U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Report No. 50-354/88-16

License NPF-57

Licensee: Public Service Electric and Gas Company
P. O. Box 236
Hancocks Bridge, New Jersey 08038

050354-870804
050354-880220
050354-880220
050354-880301
050354-880321
050354-880330
050354-880401
050354-880409
050354-880413

Facility: Hope Creek Generating Station

Dates: April 26, 1988 - May 31, 1988

Inspectors: G. W. Meyer, Senior Resident Inspector

D. K. Allsopp, Resident Inspector

Approved: R.W. Borchardt 7/6/88
For P. D. Swetland, Chief, Projects Section 2B Date

Inspection Summary:
Inspection 50-354/88-16 on April 26, 1988 - May 31, 1988

Areas Inspected: Routine, resident safety inspection of the following areas: operational safety verification, surveillance testing, maintenance activities, engineered safety feature system walkdown, licensee event report followup, emergency preparedness, and assurance of quality.

Results:

The inspectors reviewed PSE&G actions associated with the April 30 reactor scram due to loss of circulating water to the condenser, the May 5 reactor scram due to a reactor feed pump trip and the subsequent low reactor vessel level, and the May 26 Unusual Event concerning loss of both control room chillers (Section 2). The inspectors noted good judgement of the system engineers regarding repairs of the B control room chiller (Section 4). During review of the Primary Containment Instrument Gas System the inspectors identified problems regarding control of a compressor valve setting and Technical Specification interpretation, which were resolved by PSE&G (Section 5). Three licensee identified violations, which had occurred during the refueling outage, were documented in LERs (Section 6). Hope Creek performance during an emergency preparedness accountability drill was acceptable (Section 7).

Details

1.0 SUMMARY OF OPERATIONS

The unit entered this report period with the reactor at full power. On April 30 the reactor was manually scrammed from 75 % power following the loss of circulating water to the main condenser. The four circulating water pumps had consecutively tripped over a three hour period due to an electronic failure in the multiplexed control signals. The reactor was restarted on May 2.

On May 5 the reactor automatically scrammed from full power due to a low reactor vessel level condition, which had resulted from the tripping of one of the two operating reactor feed pumps. The feed pump trip was caused by an inappropriate equipment tagout for preventive maintenance on a secondary condensate pump, which resulted in its tripping. The reactor was restarted on May 6.

On May 26 an Unusual Event was declared and a Technical Specification required shutdown begun when both control room chillers were inoperable for over one hour. Within the next hour one chiller was returned to service, and the shutdown and Unusual Event were terminated. The maximum control room temperature without the chillers was 78 degrees F.

2.0 OPERATIONAL SAFETY VERIFICATION (71707, 71709, and 71881)

2.1 Inspection Activities

On a daily basis throughout the report period, inspections verified that the facility was operated safely and in conformance with regulatory requirements. Public Service Electric and Gas (PSE&G) Company management control was evaluated by direct observation of activities, tours of the facility, interviews and discussions with licensee personnel, independent verification of safety system status and limiting conditions for operation, and review of facility records. PSE&G's compliance with the radiological protection and security programs was also verified on a periodic basis. These inspection activities were conducted in accordance with NRC inspection procedures 71707, 71709, and 71881 and included weekend inspection on May 21 and backshift inspection on May 25.

2.2 Inspection Findings and Significant Plant Events

A. At 8:52 a.m. on April 30, the reactor was manually scrammed due to the loss of all circulating water pumps. The four circulating water pumps lost control power due to problems in the multiplexing of the control signals. The first pump tripped at 5:50 a.m., and the second pump tripped one hour later. The remaining pumps tripped moments before the reactor was scrammed. Evaluations of the control system later found that one power

supply and two logic cards had failed. Following repairs, reactor restart began at 5:50 a.m. on May 2.

B. At 9:17 a.m. on May 5, Hope Creek experienced an automatic reactor scram while performing preventive maintenance on the A secondary condensate pump (SCP) auxiliary oil pump. The reactor had been at 100% power with 3 primary and 3 secondary condensate pumps in operation supplying 2 reactor feed pumps (RFP). The A RFP was out of service for bearing replacement. When the A SCP auxiliary oil pump was de-energized for maintenance, the A SCP tripped, and the resulting feedwater transient tripped the B RFP. The reactor scrammed on low reactor vessel water level. All systems functioned as designed during the scram. The high pressure coolant injection system did not inject and no safety relief valves lifted. The reactor was taken critical on May 6.

C. At 6:00 a.m. on May 26, PSE&G declared an Unusual Event and began a reactor shutdown required by Technical Specifications (TS) due to both control room chillers being inoperable. The two chillers support the Control Room Emergency Filtration System. By 6:40 a.m. one chiller had been restored to service, the shutdown had been stopped at 93 % power, and the Unusual Event had been terminated. Specifically, with the A chiller removed from service for preventive maintenance, the B chiller had tripped twice due to low evaporator pressure. This resulted in both chillers being inoperable; a TS required shutdown condition. The A chiller was refilled with freon and returned to service, but it also tripped. However, following adjustments the A chiller was successfully returned to service, thus ending the event and the shutdown.

D. During the first refueling outage, two control rod drives (CRD) 26-03 and 38-59 were modified to allow the drives to recouple with their respective rods. The two drives initially failed to recouple after their control rods were shuffled from one core location to another to optimize control rod blade lifetime exposure. After repeated failed attempts to recouple the control rod blades, General Electric (GE) and PSE&G Engineering conducted various inspections. They concluded the most probable cause of the failure to recouple was a disengaged CRD inner filter. It is postulated that the disengaged inner filter caused the uncoupling rod to lift, raising the control rod lock plug which prevented recoupling. GE performed a safety evaluation to allow reactor operation with the uncoupling rod removed from both drives. The safety evaluation concluded that normal operation of the CRD without an uncoupling rod could be achieved with two additional considerations:

- Uncoupling of the CRD and control rod could be accomplished only from above (with reactor vessel head removed).

- Affected control rods should not be withdrawn beyond position 46 to prevent reduced cooling flow and subsequent CRD temperatures in excess of 250 degrees F.

Scram performance may be degraded if the disengaged inner filter binds with the index tube inner diameter and simultaneously the inner filter becomes completely blocked. In the unlikely event scram response is degraded, the core scram reactivity would not be significantly affected since both rods are located in the periphery of the core. The licensee increased the frequency for conducting the scram insertion time surveillance test on the two affected rods to once per 120 days of power operation.

With the uncoupling rods removed from both CRDs, the drives recoupled with their respective rods and have displayed normal operating parameters at position 46. These two CRDs are scheduled for disassembly and inspection during the next refueling outage.

During the manual scram inserted on April 30, rod 38-59 inserted normally at about 2.12 seconds; however, rod 26-03 inserted at about 6.5 seconds. Although this is below the 7.0 second maximum scram insertion time allowed by Technical Specifications for an operable rod, it was surprisingly high. During the low reactor vessel level scram on May 5, both rods inserted normally at approximately 2.5 seconds. The resident inspectors will continue to monitor the performance of these control rod drives.

E. On April 26, PSE&G notified the NRC that four reactor vessel level transmitters had instrument tubing lines with spans that exceeded the applicable maximum allowable unsupported span for seismic considerations. The licensee added these non-safety related transmitters in order to closely monitor vessel level oscillations which occurred early in plant life. Although the transmitters and tubing are not part of the Reactor Protection System (RPS) instrumentation, the tubing's failure during a seismic event would have depressurized RPS sensing lines for reactor pressure and vessel level instruments, resulting in incorrect readiness. PSE&G immediately isolated these tubing lines from other tubing, as the tubing was connected to transmitters used to provide GETARS computer inputs and was not necessary for continued reactor operations. The inspector reviewed the eight racks of vessel RPS instrumentation to verify that the tubing was isolated and to ensure PSE&G's information was accurate and found no problems. Later engineering evaluation of the tubing concluded that the tubing spans would not have failed under maximum seismic design loads. The tubing will not be returned to service until the tubing supports are improved. The licensee's failure to maintain the seismic design criteria of the RPS when the GETARS transmitters were connected to the system is considered a licensee identified violation of 10 CFR 50, Appendix B, design control requirements. Based on the prompt reporting of the problem, low safety significance and effective corrective action a citation will not be issued in accordance with Appendix C to 10 CFR 2 (354/88-16-01).

3.0 SURVEILLANCE TESTING (61726)

3.1 Inspection Activity

During this inspection period the inspector performed detailed technical procedure reviews, witnessed in-progress surveillance testing, and reviewed completed surveillance packages. The inspector verified that the surveillance tests were performed in accordance with Technical Specifications, approved procedures, and NRC regulations. These inspection activities were conducted in accordance with NRC inspection procedure 61726.

The following surveillance tests were reviewed, and portions were witnessed by the inspector:

- M9-ILP-02H Type B Leak Test of P-23 Penetration Blank Flange
- M9-ILP-03H Type C Leak Test of P-23 Penetration
- IC-FT.SM-005 Main Steam Line Pressure Setpoint Verification
- IC-FT.BF-001 RWCU Isolation Setpoint Verification
- IC-FT.AB-008 Function Test of Division 4 Main Steam Line Monitor
- IC-CC.BC-017 Channel Calibration of RHR B/D Injection Line Break Alarm

3.2 Inspection Findings

The testing activities inspected were apparently effective with respect to meeting the safety objectives of the surveillance testing program. No problems were identified.

4.0 MAINTENANCE ACTIVITIES (62703)

4.1 Inspection Activity

During this inspection period the inspectors observed selected maintenance activities on safety related equipment to ascertain that these activities were conducted in accordance with approved procedures, Technical Specifications, and appropriate industrial codes and standards. These inspections were conducted in accordance with NRC inspection procedure 62703.

Portions of the following activities were observed by the inspector:

Work Order	Procedure	Description
880526041	None	Add Freon to 1BK400 Chiller
880527060	MD-GP.ZZ-009	Replacement of High Side Float in 1BK400 Chiller

880503229	MD-GP.ZZ-022	Installation of 26 inch Blank Flange on P-23 Penetration

4.2 Inspection Findings

A. The maintenance activities inspected were effective with respect to meeting the safety objectives of the maintenance program. In the above sample, the inspector found the supervisory and management oversight of the work in the field to be commendable as evidenced by substantial direct involvement by management in the jobs in progress.

B. The inspector concluded that float replacement in control room chiller 1BK400 demonstrated good understanding of chiller operation by the system engineers and good reliance of plant management on the engineers' conclusions. Specifically, the high side floats in the control room chillers have exhibited an unusual failure mechanism, cracking in the float adjacent to the arm, after approximately one year. During the preventive maintenance on chiller 1BK400 approximately one month earlier, the float had been replaced with another float of the same design. Subsequently, the chiller was able to perform its function, but its operation was erratic. Although a rapid float failure was unexpected and unlikely based on past experience, the system engineers believed that such a failure existed based on the chiller's operating characteristics. When an improved design float was available, plant management agreed to remove the chiller from service (entering a TS Action Statement) to evaluate the float. When it was found to have failed, the new design float was installed.

5.0 ENGINEERED SAFETY FEATURE (ESF) SYSTEM WALKDOWN (71710)

5.1 Inspection Activity

The Primary Containment Instrument Gas (PCIG) System was reviewed in accordance with NRC inspection procedure 71710 to identify equipment conditions that might degrade performance, to determine that instrumentation was calibrated and functioning, and to verify that valves were properly positioned and locked as appropriate. Also, the inspectors reviewed the operating, alarm response, and abnormal procedures and the instrumentation logic drawings.

5.2 Inspection Findings

The PCIG System was found to be fully functional with the equipment in good physical condition. The inspector noted the following minor problems.

A. The PCIG System has two trains, each of which has a compressor. The compressors use a fraction of the discharged compressed gas to reactivate one of the two dryers on each compressor skid, using a throttle valve and local pressure gauge to set this fraction. The inspector found that both compressors had gauges reading 50 psig. However, the system operating procedure (OP-SO.KL-001) specified a pressure of 40 psig, while the valve lineup specified 60 psig. Further, in the valve lineup the throttle valves were double entered under different valve numbers and descriptions. PSE&G resolved these problems by correcting the double entries, revising the operating procedure to specify 60 psig, and resetting the throttle valves to 60 psig. The inspector concluded that the corrective actions were acceptable and that the above errors had not affected the PCIG System's ability to supply compressed gas or its ability to perform its safety function.

B. Based on interviews with licensed operators, the inspector found differing views on whether the Technical Specifications covered the PCIG System. The Technical Specifications provide requirements on the Main Steam Isolation Valve (MSIV) Sealing System, which depends on compressed gas from the PCIG System to operate. Plant management agreed with the inspectors that an inoperable train of PCIG would render the associated train of the MSIV Sealing System inoperable. A Night Order entry was made to specify this position, and PSE&G committed to establish this position in a formal Technical Specification interpretation to the operators. The inspector concluded that these actions were acceptable and sufficient.

6.0 LICENSEE EVENT REPORT (LER) FOLLOWUP (92700)

PSE&G submitted the following event reports and periodic reports, which were reviewed for accuracy and timely submission. The asterisked (*) reports received additional followup by the inspector for corrective action implementation. The (#) items identify reports which involve licensee identified Technical Specification violations which are not being cited based upon meeting the criteria of 10 CFR 2 Appendix C. The (+) items identify events which are detailed in the inspector's preceding monthly report.

- Monthly Operating Report for February, March, and April
- * Special Report 88-003-00, Valid Emergency Diesel Generator Failure To Start - Equipment Failure
- Special Report 88-004-00, Channel 2 Loose Parts Monitor Inoperable for More Than Thirty Days - Cause Undetermined

- LER 87-036-01 Loss of Control Power to High Pressure Coolant Injection, Reactor Heat Removal and Core Spray Logic Circuits

- * LER 88-002-01 Primary Containment Isolation Valves Inoperable
  # (354/88-16-02)

- LER 88-003-00 Primary Containment Leak Rate Determined in Excess of Allowable During Local Leak Rate Test Due to Component Malfunction

- *+LER 88-004-00 Failure to Perform Surveillance of Refueling Floor Exhaust Process Radiation Monitoring Channel B
  # (354/88-16-03)

- LER 88-005-00 Required Actions Not Taken Due to Inadequate
- LER 88-005-01 Design Change Package Preparation
  # (354/88-16-04)

- +* LER 88-006-00 Intermediate Range Monitor Spike Due to Welding Near IRM Cabinet Causes Full Actuation of Reactor Protection System While in the Non-Coincident Mode

- + LER 88-007-00 RPS Actuation Caused by a Spurious Upscale Spike in "G" Channel Intermediate Range Monitor

- * LER 88-008-00 Caulking Material Discovered Around Reactor Building Blowout Panels - Violation of Configuration Control
  # (354/88-16-05)

- *+LER 88-009-00 Failure to Make Two Four-Hour Flow Rate Estimates During a South Plant Vent Monitor Outage
  # (354/88-16-06)

A. The inspector closed Unresolved Item (88-05-03); Inability to meet primary containment integrity Technical Specification (TS) requirements. This item was left unresolved pending issuance of a revised LER with supplemental information concerning an overdue primary containment local leak rate test (LLRT) of the recirculation sample inboard isolation valve. Revised LER 88-02-01 containing the additional information was issued on April 5, 1988. Although the overdue LLRT surveillance due date was factored into the initiation of the refueling outage, the Operations Department was not informed when the surveillance grace period expired. The Operations Department was notified 11 hours after expiration of the surveillance grace period that the surveillance was overdue. The valve was initially believed not to have shut on command, but was later determined to

have closed but failed to generate a shut indication due to a faulty valve position indication. A subsequent LLRT determined that the inboard and outboard recirculation sample isolation valve leak rates were 2515 and 1770 standard cubic centimeters per minute (SCCM) respectively. These leak rates were a small fraction (3% and 2%) of the 76800 SCCM allowed by TSs. Nevertheless, both valves were reworked during the refueling outage. The subsequent leakage rates on each valve were less than 100 SCCM. This item is closed.

B. Special Report 88-003 describes a valid emergency diesel generator failure to start within the prescribed 10.0 seconds (actual starting time was 10.1 seconds). It was determined that one of the air receivers failed to discharge on the start command as one of the barring gear interlock pistons was stuck in the closed position. A burr on the barring gear interlock piston prevented the piston's return to the open position when the barring device was last utilized, which prevented the passage of control air to one of the main air start valves. Corrective actions included de-burring the piston, cleaning, and satisfactory retesting the diesel.

C. LER 88-004 describes an overdue surveillance test on the refueling floor exhaust process radiation monitoring (RFEPRM) channel "B" 18 month time response test. The plant was in operational condition 5 (refueling) when the overdue surveillance test was reported at 8:00 a.m. on March 1. The previous RFEPRM surveillance test expired at 12:00 p.m. on February 29. The radiation monitor was declared inoperable, the appropriate action statement entered, and the filtration, recirculation and ventilation system placed in service to establish secondary containment. This was a technical specification violation in that core alterations (control rod movements) were initiated at 6:52 a.m. on March 1. Additional details on this event are discussed in paragraph 2.2 of NRC Inspection Report 88-09.

D. LER 88-006 details a full reactor protection system (RPS) actuation (scram signal) which was generated in response to a momentary upscale spike on "A" intermediate range monitor (IRM) with RPS in the non-coincident mode (shorting links removed). There was no control rod motion in response to the scram signal as the reactor was shutdown with all rods fully inserted. The upscale spike on "A" IRM was caused by electronic noise which was created by contractor tig welding which was taking place in the vicinity of the "A" IRM pre-amp cabinet. Two similar previous occurrences were initiated by permanent station technicians and reoccurrence has been effectively precluded by training and counseling. This incident resulted from contractors apparently being unaware and uninformed of the sensitivity of the IRM circuitry.

E. LER 88-008 details the discovery of caulking around the reactor building exterior blowout panels without proper design change authorization. The plant was in cold shutdown when the caulk was discovered. The presence of the caulk was estimated by an engineering evaluation to increase the blowout panel release setpoint from 1.5 psid to 1.59 psid. The main purpose of the blowout panels is to provide pressure relief protection to the secondary containment which is designed for 3 psid. Since this value is substantially above the pressure release value of the caulked blowout panels, the structural integrity of the secondary containment was not compromised by the caulk.

F. LER 88-009 describes two missed four-hour flow rate estimates which were required by technical specification due to an inoperable south plant vent monitor. The two flow rate estimates were missed due to failure of both licensed and non-licensed operators to initiate and properly complete the daily surveillance log. Corrective actions included counseling the responsible personnel in the importance of completing all daily log forms fully. Additional details on this event are discussed in paragraph 2.2 of NRC Inspection Report 88-09.

7.0 EMERGENCY PREPAREDNESS (EP) (82301)

On May 26 the inspector observed Accountability Drill 88-02, during which the scenario included declaration of an Alert and a Site Area Emergency, with its associated personnel accountability actions. The inspector observed control room activities and reviewed PSE&G actions taken under EP Procedures EPIP 102H, Alert and 103H, Site Area Emergency. The inspector did not identify any problems.

8.0 ASSURANCE OF QUALITY

Hope Creek's approach to analyzing incidents and tracking corrective actions is very effective. The Incident Report program establishes a low entry threshold for unusual or unplanned events to be analyzed as incidents. All incidents are evaluated in regard to personnel training and experience, administrative controls, and applicable human factors aspects to determine the root cause of the event. A detailed explanation of the event, the root cause analysis, and corrective actions are entered into a computer data base for trending and recall. This data base has key word search capability and is routinely utilized to determine if similar events have occurred previously and to evaluate adequacy of corrective action.

Improvements and corrective action commitments generated at any time are entered into a computer tracking system. This computerized commitment system tracks the due date for each commitment and is reviewed by all department heads on a weekly basis.

In conclusion, this program allows an analysis of a broad number of off-normal events and effectively tracks corrective actions to implementation. The data base generated during incident evaluation has improved root cause analysis and has enhanced Hope Creek's proficiency at implementing effective corrective actions. This detailed approach to analyzing Incident Reports is beyond NRC requirements and demonstrates Hope Creek's desire to improve performance by optimizing the lessons learned from each past incident.

9.0 EXIT INTERVIEW (30703)

The inspectors met with Mr. S. LaBruna and other PSE&G personnel periodically and at the end of the inspection report period to summarize the scope and findings of their inspection activities.

Based on Region I review and discussions with PSE&G, it was determined that this report does not contain information subject to 10 CFR 2 restrictions.