U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Report No: 50-286/86-21

Docket No. 50-286

Licensee: Power Authority of the State of New York
10 Columbus Circle
New York, New York 10019

Facility: Indian Point Nuclear Generating Station, Unit 3

Location: Buchanan, New York

Dates: August 11, 1986 to September 22, 1986

Inspectors: P. S. Koltay, Senior Resident Inspector
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Reviewed by: Glenn W. Meyer
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10/15/86
date

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Inspection Summary:
Inspection on August 11, 1986 to September 22, 1986 (Inspection Report 50-286/86-21)

Areas Inspected: Routine onsite regular and backshift inspection of plant operations including shift logs and records; licensee actions on previously identified inspection findings; facility operations; reactor trips; plant tours; system walkdowns, two of which used the guidance provided in NUREG-4565, "Probabilistic Safety Study Application Program for Inspection of the Indian Point Unit 3 Nuclear Power Plant"; surveillance; maintenance; and the review of Monthly Operating Reports. The inspection involved 170 hours by the resident inspectors.

Results: An apparent violation of the Technical Specification requirement concerning safeguard pumps operability occurred during plant heatup (Section 4). The licensee experienced two reactor trips caused by random equipment failures while returning to power operations following a 59-day forced outage (Section 3).

DETAILS

1. Licensee Actions on Previously Identified Inspection Findings

(Closed) Unresolved Items (286/85-26-01 and 86-02-02) The subject reports identify the failure of the Safety Parameter Display System (SPDS) computer to record and print out sequence of events data and reports following reactor trips. Subsequently the licensee installed a computer, independent of the SPDS which has been providing the pertinent historical data. The inspector verified that the licensee also completed the necessary changes to the SPDS software and the computer recorded the sequence of events during the two recent reactor trips.

2. Facility Operations

The licensee completed a 59-day forced turbine repair outage. Two low pressure rotors, Nos. 31 and 32, were replaced and repaired, respectively, while No. 33 rotor was modified. The modification consists of the removal of both L-0 rows of blading and the installation of stationary baffles to maintain design pressure gradients. In parallel with the turbine repairs, the licensee also replaced No. 32 main transformer.

Unit heatup was initiated on September 2. An apparent violation of Technical Specification requirements was identified on the same day, when the unit was heated above cold shutdown conditions while the automatic function of three required safeguard pumps was defeated in the control room. (Section 4).

Two reactor trips occurred during plant startup and power escalation. On September 5, a turbine trip/reactor trip occurred from 58% power, when the main generator motor disconnect opened due to a control circuit fault. On September 9, the reactor tripped from 95% power due to low steam generator levels caused by feedwater perturbation (Section 3). The unit was returned to power operations on September 10.

3. Reactor Trips

During this period, two reactor trips occurred, and random equipment failures were identified as the initiating event in each case. Subsequent to the reactor trips, protection systems operated as per design and the unit was stabilized in the hot shutdown condition.

On September 5, at 3:50 p.m., a turbine/reactor trip occurred from 58% power. The turbine trip was initiated by the opening of the main generator disconnect F1-3, due to a fault in its D.C. control circuit. The faulty equipment is located in the Buchanan switchyard and is under the jurisdiction of the Consolidated Edison Company. The licensee is presently negotiating to obtain inspection and repair authority over the subject equipment.

On September 9, at 10:00 a.m., the reactor tripped from 95% power when the loss of No. 32 main feed pump resulted in low steam generator levels. The licensee's investigation determined that a normally floating main feed pump seal cocked, allowing water to travel along the shaft and enter into the bearing housing, thus contaminating the oil and clogging a control oil orifice resulting in a main feed pump trip on low control oil pressure. The licensee repaired the seal and replaced the contaminated oil prior to restoring the main feed pump to service.

The inspector verified that the licensee conducted in-depth post trip reviews and the decision to return the unit to operations was made at the appropriate management levels. Sequence of events printouts from the safety parameters display system computer were available following each event.

No violations were identified.

4. Plant Tours

4.1 Inspection Activities

The inspectors conducted routine entries into the Control Building, Turbine Building, Primary Auxiliary Building, Auxiliary Boiler Feedwater Pump Building and the Intake Structure.

The inspectors observed Central Control Room activities, including shift turnovers, log entries and responses to alarm annunciators, as well as maintenance and surveillance activities in progress. Particular note was taken for the presence of quality control inspectors, quality control evidence and housekeeping. The inspectors interviewed operators, technicians, mechanics, supervisors and plant management. The purpose of the inspection was to affirm the licensee's commitments to and compliance with 10CFR, Technical Specifications and licensee administrative procedures.

4.2 Findings

4.2.1 On September 2 at approximately 7:00 a.m., during a routine tour of the control room, the inspector noted that unit heatup from cold shutdown had commenced in order to return the unit to power operations. Plant status at the time was as follows:

- Primary coolant average temperature (Tavg) was approximately 310 F. increasing, and
- Primary coolant pressure was approximately 500 psi and increasing.

While in the control room, the inspector reviewed the completed pre-warmup checkoff list, procedure COL-RPC-1, Revision 14.

The checkoff list was completed on September 1 and each requirement to be met before exceeding RCS cold shutdown conditions was initialed by a licensed operator. A shift supervisor log entry of September 1 stated that all requirements to go above cold shutdown conditions were met. Procedure COL-RPC-1, Section A requires that Technical Specifications 3.3.A.1.d and 3.3.B.1.b be met prior to bringing the reactor coolant system above cold shutdown and exceeding 200 F temperature, respectively. Technical Specification sections 3.3.A.1.d and 3.3.B.1.b and COL-RPC-1 Sections A 3.4 and A 3.6 require that one recirculation pump and two containment spray pumps be operable prior to exceeding cold shutdown.

Contrary to the above, on September 2, the inspector observed that with the reactor coolant system at 310 F., which is in excess of cold shutdown condition temperature, all the recirculation pumps and containment spray pumps automatic start features were defeated in the control room with the control switches in the stop pullout position, rendering the required pumps inoperable. Based on control room log entries, the Technical Specification (T.S.) requirements were not met for approximately six hours. This is an apparent violation of the subject T. S. and licensee procedure. (86-21-01)

The operators took immediate corrective action to place the pump controls in the automatic position when the inspector informed them of the violation.

In addition to the one recirculation pump and two containment spray pumps identified in the violation, the inspector noted that the automatic start features of four other safeguards pumps, the redundant recirculation pump and three safety injection pumps, were also defeated in the control room. Procedure COL-RPC-1, Section B, requires that the reactor coolant system not be above 350 F. unless two recirculation pumps and three safety injection (SI) pumps are operable. The licensee's procedure checkoff list indicated that these conditions were satisfied, contrary to the inspector's finding. The shift supervisor's log entry of September 2 stated that requirements to go above 350 F. were met.

The licensee restored the SI pump lineup before reaching the 350 F. limit. Although the safeguards off-normal annunciator alarm was lighted and the plant start-up procedure required the manipulation of the safety injection pump controls at 326°F, the completion and acceptance of COL-RPC-1, Sections A and B, removed one of the formal mechanisms to systematically identify the error.

Later the inspector determined that the automatic functions of the seven safety-related pumps were defeated by placing their respective control switches in the stop pullout mode as early as August 30, two days before the completion of the pre-warmup checkoff list. This fact is supported by the licensee's procedure COL-SI-1, Safety Injection checkoff list, completed on 8/30/86, which identified the pump control switches in question in the stop pullout position. The items were properly circled in red indicating an off-normal lineup. The inspector noted that COLs performed in the field duplicate COL-RPC-1, performed in the control room, in the areas of safety-related pump control switches and critical valve positions.

Based on the review of documents including logs, checkoff lists and plant startup procedures, and on the interviews with licensed operators, the inspector concluded that the following personnel errors contributed to the noted conditions:

- The senior reactor operators did not maintain positive control of heat-up activities.

- The checkoff list, COL-RPC-1, for control room line ups, was completed and initialed, in part, by a licensed reactor operator designated as the "rover" whose primary functions during the shift are outside the control room.

- The senior reactor operators and shift supervisors did not conduct a timely review of the checkoff list prior to exceeding the 200 F. primary coolant average temperature cold shutdown limit.

- Shift turnovers at the senior reactor operator, reactor operator and shift supervisor levels did not identify the position of the safeguards pumps as improper for the existing plant conditions.

Subsequent to the event, the inspector met with the Resident Manager and the Superintendent of Power, who recognized the seriousness of the event and initiated immediate corrective action as follows:

- The pre-warmup checkoff list was reissued and properly completed. No other discrepancies in system lineups were identified.

- New control room access limit rules were established.

- Senior reactor operator leadership functions were reiterated to all shift crews.

For long term corrective actions, the licensee will:

- Revise the checkoff list and set time limits for its completion and review prior to exceeding specific plant conditions.

- Review INPO good practices for shift turnover and incorporate them into plant practices as applicable.

4.2.2 The inspector noted that the "Computer Alarm NIS Rad Tilt or Rod Deviation" annunciator alarm was continually lit in the control room following the reactor startup. He questioned the licensee concerning the cause for the alarm. The licensee stated that the alarm was caused by problems with computer input data on rod position indication and was not then indicative of a current safety problem. However, the condition could have masked a subsequent alarm condition. The inspector later confirmed that the licensee corrected the problem and returned the annunciator to operable status prior to the end of this report period.

4.2.3 The inspector noted during a routine tour of the control room that the Train B Hydrogen Sampling Line Low Temperature Alarm was annunciating. (The sampling line for the hydrogen monitors is maintained at an elevated temperature to avoid the formation of a water loop seal in the line.) The licensee stated that the alarm was due to a low temperature recorded on a section of the sample tubing which rapidly cools off when the heat tracing cycles off. However, the heat tracing was still operable and the line was still being maintained at an adequate temperature.

The inspector reviewed the initial acceptance test for the hydrogen monitors (ENG-144, Rev. 1; MOD 80-03-53 H2) and the heat tracing of their sampling lines. He noted that the Train B sampling line (the line in question) is maintained at only 220 F. versus 250 F. for Train A. The licensee stated that the heat tracing on the Train B sampling line cannot maintain the temperature along the entire line at 250 F. An engineering analysis performed by the licensee showed that a temperature of 220 F. was adequate for that line. However, a Request for Engineering Services (RES) has been issued to modify the line so that it can be maintained at 250 F. by the installed heat tracing.

The inspector reviewed Calculation No. 73 which justified the adequacy of the 220 F. setpoint on the Train B sample line. No problems were identified. However, he did note and state to the licensee that the acceptance test did not reference the calculation as justification for changing the temperature setpoint.

5. System Walkdowns

5.1 Using the licensee's approved checkoff lists, the inspector performed walkdowns of the following systems:

- Auxiliary Component Cooling System (ACCS) per COL-ACCV-1, Rev. 0
- Residual Heat Removal System (RHR) per COL-RHRV-1, Rev. 1
- Isolation Valve Seal Water System (IVSWS) per COL-CB-4, Rev. 7

Also, in support of the NRC's Safeguards Regulatory Effectiveness Review conducted onsite during the week of September 8-12, 1986, the inspector conducted walkdowns of vital equipment in the Primary Auxiliary Building and components of the Service Water System.

5.2 Probabilistic Risk Analysis Based Inspections

In addition, using the Probabilistic Risk Analysis (PRA) inspection guidance provided by NUREG-4565, "Probabilistic Safety Study Applications Program for Inspection of the Indian Point Unit 3 Nuclear Power Plant," the inspector performed modified walkdowns outlined in the NUREG for the following systems:

- Service Water System
- Reactor Protection System

5.3 Findings

5.3.1 As a result of the walkdown of the ACCS, the inspector questioned the licensee concerning the throttle valve setting of Valves 752K and 753K. These valves control the flow of cooling water from the recirculation pumps, which are located inside containment, to ensure that they receive adequate cooling in the event of a loss of coolant accident inside containment. The inspector noted apparent conflicts in the required throttle valve settings as stated in the Recirculation Pump Functional Test (3PT-R13, Rev. 4), the System Operating Procedure (SOP-CC-3), the Auxiliary Component Cooling Pump Functional Test (3PT-M19, Rev. 6), and, indirectly, (by reference to a ACCS low flow alarm) the System Description for the ACCS.

The licensee stated that review of design data on the ACCS showed that all of the throttle settings of the valves, as stated in the above documents, were more than adequate to ensure sufficient cooling flow to the recirculation pumps. However, they acknowledged that discrepancies existed between the documents and that they would be reconciled. The inspector had no further questions since no safety concern was evident.

5.3.2 The inspector noted during the walkdown of the IVSWS that the following manual isolation valves on the system were missing handwheels:

IV-1424
IV-1435
IV-1436
IV-1442
IV-1443
IV-1494

Four of the valves (IV-1436, 1442, 1443 and 1490) had deficiency tags, dating back to July 1985, which identified that handwheels were missing. However, the deficiencies remained uncorrected.

The inspector reviewed the deficiency log and noted that these deficiencies were not recorded. The Operations Superintendent stated that the tags were not shown in the log because the licensee has converted to a new deficiency tagging system since July, 1985. The deficiency tags identified by the inspector had been issued under the old system.

The inspector noted that the tags have since been reissued under the new tagging system. He also reviewed the system design drawings and noted that all of the valves that were missing handwheels were used for maintenance purposes only. Manipulation of the valves was not essential for the safe operation of the system.

No violations were identified. The inspector will review the status of the open deficiencies on his next walkdown of the system.

6. Surveillance

The inspector reviewed the completed procedures for the following surveillance tests to determine whether the results met the acceptance criteria of Technical Specifications:

- 3PT-CS4, Rev. 3, Accumulator Low Head Injection and RHR Check Valve Test
- RA-11, Rev. 3, Power Distribution and Hot Channel Factor Determination
- 3PT-M63, Rev. 1, Calibration Check of the Containment H_2 Monitors

In addition, the inspector reviewed the proposed inservice inspection hydrostatic test on the Containment Spray System (CSS) which was scheduled to be performed during this report period but was delayed.

Findings:

No violations were identified.

7. Maintenance

The inspector observed or reviewed the following maintenance activities, listed below, while they were in progress, or upon their completion, to ascertain the following:

- Approved procedures, adequate to control the activity, were being used by qualified technicians
- Evidence of QC involvement in the activity
- Proper radiological controls were implemented (where needed)
- Overall internal condition of disassembled equipment, paying particular attention for signs of excessive wear and/or corrosion and,
- Adequate post-maintenance testing was conducted.

Foxboro Isolation Amplifier Repairs - MWR-5855

The licensee is in the process of replacing various components of the Foxboro Isolation Amplifiers to correct recurrent component failures. These amplifiers are used in the Reactor Protection System (RPS) to isolate the control functions of instrumentation signals from their reactor protection functions. The inspector witnessed the span calibration on isolation amplifier 3FM-438C, Rack A2.

Diesel Generator (D/G) #31 Annual Preventative Maintenance Procedure - MWR-8749

The inspector witnessed personnel checking the intake/exhaust valve clearances and fuel injector settings on the #31 D/G per 3-PM-A-ES-3, Rev. 3. He also noted that the licensee was simultaneously conducting the quarterly and semi-annual preventative maintenance procedures on the D/G.

Replacement of the Diesel Generator #31 Air Compressor - MWR-9029

The licensee replaced the air compressor on the #31 D/G when it was determined to be inoperable. The inspector reviewed the completed installation, the procedure for the replacement, the purchase order for the compressor (P.O. #86-IP-3553), and the quality assurance certification on the compressor (Cert. I-794).

During the time interval in which the air compressor was out-of-service, the installed cross-tie between the air receivers for the #31 and #32 D/G's was aligned so that the #32 D/G air compressor was maintaining pressure on both diesel generators' air receivers. The inspector verified that after the #31 D/G air compressor was returned to service, the cross-tie between the air receivers was isolated to maintain train separation.

Findings

No violations were identified.

8. Review of Monthly Operating Reports

The Monthly Operating Reports for July and August, 1986 were reviewed. The review included an examination of selected MWR's and an examination of Significant Occurrence Reports (SOR's) to ascertain that the summary of operating experience was properly documented.

The inspector verified through record reviews and observations of maintenance in progress that:

- The corrective action was adequate for resolution of the identified item and,

- The operating report included the requirements of TS 6.9.1.5.

The inspector has no further questions relating to the report.

9. Exit Interview

At periodic intervals during the course of the inspection, meetings were held with senior facility management to discuss the inspection scope and findings. An exit interview was held on September 29, 1986 to discuss this report period. During the discussion, the licensee did not identify any 10 CFR 2.790 material.