U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Report No. 50-354/88-09

License NPF-57

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

Facility: Hope Creek Generating Station

Dates: March 22, 1988 - April 25, 1988

Inspectors: G. W. Meyer, Senior Resident Inspector

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Approved: P D Swetland 5/24/88
P. D. Swetland, Chief, Projects Section 2B Date

Inspection Summary:
Inspection 50-354/88-09 on March 22, 1988 - April 25, 1988

Areas Inspected: Resident safety inspection with increased inspection of the reactor startup and routine inspection of the following areas: operational safety verification, surveillance testing, maintenance activities, review of maintenance program, engineered safety feature system walkdown, assurance of quality, roving firewatch program, including allegation closeout, and battery room temperature.

Results: Overall, the completion of the first refueling outage and the reactor startup were accomplished acceptably. Two licensee identified violations (sleeping guard and twice omitted four hour flow rate readings while the south plant vent flow monitor was inoperable) were not cited based on NRC Enforcement Policy (Section 2.2). An earlier review of the maintenance program found it to be effective (Section 4.2). A conservative approach toward equipment testing was noted (Section 6). Reviews of the roving fire watches (Section 7) and battery room temperatures (Section 8) found these areas to be acceptable.

Details

1.0 Summary of Operations

The unit entered this report period with the reactor in cold shutdown, the reactor head removed, and having completed all core alterations. Outage work continued primarily on modifications, corrective maintenance, and system restoration. On March 30 while shutdown, a reactor scram occurred due to a spike on Intermediate Range Monitor (IRM) G concurrent with an existing half scram signal due to surveillance testing on D main steam line (MSL) high radiation monitor, and this resulted in the insertion of one control rod withdrawn for control rod drive (CRD) mechanism removal.

On April 10 the mode switch was placed in Startup, and the reactor was taken critical at 6:30 a.m., ending the 62 day first refueling outage. Primarily delayed by High Pressure Core Injection (HPCI) testing and overspeed trip problems and by main turbine torsional testing, the reactor continued to operate at low power until April 15, when the reactor was synchronized to the grid. Full power was reached shortly afterwards and remained there through the remainder of the inspection period.

Effective March 21 Glenn Meyer was assigned as Senior Resident Inspector at Hope Creek.

2.0 Operational Safety Verification (61707, 71707, 71709, 71711, 71715, 71881, 92700, 92701)

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 61707, 71707, 71709, 71711, 71715, and 71881 and included weekend and backshift inspections on April 9, 10, 11, 13, and 14.

The inspectors utilized extended coverage for the significant evolutions of the reactor startup begun on April 10, including control rod withdrawal to criticality, reactor heatup, low pressure HPCI and RCIC testing, safety relief valve (SRV) actuations, and synchronizing of the turbine to the grid.

The inspectors observed plant activities performed under the following operations procedures:

- OP-IO.ZZ-003, Startup From Cold Shutdown to Rated Power
- OP-AB.ZZ-104, Stuck Control Rod
- OP-SO.AC-001, Main Turbine Operation
- RE-ST.ZZ-005, Reactivity Anomaly Check
- RE-ST.ZZ-007, Shutdown Margin Demonstration

The inspectors reviewed the completion of testing, system restoration, and maintenance activities and sign-off of mode change prerequisites in preparation for reactor startup. This process was administratively controlled under procedure OP-IO.ZZ-002, Preparation for Plant Startup. Further, the inspectors reviewed the Temporary Modification Log regarding control of jumpers, lifted leads, and other temporary equipment changes.

The inspector reviewed the training materials provided to licensed operators covering the modifications installed in plant equipment during the outage. Also, the inspector reviewed records of operator attendance and interviewed operators on their understanding of the changes.

2.2 Inspection Findings and Significant Plant Events

A. On March 30 a reactor scram occurred while shutdown due to a spike on IRM channel G concurrent with an existing half scram signal due to surveillance testing of main steam line (MSL) high radiation channel D. One control rod was withdrawn in preparation for CRD mechanism removal at the time of the scram, and the scram inserted this rod. Preliminary PSE&G evaluation identified that installation of shield plates in the vicinity of the IRM electrical cabinets could have caused the spike.

B. On April 12 a reactor level transient occurred while at 2% power while the functional test of the vessel level 8 feed pump and main turbine trips was in progress. Due to the feed pumps being unavailable earlier, the test was performed at low power, although previous tests had routinely been done with the reactor shutdown. However, the operators and technicians did not recognize this difference, and the procedure did not alert them to the consequences of the testing if the vessel level control was in automatic mode. Accordingly, when the testing removed the vessel level inputs to the level control system, the system sensed a low level and responded by fully opening the feedwater control valve. Vessel level increased rapidly from its normal range of 35 inches and eventually reached approximately 110 inches. The control room operators reacted to the high level alarms and increasing level by determining the problem and isolating feedwater. The large addition of cold water to the reactor resulted in a power spike from 2% to approximately 10% and then returning to 2%. The operators reset the initial half scram on IRM power before the second IRM half scram occurred and thereby avoided a reactor scram. The inspector concluded that the operators' actions had been proper and timely and demonstrated good response to the transient.

PSE&G plans to revise the test procedure to highlight the potential problems and to utilize manual vessel level control and plans to emphasize the need for operators to evaluate the potential consequences if tests are performed in different modes than assumed in the test procedures.

C. On April 22 a full runback of the turbine and reactor to 60% power occurred due to a momentarily indicated loss of generator stator cooling during the calibration of a conductivity meter in the stator cooling system. PSE&G is evaluating the incident and possible design changes to this generator protection circuit, because the circuit uses a one out of one logic and had resulted in a previous runback.

D. On April 14 a valve in the HPCI control/lubrication oil system was found to be mispositioned (Section 3.2.A contains discussion of the testing aspects of this issue). The valve meters the rate at which oil is supplied to the steam supply governor valve and was adjusted during startup testing to optimize HPCI performance. (If more oil is supplied to the governor valve than necessary, the oil pressure is lessened in other areas.) To maintain the valve position as set during startup testing, PSE&G removed the handwheel, hung a caution label on the valve, and excluded it from valve checkoff lists to prevent manipulation. When found mispositioned, another handwheel had been placed on the valve. The Operations Manager stated that a design change would be implemented to physically assure that the valve position is maintained and that the valve checkoff list will be revised to verify that the position restriction device is properly in place. Further, the Operations Manager stated that this valve was the only valve which had been intentionally excluded from the checkoff list on this basis. The inspector agreed the above corrective actions were acceptable and appropriate. The acceptability of the device designed to maintain the valve's position will be reviewed under Open Item 50-354/88-09-01.

E. On April 13 readings required to be taken every four hours by a Technical Specification (TS) 3.3.7.11-1 Action Statement 122 were not taken over an eight hour period. Specifically, a flow rate monitor in the south plant vent monitoring system had been inoperable since February 15, and the four hour readings needed to estimate the flow rate had been taken. However, on April 13 an equipment operator took the 4 a.m. readings but did not transfer them to the record log sheet. The equipment operator on the next shift saw the blank column on the log sheet and did not take the readings on his eight hour shift as he assumed the action statement no longer applied. Personnel on the following shift recognized the oversight and reinitiated the readings. This error will be addressed in an LER. Although this is a TS violation, it will not be cited with a Notice of Violation based upon meeting the criteria of 10 CFR 2, Appendix C regarding licensee identified violations. (50-354/88-09-02)

F. At 1:20 a.m. on March 30, a security guard required by the Artificial Island Security Plan for access control was determined to be sleeping at her post. PSE&G detected the sleeping guard and had her relieved by a new guard. PSE&G searched the affected area for signs of unauthorized access and reported the incident to the NRC. The search indicated no unauthorized or undetected access had occurred. PSE&G determined the guard's inattentiveness to have spanned a maximum time period of 34 minutes. After reviewing the incident, PSE&G fired the inattentive security guard. Although this is a violation of the Artificial Island Security Plan, it will not be cited with a Notice of Violation based upon meeting the criteria of 10 CFR 2, Appendix C regarding licensee identified violations. (50-354/88-09-03)

G. During a local leak rate test (LLRT) on March 26, PSE&G determined that leakage through the reactor core isolation cooling (RCIC) minimum flow valve (FO-19) exceeded the Technical Specification (3.6.1.1) primary containment leakage limit of 10 gpm. The plant was in cold shutdown for its first refueling when the excessive leak rate was determined. FO-19 is a 2-inch DC solenoid operated valve which is installed such that torus pressure would tend to unseat the valve. To reduce primary containment leakage through this penetration, PSE&G has installed an additional valve similar in design to the FO-19 valve, however positioned such that torus pressure tends to seat the valve. The subject primary penetration has subsequently successfully passed an LLRT. While researching the excessive leakage on the FO-19 penetration, PSE&G identified an inaccuracy in the hydrostatic LLRT procedure. The inaccuracy resulted from pressure drops in the test rig and tubing between the test rig and the test volume. The hydrostatic LLRT procedure was revised and all hydrostatic LLRTs were reperformed. The inspector reviewed the procedure correction and observed the first LLRT reperformed. The inspector noted no deficiencies.

H. On April 3 the inspector looked for Abnormal Operating Procedure OP-AB.ZZ-132, Loss of Instrument Air and/or Service Air in the control room and found this procedure absent. The inspector checked other procedures within this book, found them all in their proper place, and concluded that the missing procedure was an isolated case. Later, the inspector confirmed that the absent procedure was placed in the book.

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, with portions witnessed by the inspector:

- OP-ST.SV-002 Remote Shutdown Panel Operability Test
- OP-ST.BJ-002 Functional Test of HPCI at Low Pressure
- OP-IS.GS-101 Containment Atmosphere Control Valve - Inservice Test
- OP-IS.BD-001 RCIC Pump - Inservice Test
- IC-CC.SE-021 Channel Calibration of LPRM Group A
- IC-CC.SE-022 Channel Calibration of LPRM Group B
- IC-FT.SE-007 Functional Test of IRM Channel C

- IC-FT.BE-005 Functional Test of Core Spray Injection Line Pressure
- IC-FT.BJ-004 Functional Test of HPCI Pump Discharge Flow
- IC-TR.SB-005 Time Response Test of Turbine Stop Valve Closure and EOC-RPT

3.2 Inspection Findings

A. The inspector reviewed the resolution of HPCI System testing concerns and concluded that the PSE&G approach was conservative. Specifically, the concerns arose when the time response test of HPCI found that rated flow was achieved within 18 seconds and the stroke time of one of the HPCI injection valves was 32 seconds. The test procedures had used the Technical Specification HPCI response time of 27 seconds as acceptance criteria for both parameters. Following further evaluation, PSE&G concluded that based on rated flow being achievable with the injection valves less than fully open, the acceptance criteria for the valve stroke time could be up to 44 seconds.

However, based on the measured 12 seconds to rated HPCI flow during the actual vessel injection test of startup testing, PSE&G concluded that the 18 second test result was too slow and further evaluated HPCI to determine the cause. A valve in the HPCI control/lubrication oil system was found fully open. When returned to 1/2 turn open, the time to rated flow was reduced to less than 12 seconds. (The control of the control oil valve is discussed in Section 2.2.D) PSE&G revised the test acceptance criteria to reflect the above evaluations.

B. The inspector noted two minor procedural problems which should have been addressed in previous tests. Specifically, in test IC-TR.SB-005 the procedure directed that a recorder lead be installed in one panel, but when no response was noted during the test run, it was found that the lead was connected to the "correct" terminal but in the wrong panel. When properly connected, the test was performed and recorded correctly. The I&C supervisor reviewed the record of the previous test and found that it had been performed according to the same incorrect procedure step. The licensee was uncertain why the incorrect panel problem was not previously identified and the procedure revised. Further, in test IC-ST.BJ-002 the procedure specified how to set the recorder for recording the HPCI flow rate. However, during the HPCI run the flow rate was recorded, but the recorder did not provide the marks by which to measure the flow rate.

Following a test procedure change, the HPCI run was repeated and the flow rate data was recorded properly. It appeared to the inspector that this error should have been corrected during previous tests.

C. The inspector found the above surveillance tests to be performed acceptably and concluded that the surveillance testing activities were effective with respect to meeting the safety objectives of the program. The inspector noted that whenever problems arose during the testing, the problems were resolved properly with good involvement of the first line supervisors. Also, in the IC-FT.BJ-004 test the trip unit setpoint was adjusted, and the procedure specified a quality control (QC) hold point for the adjustment. The coordination between the technicians and the QC inspector was good, and the QC inspector was knowledgeable.

The inspector concluded that the PSE&G response was thorough and acceptable; in both instances, applicable supervisors were involved, test procedure changes were made, and the tests were repeated properly. However, it appeared that these actions could have been taken on prior tests and apparently were not.

4.0 Maintenance Activities (37702, 62700, 62702, 62703)

4.1 Inspection Activity

During this inspection period the inspector 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.

Portions of the following activities were observed by the inspector:

Work Order	Procedure	Description
870701093	MD-PM.FD-001	HPCI Steam Turbine Inspection and Preventive Maintenance
880405094	Work Standard B653080202	Bailey 862 Humidity Modification Verification and Retest

Work Order	Procedure	Description
870816001	M9-ILP-03H	Type "C" LLRT on HV-4680
880402072	IC-GP.ZZ-008	Relay Replacement
880409093		Repair of Flow Regulator in B Recirculation Seal Purge Line

The maintenance activities inspected were effective with respect to meeting the safety objectives of the maintenance program.

4.2 Review of Maintenance Program

During November 1987 an inspector assessed the maintenance program to ensure that the program was effective and performed in compliance with regulations, Technical Specifications and commitments. The Maintenance Department was found to be well staffed with minimal need of contractor help for the day-to-day operations. However, a portion of the I&C group was still contracted from Bogen Controls. The inspector noted a strong QA interface with maintenance activities, and, during the observed work, there was sufficient QA coverage in the field.

The inspector reviewed preventive maintenance procedures SA-AP.ZZ-010, Control of Station PM Program and MD-AP.ZZ-010, Preventive Maintenance Program. The inspector also interviewed personnel involved with the preparation and implementation of the preventive maintenance program. The inspector found the preventive maintenance procedures to be technically adequate and found that maintenance personnel understood the procedures.

The inspector reviewed the following corrective maintenance procedures and records:

W/O 871011073	Replacement of J Safety Relief Valve
MD-CM.AB-006	Main Steam Relief Valve Removal and Installation
MD-CM.KF-001	General Load Handling
MD-GP.ZZ-009	Tool and Misc. Item Closure Control
W/O 871118097	Repair leak on inlet of A2 SACS HX on SW side Code Job Package H-87-092 Safety Evaluation 87-191

A. On October 10, 1987 while performing Safety Relief Valve (SRV) lift tests to retest acoustic monitors replaced on the SRVs, the J SRV failed open. (See Inspection Report 50-354/87-24 for more details.) A work package was generated to replace the failed SRV. The work was started on October 11, 1987, after the plant was in a cold shutdown condition. The work package included the work order, the corrective maintenance procedure for the removal and installation of the Main Steam Safety Relief Valve, and procedures to control the load handling and tool control. The maintenance procedures and special process procedures were found to be adequate to perform the work. The work order and work package were found to be complete and well documented.

B. On November 17, 1987, a 3/8 inch diameter hole was discovered on the service water inlet of the A2 safety auxiliary cooling system (SACS) heat exchanger. The hole was located on the bottom of the pipe at the six o'clock position near the weld area of the heat exchanger inlet. The entire circumference of the pipe in the weld region and approximately one incn upstream from the weld was ultrasonically tested for wall thickness. The results from the nondestructive test indicated that the failure was a localized event and that all the thickness readings surrounding the failure area were equal to or greater than nominal wall thickness.

The probable cause was a breakdown of the epoxy phenolic lining, known as belzone treating, during the welding process. When this exposed metal area was then subjected to a corrosive water environment, it ultimately corroded through the pipe wall. During the initial investigation and ultrasonic work the system engineer was present to aid in the evaluation of the problem and the expediting of the subsequent repair. The system engineer prepared the safety evaluation for the job. To ensure that the portion of the service water piping is repaired during the outage, the station left Deficiency Report HMD-87-128 open to provide an additional administrative control.

PSE&G repaired the pipe using a 3/4 inch plug. The inspector observed portions of the repair work. There was adequate Quality Assurance during the work. Also, the Quality Assurance group worked on the preparation of the ASME Code job package. The work package included the welding permits, the deficiency report, the safety evaluation, and the code job package. The inspector reviewed the safety evaluation and found it acceptable.

Based on the above review, the inspector concluded that the maintenance program was effective with respect to meeting the safety objectives of the maintenance program.

5.0 Engineered Safety Feature (ESF) System Walkdown (71710)

5.1 Inspection Activity

The inspector independently verified the operability of Core Spray System loop A, a selected ESF system, by performing a walkdown of accessible portions of the system to confirm that system lineup procedures match plant drawings and the as-built configuration. This ESF system was walked down in accordance with NRC inspection procedure 71710 to identify equipment conditions that might degrade performance, to determine that instrumentation is calibrated and functioning, and to verify that valves are properly positioned and locked as appropriate.

5.2 Inspection Findings

The inspector found Core Spray loop A to be in very good physical condition and fully functional. The inspector found all valves to be properly identified with tags and to be positioned correctly.

6.0 Assurance of Quality (61726)

The inspectors concluded that PSE&G utilized generally good assurance of quality during the completion of the outage and the subsequent reactor startup. During observations of operations, maintenance, and surveillance testing activities, the inspectors found the personnel to be technically knowledgeable with an appropriate understanding of the specific work task. The first line supervisors were frequently evident at the work locations, were informed of problems when not at the work location, and resolved the problems adequately. The managers exercised good safety approaches to resolving problems, and the status meetings between managers were well controlled and directed toward resolving problems. The inspectors did not observe any excessive cost or schedule pressures associated with the resumption of power operations.

The inspectors noted a commendable approach toward thorough testing of equipment. Specifically, during testing of the HPCI overspeed trip, PSE&G specified that two successive, acceptable functional tests of the trip were necessary. During the initial testing one acceptable functional test was achieved, which would normally be a sufficient basis to proceed. However, during the second test the trip failed to work properly, and this resulted in additional cleaning of the trip mechanism and oil reservoir and in further adjustments. Eventually, the HPCI overspeed trip was demonstrated to function reliably. The Technical Specifications require that the five safety relief valves (SRVs) in the Automatic Depressurization

System (ADS) be actuated while the reactor is pressurized. PSE&G actuated all fourteen SRVs. In both of the above examples, the testing activities were on the critical path to resuming power operations and represented a significant schedule problem if the tests had failed. Despite these potentially adverse considerations, PSE&G's decision to thoroughly test these components is commendable.

7.0 Roving Fire Watch Program (64704)

As a result of the numerous fire impairments identified early in the Hope Creek Penetration Seal Review, a roving fire watch program was implemented to compensate for identified fire barrier deficiencies. The fire watch program consisted of five roving watchstanders per shift who visually inspected designated fire penetrations every hour.

On March 14, 1988, the Penetration Seal review was completed, and all impairments requiring seal installation, repair, or rework were documented. This documentation consisted of a Fire Protection Impairment Permit (FPIP) being issued for each penetration seal that did not meet the required fire criteria. As a result of this review, Engineering recommended reducing the roving fire watch program to be commensurate with the number of open FPIPs which required fire watch inspection. The number of deficient penetration seals had been reduced from a maximum of over 600. Evaluation determined that the roving fire watch inspection requirements had been reduced from the original 600 to approximately 80 fire barriers. Fire watch supervision planned for the force reduction by walking down the individual tour routes and determining estimated tour times. Fire watch supervision consolidated and reduced the number of fire watches to two per shift after determining that neither roving watch should exceed 50 minutes during an inspection tour. When the transition to two roving watches was implemented several incidents were documented in which the roving watch exceeded the one hour allowed during tours. The maximum interval between specific penetration inspections was 1 hour 45 minutes, which occurred on the third shift. Fire watch supervision attempted to resolve this problem by designating a most-time efficient inspection route. Supervision also assigned the fire watch supervisor to accompany the watchstander on the first inspection of the shift to familiarize the fire watch with the new route. When an additional incident of greater than 1 hour between tours occurred, fire watch supervision added an additional fire watch to further reduce the individual tour lengths. Since implementation of this latest modification, there have been no further problems with the roving watches.

The inspectors have no further questions in this area.

8.0 Battery Room Temperature (92702)

As followup to Regional Temporary Instruction 87-07 and the battery evaluation documented in Inspection Report 50-354/88-01 and due to the potential for cold battery rooms to adversely affect the operational condition of batteries, on March 22, 1988 the inspectors measured the ambient temperature of the following battery rooms.

Battery Room	Batteries	Ambient Temperature (Degrees F)
5126	1A1D 471 1A2D 471 1B1D 471 1B2D 471	62
5104	10D 421	67
5128	10D 431	69
5539	1DD 411	78
5541	1BD 411	78
5543	1CD 411	78
5545	1AD 411	76
5526	1B2D 477 1B1D 477	63
5627	1A1D 477 1A2D 477	66
5609	1DD 477	65
5614	1CD 477	61
Fire Pump House	A; B	60

During the battery room temperature measurement, the outside air temperature was between 24 degrees and 32 degrees, and the reactor had been shutdown for over a month. The inspector concluded that these conditions represented an adequate test of the battery room temperatures. Based on the measured ambient temperatures, the inspector concluded that the batteries would be able to perform their intended design functions without impairment due to ambient temperature. Further, the inspection also reviewed the physical condition of the batteries, room ventilation and exhaust, presence of smoke detectors, and absence of localized heat sources. The inspector found these parameters to be acceptable in all battery rooms and found the general condition of all batteries to be excellent.

The above actions also close out open item TI-87-07 in regard to field inspection.

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.