FFCDEs had incorrectly justified functional failures as not being MPFFs. PSEG overturned these FFCDEs and re-categorized the functional failures as MPFFs in the PSEG maintenance rule database. The inspectors noted that the 52 MPFFs were never re-evaluated to screen for potential repeat MPFFs. As defined in PSEG procedure ER-AA-310-1004, "Maintenance Rule Performance Monitoring," a repeat MPFF is a MPFF attributable to the same maintenance related cause that occurred on a similar type of component. For most systems, a single repeat MPFF would cause the affected system to exceed its (a)(2) reliability performance criteria and, therefore, require (a)(1) monitoring actions, per PSEG procedure ER-AA-310, "Implementation of the Maintenance Rule."

The inspectors questioned PSEG about the need to screen for repeat MPFFs. Hope Creek captured the inspectors' concerns in NOTF 20678056 and directed Hope Creek engineering to re-evaluate the 52 FFCDEs for potential repeat MPFFs. The inspectors decided to sample the RMCS system to determine if a potential repeat MPFF had been missed by PSEG. This system was selected for review by the inspectors for two reasons: 1) PSEG's FASA had resulted in multiple overturned FFCDEs in RMCS; and, 2) even though RMCS MPFFs had not exceeded the (a)(1) criteria of eight MPFFs in a 36-month timeframe, the inspectors questioned the reliability of RMCS due to the high number of failed Solatron transformers.

The inspectors found that the RMCS had been declared inoperable on three separate instances in 2013 (April 1, June 28, and October 27) due to failed Solatron transformers. PSEG completed an apparent cause evaluation (70152062) following the April 1 failure, which determined that the Solatron transformer PM replacement frequency had been extended beyond its vendor recommended life expectancy without proper justification. As of April 1, 2013, all of the Solatron transformers were 13.5 years old, which exceeded the vendor and system engineer recommended replacement frequency of every 12 years. PSEG's apparent cause evaluation established multiple corrective actions including: 1) conducting a failure analysis of the failed transformer; 2) scheduling replacement of all the other Solatron transformers; and, 3) changing the periodicity of replacement from 15 years back to the vendor recommended 12 years. The inspectors reviewed the status of these corrective actions and found that, as of February 2015, they had either not been completed or had been delayed without proper justification.

The inspectors determined that the October 27 transformer failure was one of the 52 overturned FFCDEs that had not been re-evaluated for a potential repeat MPFF. Although PSEG had corrective actions planned at the time of the October 27 transformer failure, the inspectors determined that these corrective actions had not been implemented in a timely manner, and, therefore, the October 27 failure met the criteria for being classified as a repeat MPFF per PSEG procedure ER-AA-310-1004, Maintenance Rule – Performance Monitoring. Per PSEG's Maintenance Rule Program, a single repeat MPFF in the RMCS exceeds the licensee-established goal of zero repeat MPFFs in a 36-month timeframe, and requires (a)(1) monitoring actions. As such, PSEG should have been monitoring the RMCS Solatron transformers against licensee-supplied goals as required by 10 CFR 50.65(a)(1) and PSEG procedure ER-AA-310, "Implementation of the Maintenance Rule."

<u>Analysis</u>. The inspectors determined that PSEG's failure to properly evaluate and account for 52 MPFFs resulted in at least one system, RMCS, not being monitored in accordance with 10 CFR 50.65(a)(1). Per PSEG's Maintenance Rule Program, a single repeat MPFF in the RMCS exceeds the licensee-established goal of zero repeat MPFFs in a 36 month timeframe, and requires (a)(1) system monitoring actions. The inspectors

determined that this constituted a performance deficiency that was within PSEG's ability to foresee and correct, and should have been prevented. The performance deficiency was determined to be more than minor in accordance with IMC 0612 Appendix B, "Issue Screening," 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. Specifically, because PSEG did not identify the repeat MPFF and implement required (a)(1) corrective actions, goals, and monitoring, PSEG missed an opportunity to assure reliability of RMCS by preventing additional failures. In addition, example 7.d from IMC 0612 Appendix E, "Examples of Minor Issues," details that a performance deficiency can be more than minor if equipment performance problems were such that effective control of performance through appropriate preventive maintenance under (a)(2) could not be demonstrated. The inspectors determined that this finding was of very low safety significance (Green) using Exhibit 2 of IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," dated June 19, 2012, because the finding did not 1) affect a single reactor protection system (RPS) trip signal to initiate a reactor scram and the function of other redundant trips or diverse methods of reactor shutdown; 2) involve control manipulations that unintentionally added positive reactivity; or, 3) result in mismanagement of reactivity by operators.

The inspectors determined that the finding has a cross-cutting aspect in the area of Problem Identification and Resolution, Resolution, which states that licensees are expected to take effective corrective actions to address issues in a timely manner commensurate with their safety significance. In this case, the inspectors determined that PSEG failed to take effective corrective actions to resolve a known maintenance rule program deficiency with respect to non-conservative FFCDEs. This directly led to inadequate reliability monitoring of RMCS under the maintenance rule, and potentially affected other maintenance rule systems as well. [P.3]

<u>Enforcement</u>. 10 CFR 50.65 (a)(1), requires, in part, that holders of an operating license shall monitor the performance or condition of structures, systems and components (SSCs) within the scope of the rule as defined by 10 CFR 50.65(b), against licensee established goals, in a manner sufficient to provide reasonable assurance that such SSCs are capable of fulfilling their intended functions. 10 CFR 50.65(a)(2) states, in part, that monitoring, as specified in 10 CFR 50.65(a)(1), is not required where it has been demonstrated that the performance or condition of an SSC is being effectively controlled through the performance of appropriate preventative maintenance, such that the SSC remains capable of performing its intended function. Contrary to the above, from October 27, 2013 through February 13, 2015, PSEG did not monitor the performance of a system within the scope of the maintenance rule as defined by 10 CFR 50.65(b), against established goals, in a manner sufficient to provide reasonable assurance that the SSC was capable of fulfilling its intended functions. Specifically, based on the multiple functional failures and a repeat MPFF experienced by the RMCS Solatron transformers, the inspectors concluded that RMCS performance was not effectively controlled by preventive maintenance, and PSEG was required to monitor the system against licensee established (a)(1) goals. PSEG's planned corrective actions include re-evaluating the 52 overturned FFCDEs for potential repeat MPFFs, generating a new notification for any repeat MPFFs identified, and conducting a work group evaluation to determine the cause of the missed repeat MPFF reviews. Because the finding was of very low safety significance and has been entered into the licensee's

corrective action program (NOTF 20678056), this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000354/2015008-03; Inadequate Maintenance Rule Monitoring of the Reactor Manual Control System)**

.2 Assessment of the Use of Operating Experience

a. Inspection Scope

The inspectors reviewed a sample of notifications associated with review of industry operating experience (OE) to determine whether PSEG appropriately evaluated the operating experience information for applicability to Hope Creek and took appropriate actions, when warranted. The inspectors also reviewed evaluations of OE documents associated with a sample of NRC generic communications to ensure that PSEG adequately considered the underlying problems associated with the issues for resolution via their corrective action program. In addition, the inspectors observed various plant activities to determine if the station considered industry OE during the performance of routine and infrequently performed activities.

b. Assessment

The inspectors determined that PSEG appropriately considered industry OE information for applicability, and used the information to identify and prevent similar issues when appropriate. The inspectors determined that OE was appropriately applied and lessons learned were communicated and incorporated into plant operations and procedures when applicable. The inspectors also observed that industry OE was routinely discussed and considered during the conduct of Plan of the Day meetings and pre-job briefs.

c. Findings

No findings were identified.

.3 Assessment of Self-Assessments and Audits

a. Inspection Scope

The inspectors reviewed a sample of audits, including the most recent audit of the corrective action program, departmental self-assessments, and assessments performed by independent organizations. Inspectors performed these reviews to determine if PSEG entered problems identified through these assessments into the corrective action program, when appropriate, and whether PSEG initiated corrective actions to address identified deficiencies. The inspectors evaluated the effectiveness of the audits and assessments by comparing audit and assessment results against self-revealing and NRC-identified observations made during the inspection.

b. Assessment

The inspectors concluded that self-assessments, audits, and other internal PSEG assessments were generally critical, thorough, and effective in identifying issues. The inspectors observed that PSEG personnel knowledgeable in the subject completed these audits and self-assessments in a methodical manner. PSEG completed these audits and self-assessments to a sufficient depth to identify issues which were then entered into the corrective action program for evaluation. In general, the station implemented corrective actions associated with the identified issues commensurate with their safety significance.

c. Findings

No findings were identified.

.4 Assessment of Safety Conscious Work Environment

a. Inspection Scope

During interviews with station personnel, the inspectors assessed the safety conscious work environment at Hope Creek. Specifically, the inspectors interviewed personnel to determine whether they were hesitant to raise safety concerns to their management and/or the NRC. The inspectors also interviewed the station Employee Concerns Program coordinator to determine what actions are implemented to ensure employees were aware of the program and its availability with regards to raising safety concerns. The inspectors reviewed the Employee Concerns Program files to ensure that PSEG entered issues into the corrective action program when appropriate.

b. Assessment

During interviews, Hope Creek staff expressed a willingness to use the corrective action program to identify plant issues and deficiencies and stated that they were willing to raise safety issues. The inspectors noted that no one interviewed stated that they personally experienced or were aware of a situation in which an individual had been retaliated against for raising a safety issue. All persons interviewed demonstrated an adequate knowledge of the corrective action program and the Employee Concerns Program. Based on these limited interviews, the inspectors concluded that there was no evidence of an unacceptable safety conscious work environment and no significant challenges to the free flow of information.

c. Findings

No findings were identified.

4OA6 Meetings, Including Exit

On February 13, 2015, the inspectors presented the inspection results to Mr. Paul Davison, Site Vice President, and other members of the Hope Creek staff. The inspectors verified that no proprietary information was retained by the inspectors or documented in this report.

ATTACHMENT: SUPPLEMENTARY INFORMATION

SUPPLEMENTARY INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

P. Davison, Site Vice President
E. Carr, Plant Manager
S. Simpson, Regulatory Assurance Manager
S. Nevelos, Performance Improvement Manager
T. MacEwen, Compliance Engineer
A. Kazarian, System Engineer
A. Bauer, System Engineer
A. Lacorte, System Engineer
A. Contino, System Engineer
B. Booz, Maintenance Instrument and Controls
B. Ciccone, System Engineer
C. Bersak, Hope Creek CAP Coordinator
C. Reed, System Engineer
C. Payne, System Engineer
C. Lukascy, Nuclear Shift Supervisor
D. Furey, Maintenance Superintendent
D. Bedford, System Engineer
D. Bush, Business Specialist
D. Shuman, Employee Concerns Program Manager
E. Martin, Senior Engineer
G. Lichty, Maintenance Technical Specialist
H. Mullica, Emergency Services CAP Coordinator
J. Krall, Reactor Engineering Manager
J. Smith, Nuclear Equipment Operator
J. Priest, Nuclear Shift Operations Manager
K. Swing, System Engineer
K. Torres, Branch Manager
L. Koberlein, Acting Operations Support Manager
M. Conroy, Principal Nuclear Engineer
M. Peterson, Instrument and Service Air System Engineer
M. Pfizenmaier, Engineering Response Team Manager
M. Rooney, System Engineer
M. Biggs, Maintenance Rule Coordinator
M. Khan, Senior Engineer
P. Koppel, Maintenance Superintendent
S. Kugler, Chemistry Manager
T. Foster, Maintenance CAP Coordinator
T. Gingerich, System Engineer
W. Hawthorne, Supervisor, Maintenance Instrument and Controls

NRC Personnel

W. Cook, Senior Reactor Analyst, Region I

LIST OF ITEMS OPENED, CLOSED, DISCUSSED, AND UPDATED

Opened and Closed

05000354/2015008-01	NCV	Inadequate Preventive Maintenance for Safety-Related Optical Isolators in the Residual Heat Removal System (Section 4OA2.1.c.(1))
05000354/2015008-02	NCV	Failure to Submit a Licensee Event Report for a Condition Prohibited by Technical Specifications (Section 4OA2.1.c.(2))
05000354/2015008-03	NCV	Failure to Monitor the Reactor Manual Control System under 50.65(a)(1) due to Inadequate Maintenance Rule Functional Failure Evaluations (Section 4OA2.1.c.(3))

LIST OF DOCUMENTS REVIEWED

Section 4OA2: Problem Identification and Resolution

Audits and Self-Assessments
70159506, Operating Experience FASA
70161257, Evaluations of Changes, Tests, or Experiments and Permanent Plant Modifications FASA
70162305, FASA for the 2014 Fleet Maintenance Rule Program
70163330, CISA for Preventative Maintenance Program Compliance
70163699, Emergency Preparedness Drill and Exercise Performance Indicator Check-In Self-Assessment
70163702, FASA for Equipment Performance, Testing and Maintenance
80109029, NOSA-HPC-13-04, Corrective Action Program Audit Report
80110250, Radiation Protection Audit Report
80111560, NOSA-HPC-14-02, Emergency Plan, Procedures, Facilities, and Interfaces Audit Report Audit
80111784, Operations Configuration and Status Control FASA
80111810, ODCM/REMP/RETS Check-In Self-Assessment
80111812, FASA for 2014 Problem Identification and Resolution
80112297, Engineering Programs and Station Blackout QA Audit
NOSA-HPC-14-03, PSEG Nuclear Oversight Hope Creek Maintenance Audit
NOSA-HPC-15-01, PSEG Security Audit

Cause Evaluations
20674015, Prompt Investigation for Security Loss of Video Capture
70102312, ACE for ‘B’ Standby Liquid Control Pump Failed its In-service Test Multiple Times following Pump Maintenance
70111926, ACE for ‘A’ Control Room Emergency Filtration Unit Failed its 18 Month Charcoal Efficiency Test
70122311, WGE for Standby Liquid Control Valve F029B Failed High during As-found Testing
70140638, RCE for Fuel Failures

70140751, FFCDE for AK400 Trip
70141127, Remote Shutdown Panel RCIC Lube Oil Relay Indication Fail
70142887, 0KCV-266 Misposition Event
70143302, FFCDE for AK400 Trip
70143918, WGE for Maintenance CAP Declining Trend
70148443, Technical Evaluation for F029A-C41 Failed As-found Lift Set Point Test High (60096938)
70150627, ACE for Security Center Loads Tripped Unexpectedly
70150995, FFCDE for AK400 Trip
70151680, BV412 EDG Recirc Fan Trip on Low Flow
70152062, ACE for RMCS Lockup with Multiple Fault Indications
70155511 'B' FRVS Recirc Fan Low Flow Trip
70155514, Rx Scram Due To Trip of 'B' CWP
70156288, Perform CCE for component positioning
70156464, "A" NS4 Fuse Blew During I&C Testing ACE
70157730, WGE for Maintenance Department Overdue CAP Items
70159686, "A" CR Chiller Trip - ACE
70159686, FFCDE for AK400 Trip
70159885, B-RHR Pump Tripped Without Audible Indication – RF18 Loss of Shutdown Cooling RCE Report
70160516, Adverse Trend in Oper Screening Quality
70160636, Arc Flash Event - RCE
70160942, Common Cause Evaluation (CCE) for Refueling Outage 18 Required Rework
70161698, FFCDE for Multiple 'A' Moisture Separator Dump Valve Failures
70161698, RCE for Hope Creek Scram High 'A' Moisture Separator Level
70161786, OPDRV & Sec Cont LER (RF18)
70162013, Loss of 10A404 Bus ACE
70162662, Radiation Protection Department Performance Indicators Common Cause Analysis
70162284, AK400 Chiller Manually Tripped ACE
70162284, FFCDE for AK400 Trip
70164151, NOS Escalation of Fire Protection Org
70164817, ACE for Hope Creek Failed Fuel Identified
70164914, WGE for Lessons Learned from the SLC Tank Dilution
70165551, WGE for 1BD-483 Inverter DC Supply Breaker Found Tripped
70167005, WGE for 1ST Call Preventative Maintenances Out of Process
70167025, CCE for Damper Adverse Trend
70167281, WGE for Determining if Control Rod Drive System Pressure Fluctuations are Causing Reactor Recirculation Seal Purge Line Relief Valves Degradation
70167855, ACE for Relay Replacement Preventative Maintenance Testing Concerns
70168161, ACE for 'A' Standby Liquid Control Auto-initiation
70170877, ACE for Age-Related Wear not Identified during Preventative Maintenance Activities Resulted in High Room Differential Pressure and a Maintenance Rule Functional Failure
70171764, ACE for Loss of Video in SAS
70172528, WGE for ARC Flash RCE CAP Deficiencies
80000496, Design Change Package for Reactor Manual Control System BJM Box Ventilation
80107271, Technical Evaluation to Evaluate 'B' SLC Pump Valve Seat Bore
80110635, Design Change Package (DCP) for Standby Liquid Control Improvements
80112740, DCP for Security Center Motor Control Center Load Breaker Coordination
80112926, FFCDE for Service Water Ventilation System Damper (9773A2)

Effectiveness Reviews
70148287, OKC-V266 found out of position
70148430, CCE Security Human Performance Negative Trend
70156868-0070, CCE on Desensitization of Plant Health Committee Coded Work and Work Management Process
70157871, Radiation Protection Technician Took an Exempted Source Off-Site, Not in Compliance with Department of Transportation Shipping Regulations Effectiveness Review
70160636, Arc Flash RCE Effectiveness Review
70164151, Nuclear Oversight Escalation of Fire Protection Org

Non-Cited Violations and Findings
05000354/2013002-01, A Technical Specification Surveillance Procedure for Remote Shutdown Panel Instrumentation was Inadequately Implemented.
05000354/2013004-01, Failure to Follow Post-Maintenance Testing Procedure Prior to Returning the ‘B’ FRVS Recirculation Fan to Service
05000354/2013005-01, Failure to Follow Procedure for Configuration Control Adversely Affected Unidentified Leakage in the Drywell
05000354/2013005-03, Inadequate Evaluation of Containment Vent Functionality
05000354/2014002-01, Inadequate Preventative Maintenance for Safety-Related Circuit Cards
05000354/2014002-03, Failure to Follow Procedure Resulting in the Potential Inoperability of a Safety-Related System
05000354/2014003-03, Failure to Follow Procedure Resulting in the Loss of a Vital 4kV Bus
05000354/2014003-05, Inadequate Evaluation of a Main Control Room Chiller Design Change

Notifications *(* indicates that notification was generated or updated as a result of this inspection)*

20284604	20534176	20579979	20600447	20624172
20292676	20536283	20589008	20600774	20624320
20371501	20536435	20589731	20600822	20624997
20447050	20536824	20592370	20600825	20625368
20464805	20541209	20592599	20601093	20625369
20464981	20542730	20594618	20601093	20625612
20467825	20543988	20595570	20602497	20625727
20468900	20547157	20595593	20602498	20625736
20469570	20547695	20596195	20602737	20626310
20470021	20550666	20596396	20602872	20626121
20471737	20552526	20596753	20604194	20626671
20480486	20553078	20597182	20606063	20628782
20484366	20558322	20597443	20606954	20629203
20484441	20567299	20597536	20607932	20629461
20498192	20567743	20597614	20610343	20631139
20503586	20567832	20597937	20610388	20631218
20504086	20568205	20598034	20611016	20631981
20504133	20574261	20598215	20611429	20632003
20509833	20574345	20598657	20611721	20633468
20511055	20574492	20598861	20613237	20634061
20523081	20574495	20599464	20614067	20634314
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20678407*
20678409*
20678412*
20678572*
20679076

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IN 2012-23, Recent Radiography Events Resulting In Exposures Exceeding Regulatory Limits
IN 2013-01, Emergency Action Level Thresholds Outside the Range of Radiation Monitors IN
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OE301871, Excessive Corrosion on a Fire Service Isolation Valve
OE304984, Watertight Equipment Hatch Found not Watertight Following Maintenance
OE305746, RCIC Isolation Valve Closed During Surveillance
OE307785, Maximum Fraction of Limiting Power Density Threshold for Adverse Condition Monitoring Plan Reached Due to Suspected Bias in Non-Adaptive and Adaptive Models
OE308770, Emergency Diesel Generator Automatic Synchronize Permissive Light Will Not Illuminate

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HC.OP-DL.ZZ-0026, Surveillance Log, Revision 145
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LS-AA-125-1004, Effectiveness Review Manual, Revision 4
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30069323	60068125	70144603	70165551
30098556	60096071	70144715	70165659
30171843	60105925	70148443	70167005
30173613	60105926	70149779	70167025
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50169460	70079182	70162737	80030419
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60001923	70112864	70164416	80106765
60003240	70133989	70164536	80108429
60061175	70140638	70164817	

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System Health Report - Aux Bldg HVAC – Diesel Gen Area (GM), 2Q2014
System Health Report – HC Unit 1 BH-SLC Q4-2014

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System Health Report – HC Unit 1 KB Q4-2014
System Health Report - Redundant Reactivity Control (SA), 4Q2014
System Health Report - Redundant Reactivity Control (SA), 3Q2014
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VTD 326061, BWR/5 Reactor Manual Control System Troubleshooting Guide, Revision 2
VTD PM141Q-0020, Nozzle Type Relief Valve, Revision 3

LIST OF ACRONYMS

ACE	Apparent Cause Evaluation
ACIT	Action Item
ADAMS	Agency-wide Documents Access and Management System
CA	Corrective Action
CAP	Corrective Action Program
CCE	Common Cause Evaluation
CFR	Code of Federal Regulations
DCP	Design Change Package
EMI	Electromagnetic Interference
FASA	Focused Area Self-Assessment
FFCDE	Functional Failure Cause Determination Evaluation
FRVS	Filtration, Recirculation and Ventilation System
IMC	Inspection Manual Chapter
LER	Licensee Event Report
MPFF	Maintenance Preventable Functional Failure
MRC	Management Review Committee
NCV	Non-cited Violation
NOTF	Notification
NRC	Nuclear Regulatory Commission
OE	Operating Experience
PARS	Publicly Available Records System
PCM	Performance Centered Maintenance
PCR	PM Change Request
PM	Preventive Maintenance
RCE	Root Cause Evaluation
RMCS	Reactor Manual Control System
RPS	Reactor Protection System
RRCS	Redundant Reactivity Control System
SDP	Significance Determination Process
SLC	Standby Liquid Control
SOC	Station Ownership Committee
SSC	System, Structure, or Component
TS	Technical Specifications
WGE	Work Group Evaluation