February 11, 2004

Mr. Roy A. Anderson
Chief Nuclear Officer and President
PSEG LLC - N09
P. O. Box 236
Hancocks Bridge, NJ 08038

SUBJECT: HOPE CREEK NUCLEAR GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 05000354/2003006

Dear Mr. Anderson:

On December 31, 2003, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Hope Creek Station. The enclosed integrated inspection report documents the inspection findings, which were discussed on January 21, 2004 with Mr. Jim Hutton and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

This report documents one finding concerning service water system traveling screen maintenance problems that has potential safety significance greater than very low significance. This issue did not present an immediate safety concern because the traveling screen was restored to operability within technical specification requirements. In addition, the report documents three NRC-identified findings and two self-revealing findings of very low safety significance (Green). Two of these findings were determined to involve violations of NRC requirements. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these two findings as non-cited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. Additionally, two licensee-identified violations which were determined to be of very low safety significance are listed in this report. If you contest any NCV in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, and the NRC Resident Inspector at Hope Creek Facility.

Since the terrorist attacks on September 11, 2001, the NRC has issued five Orders and several threat advisories to licensees of commercial power reactors to strengthen licensee capabilities, improve security force readiness, and enhance access authorization. In addition to applicable baseline inspections, the NRC issued Temporary Instruction 2515/148, "Inspection of Nuclear Reactor Safeguards Interim Compensatory Measures," and its subsequent revision, to audit and inspect licensee implementation of the interim compensatory measures required by order.

Phase 1 of TI 2515/148 was completed at all commercial nuclear power plants during calendar year 2002, and the remaining inspection activities for Hope Creek Generating Station are scheduled for completion in calendar year 2003. The NRC will continue to monitor overall safeguards and security controls at Hope Creek Generating Station.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and 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 NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Glenn W. Meyer, Chief
Projects Branch 3
Division of Reactor Projects

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

Enclosure: Inspection Report 05000354/2003006
w/Attachment: Supplemental Information

cc w/encl:
W. F. Sperry, Director Business Support
J. T. Carlin, Vice President Nuclear Assurance
D. F. Garchow, Vice President, Engineering and Technical Support
S. Mannon, Acting Manager - Licensing
A. C. Bakken, Senior Vice President Site Operations
J. A. Hutton, Hope Creek Plant Manager
R. Kankus, Joint Owner Affairs
J. J. Keenan, Esquire
Consumer Advocate, Office of Consumer Advocate
F. Pompper, Chief of Police and Emergency Management Coordinator
M. Wetterhahn, Esquire
N. Cohen, Coordinator - Unplug Salem Campaign
W. Costanzo, Technical Advisor - Jersey Shore Nuclear Watch
E. Zobian, Coordinator - Jersey Shore Anti Nuclear Alliance
State of New Jersey
State of Delaware

Distribution w/encl:
Region I Docket Room (with concurrences)
M. Gray - NRC Resident Inspector
H. Miller, RA
J. Wiggins, DRA
G. Meyer, DRP
S. Barber, DRP
J. Jolicoeur, OEDO
J. Clifford, NRR
J. Boska, PM, NRR

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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No:	050000354
License No:	NPF-57
Report No:	05000354/2003006
Licensee:	PSEG LLC
Facility:	Hope Creek Nuclear Generating Station
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	September 28, 2003 - December 31, 2003
Inspectors:	M. Gray, Senior Resident Inspector M. Ferdas, Resident Inspector F. Bower, Senior Reactor Inspector S. Barber, Senior Project Engineer C. Colantoni, Reactor Inspector J. D'Antonio, Operations Engineer J. Furia, Senior Health Physicist J. Jang, Senior Health Physicist S. McCarver, Reactor Inspector N. McNamara, Emergency Preparedness Specialist S. Pindale, Senior Reactor Inspector
Approved By:	Glenn W. Meyer, Chief Projects Branch 3 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

IR 05000354/2003006; 09/28/2003 - 12/31/2003; Public Service Electric Gas Nuclear LLC, Hope Creek Generating Station; Licensed Operator Requalification, Maintenance Effectiveness, Operator Workarounds, Temporary Plant Modifications, Event Followup

The report covered a thirteen-week period of inspection by resident inspectors, and announced inspections by a regional radiation specialist, emergency preparedness specialist, and two health physicist inspectors. Two Green non-cited violations (NCVs), three Green findings, and one unresolved item with potential safety significance greater than Green were identified. Additionally, two licensee identified Green NCVs were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- TBD. A self-revealing finding occurred when the A SSWS traveling screen failed and PSEG determined that improper cutting of a key without procedure guidance had been a contributing cause. The inspectors identified an additional problem that contributed to the failure in that applicable maintenance procedures had not been used to set traveling chain tension and screen level. This performance issue was determined to have potential safety significance greater than very low safety significance, based on preliminary risk assessments that considered the associated pump unavailable while the traveling screen was inoperable. (Section 1R12)

- Green. An inadequate design change and incorrect calibration of an oil control switch reduced the reliability of the reactor feedwater pumps, such that a second pump did not remain in operation following the September 19, 2003 electrical transient. The reactor automatically scrammed on the resulting low reactor level. A self-revealing finding was identified, which did not involve a violation of regulatory requirements.

  This finding was more than minor, because it affected the equipment performance attribute of the initiating events cornerstone. The finding is of very low safety significance, because mitigation systems were available and operators could have recovered the unavailable equipment. (Section 4OA3.3)

- Green. The inspectors identified that incorrect engineering analyses enabled an operating procedure to contain incorrect, non-conservative limits for shutting down the reactor when excessive safety relief valve (SRV) leakage exists. The finding was a non-cited violation of 10 CFR 50, Appendix B, Criterion III, Design Control.

This finding was greater than minor, because it affected the initiating events cornerstone attribute of procedure adequacy. The inaccurate engineering analyses could have resulted in PSEG operating an SRV that could have opened prior to its setpoint being reached, causing a reactor pressure transient. The finding was of very low safety significance, because it did not increase the likelihood of a primary or secondary system loss of coolant accident initiator, did not contribute to a combination of a reactor trip and loss of mitigation equipment function, and did not increase the likelihood of a fire or internal/external flood. (Section 1R23)

Cornerstone: Mitigating Systems

- Green. The inspectors determined a self-revealing finding regarding ineffective corrective actions to address an inadvertent feedwater heater isolation workaround condition that occurred after scrams from full power. The finding did not involve a violation of regulatory requirements.

  This finding was greater than minor, because feedwater system is a mitigating system and the finding is associated with the design control attribute of the mitigating systems cornerstone. The finding is of very low risk significance, because it is a design deficiency confirmed not to result in loss of function. While manual action was required it has not resulted in loss of feedwater flow. (Section 1R16)

  Green. The inspectors identified a finding on a feedwater system workaround condition regarding the digital feedwater control system setdown function but one which did not involve a violation of regulatory requirements.

  This finding was greater than minor, because it affected the design control attribute of the mitigating systems cornerstone. This finding is of very low risk significance, because it is a design deficiency confirmed not to result in loss of function. While the setdown setpoint function has not likely operated correctly since the system was installed, there has not been a loss of feedwater function due to this problem, and operator training and procedures provide for operating RFPs in manual mode where the setdown function is not used. (Section 1R16)

- Green. The inspectors identified a non-cited violation when PSEG did not properly reactivate three limited senior reactor operator (LSRO) licenses prior to their involvement in refueling activities during the April 2003 refueling outage. This resulted in these individuals supervising fuel handling operations without being correctly verified as proficient to do so.

  This finding was greater than minor, because it resulted in LSROs performing fuel movement while not in compliance with their license conditions regarding reactivation. This finding is of very low safety significance, because it is administrative in nature and the operators were otherwise current in requalification. (Section 1R11)

B. Licensee Identified Violations

Violations of very low safety significance, which were identified by PSEG, have been reviewed by the inspectors. Corrective actions taken or planned by PSEG have been entered into PSEG's corrective action program. These violations and corrective actions are listed in Section 4OA7 of this report.

- TS 3.4.2.1, "Safety/Relief Valves," requires that 13 of the 14 SRVs open within a lift setpoint of +/- 3 percent of the specified code safety valve function lift setting. Contrary to this requirement, PSEG identified that 8 of 14 SRVs experienced setpoint drift outside of the TS limit. PSEG entered this issue into their corrective action program as notification 20143634. This finding is of very low safety significance, because the SRVs would have functioned to prevent a reactor vessel over-pressurization.

- TS 6.12.1 requires that areas having radiation dose rates in excess of 100 millirem per hour be posted, barricaded and access controlled as high radiation areas. On December 16, 2003, PSEG determined that the radiation levels in the waste filter holding pump room were 600 millirem per hour, but the room was not posted or controlled as a high radiation area, nor was the area barricaded. This event is documented as notification 20170646. This finding is of very low safety significance, because it did not involve a locked high or very high radiation area or personnel over-exposure.

REPORT DETAILS

Summary of Plant Status

The Hope Creek Generating Station (HCGS) started the inspection period at 46% power. Operators were returning the plant to full power following an automatic shutdown (scram) on September 19 due to a 500 kv electrical fault. Full power was reached on October 3. On October 4 operators manually scrammed the reactor in accordance with procedures because of an electro hydraulic control (EHC) system oil leak. The EHC oil was found to be leaking from the #4 combined intermediate control valve (CIV). After repairing the leak the plant was returned to full power on October 13.

On October 29 operators reduced power to 80% due to solar magnetic disturbances (SMD) in accordance with plant procedures. The plant was returned to 100% power on November 1. On November 15 operators reduced power to 80% for scheduled maintenance on the A reactor feedwater pump turbine and A feedwater heater string, and to perform a design change to install a new 500KV breaker. Power was reduced further to 69% when a marsh fire was identified that approached the 500 KV 5015 transmission line. The transmission line was removed from service and the design change was not performed. The plant was returned to 100% power on November 18.

On December 5 operators reduced power in order to perform scheduled maintenance on the C reactor feedwater pump and to repair a steam seal evaporator supply line that was leaking. As power was reduced personnel identified a reactor water cleanup (RWCU) system flanged joint leak. The reactor was shutdown and the leaks were repaired. Following repairs operators established reactor criticality on December 15, entered mode 1 on December 18 and synchronized the main generator to the grid on December 19. The plant reached full power on December 23. The plant operated at or near full power for the duration of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R04 Equipment Alignment (71111.04)

a. Inspection Scope

The inspectors performed five partial equipment alignment inspections. The partial alignment inspections were completed on the station service water system (SSWS), emergency diesel generator (EDG), spent fuel pool cooling system, technical support center (TSC) chiller, and safety auxiliaries cooling system (SACS) during planned maintenance that affected redundant equipment trains. The inspectors reviewed applicable documents associated with equipment alignments as listed in the Supplemental Information report section. The inspectors reviewed notification 20165973 documenting an equipment alignment problem.

Partial System Walkdowns.

PSEG installed a temporary modification 02-002 to support SSWS strainer backwash manual isolation valve replacement on each train from October 21 through October 24. The inspectors reviewed SSWS equipment line-up documents and walked down portions of the SSWS to verify the pumps and a sample of valves were correctly aligned and maintained.

On October 29 the inspectors reviewed fuel pool cooling system drawings and walked down system control room indications while the B fuel pool cooling pump was out of service for maintenance to verify proper system alignment .

From November 8 through November 10 PSEG cross connected the A and C EDG starting air subsystems. This was due to a lifting relief valve on the C EDG starting air compressor. The inspectors reviewed the applicable EDG equipment alignment procedure and walked down portions of the A and C EDG starting air subsystem to verify that they were correctly aligned and maintained to ensure the A and C EDG air receivers remained operable.

The A SACS pump was removed from service for scheduled maintenance on November 19. The inspectors verified the operability of the C SACS pump by verifying the flowpath was aligned in accordance with its operating procedure. The inspectors performed walkdowns of the SACS system and observed control room indications.

The B TSC Chiller was removed from service for scheduled maintenance from November 23 through November 25. The inspectors verified the operability of the A TSC chiller during this time period. The inspectors verified that the position of valves, switches, and operating fluid levels for the A TSC chiller were in accordance with the operating procedure. The inspector also verified proper equipment alignment by observing control room indications for the TSC chillers.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope

The inspectors observed one fire drill and performed eight plant walkdowns. The inspectors observed a fire drill on November 18 to determine the readiness of the fire brigade to prevent and respond to fires. The drill scenario involved a simulated electrical fire in a 125V DC battery charger. During plant walkdowns the inspectors observed combustible material control, fire detection and suppression equipment availability, and compensatory measures. The inspectors reviewed Hope Creek's Individual Plant Examination for External Events (IPEEE) for risk insights and design features credited in these areas. Additionally, the inspectors reviewed notifications documenting fire protection deficiencies to verify identified problems were being evaluated and corrected (20168653 and 20168918). The following plant areas were inspected:

- combined intercept valve room on October 4
- standby liquid control room on October 31
- air equipment area mezzanine on November 3
- reactor recirculation motor generator set rooms on November 14
- reactor core isolation cooling (RCIC) instrument room on November 17
- drywell walkdown during forced outage on December 10
- residual heat removal heat exchanger rooms on December 12
- service water intake structure on December 15

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

Requalification Activities Review By Resident Staff

The resident inspectors observed one simulator training scenario to assess operator performance and training effectiveness. The scenario involved an EDG that was inoperable due to low lube oil temperature, a loss of offsite power (LOP), and a subsequent station blackout (loss of all ac power) with a failure of the RCIC and high pressure coolant injection (HPCI) pumps. The inspectors assessed simulator fidelity and observed the simulator instructor's critique of operator performance. The inspectors also observed control room activities with emphasis on simulator identified areas for improvement. Finally, the inspectors reviewed applicable documents associated with licensed operator requalification as listed in the Supplemental Information report section.

b. Findings

No findings of significance were identified.

a. Inspection Scope

Biennial Review By Regional Specialist

Regional inspectors performed a biennial inspection of licensed operator requalification by reviewing the 2002 biennial written examination, and the 2002 and 2003 operating examinations to determine whether these examination materials met the criteria of the examination standards. The inspectors also observed the administration of partial operating examinations to three individuals. The full examination was not observed due to mechanical problems with the refueling bridge. The inspectors reviewed the licensee event report history for events related to licensed operator performance and training. No events of significance were noted for individual followup.

The inspectors evaluated conformance with operator license conditions by reviewing attendance records for the most recent year training cycle and license reactivation records and procedures. One finding was identified for inadequate limited senior reactor operator (LSRO) license reactivation practices.

The inspectors reviewed final requalification exam results for all operators and crews for the annual operating testing cycle. This review assessed whether pass rates were consistent with the guidance of NUREG-1021, Revision 9, “Operator Licensing Examination Standards for Power Reactors” and NRC Manual Chapter 0609, Appendix I, “Operator Requalification Human Performance Significance Determination Process (SDP)”.

The inspectors verified the following results:

- Crew failure rate on the dynamic simulator examination was less than 20% (Failure rate was 11%).
- Individual failure rate on the comprehensive biennial written exam was less than 20% (Failure rate was 0%).
- Individual failure rate on the walk-through job performance measures was less than 20% (Failure rate was 0%).
- More than 75% of the individuals passed all portions of the exam (100% of the individuals passed all portions of the exam).

The inspectors reviewed Order 70034843 concerning a licensed operator requalification examination scenario that was determined to be invalid after administration. The reason for invalidating the scenario was that the expected operator actions in the scenario guide were not procedurally required. These expected actions were to manually operate HPCI following loss of an inverter. However, the operators removed HPCI from service due to loss of instrumentation. As a result the reactor coolant system depressurized and the operators were not challenged with the prescripted critical tasks to perform emergency depressurization and recognize a failed SRV. As a result the facility administered an additional scenario to this crew.

b. Findings

Introduction. The inspectors identified a Green finding for failure to properly reactivate LSRO licenses in accordance with regulatory requirements prior to refueling activities for the refueling outage in April 2003.

Description. The inspectors identified three LSRO license holders had not properly reactivated their licenses prior to supervising refueling activities during the refueling outage commencing in April 2003. PSEG completed an apparent cause evaluation on this issue and determined that their procedure describing license reactivation did not have adequate detail concerning how LSRO licenses should be reactivated.

Regulatory requirements in 10 CFR 55.53(f)(2) require that for reactivation of a senior reactor operator (SRO) license, license holders must stand one shift in the position to which the individual will be assigned under the direction of another SRO. For the April 2003 outage, the LSROs stood reactivation watches solely under instruction in the control room with no time on the refueling floor.

In a frequently asked question (Examination Standard 605) on the NRC operator licensing web page, the NRC staff stated that the intent of this requirement may be met with a reactivation program that specifies, in detail, the tasks, activities, and procedures an LSRO must perform or simulate in order to demonstrate proficiency. This program must also ensure such activities are completed within a reasonable period of time, ideally one week, prior to the LSRO supervising such activities. While Hope Creek LSROs received classroom training in January and February 2003, received training on refueling bridge modifications conducted on the bridge, and participated in procedure verification and validation of new refueling bridge procedures, no detailed program was developed or lesson plan followed for refueling bridge activities.

Analysis. The inspector determined that the failure to properly reactivate LSRO licenses is a performance deficiency, because the applicable requirements of 10 CFR 55.53(f)(2) were not met. Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements or Hope Creek procedures. This finding is greater than minor, because it is associated with the procedure quality and human performance attributes of the mitigating systems cornerstone and affects the cornerstone objective of ensuring reliability and capability of systems that respond to initiating events (in this instance the licensed operators). However, the finding was determined to be of very low safety significance (Green) using the SDP for operator requalification human performance findings. Specifically, the inspectors determined the performance deficiency was Green and not minor, at block 27 of the SDP because greater than 20% of operator licenses reviewed had the specified deficiency. This deficiency was of an administrative nature with no evidence of the LSROs being technically deficient in their qualifications. However, not performing the under-instruction watch in the position to which assigned was a missed opportunity for operators to potentially identify proficiency and familiarization problems on the refueling bridge.

Enforcement. 10 CFR 55.53(f) requires that if a licensee has not been actively performing licensed functions before resumption of licensed functions, an authorized representative of the facility shall certify that the licensee has completed a minimum of 40 hours of shift functions under the direction of an operator or senior operator as appropriate and in the position to which the individual will be assigned. For senior operator with licenses limited to fuel handling, one shift must have been completed.

Contrary to the above, three LSRO licensees stood their license reactivation watches in the control room rather than on the refueling floor as a refueling SRO for the April 2003 Hope Creek refueling outage. However, because this failure to properly reactivate LSRO licenses is of very low safety significance and has been entered into the corrective action program in notification 70035178, this violation is being treated as an NCV, consistent with section VI.A of the NRC Enforcement Policy (NCV 50-354/03-06-01).

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed performance monitoring and maintenance activities for two systems to determine whether PSEG was adequately monitoring equipment performance to ensure their maintenance activities were effective to maintain the equipment reliable. The fire protection system and filtration, recirculation and ventilation (FRVS) systems were reviewed to verify that the systems were being effectively monitored in accordance with maintenance rule (MR) program requirements. The inspectors compared documented functional failure determinations and unavailable hours to those being tracked by PSEG to evaluate the effectiveness of condition monitoring activities and determine whether performance goals were being met. Documents reviewed are listed in the Supplemental Information section of this report and include work orders, corrective action notifications, preventive maintenance tasks, systems health reports and applicable maintenance expert panel meeting minutes.

Finally, the inspectors completed their review of PSEG’s apparent cause evaluation completed for station service water system (SSWS) traveling screen failures. This issue was identified as Unresolved Item 354/03-05-02 in NRC Inspection Report 2003-005 dated November 10, 2003. One finding having potential safety significance greater than very low was identified regarding this issue. Additionally, the inspectors determined the finding involved problem identification and resolution aspects, because traveling screen binding problems were not identified when a shear pin failed and the apparent cause evaluation did not identify likely additional procedure problems with chain tensioning.

b. Findings

Introduction. A self-revealing finding occurred when the A SSWS traveling screen failed and PSEG determined that improper cutting of a key without procedure guidance had been a contributing cause. The inspectors identified an additional problem that had contributed to the failure, in that applicable maintenance procedures had not been used to set traveling chain tension and screen level. These performance issues were determined to have potential safety significance greater than very low significance. Unresolved item 354/03-05-02 remains open pending completion of the SDP.

Description. The A traveling screen headshaft failure on July 1 was previously described in NRC Inspection Report 354/2003-05, Section 1R12. The failure necessitated the A screen bay to be dewatered and the A SSWS removed from service while maintenance was performed. PSEG completed an apparent cause evaluation and concluded the A SSWS traveling screen failed because the screen headshaft moved laterally. This had been caused by maintenance personnel who improperly shortened the drive sprocket key. The key was purchased from the vendor with a part number, and key trimming was not in the procedure, work instructions or the vendor manual. In effect, the key shortening represented an unauthorized change to the traveling screen's design.

PSEG identified a contributing cause regarding inadequate chain tensioning of the drive side carrier chain, because installed load cells used to perform chain tensioning had repeatability problems. The inspectors identified an additional causal factor due to a procedure adherence problem. In their review of the procedure and work package used to replace the screen headshaft in June 2003 (HC.MD-PM.EP-0003(Q) and work order 60037345), the inspectors noted that directions to level the headshaft and tension the chain were not included. This information was contained in preventive maintenance procedure HC.MD-PM.EP-0001(Q), which provided specific load cell ranges while leveling the headshaft. The inspectors also noted the work order package for the second shaft replacement in July 2003 did not include a completed preventive maintenance procedure to tension the carrier chains. However, comments under notification 20150715 indicted the correct procedure had been used. PSEG initiated notification 20160886 in response to the inspectors' observations.

The inspectors further determined that PSEG missed an opportunity to identify traveling screen binding problems when the A SSWS screen shear pin failed on June 28, two days prior to the headshaft failure on July 1. Maintenance personnel had replaced the shear pin and returned the traveling screen to service. However, the cause of the shear pin failure was not investigated in detail at that time and did not identify developing binding problems. The inspectors reviewed the traveling screen vendor manual and applicable PSEG procedures, which described a test shear pin that should be used to prevent significant damage during testing, adjustments, and periodic screen checks to detect increased drag and binding problems. Maintenance personnel did not install a test shear pin and run the traveling screen to help ensure there were not binding problems prior to returning the traveling screen to service on June 28. PSEG's apparent cause evaluation provided corrective actions to change procedures to address this problem.

Finally, the inspectors identified a problem with the preventive maintenance procedure direction for checking the drive chain tension. Procedure HC.MD-PM.EP-0001(Q) step 5.2.4 checked the drive chain for looseness and specified a minimum of 4 inches of chain sag. This procedure step directed maintenance personnel to consider removing a chain link if the sag was sufficient to allow for removal of one link and still maintain 4 inches of chain sag. The vendor manual specified a range of 4 to 8 inches of chain sag. The inspectors observed the upper bound was not in PSEG's implementing procedure. The inspectors reviewed previous yearly preventive maintenance packages (work order

30063608 and 30046400) and identified instances where the A SSWS traveling screen was left in service with 20 and 12 inches of drive chain sag without a record of links being removed. The inspectors concluded that in these instances the drive chain was loose and indicated wear beyond that recommended as acceptable by the vendor. However, the inspectors concluded this issue did not likely cause the A traveling screen failure on July 1, 2003 because of chain maintenance performed in June 2003.

Analysis. The inspectors determined that the issue was more than minor, because it was associated with the equipment performance attribute of the mitigating systems cornerstone objective. Specifically, maintenance procedure adherence problems resulted in increased unavailability of the A SSWS pump when the A SSWS traveling screen failed and while repairs were completed. This issue also impacted the initiating events cornerstone objective to limit the likelihood of those events that affect plant stability and challenge critical safety functions during shutdown and power operations. The unavailability of one train of SSW increased the likelihood of a loss of service water (LOSW) event. The inspectors completed an SDP Phase 1 screening of the finding and determined that a more detailed Phase 2 evaluation was needed to assess the safety significance.

The SDP Phase 2 evaluation used the loss of service water worksheet and determined that the finding to potentially be of low to moderate safety significance (White). The following assumptions were made in the Phase 2 analysis:

- The A SSWS pump was unavailable during repairs of its associated traveling screen.

- The A SSWS pump was unavailable for approximately nine days; therefore an exposure time of 3 to 30 days was used in the analysis.

- No operator recovery credit was assumed.

- SSWS was considered to be a multi-train normally cross-tied support system. Therefore the initiating event likelihood was increased by one order of magnitude for the associated special initiator.

The preliminary results showed the finding represented an increase in risk of greater than 1E-7 per year for internal initiating events. At the end of the inspection further information was being assessed to determine the availability of the A SSWS pump with the traveling screen inoperable but the bay returned to service, and the risk associated with external events. This information will be used to complete an SDP Phase 3 analysis to confirm the safety significance of the issue.

Enforcement. 10 CFR 50, Appendix B, Criterion V, Instructions Procedures and Drawings, requires that activities affecting quality be accomplished in accordance with documented instructions, procedures or drawings, which shall include appropriate qualitative and quantitative acceptance criteria to ensure that the task can be accomplished satisfactorily. Contrary to the above, maintenance personnel did not follow their procedures and work order 60037345 instructions by trimming the A SSWS traveling screen drive sprocket key without procedure guidance. Additionally, PSEG Procedure HC.MD-PM.EP-0001(Q) provided qualitative and quantitative criteria for tension screen carrier chains that was not used under the same work order. Pending determination of the of the finding's safety significance, this unresolved item will remain open. (URI 50-354/03-05-02)

1R13 Maintenance Risk Assessments and Emergent Work Evaluation (71111.13)

a. Inspection Scope

The inspectors reviewed two on-line risk management evaluations through direct observation and document reviews for the following configurations:

- emergent unavailability of the A EHC pump due to a clogged discharge filter on November 13
- planned unavailability of the service air compressor (00-K-107) due to scheduled maintenance from November 18 through November 21

The inspectors reviewed the applicable risk evaluations, work schedules and control room logs for these configurations to verify that concurrent planned and emergent maintenance and test activities did not adversely affect the plant risk already incurred with these configurations. PSEG's risk management actions were reviewed during shift turnover meetings, control room tours, and plant walkdowns. The inspectors also used PSEG's on-line risk monitor (Equipment Out Of Service workstation) to gain insights into the risk associated with these plant configurations. Finally, the inspectors reviewed notifications documenting problems associated with risk assessments and emergent work evaluations (20163077 and 20166498). Documents reviewed are listed in the Supplemental Information report section.

b. Findings

No findings of significance were identified.

1R14 Operator Performance During Non-Routine Evolutions and Events (71111.14)

a. Inspection Scope

The inspectors evaluated PSEG's performance during two non-routine evolutions to determine whether the operator responses were consistent with applicable procedures, training, and PSEG's expectations. The inspectors observed control room activities, and reviewed control room logs and applicable operating procedures to assess operator performance. PSEG's evaluations of operator performance were also reviewed. The inspectors walked down control room displays and portions of plant systems to verify status of risk significant equipment and interviewed operators and engineers. Documents reviewed are listed in the Supplemental Information report section. Operator performance during the following two non-routine evolutions were reviewed:

Grid Disturbance Due to Marsh Fire

On November 15, 2003, while performing a power reduction to support planned maintenance, a marsh fire was reported in the vicinity of 500 kV transmission line 5015. Control room operators were communicating with the electrical system operator while actions were being made to remove line 5015 from service. The system operator provided several orders to the control room operators of varying magnitude to control 500 kV system voltage during the power reduction and impending 5015 line isolation. Subsequently, it was determined that the system operator guidance was initially incorrect, and resulted in a higher voltage on the 500 kV switchyard than expected. In response to accompanying alarms, the control room operators implemented prompt actions in accordance with response procedures and restored voltage to normal. During the electrical transient, the system voltage reached a high of 578 kV. PSEG initiated notification 20166852 and confirmed that operator performance was adequate and plant equipment was not adversely affected by the transient.

Plant Shutdown Due to Steam Leaks

On December 5 operators reduced power to perform maintenance on the C reactor feedwater pump and repair a steam leak on a steam seal evaporator steam supply line. During the course of the power reduction a leak was discovered on the reactor water cleanup (RWCU) system. A plant shutdown was performed to repair the RWCU system leak.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed five operability determinations for non-conforming conditions associated with:

- control rod insert and withdraw speeds (70033715)
- material condition of the A, B, C and D emergency diesel generator (EDG) exhaust hoods (70034874, 70034875, 70034877, 70034876)
- service water pump head tank lube water supply valve (EA-SV-2247A) installed in the wrong orientation (70035092)
- core spray check valve F006A test results (20169632)
- B emergency diesel generator (70035290)

The inspectors reviewed the technical adequacy of the operability determinations to ensure the conclusions were technically justified. The inspectors also walked down accessible equipment to corroborate the adequacy of the operability determinations. Additionally, the inspectors reviewed other safety-related equipment deficiencies PSEG identified during this report period and assessed the adequacy of their operability screens. Notifications and documents reviewed in this regard are listed the Supplemental Information report section.

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (71111.16)

a. Inspection Scope

The inspectors reviewed one inspection sample regarding the cumulative effects of operator workaround issues on the reliability, availability and potential for misoperation of plant equipment. This included reviews of corrective action notifications that tracked items listed in the Hope Creek operations workaround list and concerns list to ensure there were not unidentified impacts due to combinations of issues. The inspectors reviewed operator logs and control room instrument panels to evaluate potential impacts on the operators' ability to implement abnormal or emergency operating procedures. Additionally, the inspectors reviewed one workaround condition regarding inadvertent feedwater heater isolation during reactor scrams from full power. This workaround condition was reviewed in regard to the October 4 reactor scram from full power to determine whether it adversely affected the functional capability of the feedwater system. One Green finding was identified. Documents reviewed are listed in the Supplemental Information report section.

b. Findings

Feedwater Heater Isolation Workaround

Introduction. The inspectors observed a self-revealing Green finding regarding ineffective corrective actions to address an inadvertent feedwater heater isolation workaround condition. The finding did not involve a violation of regulatory requirements.

Description. On October 4 Hope Creek operators manually scrammed the plant due to an electric hydraulic control (EHC) system oil leak from a combined intercept turbine valve actuator. After the plant scram the operator monitoring reactor water level tripped the A and B reactor feedwater pumps (RFPs) in accordance with procedures to reduce feedwater flow and control reactor level. Within one minute after the scram the reactor operator observed indications that all the 1st and 2nd stage feedwater heater string isolation valves were closing. The operator manually opened the common feedwater heater bypass valve to prevent isolation of all feedwater flow to the reactor vessel due to low suction pressure. The operator subsequently tripped the C RFP. During this time reactor water level increased to the Level 8 (54 inches) setpoint and subsequently dropped to the Level 3 setpoint (12.5 inches). As the operator opened start-up control valves, a second Level 8 high level condition occurred before the operator maintained level within the normal band with primary and secondary condensate pumps.

Hope Creek management reviewed the plant trip and operator response and concluded the action to open the feedwater bypass valve delayed the operator from tripping the C RFP. This was a causal factor in overfeeding the reactor level and reaching the Level 8 setpoint. Further management review found that inadvertent feedwater isolations and manual operator actions had occurred during prior reactor scrams from full power since at least November 1998 and that the issue had been evaluated in notification 20103628.

Notification 20103628 described a plant scram in June 2002 where all three strings of 1st and 2nd stage feedwater heaters (FWHs) isolated due to a high water level in the steam side of the feedwater heaters. The high water level setpoint and automatic heater isolation were designed to respond to internal heater tubes ruptures. However, engineering personnel determined that high water level conditions occurred because the differential pressure between the condenser and the extraction steam supply greatly decreased after a full power scram or turbine trip. This reduced condensed extraction steam flow to the condenser and increased feedwater heater level. PSEG had proposed modification options to correct this condition in April 2003 under order 70025565; however, they were deferred to a future power uprate project.

As a result of the reactor level control challenges on October 4, PSEG management initiated notification 20161375 to correct this problem in a more timely fashion independent of the power uprate project. Additionally, procedures were enhanced in the interim by adding additional direction to the laminated procedure posted at the RFP console (HC.OP-AB.ZZ-0001, Attachment 14) to highlight and respond to this expected condition.

The inspectors reviewed order 70025565 and noted that the modification work to correct this problem had been determined by PSEG to be a system enhancement. However, the inspectors concluded the modification work was more than an enhancement, because it resolved a problem that affected feedwater system reliability during post-scram conditions. Furthermore, the inspectors concluded procedure guidance contained in abnormal procedure HC.OP-AB.RPV-0004 could have addressed this issue better by describing the potential isolation of the 1st and 2nd stage FWHs as an expected plant response from full power scrams rather than a possible abnormal condition.

<u>Analysis</u>. The inspectors concluded that while PSEG identified the problem, the corrective action to correct this condition by modification was untimely and the interim corrective action to address this by procedure was not fully effective. This performance issue reduced feedwater system reliability after reactor scrams from full power, because it necessitated manual operator action to open a bypass valve that was a contributing causal factor to poor control of reactor water level on October 4.

The non-safety feedwater system is a mitigating system, and it provides flow to the reactor vessel to maintain the core covered and ensure decay heat removal during normal and plant scram conditions. The problem involved a design deficiency that was not corrected in a timely manner. The finding is associated with the design control attribute of the mitigating systems cornerstone and affected the cornerstone objective of equipment reliability. Therefore, the finding is greater than minor. The risk associated with this finding was assessed by an SDP Phase 1 evaluation and determined to be of very low risk significance because it is a design deficiency confirmed not to result in loss of function. While manual action was needed, the loss of feedwater flow or tripping of a RFP did not result.

Enforcement. The feedwater system is non-safety related and the feedwater heater isolation on high water level is not described in the safety analysis report. Therefore, this finding does not involve a violation of NRC requirements. This issue is being addressed in the PSEG corrective action program via notification 20161375.
(FIN 50-354/03-06-02)

Feedwater Setdown Setpoint

Introduction. A feedwater system workaround condition regarding the digital feedwater control system setdown function was identified by the inspectors. The finding did not involve a violation of regulatory requirements.

Description. The inspectors observed the laminated procedure for stabilizing reactor water level post-scram allowed for either manual and automatic control of RFPs. The inspectors determined that the digital feedwater control system (DFCS) provided a setdown setpoint feature to help prevent excessive feedwater make-up by RFPs in automatic mode after a reactor scram, as level decreased due to steam void collapse. The setdown setpoint circuit was designed such that ten seconds after reactor water level lowered to below 12.5 inches (level 3), the reactor level control setpoint would automatically be setdown from the normal 35 inches to 18 inches level. The setdown functioned for RFPs in the automatic control mode and not the manual mode.

The inspectors questioned operators about this function and the reason for placing RFPs in manual on October 4, and some operators questioned the effectiveness of the setdown circuit to control reactor water level based on their experience. The inspectors requested that Hope Creek engineering personnel provide the design basis for the setdown setpoint level and time delay, and determine whether the setdown function would have operated as intended on October 4 if the RFPs were left in automatic mode.

In response Hope Creek engineers reviewed the reactor water level response from October 4 and determined the 10 second time delay was too long and would have prevented the setdown function from operating. This was because reactor water level was less than the zero level after 10 seconds because of steam void collapse. Since the level transmitter providing the level signal to the setdown circuit had a span between zero and 60 inches the DFCS tagged the transmitter input as failed when at 10 seconds it was below zero and the DFCS logic disregarded the input. Consequently, the setdown function would not have operated on October 4 if the RFPs were in automatic control mode. Hope Creek personnel initiated notification 20164378 to evaluate the problem and develop a modification to correct this condition. The issue was also tracked as an additional operator workaround condition.

Analysis. The inspectors concluded the setdown setpoint time delay had been too long, such that the feature was not effective following scrams from full power. This problem forced manual operator action on the feedwater system after reactor scrams from full power when RFPs were operated in the automatic mode, because the feedwater level control was not effective and caused operators to control reactor water level manually. The non-safety feedwater system is a mitigating system and it provides flow to the reactor vessel to maintain the core covered and ensure decay heat removal during normal and plant scram conditions. This finding did not affect the likelihood of an initiating event such as a reactor scram, because the feedwater setpoint setdown function operates after a reactor scram from full power.

The finding is associated with the design control attribute of the mitigating systems cornerstone and affected the cornerstone objective of equipment reliability. Therefore, the finding is greater than minor. The risk associated with this finding was assessed by an SDP Phase 1 evaluation and determined to be of very low risk significance, because it is a design deficiency confirmed not to result in loss of function. While the setdown setpoint function has not likely operated correctly since the DFCS was installed in 1994, there has not been a loss of feedwater function due to this problem and operator training and procedures provide for operating RFPs in manual mode.

Enforcement. The feedwater system is non-safety related and the feedwater setdown setpoint is not described in the safety analysis report. Therefore, this finding does not involve a violation of NRC requirements. This issue are being addressed in the PSEG corrective action program via notification 20164378. **(FIN 50-354/03-06-03)**

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope

The inspectors reviewed the following two design changes installed during the inspection period:

- Addition of oil recovery system to the A control room chiller (80064555)
- B EDG IDR relay modification (80060791)

The design bases, licensing bases, modification instructions and post modification testing of the affected components were reviewed to verify the performance capability of this equipment was not adversely affected. The inspectors reviewed the applicable technical specifications for this equipment to ensure that operability requirements and allowable outage time limits were met. The inspectors also reviewed notifications documenting deficiencies identified related to permanent plant modifications. The documents reviewed as part of these inspections are listed in the Supplemental Information report section.

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors observed portions of and/or reviewed the results of five post maintenance tests (PMT) for the following equipment:

- reactor core isolation cooling system (RCIC) pump on October 14
- C SSW traveling screen on October 20
- C EDG on October 21
- B spent fuel cooling pump on October 31
- C safety auxiliary cooling (SAC) pump on November 19

The inspectors verified that the PMTs were adequate for the scope of the maintenance performed. The inspectors reviewed notifications documenting deficiencies identified during PMTs (20163139, 20163498, and 20162546). The inspectors also reviewed applicable documents associated with PMTs as listed in the Supplemental Information report section.

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

a. Inspection Scope

Following the December 5 plant shutdown described in Section 1R14, the inspectors evaluated PSEG's shutdown risk management actions and forced outage configuration control. The inspectors toured the Hope Creek containment drywell to observe equipment conditions and drywell cleanliness. Notifications documenting problems identified during the outage were reviewed to verify the extent of the problem was identified and corrective actions taken that were required prior to plant startup. The inspectors monitored portions of reactor heatup, startup activities and power ascension. The inspectors reviewed the documents and notifications associated with outage activities as listed in the Supplemental Information report section.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors observed portions of the following two surveillance tests and reviewed the results:

- B EDG on October 27
- C/D pump core spray (CS) IST on October 28

The inspectors evaluated the test procedures to verify that applicable system requirements for operability were adequately incorporated into the procedures and that test acceptance criteria were consistent with the technical specification requirements and the updated final safety analysis report (UFSAR). The inspectors also reviewed notifications documenting deficiencies identified during these surveillance tests.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed the following two temporary plant modifications:

- Increase the alarm setpoint for tailpipe temperature to 225 ^{o}F for safety relief valve 1ABPSV-F013P (T-Mod 03-041)
- Installation of temporary service water strainer backwash discharge piping (T-Mod 02-002)

The inspectors verified the modifications were consistent with the design and licensing bases of the affected systems and that the performance capability of these systems were not degraded by these modifications. The inspectors also reviewed the modifications to verify applicable technical specification operability requirements were met during installation. The inspectors verified the modified equipment alignment through control room instrumentation and plant walkdowns of accessible portions of the affected equipment. The inspectors further reviewed notifications documenting problems associated with equipment affected by temporary modifications (20164977).

b. Findings

Introduction. The inspectors identified that incorrect engineering analyses enabled an operating procedure to contain incorrect, non-conservative limits for shutting down the reactor when excessive safety relief valve (SRV) leakage exists. The finding is of very low safety significance (Green) and a non-cited violation of 10 CFR 50, Appendix B, Criterion III, Design Control.

Description. During a procedure review related to T-Mod 03-041, the inspectors identified multiple incorrect, non-conservative temperature limits for elevated SRV tailpipe temperatures in procedure HC.OP-DL.ZZ-0003, Log 3 Control Console Log Condition 1, 2 and 3). The limits specify when a plant shutdown should be initiated. Elevated tailpipe temperature is an indication of SRV pilot leakage, which can cause an SRV to lift prior to its reactor pressure setpoint being reached.

In engineering analyses PSEG determined the limits from vendor test data (steam temperature as a function of distance from a SRV with a specified SRV leak rate) and the thermocouple locations for each installed SRV. Given the leak rate which could cause an inadvertent SRV actuation, PSEG computed the maximum acceptable tail pipe temperature for each SRV. However, the inspectors determined that some thermocouple location data was incorrect. When PSEG re-performed the calculation with correct data, the original limits for seven of the fourteen SRVs (C, E, G, H, K, L, and P) were incorrect; five of the seven were non-conservative.

Additionally, the inspectors determined that the limits contained in the procedure were established via an informal analysis and had not been documented as a controlled calculation. The original thermocouple location data was in a previous engineer's file, and the data had not been verified against design drawings.

Analysis. The performance deficiency was more than minor, because it affected the initiating events cornerstone attribute of procedure adequacy. The inaccurate engineering analyses produced SRV tailpipe temperature limits which could have resulted in PSEG operating an SRV that may open prior to its setpoint being reached, thus causing a reactor pressure transient. PSEG has reviewed the previous and current operating cycle SRV tailpipe temperature data and determined the SRV tailpipe temperatures did not exceed the revised limits. Additionally, PSEG's methodology included margin such that prior minor leakage did not exceed the tailpipe temperature limits where SRV reliability would have been impacted.

The inspectors determined that the finding was of very low safety significance (Green) by the SDP Phase 1 screening worksheet for initiating events, because the finding did not increase the likelihood of a primary or secondary system loss of coolant accident initiator, did not contribute to a combination of a reactor trip and loss of mitigation equipment function, and did not increase the likelihood of a fire or internal/external flood.

Enforcement. 10 CFR Part 50, Appendix B, Criterion III requires that design control measures shall assure that the design basis is correctly translated into procedures. Contrary to the above, engineering analyses used incorrect SRV location data which resulted in multiple incorrect, non-conservative SRV tailpipe temperature limits, which were included in procedure HC.OP-DL.ZZ-0003 in March 2003. However, because the violation is of very low safety significance (Green) and PSEG entered the deficiency into their corrective action system (Notification 20164197), this finding is being treated as a non-cited violation, consistent with section VI.A. of the NRC Enforcement Policy, issued May 1, 2000 (65FR25368). (NCV 50-354/03-06-04)

Cornerstone: Emergency Preparedness

1EP2 Alert and Notification System (ANS) Testing (71114.02)

a. Inspection Scope

A regional inspector reviewed PSEG's ANS to ensure prompt notification of the public for taking protective actions. The inspection included a review of the following procedures: (1) NC.EP-DG.ZZ-0007(Z), Siren Test Process; and (2) Alert Notification System Daily Operational Guideline. In addition, the inspector interviewed the siren program technicians, and reviewed maintenance and 2002/2003 test records to determine if test failures were being immediately assessed and repaired, and sirens were being routinely maintained. The inspection was conducted in accordance with NRC Inspection Procedure 71114, Attachment 02, and the applicable planning standard, 10 CFR 50.47(b)(5) and its related 10 CFR 50, Appendix E requirements were used as reference criteria.

b. Findings

No findings of significance were identified.

1EP3 Emergency Response Organization (ERO) Augmentation Testing (71114.03)

a. Inspection Scope

A regional inspector reviewed the PSEG ERO augmentation staffing requirements and the process for notifying the ERO to ensure the readiness of key staff for responding to an event and timely facility activation. The inspector reviewed the 2002/2003 communication pager test records and associated notifications. A review was also conducted of the backup notification systems that would be used in case of a power outage. The inspector interviewed the EP training instructor to determine the adequacy of the lesson plans used for training ERO, which included detailed lesson plans and lessons learned from past drills for correcting ERO performance problems. Finally, the emergency plan qualification records for key ERO positions were reviewed to ensure all ERO's qualifications were current. The inspection was conducted in accordance with NRC Inspection Procedure 71114, Attachment 03, and the applicable planning standard, 10 CFR 50.47(b)(2) and its related 10 CFR 50, Appendix E requirements were used as reference criteria.

b. Findings

No findings of significance were identified.

1EP4 Emergency Action Level (EAL) Revision Review (71114.04)

a. Inspection Scope

A regional in-office review of revisions to PSEG's emergency plan, implementing procedures and EAL changes was performed for determining that changes had not decreased the effectiveness of the plan. The revisions covered the period from January to December 2003. Onsite the regional inspector evaluated the associated 10 CFR 50.54(q) reviews in which PSEG determined that a decrease in effectiveness had not occurred. The inspection was conducted in accordance with NRC Inspection Procedure

71114, Attachment 04, and the applicable requirements in 10 CFR 50.54(q) were used as reference criteria.

b. Findings

No findings of significance were identified.

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies (71114.05)

a. Inspection Scope

A regional inspector reviewed corrective actions identified by PSEG pertaining to findings from 2002/2003 drill/exercise reports and the associated corrective action notifications to determine the significance of the issues and to determine if repeat problems were occurring. Also, various quality assurance audit reports from 2002 and 2003 were reviewed to assess PSEG's ability to identify issues, assess repetitive issues and the effectiveness of corrective actions through their independent audit process. In addition, the inspector reviewed 2002/2003 self assessment reports to assess PSEG's ability to be self critical, thus avoiding complacency and degradation of their emergency preparedness (EP) program. Audit and self assessment reports reviewed are listed in the Supplemental Information section of this report.

Finally, the inspector reviewed several trending reports generated for tracking various program activities, ERO qualifications and ERO exercise/drill performance breakdowns. The reports are an assessment tool used for identifying program problem areas, management briefings and identifying topics for self assessments. This inspection was conducted according to NRC Inspection Procedure 71114, Attachment 05, and the applicable planning standard, 10 CFR 50.47(b)(14) and its related 10 CFR 50, Appendix E requirements were used as reference criteria.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

The resident inspectors observed two licensed operator requalification scenario exams on October 16 in the simulator. The scenarios were reviewed prior to the exams to identify the expected event classification and notification actions. The inspectors observed the exams and PSEG's post-exam critique of operator performance to verify that weaknesses and deficiencies were adequately identified. The inspectors specifically focused on ensuring PSEG identified any operator performance problems with event classification and notification activities, and ensured the problems were corrected.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Public Radiation Safety

2PS1 <u>Radioactive Gaseous and Liquid Effluent Treatment and Monitoring Systems</u> (71122.01)

a. <u>Inspection Scope</u>

The inspectors completed nine inspection samples relative to radioactive gaseous and liquid effluent treatment and monitoring. The following documents were reviewed to evaluate the effectiveness of PSEG's radioactive gaseous and liquid effluent control programs. The requirements of the radioactive effluent controls are specified in the Technical Specifications/Offsite Dose Calculation Manual (TS/ODCM).

- 2002 Radiological Annual Effluent Release Report and Radiation Dose Assessment Report
- current ODCM (Revision 20, April 2002) and technical justifications for ODCM changes
- implementation of IE Bulleting 80-10, Contamination of Non-Radioactive System and Resulting Potential for Unmonitored, Uncontrolled Release of Radioactivity to environment
- selected 2003 analytical results for radioactive liquid, charcoal cartridge, particulate filter, and noble gas samples
- selected 2002-2003 radioactive gaseous and liquid release permits, including monthly projected public dose assessments
- implementation of the compensatory sampling and analysis program when the effluent radiation monitoring system (RMS) is out of service
- trending evaluations of the availability for effluent RMS
- calibration records for chemistry laboratory measurements equipment (gamma and liquid scintillation counters)
- implementation of the measurement laboratory quality control (QC) program, including control charts
- implementation of the interlaboratory comparisons by PSEG and the contractor laboratory
- 2003 QA Audit (Audit Numbers 2003-0012, 2003-0016, and 2003-0175), audit findings
- chemistry self assessment reports (Report Numbers 70028108, Counting Room Assessment and 80048283-0160, ODCM Implementation)

The inspectors reviewed the most recent channel calibration and channel functional test results for the radioactive liquid and gaseous effluent radiation monitoring system (RMS) and its flow measurement devices for those listed in the Tables 4.3.7.10-1 and 4.3.711-1 of the ODCM. Specifically, the following RMS channel and flow monitor calibration results were reviewed:

RMS Channel Calibration

- Liquid Radwaste Discharge Line to the Cooling Tower Discharge Line
- Turbine Building Circulating Water Dewatering Sump Disacharge Line to the Cooling Tower
- Cooling Tower Blowdown Effluent
- FRVS Noble Gas Activity Monitor
- South Plant Vent Noble Gas Activity Monitor
- North Plant Vent Noble Gas Activity Monitor

Flow Monitor Calibration

- Liquid Radwaste Discharge Line to Cooling Tower Blowdown Line
- Cooling Tower Blowdown Weir
- Turbine Building Circulating Water Dewatering Sump Discharge Line to the Cooling Tower
- FRVS Sampler Flow Rate Monitor
- FRVS Flow Rate Monitor
- South Plant Vent Flow Rate Monitor
- South Plant Vent Sampler Flow Rate Monitor
- North Plant Vent Flow Rate Monitor
- North Plant Vent Sampler Flow Rate Monitor

The inspectors reviewed the most recent surveillance test results (visual inspection, delta P, in-place testings for HEPA and charcoal filters, air capacity test, and laboratory test for iodine collection efficiency) for the following air treatment systems:

- TS 3/4.7.2 Control Room Emergency Filtration System
- TS 3/4.6.5.3 Filtration, Recirculation and Ventilation Systems (FRVS)
- UFSAR Commitment Systems: (1) Reactor Building Ventilation Exhaust; (2) Offgas Exhaust System; (3) Radwaste Exhaust System; and (4) Radwaste Vent Filter System.

The inspectors toured and observed the following activities to evaluate the effectiveness of PSEG's radioactive gaseous and liquid effluent control programs.

- walkdown for determining the availability of radioactive liquid/gaseous effluent RMS and for determining the equipment material condition;
- walkdown for determining operability of air cleaning systems and for determining the equipment material condition; and
- observed PSEG's radioactive effluent sampling techniques and preparing the measurement at the laboratory.

The inspectors reviewed Special Report 354/03-006 dated October 1, 2003. The inspectors also reviewed notifications documenting problems concerning effluent RMS, air cleaning systems, and routine effluent control programs as listed in the Supplemental Information section of this report.

b. Findings

No findings of significance were identified.

2PS2 Radioactive Material Processing and Transportation (71122.02)

a. Inspection Scope

The inspectors completed six samples relative to radioactive material processing and transportation. The inspectors reviewed the solid radioactive waste system description in the updated final safety analysis report (UFSAR) and the recent radiological effluent release report for information on the types and amounts of radioactive waste disposed. The inspectors reviewed the scope of PSEG's audit program to verify that it meets the requirements of 10 CFR 20.1101(c).

The inspectors walked-down the liquid and solid radioactive waste processing systems and determined that the current system configuration and operation agree with the descriptions contained in the UFSAR and in the Process Control Program (PCP). The inspectors reviewed the status of any radioactive waste process equipment that is not operational and/or is abandoned in place. The inspectors verified that the changes were reviewed and documented in accordance with 10 CFR 50.59 as appropriate. The inspectors reviewed current processes for transferring radioactive waste resin and sludge discharges into shipping/disposal containers to determine if appropriate waste stream mixing and/or sampling procedures, and methodology for waste concentration averaging provided representative samples of the waste product for the purposes of waste classification as specified in 10 CFR 61.55 for waste disposal. The systems/subsystems reviewed included: reactor water clean-up; spent fuel pool clean-up; floor drain; equipment drain; miscellaneous waste; and, solid waste processing. The inspectors also toured current and abandoned in-place radwaste equipment and facilities, and interim storage locations used for processed radwaste. The areas toured by the inspectors are listed in the Supplemental Information report section.

The inspectors reviewed the radio-chemical sample analysis results for each of PSEG's radioactive waste streams. The inspectors reviewed PSEG's use of scaling factors and calculations used to account for difficult-to-measure radionuclides. The inspectors verified that PSEG's program assures compliance with 10 CFR 61.55 and 10 CFR 61.56 as required by Appendix G of 10 CFR Part 20. The inspectors reviewed PSEG's program to ensure that the waste stream composition data accounted for changing operational parameters.

The inspectors previously observed shipment packaging, surveying, labeling, marking, placarding, vehicle checks, emergency instructions, disposal manifest, shipping papers provided to the driver, and PSEG's verification of shipment readiness as documented in NRC Inspection 05000354/2003004. Shipment 03-53 was observed. The inspectors verified that the requirements of any applicable transport cask Certificate of Compliance were met. The inspectors verified that the receiving licensee was authorized to receive the shipment packages. The inspectors observed radiation workers during the conduct of radioactive waste processing and radioactive material shipment preparation activities. The inspectors determined that the shippers were knowledgeable of the shipping regulations and that shipping personnel demonstrated adequate skills to accomplish the package preparation requirements for public transport with respect to NRC Bulletin 79-19 and 49 CFR Part 172 Subpart H. The inspectors verified that PSEG's training program provides training to personnel responsible for radioactive waste processing and radioactive material shipment preparation activities.

The inspectors reviewed 5 non-excepted package shipment (LSA I, II, III, SCO I, II, Type A, or Type B) records. The inspectors reviewed these records for compliance with NRC and DOT requirements. Shipments reviewed included: 03-17, 03-18, 03-36, 03-53, and 03-74. Finally, the inspector reviewed notifications, audits, and self-assessments related to the radioactive material and transportation programs performed since the last inspection.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

a. Inspection Scope

The inspectors reviewed PSEG's program to gather, evaluate and report information on the following eight performance indicators (PIs). The inspectors used the guidance provided in NEI 99-02, Revision 2, "Regulatory Assessment Performance Indicator Guideline" to assess the accuracy of PSEG's collection and reporting of PI data.

Unplanned Scrams per 7,000 Critical Hours

The inspectors verified the accuracy and completeness of reported manual and automatic unplanned scrams during the period of July 1, 2002 through September 30, 2003. The inspectors reviewed licensee event reports, corrective action notifications, monthly operating reports, and PSEG nuclear plant power history charts.

Scrams With Loss of Normal Heat Sink

The inspectors reviewed and verified PSEG's basis for including or excluding an unplanned manual and automatic reactor scram in the scrams with loss of normal heat removal PI during the period of July 1, 2002 through September 30, 2003. The inspectors reviewed operating logs, corrective action notifications, and PSEG nuclear plant power history charts.

Unplanned Transients per 7,000 Critical Hours

The inspectors verified the accuracy and completeness of reported transients that resulted in unplanned changes and fluctuations in reactor power of greater then 20 percent power during the period of July 1, 2002 through September 30, 2003. The inspectors reviewed operating logs, corrective action notifications, monthly operating reports, and PSEG nuclear plant power history charts.

Safety System Unavailability (SSU) Residual Heat Removal System

The inspectors verified the accuracy and completeness of reported unavailability hours for the RHR system during the period of July 1, 2002 to September 30, 2003. The inspectors reviewed control room operating logs, corrective action program notifications, and MR electronic databases.

RETS/ODCM Radiological Effluent Occurrences

The inspectors verified the accuracy and completeness of reported radiological effluent release occurrences at Hope Creek during the period of June 1, 2002 to September 30, 2003. The inspectors reviewed monthly and quarterly projected liquid and gaseous effluent releases dose assessment results and corrective action program notifications.

Emergency Preparedness Program

The inspectors reviewed PSEG's procedure for developing the data for the three 2003 emergency preparedness PIs: (1) Drill and Exercise Performance (DEP), (2) ERO Drill Participation, and (3) alert and notification system (ANS) Reliability. The inspector also reviewed PSEG's 2003 drill/exercise reports, training records and ANS testing data to verify the accuracy of the reported data.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

1. Annual Sample Review

a. Inspection Scope

The inspectors completed one sample review regarding PSEG's evaluation and resolution of the A EDG intercooler pump mechanical seal leak that occurred in June 2003. This pump seal leak is described in NRC Inspection Report 354/2003004 dated August 1, 2003, Section 1R12. The root cause evaluation was documented in Order 70032114. The inspectors reviewed the evaluation to determine whether the problem was identified in timely manner. The inspectors determined whether the evaluation adequately identified the scope of the problem and considered industry operating experience. The technical detail and depth of the evaluation were considered to assess whether the causal factors identified were adequately supported. Finally, the inspectors reviewed the schedule and completion of corrective actions to determine whether the actions were completed consistent with the safety significance of the problem.

b. Findings and Observations

The inspectors concluded that the root cause evaluation and corrective actions for the A EDG intercooler pump mechanical seal leak were adequate. However, the inspectors also concluded that a more in-depth problem assessment by PSEG engineering personnel as the leakage developed in 2003 could have provided for more timely resolution of the problem in June 2003. Additionally, the inspectors observed similar weakness in PSEG's evaluation of a current EDG lube oil leak.

The inspectors determined the A EDG root cause evaluation adequately identified the problem by reviewing pump seal maintenance history for each EDG, oil sample trend information and industry experience. The evaluation methodology was adequate and used fault tree, and cause and effect analyses to identify the events leading to the pump intercooler leakage, and time change analysis to evaluate the seal component performance. During pump disassembly in June 2003, PSEG identified the physical cause of the intercooler leakage was a seized thrust bearing that allowed excessive axial pump shaft movement. This caused excessive movement of the intercooler pump seal faces. The carbon faced pump seal had been shimmed excessively to minimize leakage which led to increased seal wear. After a number of years this resulted in intercooler pump seal leakage.

PSEG personnel identified the underlying causal factors leading up to this condition were inadequate verification of thrust bearing oil groove size prior to bearing installation. Additionally, PSEG maintenance procedures were inadequate to identify this problem, because they did not ensure pump shaft axial movement was checked during periodic pump maintenance. Contributing causes included omitted information in the vendor manual regarding pump thrust and a past, inappropriate heavy reliance on vendor representatives to provide this technical guidance during performance diesel maintenance. Corrective actions included replacing the seized bearing, improving the verification of critical bearing characteristics, verifying other similar installed EDG bearings were not affected, and improving applicable maintenance procedures to check for pump shaft and bearing performance during seal periodic seal replacements. Based on this review the inspectors concluded the evaluation and corrective actions were adequate to prevent recurrence.

Notwithstanding, the inspectors concluded the evaluation did not identify past problem identification performance weaknesses. By design, leakage from either the intercooler pump oil seal or jacket water seal was directed to a common telltale pipe. The inspectors determined that notification 20140755 was initiated on April 21, 2003 to identify an 80 drops per minute (dpm) telltale pipe oil leak during a monthly surveillance test. On April 25 the intercooler pump was leaking approximately 30 dpm of jacket water with the EDG in standby (notification 20141433). On May 26 the intercooler pump seal leaked 80 dpm oil during EDG testing. Subsequently, in June the seal leakage increased and the EDG was declared inoperable. The leakage was sampled at that time and found to be jacket water. The sample was black in color due to carbon wear from the pump seal face.

The inspectors concluded that a more in-depth technical assessment of these leaks in April and May by PSEG engineering personnel could have helped identify the problem of excessive pump shaft movement. Leaks alternating from oil to jacket water as described in the notifications may indicate significant shaft movement as the shaft moves to different positions during run and standby conditions. Additionally, if personnel had sampled the oil leak they may have identified jacket water with carbon that was indicative of abnormal pump seal carbon face wear. However, the inspectors determined the initial assessments of these leaks focused on the ability of the jacket water and lubrication oil systems to make-up the losses and not on the nature of the leaks.

The inspectors identified a similar instance of less than adequate initial problem assessment during the monthly surveillance testing of the C EDG on October 21. During the test lube oil leakage was observed from a bolted joint that feeds the main shaft seal. PSEG personnel initiated notification 20163353 and characterized the problem as a housekeeping leak because the leak-rate was well within the lube oil make-up system capacity. The inspectors walked down the same joint on the other EDGs and determined the A and C EDGs had similar leaks. Additionally, the inspectors observed inconsistencies in the hardware installed between EDGs. The inspectors further reviewed the maintenance history and determined these joint leaks were repetitive. The inspectors provided these observations to PSEG personnel who initiated notifications 20164369, 20164433 and 20164434 to identify undocumented modifications on the A, B and C EDGs. Additionally, bolt torque checks were performed and information added to the notification problem descriptions regarding the joint design and ability to hold pressure. The inspectors concluded this issue was minor, because the oil leaks did not impact the EDG reliability. However, this is a similar instance of less than adequate initial problem assessment of EDG leaks.

2. <u>Cross-References to PI&R Findings Documented Elsewhere</u>

Section 1R12 describes a finding regarding the failure of the A SSWS traveling screen that was caused by improper cutting of a key without maintenance procedure guidance. The inspectors identified additional problems regarding traveling chain tensioning and inspection that were not identified by PSEG's evaluation. Additionally, the finding involved problem identification aspects because traveling screen binding problems were not identified when a shear pin failed.

Section 1R16 describes a finding regarding a workaround condition regarding feedwater heater system isolation. This finding involved ineffective corrective actions.

Section 1R16 also describes a finding regarding a feedwater system setdown setpoint design problem that was identified through the inspectors questions. This finding involved a problem identification aspect.

4OA3 Event Followup (71153)

1. (Closed) LER 50-354/03-003, As Found Values for Safety Valve Lift Setpoints Exceed Technical Specification Allowable Limits

On April 26, 2003 PSEG determined that the as-found lift setpoint for eight of fourteen main steam safety relief valves (SRV) failed to open within the required Technical Specification (TS) actuation pressure setpoint tolerance. TS 3.4.2.1 provides an allowable pressure band of +/- 3 percent for an individual SRV. All eight of the SRVs opened above the required pressure band (actual range was +3.1 to +7.5 percent). PSEG determined that the apparent cause for six of the setpoint failures was due to corrosion bonding/sticking of the pilot disc, and the apparent cause of the other two failures was due to pilot seat leakage. All fourteen SRVs were replaced with tested and certified spare pilot assemblies.

The inspectors determined the finding was more than minor, because it affected the mitigating systems cornerstone objective of ensuring equipment reliability of the SRVs to perform their intended safety function. The finding was associated with the equipment performance attribute of the mitigating systems cornerstone. However, the finding was determined to have very low safety significance (Green) using the SDP Phase 1 screening worksheet for mitigating systems, because there was no loss of system safety function. This licensee-identified finding involved a violation of TS 3.4.2.1. The enforcement of licensee identified violations is discussed in Section 4OA7 of this report. This LER is closed.

2. (Closed) LER 50-354/03-008, Manual Reactor Scram Following Electro-Hydraulic Control (EHC) Oil Leak

This LER described a manual reactor scram due to a EHC oil leak on a combined intermediate control valve (CIV). The LER discussed the plant response to the reactor scram, including the isolation of the 1st and 2nd stage feedwater heater strings. The inspectors reviewed the EHC leak in NRC Inspection Report 50-354/2003-07 and the feedwater heater string isolation in this report, Section 1R16. This LER is closed.

3. (Closed) LER 50-354/03-007, Reactor Scram Due to Electrical Transient, Low Reactor Water Level and Loss of Reactor Feed Pumps A and C

a. Inspection Scope

This LER documents an event that occurred on September 19 in which an electrical transient in the 500 kv switchyard resulted in two reactor feedwater pumps tripping and a low reactor water level condition. The reactor automatically scrammed on the low level condition. The inspectors reviewed the LER and supporting root cause evaluation to verify that the contributing causes were identified and corrective actions were initiated to address each causal factor to prevent recurrence. The inspectors' initial review of operator performance and plant response prior to completion of the root cause evaluation is documented in NRC Inspection Report 50-354/2003-005, Section 1R14 dated November 10, 2003.

b. Findings

Introduction. An inadequate design change and incorrect calibration of an oil control switch reduced the reliability of the reactor feedwater pumps, such that a second pump did not remain in operation following the September 19, 2003 electrical transient. The reactor automatically scrammed on the resulting low reactor level. A Green self-revealing finding was identified.

Description. On September 19 an electrical transient in the 500 kV switchyard caused power to be lost from some plant components. The three reactor feed pumps (RFPs) were affected as follows:

- A RFP lost power to both the main and auxiliary oil pumps and tripped.
- B RFP retained power to the main and auxiliary oil pumps and continued to operate.
- C RFP lost power to the main oil pump but retained power to the auxiliary oil pump and should have continued to operate.

The C RFP auxiliary oil pump started on low oil pressure and should have been able to maintain an acceptable oil pressure; however, it did not and the C RFP tripped, causing a low reactor water level which caused the reactor scram.

PSEG performed a root cause investigation and identified the likely causal factors that contributed to the trip of the C RFP. PSEG personnel determined that the reactor feed pump oil system keep fill lines were undersized and may have been clogged, thereby allowing a void to form in the standby pump discharge piping. The presence of a void could have delayed restoration of pressure by the auxiliary oil pump. The keepfill oil line was installed in 1986 based on recommendations by the pump vendor to install an oil line that included a 1/16 inch diameter orifice. However PSEG determined the installed keepfill line was undersized, because the tubing itself was 1/16 inside diameter. This reduced keepfill flow and was a likely causal factor in the failure of the C RFP auxiliary oil pump to maintain adequate oil pressure.

PSEG identified a second causal factor for the C RFP turbine was incorrect calibration of the control oil header pressure switch that started the auxiliary oil pump. The switch had been calibrated to an incorrect setpoint in March 2003 such that the auxiliary oil pump started when oil pressure was 10 psig lower then the design setpoint of 86 psig. PSEG concluded this was likely caused because of an incorrect assumption by the technician who performed the calibration that the switch operated on increasing pressure instead of decreasing pressure. The inspectors reviewed notification 20168195 and determined the extent of this problem was adequately addressed and corrective actions implemented to check other similar calibration tasks.

At the end of the inspection period PSEG continued to evaluate RFP performance to determine whether there were was an additional causal factor related internal oil system check valve tightness. In the interim PSEG implemented corrective actions to operate both the main and auxiliary oil pumps associated with each RFP until corrective actions are finalized.

The inspectors concluded the evaluation was of sufficient detail to identify likely causal factors and the corrective action to run both oil pumps should ensure RFP reliablity until corrective actions are finalized. However the inspectors observed that a similar problem occurred previously in 1999 when the A and B RFP operating main oil pumps tripped due to an electrical transient. The A and B RFP auxiliary oil pumps both started, but the A RFP auxiliary pump did not maintain adequate oil pressure to prevent the A RFP from tripping trip on low oil pressure. PSEG's evaluation (70000775) concluded the A RFP tripped because an oil accumulator bladder leaked. However, in performing the root cause evaluation for the September 19 event, PSEG concluded the accumulator was not designed to maintain oil pressure during pump start.

Analysis. Although PSEG identified the causal factors for this problem, the unreliability of the C RFP oil system occurred through a self-revealing event. The performance deficiencies associated with this finding were inadequate design control and inadequate maintenance. The inspectors determined that the finding was more than minor, because it affected the design control (modifications) attribute of the Initiating Events Cornerstone. Unreliable RFP performance resulted in a low water level and reactor scram during an electrical transient. The inspectors reviewed this finding using the Phase 1 SDP worksheet for initiating events and determined that a Phase 2 analysis was needed, because the finding contributed to both the likelihood of a reactor trip and unavailability of mitigating equipment. Specifically, the failure of the C RFP after the electrical transient contributed to a reactor scram and it was not available to pump feedwater to the reactor vessel after the initiating event.

The inspectors completed a SDP Phase 2 evaluation and determined that the finding was of very low safety significance (Green). The inspectors used the following assumptions in the Phase 2 evaluation:

- An exposure time of greater then 30 days.
- The initiating event likelihood was increased by one order of magnitude, because the amount of increase in the frequency of the initiating event due to the inspection finding was not known.
- The power conversion system (PCS) mitigating capability was reduced by one order of magnitude to reflect the performance deficiency.
- Operator recovery credit was assumed, because the pumps could be manually restarted and oil pressure was recoverable after a RFP trip.
- The performance deficiency impacted the transient initiating events and not the loss of coolant initiating events, therefore only the transient SDP worksheet was evaluated.

The inspectors determined that two dominant core damage sequences existed for a transient (reactor trip) event. The first sequence involved a failure of PCS, containment heat removal (CHR), and containment venting (CV). The second sequence involved a failure of PCS, high pressure injection (HPI), and depressurization.

Enforcement. This finding was not a violation of NRC requirements. The RFPs have a meaningful contribution to the risk assessment of plant operations and the Initiating Events Cornerstone was affected in this case. Nonetheless, the finding occurred on the RFPs, which are non-safety related components. PSEG entered this issue into its corrective action program as notifications 20158787 and 20168195. This LER is closed. (FIN 50-354/03-06-05)

4OA6 Meetings, Including Exit

On January 21, 2004 the inspectors presented their overall findings to members of PSEG management led by Mr. Jim Hutton. PSEG management stated that none of the information reviewed by the inspectors was considered proprietary.

4OA7 Licensee-Identified Violations.

The following violations of very low significance (Green) were identified by PSEG and are violations of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as NCVs.

- TS 3.4.2.1, "Safety/Relief Valves," requires that 13 of the 14 SRVs open within a lift setpoint of +/- 3 percent of the specified code safety valve function lift setting. Contrary to this requirement, PSEG identified that 8 of 14 SRVs experienced setpoint drift outside of the TS limit. PSEG entered this issue into their corrective action program as notification 20143634. This finding is of very low safety significance because the SRVs would have functioned to prevent a reactor vessel over pressurization.

- Plant Technical Specification 6.12.1 requires that areas having radiation dose rates in excess of 100 millirem per hour be posted, barricaded and access controlled as a high radiation area. On December 16, 2003, PSEG determined that the radiation levels in room 3326 (Waste Filter Holding Pump Room) were 600 millirem per hour, but the room was not posted or controlled as a high radiation area, nor was the area barricaded. This event is documented as notification 20170646. This finding is of very low safety significance, because it did not involve a locked high or very high radiation area or personnel over-exposure.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel

C. Banner, EP Supervisor
D. Bartlett, System Engineer
M. Bergman, System Engineer
D. Boyle, Hope Creek Operations Superintendent
B. Blomquist, System Engineer
D. Burgin, EP Manager
T. Cellmer, Radiation Protection Manager
M. Conroy, Senior Engineer, Maintenance Rule Coordinator
M. Crisafulli, Hope Creek, Mechanical Superintendent
M. Dammann, Maintenance Manager - Controls & Power Distribution
J. Dower, Hope Creek Training Supervisor
D. Groves, Valve Engineer
A. Faulkner, Hope Creek Training Instructor
J. Frick, Shipping Supervisor
C. Johnson, Valve Engineer
J. Hutton, Hope Creek Plant Manager
B. Nurnberger, Hope Creek Chemistry Superintendent
D. Price, Refueling/Outage Manager
L. Rajkowski, Hope Creek System Engineering Manager
J. Reid, Operations Training Leader
B. Sebastian, Radiation Protection Manager
G. Sosson, Hope Creek Operations Manager
B. Thomas, Sr. Licensing Engineer
P. Tocci, Hope Creek Maintenance Manager
B. Tyers, System Engineer
L. Wagner, Plant Support Manager
R. Yewdall, Licensing

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened/Closed

50-354/03-06-01	NCV	Improper Reactivation of Limited Senior Reactor Operator (Section 1R11)
50-354/03-06-02	FIN	Ineffective Resolution of Feedwater System Workaround Condition (Section 1R16)

50-354/03-06-03	FIN	Ineffective identification of Feedwater Setdown Setpoint Function (Section 1R16)
50-354/03-06-04	NCV	Failure to Correctly Translate Design Basis for SRV Leakage Limits into Procedure Requirements (Section 1R23)
50-354/03-06-05	FIN	Inadequate Design Control and Maintenance Results in Unreliable RFPT Operation (Section 4OA3.3)

Closed

50-354/03-003	LER	As Found Values for Safety Valve Lift Setpoints Exceed Technical Specification Allowable Limits (Section 4OA3.1)
50-354/03-007	LER	Reactor Scram Due to Electrical Transient, Low Reactor Water Level and Loss of Reactor Feed Pumps A and C (Section 4OA3.3)
50-354/03-008	LER	Manual Reactor Scram Following Electro-Hydraulic Control Oil Leak (Section 4OA3.2)

Discussed

50-354/03-05-02	URI	Inadequate Procedure Adherence During Maintenance on A SSWS Traveling Screen (Section 1R12)

LIST OF DOCUMENTS REVIEWED

In addition to the documents identified in the body of this report, the inspectors reviewed the following documents and records:

Hope Creek Generating Station (HCGS) Updated Final Safety Analysis Report
Technical Specification Action Statement Log (SH.OP-AP.ZZ-108)
HCGS NCO Narrative Logs
HCGS Plant Status Reports
Weekly Reactor Engineering Guidance to Hope Creek Operations
Hope Creek Operations Night Orders and Temporary Standing Orders

Equipment Alignment (71111.04)
Service Water System Operation (HC.OP-SO.EA-0001)
Service Water Traveling Screens System Operation (HC.OP-SO.EP-0001)
Emergency Diesel Generator Operations (HC.OP-SO.KJ-0001)
Safety and Turbine Auxiliaries Cooling Water System Operations (HC.OP-SO.EG-0001)
Control Area Chilled Water System Operation (HC.OP-SO.GJ-0001)

Control Area Ventilation System Operation (HC.OP-SO.GK-0001)
Safety and Turbine Auxiliaries Cooling Water System Operation (HC.OP-SO.EG.0001)
EA 'B' SSW Pump Backwash Valve Replacement Tagging Work List
Hope Creek Generating Station Service Water P&ID (M-10-1), Sheet 1 of 4
Notification 20165973

Licensed Operator Requalification (71111.11)
NC.NA-AP.ZZ-0014(Q) Rev 10 "Training, Qualification, and Certification"
NC.TQ-TC.ZZ-0306(Z) Rev 1 "Limited Senior Reactor Operator (LSRO) Training Program"
SH.TQ-TC.ZZ-0303(Z) Rev 14 "NRC Licensed Operator Requalification Program"
SH.OP-DD.ZZ-0067(z) Rev 1 "Personnel Qualification and Training"
LSRO Task Lists
Operability Assessment and Equipment Control Program (SH.OP-AP.ZZ-0108)
Reactor Scram (HC.OP-AB.ZZ-0000)
Grid Disturbance (HC.OP-AB.BOP-0004)
Reactor/Pressure Vessel (RPV) Control (HC.OP-EO.ZZ-0101)
Primary Containment Control (HC.OP-EO.ZZ-0102)
Emergency RPV Depressurization (HC.OP-EO.ZZ-0202)
Notification: 20169073
Orders: 70035178, 70034843

Maintenance Effectiveness (71111.12)
System Function Level Maintenance Rule VS Risk Reference (SE.MR.HC.02)
NRC Regulatory Guide 1.160, Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, Revision 2
NUMARC 93-01, Industry Guideline For Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, Revision 2
Fire Protection (KC & QK) System Health Report, Period 10/01/02 to 12/31/2002
Fire Protection (KC & QK) System Health Report, Period 03/15/03 to 06/15/2003
Fire Protection (KC & QK) System Health Report, Period 06/15/03 to 09/15/2003
FRVS (GU) System Health Report, Period 10/1/02 to 12/20/02
FRVS (GU) System Health Report, Period 03/01/03 to 05/31/03
FRVS (GU) System Health Report, Period 06/01/03 to 08/31/03
Notifications: 20162120, 20069111, 20154871, 20055844, 20160858, 20154430, 20117903, 20103021, 20124148, 20092942, 20100455, 20102413, 20107576, 20107823, 20108331, 20108584, 20110484, 20131200, 20132009, 20132317, 20132339, 20132983, 20134877,20135053, 20138664, 20139763, 20140089, 20143377, 20144213, 20146834, 20153065, 20153221, 20158688, 20166852 , 20074269.
Orders: 60038582, 70033078, 70000121, 80060715

Maintenance Risk Assessment and Emergent Work Control (71111.13)
System Function Level Maintenance Rule VS Risk Reference (SE.MR.HC.02)
HCGS PSA Risk Evaluation Forms for Work Week Nos. 143(10) to 156(12)
On-Line Risk Assessment (SH.OP-AP.ZZ-108)
NRC Regulatory Guide 1.182, Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants

NUMARC 93-01, Industry Guideline For Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, Section 11- Assessment of Risk Resulting from Performance of Maintenance Activities, dated February 11, 2000

Operator Performance During Non-Routine Evolutions and Events (71111.14)

TARP Report - 11/15/03 Hope Creek Grid Disturbance due to 500 kV Line [5015] Marsh Fire
Shutdown From Rated Power (HC.OP-IO.ZZ-0004)
Preparation For Plant Startup (HC.OP-IO.ZZ-0002)
Notifications: 20166852

Operability Evaluations (71111.15)

Operability Assessment and Equipment Control Program (SH.OP-AP.ZZ-0108)
NRC Generic Letter No. 91-18, Revision 1, Resolution of Degraded and Nonconforming Conditions
Notification Process (NC.WM-AP.ZZ-0000)
Service Water Subsystem A Valves - Inservice Test (HC.OP-IS.EA-0101)
Calculation EA-0012, Rev. 3 Service Water Lubrication Header Size and Available Head
Operation and Maintenance Manual for Solenoid Valves (PJ603Q-0042-03)
Update Final Safety Analysis Report Section 9.5.8, Standby Diesel Generator Combustion Air Intake and Exhaust System
Memorandum FROM W. Capper TO Hope Creek Operations SUBJECT “Scramming Control Rods with Speed Problems, dated September 27, 2003
Letter FROM N. Sadeghi TO C. Brennan SUBJECT “Control Rod Withdrawal Speed Assessment for Hope Creek”, dated April 4, 1996 (NFSI 96-163)
CRD Insertion and Withdraw Speed Test, Adjustment, and Stalled Flows (HC.OP-FT.BF-0001)
Reactor Manual Control System Operation (HC.OP-SO.SF-0001)
HC.RE-ST.BF-0001 Form 2, Single Control Rod Scram Checklist: Control Rod 50-19 (9/27/03)
HC.RE-ST.BF-0001 Form 2, Single Control Rod Scram Checklist: Control Rod 34-15 (9/27/03)
HC.RE-ST.BF-0001 Form 2, Single Control Rod Scram Checklist: Control Rod 34-07 (9/27/03)
HC.RE-ST.BF-0001 Form 2, Single Control Rod Scram Checklist: Control Rod 14-43 (9/27/03)
HC.RE-ST.BF-0001 Form 2, Single Control Rod Scram Checklist: Control Rod 22-59 (9/27/03)
HC.RE-ST.BF-0001 Form 2, Single Control Rod Scram Checklist: Control Rod 22-11 (9/27/03)
HC.OP-FT.BF-0001 Attachment 1, CRD Insertion and Withdraw Speed Test, Adjustment, and Stalled Flows, dated October 7, 2003. (70033715)
P&ID Control Rod Drive Hydraulic (Dwg. —47-1)
UFSAR Section 15.4.1.2, Continuous Rod Withdrawal During Reactor Startup
NRC Inspection Report 50-354/96-03
Operations Department Night Order - Basis for Selection of Control Rods for Speed Time Testing HC-2003-62, dated October 6, 2003
HC.OP-IS.BE-0103, “Core Spray System Valvs - Cold Shutdown Inservice Test, Rev 14
Notifications: 20158056, 20162587, 20166354, 20166355, 20166356, 20155357, 20169632, 20168094, 20167580, 20167754, 20168995, 20168984 and 20171776
Orders: 50065906, 60035544, 60039433, 60039610, 60039491, 70033715, 70034940, 70034874, 70035290

Operator Workarounds (71111.16)

Condition Resolution Operability Determination Notebook
Inoperable Instrument/Alarm/Indicators/Lamps/Device Log
Inoperable Computer Point Log
Hope Creek Operator Workaround List
Hope Creek Operator Concerns List
Technical Issues Fact Sheet, “1 and 2 FWH Isolated Following Reactor Scram,” October 8, 2003
Engineering Document H-1-AE-ECS-0128, “Digital Feedwater Control System,” Rev. 0
Notifications: 20161375, 20161063, 20159307, 20103628, 20164378

Permanent Plant Modifications (71111.17)
UFSAR Section 9.2.7.2, Control Area Chilled Water System
Chiller Unit & Compressor P.M. (HC.MD-PM.GJ-0001)
1989 DCP to Install Oil Recovery System (4-HM-0158)
NRC INFO 94-82, “Effect of Cold Condenser Water Temperatures on Chiller Performance”
Notifications: 20128071, 20167910, 20169122, 20161055, 20160986, and 20168094
Orders: 60039404, 60037671, 70033848, 70033961, 80064555

Post Maintenance Testing (71111.19)
Maintenance Testing Program Matrix (NC.NA-TS.ZZ-0050)
B Fuel Pool Cooling Pump (BP211) Functional Test Semi-Annual and After Pump Maintenance (HC.OP-FT.EC-0002)
C SACS Pump-CP210- Inservice Test (HC.OP-IS.EG-0003)
Reactor Core Isolation Cooling Pump Inservice Test (HC.OP-IS.BD-0001)
Notification: 20162297

Refueling and Other Outage Activities (71111.20)
Outage Management Program (NC.NA-AP.ZZ-0055)
Outage Risk Assessment (NC.OM-AP.ZZ-0001)
Preparation for Plant Startup (HC.OP-IO.ZZ-0002)
Startup From Cold Shutdown to Rated Power (HC.OP-IO.ZZ-0003)
Shutdown From Rated Power to Cold Shutdown (HC.OP-IO.ZZ-0004)
Shutdown Cooling (HC.OP-AB.RPV-0009)
Startup Readiness Evaluation for Drywell Debris Condition
P&ID Main Steam (Dwg M-01-1)
Notifications: 20170791, 20170515, 20170738, and 20170485

Surveillance Testing (71111.22)
B & D Core Spray Pump -BP206 and DP206 Inservice Test (HC.OP-IS.BE-0002)
Emergency Diesel Generator BG400 Operability Test - Monthly (HC.OP-ST.KJ-0002)

Temporary Plant Modifications (71111.23)
Log 3 Control Console Log Condition 1, 2, 3 (HC.OP-DL.ZZ-0003)
Target Rock Engineering Test Report Model 756F SRV Leakage Tolerance Test (VTD 325477)
FAB Isometric Main Steam R.V. Discharge From Line A (DWG 1-P-AB-019)
FAB Isometric Main Steam R.V. Discharge From Line B (DWG 1-P-AB-025)

FAB Isometric Main Steam R.V. Discharge From Line C (DWG 1-P-AB-030)
FAB Isometric Main Steam R.V. Discharge From Line D (DWG 1-P-AB-033)
FAB Isometric Main Steam R.V. Discharge From Line C (DWG 1-P-AB-028)
FAB Isometric Main Steam R.V. Discharge From Line B (DWG 1-P-AB-027)
FAB Isometric Main Steam R.V. Discharge From Line C (DWG 1-P-AB-031)
FAB Isometric Main Steam R.V. Discharge From Line D (DWG 1-P-AB-032)
FAB Isometric Main Steam R.V. Discharge From Line A (DWG 1-P-AB-021)
FAB Isometric Main Steam R.V. Discharge From Line B (DWG 1-P-AB-026)
FAB Isometric Main Steam R.V. Discharge From Line C (DWG 1-P-AB-029)
FAB Isometric Main Steam R.V. Discharge From Line D (DWG 1-P-AB-034)
FAB Isometric Main Steam R.V. Discharge From Line B (DWG 1-P-AB-024)
FAB Isometric Main Steam R.V. Discharge From Line A (DWG 1-P-AB-020)
Order: 70034486

Emergency Preparedness (71114)
PSEG Nuclear Emergency Plan
Emergency Plan Implementing Procedures
NC.EP-DC.ZZ-0010, EP Self-assessment Guide
NEP-PER-02-001A, Ability to Perform Self-Assessments, July 18, 2002
NEP-PER-02-002A, ERO Qualifications Self Assessment, July 23, 2002
QA Assessment Report 2002-0210, 10 CFR 50.54(t) EP review, September 30, 2002
QA Assessment Monitoring Feedback 2002-0274, Unannounced Drill, September 23, 2002
QA Assessment Report 2003-0020, Salem Practice Exercise, March 12, 2003
QA Assessment Report 2003-0180, Unannounced Drill, June 25, 2003
QA Assessment Report 2003-0240, Hope Creek Drill
QA Assessment Report 2003-0197, NRC Performance Indicators
QA Emergency Preparedness Integrated Master Assessment Plan
NEP-PER-02-004A, Facilities and Equipment Readiness, 12/2002
NEP-PER–03-001A, Quality of Response to Plant Events or Drill/Exercise Scenarios, 4/2003
NEP-RV-03-001D, Observation of the Corrective Action Program in EP, 3/2003
NEP-RV-03-001B, Salem/HC Technical Document Room Program Capabilities, 3/2002
NEP-PER-03-001C, How effectively workers and their supervisors utilize operating experience information in Emergency Preparedness, 3/2003
NEP-PER-03-002B, Human Performance Action Plan Status, June/2003
CR No. 80063899-0050, Performance Issues in the TSC and Control Point
CR No. 80063897-0030, Conflicting Information at Joint News Center During Exercise
CR No. 20148989, Interface Between ERO Callout System and ERO Pager System
CR No. 20148989, Untimely Activation of TSC
CR No. 20146629, Accountability Problems

Radioactive Gaseous and Liquid Effluent Treatment and Monitoring Systems (71122.01)

Notifications: 20151430, 20139438, 20159121, 20170309, 20128081, 20156913, 20105187, 20115491, 20120085, 20127284, 20134459, 20137227, 20139732, 20124966, 20109299, 21032318, 20132387, 20158069, 20158423, 20160969, 20162200, 20169647, 21169766, 20128023, 20128081, 20139438

Radioactive Material Processing and Transportation (71122.02)
Areas Inspected:
Service/Radwaste Building elevation 54', cubicles containing:

- Waste surge tank and pumps
- Waste sample tanks A & B and pumps
- Neutralizer tanks A & B and pumps
- Waste collector tanks A & B and pumps
- Cation and anion vessel and pumps
- Decon solutions concentrator package
- Spent resin tank and pumps
- Floor drain collector tanks A & B and pumps
- A, B Floor drain sample tanks and pumps
- Waste evaporator packages A & B
- Concentrator tanks A & B and pumps
- A, B Cleanup phase separators and pumps
- Decon solutions concentrated waste tank and pumps
- Waste sludge phase separator and pumps
- Chemical waste tank and pumps
- Detergent drain tank and pumps

Service/Radwaste Building elevation 102', cubicles containing:

- Fuel pool filter hold pumps
- Waste filter hold pumps
- Extruder evaporators A & B
- Crystalizer bottoms tank
- Extruder evaporator turntable rooms
- Floor drain hold pumps
- Dry waste compactor
- Centrifuge feed tank
- Crystalizer recirculation pump room
- Extruder evaporator drum processing aisle

Service/Radwaste Building elevation 132', cubicles containing:

- Vapor compressor and pumps
- Crystalizer condenser cooler and pumps
- Crystalizer heater and pumps

Quality Assurance Assessment Report 2003-0229
Quality Assessment Monitoring Feedback 2003-0173

Event Followup (71153)
Lube Oil (P&ID M-19-1)
Instrument Calibration Data Report for Order 30021669, dated March 9, 2003
Instrument Calibration Data Report for Order 60039440, dated September 29, 2003
DeLaval Inc Customer Service Letter (CSL) 0002, dated November 27, 1967
DeLaval Instruction Manual Reactor Feed Pump Turbine (PMO12-0099)
Engineering Change Authorization 4HE-0297
Licensee Event Report 05000325/01-03-001
Licensee Event Report 05000354/03-07-000
TARP Report, “Hope Creek Reactor Scram and Loss of Power to T-2, T-4 Transformers and 5037 500 KV Line”, dated September 19, 2003 (Notification 20158787)
Feedwater and Subsystem (AE) System Health Report, Period 10/1/02 to 12/31/02
Feedwater (AE/FW/CJ) System Health Report, Period 4/1/03 to 5/31/03
NRC Inspection Report 50-354/99-05
Notifications: 20158787, 20168195, 20159974, 20159657, 20140623, 20159534, 20159417, 20159367, 20159395, 20159396, 20045028, 20054898, 20030272, 20079308
Order: 30068745, 70033575, 70000770

LIST OF ACRONYMS

ANS	Alert and Notification System
CFR	Code of Federal Regulations
CHR	Containment Heat Removal
CIV	Combined Intermediate Control Valve
CV	Containment Venting
DEP	Drill and Exercise Performance
DFCS	Digital Feedwater Control System
dpm	Dose Per Minute
EAL	Emergency Action Level
EDG	Emergency Diesel Generator
EHC	Electro-Hydraulic Control
EP	Emergency Preparedness
ERO	Emergency Response Organization
FRVS	Filtration, Recirculation and Ventilation System
FWHs	Feedwater Heaters
HCGS	Hope Creek Generating Station
HEPA	High-Efficiency Particulate Air (filter)
HPCI	High Pressure Coolant Injection
HPI	High Pressure Injection
IMC	Inspection Manual Chapter
IPEEE	Individual Plant Examination For External Events
LERs	Licensee Event Reports
LOP	Loss of Offsite Power
LOSW	Loss of Service water
LSRO	Limited Senior Reactor Operator
MR	Maintenance Rule
NCV	Non Cited Violation
NRC	Nuclear Regulatory Commission
ODCM	Offsite Dose Calculation Manual
PARS	Publicly Available Records
PCP	process control program
PCS	Power conversion system
PIs	Performance Indicators
PMT	Post Maintenance Testing
PSEG	Public Service Electric Gas
QC	Quality Control
RCIC	Reactor Core Isolation Cooling
RFP	Reactor Feedwater Pump
RFPT	Reactor Feedwater Pump Turbine
RMS	Radiation Monitoring System
RPV	Reactor/Pressure Vessel
RWCU	Reactor Water Cleanup
SACS	Safety Auxiliaries Cooling System
SDP	Significance Determination Process
SMD	Solar Magnetic Disturbances

SRV	Safety Relief Valves
SSU	Safety System Unavailability
SSWS	Station Service Water System
T-Mod	Temporary Modification
TARP	Transient Assessment Response Plan
TS	Technical Specification
TSC	Technical Support Center
UFSAR	Updated Final Safety Analysis Report