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

May 9, 2018

Mr. Peter P. Sena, III
President and Chief Nuclear Officer
PSEG Nuclear LLC - N09
Hancocks Bridge, NJ 08038

SUBJECT: HOPE CREEK GENERATING STATION UNIT 1 – INTEGRATED INSPECTION REPORT 05000354/2018001

Dear Mr. Sena:

On March 31, 2018, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at Hope Creek Generating Station (HCGS). On April 10, 2018, the NRC inspectors discussed the results of this inspection with Mr. Eric Carr, Site Vice President and other members of your staff. The results of this inspection are documented in the enclosed report.

NRC inspectors documented one finding of very low safety significance (Green) in this report. The finding did not involve a violation of NRC requirements.

If you disagree with a cross-cutting aspect assignment or a finding not associated with a regulatory requirement in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the U. S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC, 20555-0001; with copies to the Regional Administrator, Region I, and the NRC Resident Inspector at HCGS.

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

Sincerely,

/RA/

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

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

Enclosure:
Inspection Report 05000354/2018001

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SUBJECT: HOPE CREEK GENERATING STATION UNIT 1 – INTEGRATED INSPECTION REPORT 05000354/2018001 DATED MAY 9, 2018

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DATE	5/8/18	5/8/18	5/7/18	5/9/18	

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U.S. NUCLEAR REGULATORY COMMISSION
Inspection Report

Docket Number:	50-354
License Number:	NPF-57
Report Number:	05000354/2018001
Enterprise Identifier:	I-2018-001-0051
Licensee:	PSEG Nuclear LLC (PSEG)
Facility:	Hope Creek Generating Station (HCGS)
Location:	Hancocks Bridge, NJ 08038
Inspection Dates:	January 1, 2018 to March 31, 2018
Inspectors:	J. Hawkins, Senior Resident Inspector S. Haney, Resident Inspector M. Hardgrove, Resident Inspector (Acting) M. Draxton, Project Engineer J. Furia, Senior Health Physicist
Approved By:	Fred L. Bower, III, Chief Reactor Projects Branch 3 Division of Reactor Projects

SUMMARY

The U.S. Nuclear Regulatory Commission (NRC) continued monitoring PSEG's performance at Hope Creek Generating Station (HCGS) Unit 1 by conducting the baseline inspections described in this report in accordance with the Reactor Oversight Process. The Reactor Oversight Process is the NRC's program for overseeing the safe operation of commercial nuclear power reactors. Refer to https://www.nrc.gov/reactors/operating/oversight.html for more information. NRC identified and self-revealed findings, violations, and additional items are summarized in the table below.

List of Findings and Violations

Implementing Procedures for Beyond Design Basis FLEX Mitigating Strategies Not Followed			
Cornerstone	Significance	Cross-Cutting Aspect	Report Section
Mitigating Systems	Green Finding FIN 05000354/2018001-01 Closed	H.5 – Human Performance – Work Management	71152
A Green finding was identified by the inspectors for multiple examples of PSEG not following the station specific procedures that implement the Salem and HCGS Final Integrated Plans for Beyond Design Basis Diverse and Flexible Coping Strategies (FLEX) Mitigating Strategies, EM-SA-100-1000 and EM-HC-100-1000, respectively. Specifically, since compliance with the FLEX order was met on November 10, 2016, PSEG did not follow the common PSEG fleet preventive maintenance (PM) process and diesel fuel oil testing program procedures, MA-AA-716-210, CY-AB-140-410, and SC.OP-LB.DF-0001 for the annual fuel oil sampling of FLEX equipment. In addition to this, between December 6, 2017, and March 8, 2018, PSEG did not follow site specific procedures for FLEX equipment unavailability and mitigation capability protection in accordance with the HCGS and Salem procedures, OP-HC-108-115-1001 and OP-SA-108-115-1001, Operability Assessment and Equipment Control Program, respectively.			

Additional Tracking Items

Type	Issue number	Title	Report Section	Status
LER	05000354/2016-003	As-Found Values for Safety Relief Valve Lift Setpoints Exceed Technical Specification Allowable Limit	Inspection Results, IP 71153	Closed
LER	05000354/2016-003-01	As-Found Values for Safety Relief Valve Lift Setpoints Exceed Technical Specification Allowable Limit (Supplement)	Inspection Results, IP 71153	Closed

Type	Issue number	Title	Report Section	Status
URI	05000354/2018001-02	Concern Regarding As-Found Values for Safety Relief Valve Lift Setpoints Exceed Technical Specification Allowable Limit	Inspection Results, IP 71153	Open

PLANT STATUS

Hope Creek Generating Station began the inspection period at 100 percent rated thermal power (RTP). On January 13, 2018, Hope Creek reduced power to approximately 69 percent rated thermal power to support planned main turbine valve testing, control rod scram time and settle testing, control rod sequence exchange, and plant repairs, and returned to full power on January 13, 2018. There were no other operational power changes of regulatory significance for the remainder of the inspection period.

INSPECTION SCOPES

Inspections were conducted using the appropriate portions of the inspection procedures (IPs) in effect at the beginning of the inspection unless otherwise noted. Currently approved IPs with their attached revision histories are located on the public website at http://www.nrc.gov/reading-rm/doc-collections/insp-manual/inspection-procedure/index.html. Samples were declared complete when the IP requirements most appropriate to the inspection activity were met consistent with Inspection Manual Chapter (IMC) 2515, "Light-Water Reactor Inspection Program - Operations Phase." The inspectors performed plant status activities described in IMC 2515, Appendix D, "Plant Status" and conducted routine reviews using IP 71152, "Problem Identification and Resolution." The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel to assess PSEG performance and compliance with Commission rules and regulations, license conditions, site procedures, and standards."

REACTOR SAFETY

71111.01 - Adverse Weather Protection

Impending Severe Weather (1 Sample)

The inspectors evaluated readiness for impending adverse weather conditions for the onset of extreme winter and hazardous weather (Nor'easter with 8 inches of snow, 45 mph winds, and negative temperature conditions) between January 3 and January 5, 2018.

71111.04 - Equipment Alignment

Partial Walkdown (4 Samples)

The inspectors evaluated system configurations during partial walkdowns of the following systems/trains:

(1) 'C' safety auxiliaries cooling system on January 9, 2018
(2) High pressure coolant injection (HPCI) system during reactor core isolation cooling (RCIC) system planned maintenance on January 18, 2018
(3) 'B' residual heat removal (RHR) subsystem during 'A' RHR pump planned maintenance on February 28, 2018
(4) 'A' filtration, recirculation, and ventilation system (FRVS) ventilation fan and recirculation system during 'B' FRVS ventilation fan planned maintenance on March 13, 2018

Complete Walkdown (1 Sample)

The inspectors evaluated system configurations during a complete walkdown of the standby liquid control (SLC) system on January 30, 2018.

71111.05AQ - Fire Protection Annual/Quarterly

Quarterly Inspection (5 Samples)

The inspectors evaluated fire protection program implementation in the following selected areas:

(1) Motor control center (MCC) area in the reactor building on January 11, 2018
(2) HPCI pump and turbine room on January 18, 2018
(3) FRVS rooms, MCC area, and recombiner area in the reactor building on January 24, 2018
(4) Diesel driven fire pump house and fuel oil storage tank on February 5, 2018
(5) Control equipment mezzanine, elevation 117 foot, 6 inch, and 124 foot areas, on March 8, 2018

Annual Inspection (1 Sample)

The inspectors evaluated fire brigade performance during an unannounced fire drill on March 9, 2018.

71111.11 - Licensed Operator Requalification Program and Licensed Operator Performance

Operator Requalification (1 Sample)

The inspectors observed and evaluated a crew of licensed operators in the plant's simulator during licensed operator requalification training that involved lowering river level, closure of an outboard main steam isolation valve, HPCI isolation, RCIC failure to auto start, and a loss of offsite power with an emergency diesel generator (EDG) failure on January 8, 2018.

Operator Performance (1 Sample)

The inspectors observed and evaluated a planned down power to 69 percent RTP for quarterly main turbine valve testing, control rod testing, and safety-related inverter troubleshooting on January 13, 2018.

71111.12 - Maintenance Effectiveness

Routine Maintenance Effectiveness (2 Samples)

The inspectors evaluated the effectiveness of routine maintenance activities associated with the following equipment and/or safety significant functions:

(1) Reactor manual control system transformer and branch junction module failures on January 9, 2018
(2) Service water intake structure structural steel degradation on January 24, 2018

Quality Control (1 Sample)

The inspectors evaluated maintenance and quality control activities associated with the following equipment performance issues:

(1) RCIC system 24 Volt (V) direct current (DC) power supplies on January 18, 2018

71111.13 - Maintenance Risk Assessments and Emergent Work Control (6 Samples)

The inspectors evaluated the risk assessments for the following planned and emergent work activities:

(1) Unplanned maintenance and troubleshooting of the ‘B’ torus to drywell vacuum breaker while performing the quarterly surveillance test on January 10, 2018
(2) Planned maintenance for replacement and retest of the RCIC system 24 VDC power supplies on January 17, 2018
(3) Planned maintenance window for the ‘A’ EDG on January 29, 2018
(4) Planned maintenance window for the ‘B’ EDG on February 12, 2018
(5) Emergent corrective maintenance on the ‘B’ station service water (SSW) pump during planned maintenance on the ‘A’ control room chiller on February 19, 2018
(6) Risk assessment of missed surveillance – EDG output breaker auto-close logic on February 26, 2018

71111.15 - Operability Determinations and Functionality Assessments (6 Samples)

The inspectors evaluated the following operability determinations and functionality assessments:

(1) ‘A’ SSW traveling water screen broken drive spring on January 12, 2018
(2) Control rod 10-19 slow scram time on January 13, 2018
(3) ‘D’ FRVS recirculation fan MasterPact breaker failure to close on January 26, 2018
(4) ‘A’ control room chiller outlet temperature high on February 15, 2018
(5) Vital bus infeed missed surveillance on March 5, 2018
(6) ‘C’ EDG elevated lubricating oil consumption on March 6, 2018

71111.18 - Plant Modifications (1 Sample)

The inspectors evaluated the following temporary modification:

(1) 4HT-17-005, temporary repair and bracing of instrument air leak installed on December 1, 2017

71111.19 - Post Maintenance Testing (6 Samples)

The inspectors evaluated post maintenance testing for the following maintenance/repair activities:

(1) Residual heat removal test return valve repairs on January 4, 2018
(2) Hydraulic control unit 10-23 troubleshooting and repairs on January 13, 2018
(3) RCIC system 24 VDC power supply replacements on January 17, 2018

(4) ‘A’ EDG planned maintenance for control relay replacements on February 2, 2018
(5) SSW traveling water screen structural support lattice repairs on March 21, 2018
(6) ‘B’ main control room chiller leak repairs on March 29, 2018

71111.22 - Surveillance Testing

The inspectors evaluated the following surveillance tests:

Routine (2 Samples)

(1) HC.OP-ST.GS-0004, Suppression Chamber/Drywell Vacuum Breaker Operability Test on January 10, 2018
(2) HC.OP-ST.KJ-0004, Emergency Diesel Generator 1DG400 Operability Test – Monthly on January 22, 2018

Inservice (2 Samples)

(1) HC.OP-IS.BE-0001, ‘A’ and ‘C’ Core Spray Pumps – AP206 and CP206 - Inservice Test on January 2, 2018
(2) HC.OP-IS.BJ-0101, High Pressure Coolant Injection System Valves - Inservice Test on January 11, 2018

71114.06 - Drill Evaluation

Drill/Training Evolution (1 Sample)

The inspectors observed a simulator training evolution for licensed operators that involved lowering river level, closure of an outboard main steam isolation valve, HPCI isolation, RCIC failure to auto start, and a loss of offsite power with an emergency diesel generator failure on January 16, 2018.

RADIATION SAFETY

Cornerstone: Occupational and Public Radiation Safety

71124.01 - Radiological Hazard Assessment and Exposure Controls

Radiological Hazard Assessment (1 Sample)

The inspectors conducted independent radiation measurements during walkdowns of the facility and reviewed the radiological survey program, air sampling and analysis, continuous air monitor use, recent plant radiation surveys for radiological work activities, and any changes to plant operations since the last inspection to verify survey adequacy of any new radiological hazards for onsite workers or members of the public.

Instructions to Workers (1 Sample)

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

71124.02 - Occupational As Low As Reasonably Achievable (ALARA) Planning and Controls

Radiation Worker Performance (1 Sample)

The inspectors observed radiation worker and radiation protection technician performance during radiological work to evaluate worker ALARA performance according to specified work controls and procedures.

OTHER ACTIVITIES – BASELINE

71152 - Problem Identification and Resolution

Annual Follow-up of Selected Issues (3 Samples)

The inspectors reviewed PSEG's implementation of its corrective action program (CAP) related to the following issues:

(1) Notifications (NOTF) 20782178 and 20782212 concerning safety-related battery deficiencies and equipment issues.
(2) NOTFs 20783115, 20787557, 20787861, 20787862, 20787863, 20787879, 20787880, 20787881, 20787882, 20787883, and 20787884 concerning FLEX equipment failures and PM issues.
(3) Safety Relief Valve Setpoint Drift Issues (Notification/Order 20747318, 20772038, and 80110848)

71153 - Follow-up of Events and Notices of Enforcement Discretion

Licensee Event Reports (LER) (2 Samples)

The inspectors evaluated the following LER, which can be accessed at https://lersearch.inl.gov/LERSearchCriteria.aspx:

(1) LER 05000354/2016-003, As-Found Values for Safety Relief Valve Lift Setpoints Exceed Technical Specification Allowable Limit, dated December 20, 2016.
(2) Supplemental LER 05000354/2016-003-01, As-Found Values for Safety Relief Valve Lift Setpoints Exceed Technical Specification Allowable Limit, dated March 8, 2017

INSPECTION RESULTS

Implementing Procedures for Beyond Design Basis FLEX Mitigating Strategies Not Followed

Cornerstone	Significance	Cross-Cutting Aspect	Report Section
Mitigating Systems	Green FIN 05000354/2018001-01 Closed	H.5 – Human Performance – Work Management	71152

A Green finding (FIN) was identified by the inspectors for multiple examples of PSEG not following the station specific procedures that implement the Salem and HCGS Final Integrated Plans for Beyond Design Basis FLEX Mitigating Strategies, EM-SA-100-1000 and EM-HC-100-1000, respectively. Specifically, since compliance with the FLEX order was met on November 10, 2016, PSEG did not follow the common PSEG fleet PM Process and diesel fuel oil testing program procedures, MA-AA-716-210, CY-AB-140-410, and SC.OP-LB.DF-0001 for the annual fuel oil sampling of FLEX equipment. In addition to this, between December 6, 2017, and March 8, 2018, PSEG did not follow site specific procedures for FLEX equipment unavailability and mitigation capability protection in accordance with these procedures, OP-HC-108-115-1001 and OP-SA-108-115-1001, Operability Assessment and Equipment Control Program.

Description: PSEG is committed to comply with NEI 12-06, Diverse and Flexible Coping Strategies (FLEX) Implementation Guide, and NRC Order on Mitigation Strategies, EA-12-049.

FLEX Equipment Preventive Maintenance

Section 11.5.2 of NEI 12-06 states, in part, that portable equipment that directly performs a FLEX mitigation strategy for the core, containment, or spent fuel pool (SFP) should be subject to maintenance and testing guidance provided in Institute of Nuclear Power Operations (INPO) AP 913, Equipment Reliability Process, to verify proper function. The maintenance program should ensure that the FLEX equipment reliability is being achieved. Standard industry templates (e.g., EPRI) and associated bases will be developed to define specific maintenance and testing.

In complying with NRC Order EA-12-049, PSEG implemented EM-HC-100-1000 and EM-SA-100-1000. In Sections 2.18.7 of these procedures it states that FLEX mitigation equipment is subject to initial acceptance testing and subsequent periodic maintenance and testing to verify proper function. FLEX diesel generators and pumps are in PSEG's fleet common PM process, MA-AA-716-210, which defines periodic testing and maintenance and follows the PM template requirements in EPRI's Preventive Maintenance Basis for FLEX Equipment – Project Overview Report (EPRI Report 3002000623), dated September 2013.

The inspectors reviewed a number of recent equipment and PM issues at PSEG associated with the HCGS, Salem, and fleet common FLEX diesel generators and pumps. During the review, the inspectors found that this equipment is scheduled per PSEG's PM program and, in accordance with EPRI guidance, should be tested every 6 months and the fuel oil should be sampled every 12 months. Based on the inspector's requests and questions related to the FLEX fuel oil cloud point and sample results, PSEG found that the initial fuel oil samples for all of the FLEX diesel generators and pumps were either never taken (at Salem) or not analyzed (at HCGS). Because of this, the inspectors determined that since compliance with the FLEX order was met on November 10, 2016, PSEG has not followed the common PSEG fleet PM Process and diesel fuel oil testing program procedures, MA-AA-716-210, CY-AB-140-410, and SC.OP-LB.DF-0001, for the annual fuel oil sampling of FLEX equipment.

FLEX Equipment Unavailability and Protection

Section 11.5.3 of NEI 12-06 states, in part, that the unavailability of equipment and applicable connections that directly performs a FLEX mitigation strategy for the core, containment, and SFP should be managed such that risk to mitigating strategy capability is minimized. The unavailability of installed plant equipment is controlled by existing plant processes such as the technical specifications.

PSEG's FLEX equipment allowable outage times and required actions for equipment unavailability are maintained in site specific operations procedures OP-HC-108-115-1001 and OP-SA-108-115-1001 in order to meet the requirements in NEI 12-06.

For the three site FLEX diesel pumps (H1FLX-10-P-500 (HCGS)); SCFLX-1FLXE18 (Salem); C1FLX-1FLXE42 (back-up common to Salem and HCGS), a loss of two of three represents a loss of a FLEX mitigation capability. OP-HC-108-115-1001 and OP-SA-108-115-1001 state, in part, that when installed equipment which supports FLEX strategies becomes unavailable, then the FLEX strategy affected by this unavailability does not need to be maintained during the unavailability. The required beyond design basis (BDB)/FLEX equipment may be unavailable for 90 days provided that the site BDB/FLEX capability (N) is met. If the site BDB/FLEX capability is met but not protected for all of the sites' applicable hazards (flood, earthquake, high winds from hurricane or tornado, or local intense precipitation), then the allowed unavailability is reduced to 45 days.

On February 19, 2018, PSEG documented NOTF 20787557 for the FLEX diesel back-up pump common to Salem and HCGS (C1FLX-1FLXE42) failure to start that was not returned to an available condition until March 8. A NOTF (20783115) dated December 6, 2017, 75 days earlier, documented a failure to start with the same common FLEX diesel pump. The inspectors noted that no actions were taken to resolve the December issue other than attempting to start the pump multiple times over 12 days until the pump started on December 18, 2017. At this point, PSEG declared the pump available without performing any corrective maintenance or documenting any basis for the pump being available. The inspectors questioned PSEG about the time period mentioned above and how PSEG's BDB/FLEX capability was protected during that time for all of the applicable site hazards as all three pumps are located in outside FLEX storage areas at ground level. Because of this, the inspectors determined that PSEG did not follow site specific procedures for FLEX equipment unavailability and mitigation capability protection for this common diesel pump between December 6, 2017, and March 8, 2018 (92 days).

Based on all of the information above, the inspectors determined that there were multiple examples of PSEG not following the station specific procedures for FLEX Mitigating Strategies. Specifically, PSEG did not follow the common PSEG fleet PM Process and diesel fuel oil testing program procedures for the annual fuel oil sampling of FLEX equipment, or site specific procedures for FLEX equipment unavailability so that equipment issues were appropriately tracked and adequately protected to allow it to be unavailable for greater than 90 days when availability should have been limited to less than 45 days.

Corrective Actions: PSEG's corrective actions for the above issues included obtaining fuel oil samples from all the Salem, HCGS, and common FLEX equipment onsite and analyzing the samples to ensure the fuel oil quality remained adequate. PSEG also replaced the starting solenoid on the common FLEX diesel pump that failed to start and returned the pump to an available status on March 8, 2018, 92 days after it first became unavailable.

Corrective Action References: 20787557, 20783115, 60138024, 20787861, 20787862, 20787863, 20787879, 20787880, 20787881, 20787882, 20787883, 20787884, 20791977, 20791974, and 80122006.

Performance Assessment:

Performance Deficiency: PSEG's station specific procedures EM-SA-100-1000 and EM-HC-100-1000 implement the Salem and HCGS FLEX Mitigating Strategies, which includes FLEX equipment PM and unavailability. The inspectors determined that since January 2017, there were multiple examples of PSEG not implementing these procedures utilizing existing procedures for the PM process, diesel fuel oil testing or operability assessment and equipment control, and that this represented a performance deficiency.

Screening: The performance deficiency is more than minor because it was associated with the equipment performance attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). The inspectors also reviewed IMC 0612, Appendix E, "Examples of Minor Issues," and found it was sufficiently similar to Example 3.k, in that significant programmatic deficiencies were identified that could have led to worse outcomes.

Significance: Issues identified concerning FLEX are evaluated through a cross-regional panel using IMC 0609, Appendix M, "Significance Determination Process Using Qualitative Criteria," as informed by Appendix O, "Post Fukushima Mitigation Strategies Significance Determination Process (Orders EA-12-049 and EA-12-051)" (ML16055A351). The finding was determined to be of very low safety significance (Green) because the inspector answered "no" to the five questions in the draft Appendix O. Specifically, this condition was not associated with SFP level instrumentation required by NRC Order EA-12-051 and did not result in a complete loss of function to maintain or restore core cooling, containment pressure control/heat removal and/or SFP cooling capabilities.

Cross-Cutting Aspect: This finding has a cross-cutting aspect in the area of Human Performance, Work Management, because PSEG did not implement a process of planning, controlling, and executing work activities such that nuclear safety was the overriding priority and did not identify and manage the coordination of different Salem, HCGS and PSEG common work groups or job activities. Specifically, PSEG did not execute work activities associated with the FLEX fuel oil sampling or corrective maintenance activities on FLEX equipment that would ensure that equipment's reliability and availability. (H.5)

Enforcement: This finding does not involve enforcement action because no violation of regulatory requirements was identified. Because the finding does not involve a violation of regulatory requirements and has very low safety significance, it is identified as a finding.

Observation	71152 Annual Follow-up of Selected issues

Review of Recent FLEX Equipment and Preventive Maintenance Issues

The inspectors noted the following observations during the review:

1. PSEG is inconsistent when conducting CAP screening for NOTFs involving FLEX equipment failures in accordance with procedure LS-AA-120, Issue Identification and Screening Process. NOTFs 20775917 and 20766130 for FLEX diesel generator (H1FLX-10-G-2026) and pump (H1FLX-10-P-500) failures to start were screened as significance level (SL) 4, a non-corrective action program condition (N-CAP), when similar failures to start of a FLEX diesel pump (C1FLX-1FLXE42) in NOTFs 20783115 and 20787557 were screened as SL3, a condition affecting regulatory compliance (CARC). NOTF 20788124 for the spare FLEX diesel generator (SCFLX-1FLXE10) low engine coolant temperature and determined it to be non-functional, but the NOTF was screened as SL4 instead of SL3.

2. PSEG did not have a process or procedure in place to ensure that the fuel oil used for outdoor FLEX equipment has the required fuel additives to ensure proper operation during cold weather operations. PSEG documented the inspector's concern in NOTF 20786860.

3. PSEG did not quarantine and send out for failure analysis a failed FLEX component, the engine control module from a FLEX diesel generator (H1FLX-10-G-2026), identified in NOTF 20775917. PSEG has initiated NOTFs 20774397 and 20783803 to document delays and a lack of oversight in the failure analysis tracking process. PSEG has created corrective actions under orders 70196257 and 70197907 to revise ER-AA-230-1004, Failure Analysis Tracking and Reporting by April 2018.

Observation	71152 Annual Follow-up of Selected issues

Review of PSEG's corrective actions, and whether there was an associated violation of NRC requirements for repetitive lift setpoint test failures for main steam safety relief valves.:

The inspectors performed an in-depth review of PSEG's evaluation and corrective actions associated with main steam safety relief valve (SRV) setpoint drift issues at Hope Creek. Specifically, since the Hope Creek technical specifications were revised in 1999 to increase the SRV as-found lift setpoint to +/- 3 percent, SRV testing at Hope Creek has resulted in one or more SRVs exceeding the technical specification allowable as-found lift setpoint acceptance criteria in ten of 11 post-operating cycles. The setpoint drift has been attributed to "corrosion bonding," and this phenomenon typically affects the initial SRV actuation. The inspectors also reviewed PSEG's actions since the most recent test results were reported (Cycle 20), where ten of 14 SRVs exceeded their technical specification allowable lift setpoints. This inspection was conducted onsite in July 2017, and continued from the NRC Region I office until its conclusion in the first quarter of 2018.

The inspectors assessed PSEG's problem identification threshold, problem analysis, extent of condition reviews, operating experience, compensatory actions, and the prioritization and timeliness of their corrective actions to determine whether PSEG staff were appropriately identifying, characterizing, and correcting problems associated with this issue, and whether the planned or completed corrective actions were appropriate. The inspectors compared the actions taken to the requirements of PSEG's CAP, 10 CFR Part 50, Appendix B, and technical specifications. The inspectors reviewed associated documents and interviewed engineering personnel to assess the adequacy of PSEG's actions. The inspectors also reviewed PSEG's classification and certification of SRV sub-components to determine whether the components were of the proper safety classification. Finally, the inspectors reviewed PSEG's technical evaluations related to the overpressure protection capability and the structural integrity of associated pipe and supports considering the as-found SRV test results.

History and Operating Experience:

Hope Creek has 14 safety-related main steam SRVs that provide reactor pressure vessel overpressure protection and an automatic/manual depressurization function. Hope Creek technical specification 3.4.2.1, "Safety/Relief Valves," requires that 13 of the 14 SRVs be operable with the specified code safety valve function lift setting (+/- 3 percent).

The inspectors noted these 2-stage SRVs, manufactured by Target Rock, have been subject to setpoint drift, typically in the increased setpoint direction at a number of boiling water reactor nuclear power plants. The NRC approved a change to the Hope Creek technical specifications in 1999 to increase the SRV as-found lift test setpoint tolerance from +/-1 percent to +/-3 percent as a result of insights (circa late 1970's) from NRC Generic Safety Issue B-55, "Improved Reliability of Target Rock Safety Relief Valves" and from the Boiling Water Reactor Owners Group. The specific issue associated with the 2-stage SRV was a corrosion bonding problem, which occurs due to bridging oxides created between the pilot disc surface and the pilot valve body disc seating surface during service. The corrosion bonding phenomenon has resulted in the valve lifting at a higher pressure, failing to meet its setpoint criteria during the first lift attempt, but typically, lifting satisfactorily at its nominal setpoint during consecutive tests (after the corrosion bond is broken during the initial lift).

In August 2000, the NRC notified the industry via NRC Regulatory Issue Summary 2000-12, that the NRC considered Generic Safety Issue B-55 to be resolved. Specifically, for the 2-stage SRVs, the primary cause of the upward setpoint drift problem was determined to be corrosion bonding of the pilot valve disc to its seat. The Regulatory Issue Summary identified three modifications that were found to improve performance:

- installation of ion beam implanted platinum pilot valve disks;
- installation of Stellite 21 pilot valve disks; and
- installation of additional pressure actuation switches.

The Regulatory Issue Summary further indicated that there had been significant improvements in the performance of both the 3- and 2-stage SRVs, and that plant owners and the Boiling Water Reactor Owners Group were continuing to evaluate further enhancements. Subsequently, the NRC issued Information Notice 2006-24 to communicate additional operating experience insights associated with SRVs that continued to exceed the TS lift setpoint tolerance. The Information Notice documented that, while the individual events were within the American Society of Mechanical Engineers (ASME) tolerance limit or within accident analyses, there remained a number of reported events of valve setpoint issue at various plants.

While technical specification 4.4.2.2 requires that at least half of the SRV pilot stage assemblies be removed and set pressure tested, the inspectors determined PSEG staff typically performed as-found lift tests on all 14 SRV pilot valves each refueling outage due to the past test results. The inspectors noted the setpoint tests were conducted at a remote, certified testing facility after the SRV pilot valves were removed during refueling outages. During the last six operating cycles, the number of test failures were as follows (all 14 SRV pilot valve assemblies tested each time):

Operating Cycle	No. of SRVs beyond +/- 3 percent test acceptance criteria
15	6
16	6
17	6
18	5
19	10
20	10

Corrective Actions:

The inspectors determined PSEG staff considered and implemented several corrective actions and mitigation strategies intended to improve SRV performance. Some of these activities included applying a platinum coating to the pilot valve discs (in 1997), increasing the TS as-found setpoint tolerance acceptance criteria (in 1999), and replacing the platinum coated pilot valve discs with a solid Stellite 21 material (in 2006) believed to be less susceptible to corrosion bonding. PSEG staff also conducted several investigations to determine whether other factors contributed to the problem (evaluated critical pilot disc and seat dimensions, evaluated SRV insulation installation and placement, and evaluated SRV vibration after an extended power uprate was implemented).

PSEG had previously planned to install 3-stage Target Rock SRVs as an action to eliminate the corrosion bonding issue with the 2-stage SRVs. Specifically, they had planned on installing several 3-stage Target Rock SRVs in May 2015, however, several months prior to the start of Hope Creek's refueling outage, there was significant operating experience with the replacement 3-stage SRVs (at the Pilgrim Nuclear Power Plant). A 10 CFR Part 21 Report documented this substantial safety hazard was submitted to the NRC by Target Rock on May 1, 2015, describing this issue. Subsequently, Target Rock initiated efforts to re-design the 3-stage SRV to eliminate this problem.

In addition to the above corrective actions intended to reduce the likelihood of corrosion bonding, PSEG conducted several evaluations to determine whether plant specific configuration or design issues contributed to setpoint drift or amplification of the corrosion bonding phenomenon, and continued to work with the Boiling Water Reactor Owners Group to further investigate the 2-stage SRV performance issues. During this inspection, the inspectors noted that PSEG staff planned additional corrective actions, to be implemented at the next refueling outage (Spring 2018). Specifically, PSEG staff planned to 1) re-evaluate the platinum coating process of the pilot valve disc for the existing 2-stage SRVs, and 2) to procure and install the recently re-designed 3-stage Target Rock SRV in a phased approach. PSEG was engaged in discussions with Target Rock regarding the re-designed 3-stage SRV, and how the re-design is expected to resolve the substantial safety hazard identified in Target Rock's May 1, 2015, letter to the NRC.

Evaluation of As-Found Condition and Current Operability:

Relative to the ten of 14 SRVs that did not meet test acceptance criteria at the end of Cycle 20, PSEG staff performed two separate technical evaluations. The first evaluation assessed the reactor pressure vessel over-pressure function of the SRVs, the impact to associated safety-related systems (e.g., HPCI), and reactor fuel impact. The second technical evaluation considered the increased stress impact on the SRV downcomer piping (SRV discharge to torus), supports, spargers and torus loads to determine whether the SRVs and connected pipe remained capable of performing their intended function to direct steam to the torus for “quenching.” In particular, the second evaluation assessed two specific SRVs (A and F), which exhibited as-found lift setpoints that exceeded the maximum allowable percent increase (MAPI) value. The inspectors determined the MAPI value is the upper limit associated with each SRV based on the SRV discharge line design allowable stresses; and each MAPI is unique to specific SRV discharge lines (based on configuration, supports, etc.). Because two SRVs exceeded the MAPI in the most recent operating cycle (Cycle 20) and one exceeded the MAPI in each of the two prior cycles, PSEG staff evaluated prior operability/functionality of the SRVs (in the aggregate) using Level D Service Limits to show that the SRVs could have fulfilled their safety function. PSEG staff’s evaluations concluded that the SRVs remained capable of performing their intended functions.

The inspectors, with the assistance from NRC technical staff in the Office of Nuclear Reactor Regulation, reviewed both technical evaluations and concluded there was reasonable assurance the SRVs remained capable of performing their intended functions. However, with respect to the second technical evaluation related to downcomer pipe and supports, design margin was reduced by the application of Level D Service Limits. Specifically, consistent with guidance to NRC inspectors in NRC IMC 0326, “Operability Determinations and Functionality Assessments for Conditions Adverse to Quality or Safety,” PSEG staff evaluated the main steam and SRV piping and supports using the criteria in Appendix F of Section III (Division 1) of the ASME Code. This Appendix uses Level D Service Limits to demonstrate equipment pressure retaining capability. The inspectors noted that while these limits are intended to demonstrate the pressure retaining capability of SRV downcomer pipes and components, Level D Service Limits allow for the possibility of deformation and the potential that component repair may be required. The inspectors concluded that PSEG’s post trip reviews and the CAP provided processes to ensure downcomer pipe, components, and supports would be evaluated if SRVs initially lifted higher than the specified setpoint bands.

The guidance provided in IMC 0326 indicated that licensees “may use these criteria until compliance with current licensing basis criteria can be satisfied (normally the next refueling outage).” The inspectors observed PSEG staff applied Level D Service Limits in technical evaluations over several operating cycles. While repetitive application of Level D Service Limits is not typical, the inspectors concluded that, in this instance, PSEG’s completed corrective actions and planned actions involving replacement of all SRVs over the next few operating cycles with an improved design were reasonable and appropriate, considering SRVs remained capable of performing their intended safety functions.

Relative to current operability of the installed SRVs, PSEG staff stated that they consider the installed SRVs to be operable because the SRVs were tested to within the required +/- 1 percent (as-left) tolerance prior to installation. They further stated that there was no method available to assess the setpoint of the valves during the operating cycle (that the valves are removed from the plant prior to testing). And, if the valves do not meet the setpoint criteria during post-operating cycle testing, the impact on plant safety is assessed. Finally, PSEG staff stated that, in all cases, the as-found set-point of the valves were found to support the specific safety function to protect the reactor pressure vessel from over-pressurization. The inspectors acknowledged PSEG's position that direct evidence is not available to indicate which, how many, and to what degree, SRVs may have drifted during an operating cycle. However, the inspectors noted that PSEG staff did not document their rationale as to which steps in their operability procedure applied to justify not entering the operability process.

Summary:

There have been repeated SRV lift setpoint test failures at Hope Creek, attributed to a generic issue with Target Rock 2-stage SRVs resulting in corrosion bonding between the pilot disc and seating surfaces. PSEG staff has been active with the Boiling Water Reactor Owners Group in evaluating SRV setpoint drift issues, and has an auditable history of their implementation of corrective actions, specifically intended to address their chronic SRV setpoint drift issue. Notwithstanding their efforts, PSEG staff has been unsuccessful in resolving this issue. They are planning to implement additional actions during the next refueling outage, including the application of a platinum coating of the pilot valve disc and a phased approach to install a recently redesigned 3-stage Target Rock SRV. Additional discussion on this issue is documented in Inspection Results, 71153, Unresolved Item, in this report.

Unresolved Item (Open)	Concern Regarding As-Found Values for Safety Relief Valve Lift Setpoints Exceed Technical Specification Allowable Limit URI 05000354/2018001-02	71153 Follow-up of Events and Notices of Enforcement Discretion

Description:

On October 22, 2016, PSEG staff received results that the as-found setpoint tests for the main steam SRV pilot stage assemblies had exceeded the lift setting tolerance prescribed in technical specification 3.4.2.1. Specifically, ten of the 14 pilot stage assemblies tested experienced drift beyond the +/- 3 percent tolerance permitted by technical specification 3.4.2.1. PSEG staff concluded that the cause of the setpoint drift was attributed to corrosion bonding between the pilot disc and seating surfaces, and that is consistent with industry experience. This condition was reportable under 10 CFR 50.73(a)(2)(i)(B) as any operation or condition which was prohibited by the plant's technical specifications.

Based on a review of the Cycle 20 test results of the main steam SRV pilot stage assembly setpoint tests, and the nature of the predominant failure mechanism (corrosion bonding), the inspectors concluded that an unacceptable number (greater than one) of SRVs likely and reasonably became inoperable at some indeterminate time during the operating cycle. As documented in Inspection Results, 71152, Observations in this report, there is a history of SRV lift setpoint test failures due to a long-standing, generic issue with Target Rock 2-stage SRVs. In particular, PSEG staff has been active with the Boiling Water Reactor Owners Group in evaluating SRV setpoint drift issues, and has an auditable history of their implementation of corrective actions, specifically intended to address their chronic SRV setpoint drift issue. Notwithstanding their efforts, PSEG staff has been unsuccessful in realizing an improvement in SRV performance in this area. PSEG staff has elected to implement additional corrective actions beginning the spring 2018 refueling outage.

Specifically, they plan to reinstitute platinum coating of the pilot valve disc, and they plan to install the recently redesigned 3-stage Target Rock SRV in a phased approach.

While this issue has not been effectively resolved, PSEG's post-test evaluations have demonstrated that, in their as-found condition, the SRVs would have satisfactorily performed their intended safety function (i.e., mitigating the consequences of a postulated accident); and therefore, was of low safety significance.

Additional NRC review is necessary to determine the appropriateness of PSEG's corrective actions to date, given the corrective action options available, and whether there was an associated violation of NRC requirements in addition to the consequential violation of technical specification 3.4.2.1.

Planned Closure Actions: The NRC is continuing a review of the generic issue with the 2-stage Target Rock SRVs and the associated safety significance. The results of this review will be considered in determining the appropriateness of PSEG's corrective actions to date and whether an associated violation of NRC requirements existed, as well as the characterization of the consequential violation of technical specification 3.4.2.1.

PSEG Actions: Specific to the fall 2016 SRV lift setpoint test results, all 14 of the SRVs were refurbished and adjusted as necessary; and were all tested and demonstrated to meet the required +/- 1 percent as-left tolerance prior to installation. PSEG also planned additional corrective actions, to be implemented during the spring 2018 refueling outage, including: 1) to re-evaluate the platinum coating process of the pilot valve disc for the existing 2-stage SRVs, and 2) to procure and install the recently re-designed 3-stage Target Rock SRV in a phased approach. Finally, PSEG communicated with the SRV vendor concerning the re-design of the 3-stage SRV following a prior identification (May 2015) of a substantial safety hazard to ensure that the re-design addressed the identified problems.

Corrective Action References: Notification/Order 20747318, 20772038, and 80110848

This review closes LER 05000354/2016-003 and Supplemental LER 05000354/2016-003-01.

EXIT MEETINGS AND DEBRIEFS

The inspectors verified no proprietary information was retained or documented in this report.

- On January 26, 2018, the inspectors presented the radiation safety inspection results to Mr. H. Trimble, Radiation Protection Manager, and other members of the licensee staff
- On April 10, 2018, the inspectors presented the quarterly resident inspector inspection results to Mr. Eric Carr, HCGS Site Vice President, and other members of the PSEG staff.
- On May 2, 2018, the inspectors presented the SRV Problem Identification and Resolution and Follow-up of Events and Notices of Enforcement Discretion inspection results via telephone to Mr. David Mannai, Senior Director Regulatory Operations, and other members of PSEG staff.

THIRD PARTY REVIEWS

Inspectors reviewed INPO reports that were issued during the inspection period.

DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection

Procedures
HC.OP-AB.COOL-0001, Station Service Water, Revision 21
HC.OP-AB.MISC-0001, Acts of Nature, Revision 31
HC.OP-GP.ZZ-0003, Station Preparations for Winter Conditions, Revision 31
HC.OP-SO.EG-0001, Safety and Turbine Auxiliaries Cooling Water System Operation, Revision 55
OP-AA-108-111-1001, Severe Weather and Natural Disaster Guidelines, Revision 15
SH.FP-TI.FP-0001, Freeze Prevention and Winter Readiness of Fire Protection Systems, Revision 5
WC-AA-107, Seasonal Readiness, Revision 14

Notifications
20784512

Section 1R04: Equipment Alignment

Procedures
HC.OP-IS.BH-0001, Standby Liquid Control Pump – AP208 – Inservice Test, Revision 43
HC.OP-IS.BH-0002, Standby Liquid Control Pump – BP208 – Inservice Test, Revision 44
HC.OP-IS.BJ-0101, High Pressure Coolant Injection System Valves – Inservice test, Revision 67
HC.OP-SO.BH-0001, Standby Liquid Control System Operation, Revision 17
HC.OP-SO.BJ-0001, High Pressure Coolant Injection System Operation, Revision 50

Notifications

20754527	20758897	20759153	20760534	20763441	20764666
20768894	20774191	20779340	20780543	20780911	20780912
20780913	20781556	20782876	20783126	20783127	20783233
20783535	20783840	20784280	20785755		

Maintenance Orders/Work Orders

30274332	30278094	30282345	30283130	30287071	30291703
30291734	30293424	30295266	30298970	30298981	30299090
30299105	30299574	30299621	50124688	60137449	60137688
80110635					

Miscellaneous
HC-005.003, Standby Liquid Control System (SLC) System Notebook
M-48-1, Sheet 1, Standby Liquid Control, Revision 17
M-51-1, Sheet 1, Residual Heat Removal, Revision 51
PN1-E41-C002-0050, Oil Piping Diagram, Revision 7

Section 1R05: Fire Protection

Procedures
FP-AA-024, Fire Drill Performance, Revision 1
FP-HC-004, Actions for Inoperable Fire Protection – Hope Creek Station, Revision 4

FRH-II-413, Hope Creek Pre-Fire Plan - HPCI Pump and Turbine Room, RHR Pump and Heat Exchanger Rooms, Revision 3
FRH-II-434, Hope Creek Pre-Fire Plan - Reactor Building, MCC Area, Revision 3
FRH-II-461, Hope Creek Pre-Fire Plan - FRVS Rooms, MCC Area, Recombiner Areas, Spent Fuel and Gamma Scan Detector Area, Revision 3
FRH-II-542, Hope Creek Pre-Fire Plan - Control Equipment Mezzanine Elevation 117'-6" & 124'-0", Revision 9
FRH-III-714, Hope Creek Pre-Fire Plan - Fire Water Pump House, Revision 4
HC.CH-SA.ZZ-0011, Diesel Fuel Oil Sampling, Revision 24
HC.OP-AR.QK-0001, Fire Protection Status Panel 10C671/10Z644 Alarm Summary, Revision 30
SH.FP-EO-ZZ-0002, Fire Department Fire Response, Revision 4

Notifications

20673188	20775210	20785990	20786131	20786335	20787153
20788675	20788745				

Miscellaneous
FP-AA-024, Attachment 1, Fire Drill Record, Drill Scenario 55570230, dated March 9, 2018

Section 1R11: Licensed Operator Requalification Program

Procedures
OBE Scenario Guide, Leadership and Teamwork Effectiveness, Scenario Number SG-777, Revision 0

Section 1R12: Maintenance Effectiveness

Procedures
ER-AA-310-101, Condition Monitoring of Structures, Revision 0
HC.IC-TS.SF-0001, Reactor Manual Control Maintenance Guide, Revision 6
HC.OP-AB.IC-0001, Rod Control, Revision 16
HC.OP-AB.ZZ-0136, Loss of 120 VAC Inverter, Revision 24
HC.OP-ST.BF-0002, Control Rod Drive Accumulator Operability Check Weekly, Revision 10

Notifications

20681079	20780598	20784911	20785141	20786132	20788480

Maintenance Orders/Work Orders

30147406	30178808	30261871	60137466	60137566	70152062
70174347	70179117	70198721			

Miscellaneous
Purchase Order 4500788486
PSE-58661, Parts Quality Initiative Testing of Power Supplies, dated October 17, 2017
PSE-72665, Parts Quality Initiative Testing of Power Supplies, dated December 27, 2017

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Procedures
ER-AA-600-1012, Risk Management Documentation, Revision 11
ER-AA-600-1045, Risk Assessments of Missed of Deficient Surveillances, Revision 1
HC.OP-AB.ZZ-0135, Station Blackout // Loss of Offsite Power // Diesel Generator Malfunction, Revision 43
OP-AA-108-116, Protected Equipment Program, Revision 12
OP-AA-101-112-1002, On Line Risk Assessment, Revision 10
WC-AA-101, On-Line Work Management Process, Revision 25

Notifications

20749605	20772157	20781371	20782730	20783089	20783113
20783434	20785205	20785206	20787472	20787547	20787586
20787649	20787671	20787885	20787890	20787898	

Maintenance Orders/Work Orders

30147406	50198624	50199664	50200997	70199025	80121566

Miscellaneous
HC-SURV-013, Risk Assessment of Missed Surveillance – EDG Output Breaker Auto-Close Logic, Revision 0
Hope Creek Generating Station On-Line Risk Assessment, Work Week 803, Applicable Dates 01/14/2018 – 01/20/2018, Revision 0
Hope Creek Generating Station On-Line Risk Assessment, Work Week 805, Applicable Dates 01/28/2018 – 02/03/2018, Revision 0
Hope Creek Generating Station On-Line Risk Assessment, Work Week 807, Applicable Dates 02/11/2018 – 02/17/2018, Revision 0
Hope Creek Generating Station On-Line Risk Assessment, Work Week 809, Applicable Dates 02/25/2018 – 03/03/2018, Revision 0
OP-AA-108-16, Form 1, Protected Equipment Log – 'B' Core Spray Loop, Revision 12
OP-AA-108-16, Form 1, Protected Equipment Log – HPCI, Revision 12

Section 1R15: Operability Determinations and Functionality Assessments

Procedures
HC.OP-AB.IC-0001, Control Rod, Revision 16
HC.OP-AR.KJ-0005, Diesel Generator Remote Engine Control Panel 1CC423, Revision 23
HC.OP-SO.GU-0001, Filtration, Recirculation, and Ventilation System, Revision 27
HC.OP-SO.KJ-0001, Emergency Diesel Generator, Revision 74
HC.OP-ST.GJ-0001, Control Room Ventilation Heat Load Removal Test, Revision 3
HC.OP-ST.KJ-0016, EDG 1CG400 – 24 Hour Operability Run and Hot Restart Test, Revision 35
HC.RE-RA.BF-0002, Channel Distortion Testing, Revision 18
HC.RE-ST.BF-0001, Control Rod Scram Time Surveillance, Revision 36
OP-HC-108-115-1001, Operability Assessment and Equipment Control Program, Revision 35
OP-HC-108-115-1001, Operability Assessment and Equipment Control Program, Revision 36
SM-AA-300-1005, PSEG Nuclear LLC In-Storage Shelf Life Program, Revision 5

Notifications

20559119	20749605	20774652	20784570	20785176	20785205
20785328	20786158	20786204	20786261	20786813	20787885
20787890	20788072	20788501	20789137	20786739	20757880
20786261	20786158	20788709	20789137	20790032	20791392

Maintenance Orders/Work Orders

50188464	50185545	60137798	60137896	70190779	70194349
70198723	70199025	80106037			

Miscellaneous

HC-SURV-013, Risk Assessment of Missed Surveillance – EDG Output Breaker Auto-Close Logic, Revision 0
LCO 18-048, Technical Specification Action Statement Log, dated February 26, 2018
LCO 18-049, Technical Specification Action Statement Log, dated February 26, 2018

Section 1R18: Plant Modifications

Procedures

CC-AA-112, Temporary Configuration Changes, Revision 15

Notifications

20781093

Maintenance Orders/Work Orders

60137003   80121384

Miscellaneous

10855-D3.15, Design, Installation and Test Specification for Compressed Air System for the Hope Creek Generating Station, Revision 9

Section 1R19: Post-Maintenance Testing

Procedures

HC.IC-GP.ZZ.01333, Power Supply Voltage Check, Revision 14
HC.OP-SO.BD-0001, Reactor Core Isolation Cooling System Operation, Revision 44
HC.OP-ST.KJ-0001, Emergency Diesel Generator 1AG400 Operability Test – Monthly, Revision 78

Notifications

20722186	20722332	20736090	20742639	20773484	20781204
20786359	20787261	20787262	20789470	20789940	20789942
20790884					

Maintenance Orders/Work Orders

30147406	50146765	50200997	60080045	60084628	60097020
60130362	60133943	60138104	60138105	80122127	80122128

Section 1R22: Surveillance Testing

Procedures
HC.OP-IS.BE-0001, ‘A’ and ‘C’ Core Spray Pumps – AP206 and CP206 – IST, Revision 50
HC.OP-IS.BJ-0101, High Pressure Coolant Injection System Valves – Inservice Test, Revision 67
HC.OP-ST.GS-0004, Suppression Chamber / Drywell Vacuum Breaker Operability Test – Monthly, Revision 15
HC.OP-ST.KH-0004, Emergency Diesel Generator 1DG400 Operability Test – Monthly, Revision 76

Notifications
20750266 20771521

Maintenance Orders/Work Orders
50198624 50198783 50199014 50200091

Section 1EP6: Drill Evaluation

Procedures
OBE Scenario Guide, Leadership and Teamwork Effectiveness, Scenario Number SG-777, Revision 0

Section 2RS1: Radiological Hazard Assessment and Exposure Controls

RP-AA-460, Control for High and Very High Radiation Areas, Revision 18
RP-AA-463, High Radiation Area Key Control, Revision 4

Section 2RS2: Occupational As Low As Reasonably Achievable (ALARA) Planning and Controls

RP-AA-401, ALARA Program, Revision 14
White Paper – H1R21 Dose Estimate Development, Approval and Tracking

Section 4OA2: Problem Identification and Resolution

Procedures
CY-AB-140-410, Hope Creek Station Diesel Fuel Oil Testing Program, Revision 8
EM-HC-100-1000, Hope Creek Final Integrated Plan for Beyond Design Basis FLEX Mitigating Strategies, Revision 1
EM-SA-100-1000, Salem Final Integrated Plan for Beyond Design Basis FLEX Mitigating Strategies, Revision 1
HC.MD-GP.ZZ-0014, Single Cell Battery Charging, Replacement and Jumpering, Revision 26
HU-AA-1212, Technical Task Risk / Rigor Assessment, Pre-Job Brief, Independent Third Part
LS-AA-115, Operating Experience Program, Revision 16
LS-AA-120, Issue Identification and Screening Process, Revision 14
LS-AA-125, Corrective Action Program, Revision 23
LS-AA-125, Corrective Action Program, Revision 24
MA-AA-716-004, Conduct of Troubleshooting, Revision 14
MA-AA-716-210, Preventive Maintenance (PM) Process, Revision 11
MA-AA-716-232-1004, Failure Analysis Tracking and Reporting, Revision 3

MA-AA-726-101, Stored Battery Cell Inspection, Charging and Performance Discharging, Revision 7
OP-HC-108-115-1001, Operability Assessment and Equipment Control Program, Revision 36
OP-SA-108-115-1001, Operability Assessment and Equipment Control Program, Revision 10 Review, and Post-Job Brief, Revision 9
SC.OP-LB.DF-0001, Salem Diesel Fuel Oil Testing Program, Revision 3
SM-AA-4028, Material Repair Process, Revision 8

Calculations/Engineering Evaluations
322869-01, Safety Review for HCGS Safety/Relief Valve Tolerance Analyses, 3/13/97
70177495-0010, Technical Evaluation, Impact of the RF19 As-Found ‘F’ SRV Setpoint Pressure on the ‘B’ Main Steam Line and ‘F’ SRV Discharge Line, Revision 0
70190219-0100, Technical Evaluation, Impact of the RF20 As-Found ‘A’ and ‘F’ SRV Setpoint Pressure on ’A’ and ‘B’ Main Steam Lines and ‘A’ and ‘F’ SRV Discharge Lines, Revision 0

Notifications

20747318	20766130	20769860	20772038	20774397	20775917
20780781	20780869	20780871	20782178	20782212	20782601
20783115	20783803	20786860	20787463	20787464	20787557
20787773	20787861	20787862	20787863	20787879	20787880
20787881	20787882	20787883	20787884	20790526	20790625

Maintenance Orders/Work Orders

30306417	60137200	70197783	80110848	80112074	80121410
80122006					

Other Documents
DEH120045, SRV Setpoint Drift Root Cause Evaluation (70128407), 2/17/12
LER 2016-003-00, “As-Found Values for Safety Relief Valve Lift Set Points Exceed Technical Specification Allowable Limit,” 12/20/16
Supplemental LER 2016-003-01, “As-Found Values for Safety Relief Valve Lift Set Points Exceed Technical Specification Allowable Limit,” 3/8/17
Letter, PSEG to NRC, Request for Change to Technical Specifications, Safety Relief Valve Setpoint Tolerances, 4/28/98
Letter, PSEG to NRC, Supplement to a Request for Change to Technical Specifications, Safety Relief Valve Setpoint Tolerances, 12/8/98
Letter, PSEG to NRC, Supplement to a Request for Change to Technical Specifications, Safety Relief Valve Setpoint Tolerances, 9/29/98
OTDM 17-004, “3-Stage Target Rock Model 0867F SRVs planned to be installed by DCP 80107006 in RF21,” Revision 0

71153 - Follow-Up of Events and Notices of Enforcement Discretion

Procedures
LS-AA-120, Issue Identification and Screening Process, Revision 14
LS-AA-125, Corrective Action Program, Revision 23

Calculations/Engineering Evaluations

322869-01, Safety Review for HCGS Safety/Relief Valve Tolerance Analyses, 3/13/97

70177495-0010, Technical Evaluation, Impact of the RF19 As-Found ‘F’ SRV Setpoint Pressure on the ‘B’ Main Steam Line and ‘F’ SRV Discharge Line, Revision 0

70190219-0100, Technical Evaluation, Impact of the RF20 As-Found ‘A’ and ‘F’ SRV Setpoint Pressure on ’A’ and ‘B’ Main Steam Lines and ‘A’ and ‘F’ SRV Discharge Lines, Revision 0

Notifications/Orders

20747318 20772038 80110848

Other Documents

DEH120045, SRV Setpoint Drift Root Cause Evaluation (70128407), 2/17/12

LER 2016-003-00, “As-Found Values for Safety Relief Valve Lift Set Points Exceed Technical Specification Allowable Limit,” 12/20/16

Supplemental LER 2016-003-01, “As-Found Values for Safety Relief Valve Lift Set Points Exceed Technical Specification Allowable Limit,” 3/8/17

Letter, PSEG to NRC, Request for Change to Technical Specifications, Safety Relief Valve Setpoint Tolerances, 4/28/98

Letter, PSEG to NRC, Supplement to a Request for Change to Technical Specifications, Safety Relief Valve Setpoint Tolerances, 12/8/98

Letter, PSEG to NRC, Supplement to a Request for Change to Technical Specifications, Safety Relief Valve Setpoint Tolerances, 9/29/98

OTDM 17-004, “3-Stage Target Rock Model 0867F SRVs planned to be installed by DCP 80107006 in RF21,” Revision 0