U.S. NUCLEAR REGULATORY COMMISSION

Region I

Report No. 82-06

Docket No. 50-333

License No. DPR-59 Priority -- Category C

Licensee: Power Authority of the State of New York
P. O. Box 41
Lycoming, New York 13093

Facility Name: James A. FitzPatrick Nuclear Power Plant

Inspection at: Scriba, New York

Inspection conducted: March 1-31, 1982

Inspectors: J C Linville 4/7/82
J. C. Linville, Resident Inspector date signed

L. T. Doerflein 4/7/82
L. T. Doerflein, Resident Inspector date signed

date signed

Approved by: H B Kister 4/9/82
H. B. Kister, Chief, Reactor Projects Section 1C date signed

Inspection Summary:

Inspection on March 1-31, 1982 (Report No. 50-333/82-06)

Areas Inspected: Routine and reactive inspection during day and backshift hours by two Resident Inspectors (179 hours) of licensee action on previous inspection findings; licensee event report review; operational safety verification; surveillance observations; maintenance observations; review of plant operations and followup on plant trip.

Results: Three violations were observed in the seven areas inspected. Failure to assure valves properly aligned prior to startup (detail paragraphs 3 and 7); Heatup rate limit exceeded during startup (detail paragraph 7), and Failure to continuously monitor primary containment oxygen concentration (detail paragraph 3).

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Region I Form 12
(Rev. April 77)

DETAILS

1. Persons Contacted

*R. Baker, Superintendent of Power
*N. Brosee, Maintenance Superintendent
V. Childs, Senior Resident Engineer
*R. Converse, Operations Superintendent
M. Cosgrove, Site Quality Assurance Engineer
*W. Fernandez, Technical Services Superintendent
*H. Keith, Instrument and Control Superintendent
*C. McNeill, Resident Manager
*E. Mulcahey, Radiological & Environmental Services Superintendent
C. Orogvany, Reactor Analyst Supervisor
T. Teifke, Security & Safety Superintendent

The inspectors also interviewed other licensee personnel during this inspection including shift supervisors, administrative, operators, health physics, security, instrument and control, maintenance and contractor personnel.

*Denotes those present at an exit interview.

2. Licensee Action on Previous Inspection Findings

(Closed) UNRESOLVED ITEM (333/81-14-02): Amendment 66 to the Facility License changed technical specifications by deleting the surveillance requirement on the Standby Gas Treatment System Humidity Elements.

(Closed) UNRESOLVED ITEM (333/79-17-09): Modification F1-81-047 installed a new torus temperature monitoring system during the 1981-1982 refueling outage. By review of safety evaluation JAF-SE-81-092, the inspector determined that all equipment in this modification except the datalogger and indicator is qualified to the requirements of Regulatory Guide 1.97, Revision 2.

3. Review Licensee Event Report (LER)

The inspector reviewed LER's to verify that the details of the events were clearly reported. The inspector determined that reporting requirements had been met, the report was adequate to assess the event, the cause appeared accurate and was supported by details, corrective actions appeared appropriate to correct the cause, the form was complete and generic applicability to other plants was not in question.

LER 82-02 reported that the rated thermal power limit in paragraph 2.C.1 of the License was exceeded for about 46 days of operation during cycle 4 because of non-conservative drift of the feedwater flow instruments. The LER states that an evaluation of alternatives for corrective action is still under evaluation. At the exit meeting, the licensee stated that the feedwater flow instruments will be recalibrated anytime the plant is shutdown and it has been greater than 90 days since the last calibration. Additional long term corrective action will be described in the followup LER which will be submitted by April 15, 1982. This item is unresolved pending review of the followup LER and completion of the corrective action. (333/82-06-01)

LER 82-03 reported normal shutdown operations with less than the three required operable IRM channels in RPS trip system A. However, it does not report that about 20 control rods were individually withdrawn and inserted during the two shifts in which this condition existed as the inspector determined by a review of the control room alarm printer log. Withdrawal of control rods in this condition is what makes the event prompt reportable. In addition, the corrective action to prevent recurrence stated does not appear to be adequate in that the licensee was not maintaining the Instrument and Control (I&C) Work Activity Log Book required by I&C Department Standing Order No. 6 during the refueling outage and there is no procedure or checklist specifying the prerequisites for control rod withdrawal in the refuel mode. At the exit meeting the licensee agreed to submit a followup LER correcting the description of the event and providing more comprehensive corrective action including a checklist for control rod withdrawal in the refuel mode by April 15, 1982. This item is unresolved pending review of the followup LER and completion of the corrective action. (333/82-06-02)

LER 82-04 reported that parts of logic testing for some drywell isolation valves required by Table 4.2-1 in the Technical Specifications had not been performed in the past because the procedure was inadequate. The inspector told the licensee that the information provided in the LER was not sufficient to understand the event. The licensee agreed to revise the LER by April 15, 1982 to explain that the logic involved was the closure of the drywell purge isolation valves on 9 high reactor building radiation signals. The inspector will review the revision when it is issued. (333/82-06-03)

LER 82-05 reported that containment oxygen concentration exceeded the 4 percent Technical Specification limit. It stated that the cause of the event was a failure of a gasket on a breathing air filter. The inspector disagrees with this evaluation and considers an improperly positioned manual containment isolation valve, BAS4, on penetration X61 in the breathing air system, to be the cause. If BAS4 had been closed as required by Technical Specification Table 3.7-1 and locked as indicated by the February 28, 1982 dated signature on the data sheet for F-ST-15H, Primary Containment Integrity, Manual Isolation Valves Position Verification, Revision 2, dated May 13, 1981, the failure of a gasket on a breathing air filter would not have resulted in exceeding the containment oxygen limit during normal operation. Review of the "Cold Startup Checkoff" list contained in F-OP-65, Startup and Shutdown Procedure, Revision 10, dated January 22, 1982 indicated that there was no requirement to check the alignment of the breathing air system containment isolation valve, BAS4 prior to startup. Failure to establish and implement startup procedures which assure that valves are properly aligned, is an example of a violation of paragraph 5.3.4.1 of ANSI 18.7-1972 and Technical Specification 6.8(A). (333/82-06-04)

Review of the Shift Supervisor's Log and the Shift Turnover Sheets prior to and during this event indicated that both of the installed containment oxygen monitors were out of service. The B monitor had been out of service since prior to startup from the outage on March 6, 1982 and the A monitor had failed at 10:00 p.m. on March 12, 1982, was restored to service from 10:00 a.m. on March 13, 1982 until about 4:30 p.m. on March 13, 1982 and was out of service from about 4:30 p.m. on March 13, 1982 until 11:20 a.m. on March 15, 1982. In anticipation of this possibility, the Plant Operations Review Committee (PORC) Meeting No. 82-025 held on March 6, 1982 found acceptable the use of a portable oxygen analyzer to meet Technical Specification 3.7.9.2 requirement for continuous monitoring of containment oxygen. However, no guidance was provided on how to use the portable oxygen analyzer to meet the requirement. The Shift Supervisor's log recorded the results of four grab samples taken during the period of inoperability prior to the one which indicated that the containment oxygen was greater than the 4 percent Technical Specification limit. Shift Turnover Sheets for the period indicated that an additional seven samples for which the results were recorded were taken, and that hourly samples were taken during the two shifts, although no results for these samples were recorded. The licensee considered the sampling adequate because Technical Specification 4.7.6.a only requires that containment oxygen concentration be measured and recorded at least twice weekly, because Technical Specification 4.7.9.a, which refers to Table 4.7-1, requires only daily sensor checks and because the increase in excess of the limit was quickly identified. Discussions with licensed operators on watch at the time of the event indicate that the problem was initially identified by drywell pressure fluctuations apparently caused by the failure of a breathing air filter gasket, not by an increase in oxygen concentration. The inspector disagrees with the licensee's position because the installed oxygen monitoring equipment would provide an alarm when drywell oxygen exceeds 3.5 percent. To provide equivalent continuous monitoring capability, the portable equipment must be monitored continuously. The inspector further noted that the scale on the portable monitor is from 0 to 40 percent as opposed to from 0 to 5 percent on the installed equipment, making it difficult to determine when the 4 percent limit is exceeded when using the portable monitor. In addition, there is no calibration program for the portable monitor, and finally, the portable monitor would not be accessible to post-accident using the TMI NUREG-0737 source terms. Failure to continuously monitor primary containment oxygen concentration when containment integrity was required, is a violation of Technical Specification 3.7.9.a. (333/82-06-05)

4. Operation Safety Verification

a. Control Room Observations

(1) Daily, the inspectors verified selected plant parameters and equipment availability to ensure compliance with limiting conditions for operation of the plant Technical Specifications. Items checked included:

-- Power distribution limits

-- Availability and proper valve lineup of safety systems

-- Availability and proper alignment of onsite and offsite emergency power sources

-- Reactor control panel indications

-- Primary containment temperature and pressure

-- Drywell to suppression chamber differential pressure

-- Standby Liquid Control Tank level and concentration

-- Stack monitor recorder traces

(2) The inspectors directly observed the following plant operations to ensure adherence to approved procedures:

-- Reactor Startups

-- Routine Power Operation

-- Issuance of RWP's and Work Request/Event/Deficiency forms

-- Routine Shutdown Operations

(3) Selected lit annunciators were discussed with control room operators to verify that the reasons for them were understood and corrective action, if required, was being taken.

(4) Shift turnovers were observed to ensure proper control room and shift manning. Shift turnover checklists and log review by the oncoming and offgoing shifts were also observed by the inspectors.

No violations were observed.

b. Shift Logs and Operating Records

(1) Selected shift logs and operating records were reviewed to:

-- Obtain information on plant problems and operations;

-- Detect changes and trends in performance;

-- Detect possible conflicts with Technical Specifications or regulatory requirements;

-- Determine that records are being maintained and reviewed as required, and

-- Assess the effectiveness of the communications provided by the logs.

(2) The following logs and records were reviewed:

-- Shift Supervisor Log

-- Nuclear Control Operator Log

-- Night Orders

-- Shift Turnover Check Sheet

-- Protective Tag Record Log

-- Jumper Log

-- Liquid Radwaste Discharge Log

-- Gaseous and Particulate Sample Logs

-- Weekly Chemistry Status Log

-- Air Sample Log

No violations were observed.

c. Plant Tours

(1) During the inspection period, the inspectors made observations and conducted tours of plant areas including the following:

-- Control Room

-- Relay Room

-- Reactor Building

-- Turbine Building

-- Diesel Generator Rooms

-- Electric Bays

-- Pumphouse-Screenwell

-- Standby Gas Treatment Building

-- Drywell

-- Radwaste Building

-- Crescent Rooms

-- Torus Room

-- Plant Perimeter

-- Condenser Area

(2) During the plant tours, the inspector conducted a visual inspection of selected piping between containment and the isolation valves for leakage or leakage paths. This included verification that manual valves were shut, capped and locked when required and that motor operated or air operated valves were not mechanically blocked. Other items verified during the plant tours included:

(a) Fire Protection Conditions

-- No significant fire hazards existed.

-- Extinguishing equipment, fire alarms, actuating controls, fire fighting equipment and emergency equipment was operable.

-- Ignition sources and flammable material were properly controlled.

(b) Housekeeping/Cleanliness Conditions

-- Critical clean areas like the refueling floor were properly controlled.

-- Combustible material was properly controlled.

(c) Radiation Protection Controls

-- Surveys were properly performed.

-- Radiation Protection instruments were calibrated and operable.

-- Radiation Work Permits were complete, appropriate and followed.

-- Methods used to control exposures of those working in high radiation areas were appropriate.

-- Activities in radioactive waste system areas were conducted in accordance with approved procedures.

(d) Physical Security Plan Implementation

-- The security organization appeared to be properly manned and capable of performing its assigned function.

-- Isolation zones were clear.

-- Persons and packages were checked prior to entry into the protected area.

-- Vehicles were properly searched and escorted or controlled within the protected area.

-- Persons within the protected area displayed photo identification badges and persons requiring escorts were properly escorted.

-- Compensatory measures were employed when required by security equipment failure or impairment.

-- Protected area and vital area barriers were not degraded and access to these areas was properly controlled.

(e) Verification of adherence to selected Technical Specification Limiting Conditions for Operation.

No violations were observed.

d. Tagout Verification

The inspectors verified that the following safety related protective tagout records (PTR) were proper by observing the positions of breakers, switches and/or valves.

-- PTR 820456 on B Low Pressure Coolant Injection (LPCI) Battery Output Breaker.

-- PTR 820472 on High Pressure Coolant Injection Valve 23 MOV 58.

-- PTR 820435 on Unit Cooler 66 UC 22B.

-- PTR 820492 on Reactor Core Isolation Cooling Turbine Steam Line Trap Bypass Valve 13 AOV 32.

-- PTR 820437 on Control Rod Drive Hydraulic Control Unit 06-19.

-- PTR 820379 on Residual Heat Removal LPCI Injection Line Testable Check Valve 10 AOV 68B.

No violations were observed.

e. Radioactive Waste Systems Controls

(1) The inspector witnessed selected portions of a liquid radioactive release to verify the following:

-- The required release approvals were obtained.

-- The required samples were taken and analyzed.

-- The radioactive waste system was operated in accordance with approved procedures.

On March 21, 1982, the inspector witnessed a portion of the release of Batch 4399, Laundry Drain Tank (LDT) A.

No violations were observed.

f. Emergency System Operability

The inspectors verified operability of the High Pressure Coolant Injection System and the A train of the Standby Liquid Control System. The following items were included in the system verification:

-- Confirmation that each accessible valve in the primary flow path was in the correct position.

-- Confirmation that power supplies and breakers are properly aligned for components that must activate upon an initiation signal.

-- Visual inspection of the major components for leakage and other conditions which might prevent fulfillment of their functional requirements.

No violations were observed.

5. Surveillance Observations

The inspectors observed portions of the surveillance procedures below to verify that the test instrumentation was properly calibrated, approved procedures were used, the work was performed by qualified personnel, limiting conditions for operation were met, and the system was correctly restored following the testing.

-- F-ST-1G, Main Steam Line High Radiation Functional Test, Revision 4, dated December 1980, performed on March 7, 1982.

-- F-ST-24B, RCIC MOV Operability Test, Revision 4, dated December 1980, performed on March 7, 1982.

-- F-ST-4A, HPCI Simulated Automatic Actuation Test, Revision 7, dated September 1981, performed on March 8, 1982.

-- F-ST-4E, HPCI Subsystem Logic System Functional Test, Revision 12, dated October 1981, performed on March 8, 1982.

-- F-ST-1D, MSIV's, Main Steam Line Drain Valves, and Reactor Water Sample Valves Logic Functional Test, Revision 7, dated February 23, 1982, performed on March 2, 1982.

-- F-ST-4B, HPCI Flow Rate Test (ISI), Revision 7, dated February 12, 1982, performed on March 7, 1982.

-- F-ST-4C, HPCI Pump Operability Test (ISI), Revision 8, dated March 16, 1981, performed on March 7, 1982.

-- F-ST-4D, HPCI MOV Valve Operability Test, Revision 4, dated April 2, 1981, performed on March 7, 1982.

-- F-ST-24A, RCIC Pump Operability (ISI), Revision 8, dated July 10, 1981, performed on March 7, 1982.

-- F-ST-24C, RCIC Flow Rate Test (ISI), Revision 8, dated October 22, 1981, performed on March 7, 1982.

During the performance of tests F-ST-4B, F-ST-4C, F-ST-24A and F-ST-24C, the inspector determined that the licensee only planned to conduct these tests on the High Pressure Coolant Injection (HPCI) System and the Reactor Core Isolation Cooling (RCIC) System once during the startup of 150 psig reactor pressure. The inspector informed the licensee that since Technical Specifications 4.5.C.1 and 4.5.E.1 require that these systems be tested and demonstrated operable for a system head corresponding to a reactor pressure of 1120 psig to 150 psig and since it had been more than 3 months since system operability had been demonstrated at operating reactor pressure because of the outage, additional testing was required to demonstrate operability over the required range. Additional testing was performed on the HPCI system at operating reactor pressure on March 15, 1982 to obtain verification data for the new turbine steam line high steam flow differential pressure isolation setpoint. Additional testing was performed on the RCIC to verify the existing turbine steam line high steam flow differential pressure isolation setpoint on March 22, 1982. At the exit meeting the licensee agreed to revise HPCI and RCIC surveillance procedures to require test performance at both 150 psig and operating reactor pressure upon startup from a refueling or other extended outage. After they are issued, the inspector will review these revisions which the licensee stated would be completed by June 1, 1982. (333/82-06-06)

During the performance of F-ST-4B, the HPCI suction line isolation valves 23MOV57 and 23MOV58 failed to close within the required 60 seconds. Although Technical Specification Table 3.7-1 indicates a closing time for 60 seconds for these valves, note 7 of the table states that this is based on a standard closure rate of sixty seconds for a nominal line size of 12 inches. The vendor print for the valve shows that the 16 inch valves have a stroke time of 12 inches per minute resulting in a total closing time of 80 seconds. The NRR licensing project manager and the inspector agreed that the demonstrated closing times for the valves were acceptable and that an administrative change to the technical specifications is required. The inspector will review the Technical Specification change which the licensee requested when it is issued and will review the subsequent revisions to the licensee's procedure. (333/82-06-07)

6. Maintenance Observations

The inspectors observed portions of various safety related maintenance activities. Through direct observation and review of records, they determined, where appropriate, that:

-- Qualified personnel performed the activities.

-- Redundant components were operable.

-- These activities did not violate the limiting conditions for operation.

-- Required administrative approvals and tagouts were obtained prior to initiating the work.

-- Approved procedures were used or the activity was within the "skills of the trade".

-- Appropriate radiological controls were properly implemented.

-- Ignition/fire prevention controls were properly implemented.

-- Equipment was properly tested prior to returning it to service.

-- Tools and gages were properly calibrated.

-- Parts and materials were properly certified.

-- QC hold points were observed and provided independent verification.

During this inspection period, the following activities were observed:

-- WR 71/14835, Replacement of B LPCI Battery Cell No. 182, performed on March 5, 1982.

-- WR 27/10183, Repair of A Containment Oxygen Analyzer.

The inspector observed that the vendor representative was unable to restore B oxygen analyzer to service before the end of the outage. The subsequent failure of A oxygen analyzer described in the paragraph on LER 82-05 in paragraph 3 led to a Technical Specification violation. The licensee stated that A and B oxygen analyzers will be repaired shortly by the vendor representative who was on site, that more spare parts would be stocked to improve oxygen analyzer reliability, and that long term plans are to replace the existing oxygen analyzers with more state of the art equipment during the 1983 refueling outage. This item is unresolved pending restoration of the oxygen analyzers to service. (333/82-06-08)

-- WR 10/14349, C Residual Heat Removal (RHR) Pump discharge check valve repair performed March 8, 1982.

On March 9, 1982, the licensee experienced difficulty in getting 10 RHR 42C to seat. Attempts were made to get the valve to seat by operating the parallel A & C RHR pumps and then stopping the C RHR pump. When these were unsuccessful, the licensee declared C RHR pump inoperable to repair 10 RHR 42C. The licensee stated that inspection of the valve indicated that a cap screw which attaches the disc holder assembly to the valve body had come off. Two cap screws were replaced and torqued to 130 foot-pounds. At the exit meeting, the licensee stated that long term corrective action would be identified in the LER.

-- WR 23/13299 and WR 23/18415, Adjustments to High Pressure Coolant Injection (HPCI) System turbine steam line high flow differential pressure instrument snubbers pin settings performed on March 11, 1982 and March 17, 1982. These adjustments were necessary to prevent spurious turbine steam line isolation signals on high steam flow after the isolation signal differential pressure was reduced from 230 inches of water to 106 inches of water as described in LER 82-01. The first adjustment of the existing installed pin setting on March 11, 1981 was insufficient to prevent the spurious isolations during quick cold starts of the HPCI system. Consequently, new pins which provided a longer time delay were obtained and installed on March 17, 1982 providing time delays of between 6.7 and 9.8 seconds on DPIS 76 and DPIS 77. There was no isolation when the system was tested with the new pins and settings.

-- WR 10/11082, Repair and Partial Replacement of Hydraulic Snubbers on Spent Fuel Cooling (SFC) Return Line to Residual Heat Removal System.

On March 17, 1982, the licensee reported that two hydraulic snubbers on the SFC Return Line to the RHR system required by Technical Specification to be operable had been damaged such that they were inoperable. It appears that they were damaged during efforts to seat RHR pump C discharge check valve on March 11, 1982. The snubber swivels were bent and they failed the functional test in compression for both lockup and bleed rate. The licensee replaced the hydraulic piston assembly and repaired the swivels. At the exit meeting, the licensee stated that these snubbers were not intended to withstand the loads associated with the check valve slam. The licensee further stated that additional visual inspections of snubbers are not necessary because this failure was caused by a known operational event, but that they would insure that snubbers in affected systems would be checked in the future after similar water hammer events. The licensee stated that they had walked the remainder of the RHR system to assure that no additional failures were caused by this event. The inspector also checked many of the accessible snubbers in the system and found no additional failures. The licensee stated that long term corrective action would be identified in the LER.

7. Review of Plant Operations

a. Safety System Verification

The inspector performed a walk thru of the following systems distributed during the refueling outage to verify that they had been properly returned to service prior to plant startup:

-- Diesel Generator Emergency Power System (EDG).
Several check valves in EDG system were listed as open.

-- Residual Heat Removal System (RHR).

In addition to the system walk thru, the inspector reviewed the licensee startup valve lineups and the P&ID's and noted the following deficiencies:

Two manual valves in the RHR system, RHR 250C and RHR 45C, were in a different position from that noted on the licensee's valve lineup. Valve RHR 250C was signed off as being closed, the normal position, when in fact it was open. Valve RHR 45C, which was signed off as being locked open, the normal position, was actually throttled. There was an informal shipping tag on RHR pump C switch indicating that the discharge valve was throttled.

Two valves, RHR 403A and 403B, were signed off as being locked, capped and closed when in fact neither valve was capped and RHR 403B was not locked.

One valve, RHR 738A, listed on the same line as RHR 737A, was signed off as being locked, capped and closed when in fact RHR 738A does not exist. The P&ID also incorrectly shows this valve.

Three valves, RHR 743C and two unnumbered drain valves on the Head Spray line next to RHR 76 and 77, which do exist, were not listed on the valve checkoff list. Also the P&ID does not show the two unnumbered drain valves on the Head Spray line.

With the exception of the mispositioned valves, the licensee stated that most of the above discrepancies had been identified while performing the valve lineups (VLU). The inspector noted, however, that the VLU's were not annotated to identify the discrepancies and that the licensee does not have a procedure or standing order defining rules for conduct of VLU's such as for repositioning valves prior to startup after they are signed off as ready for startup. The licensee procedures only require that the completed VLU be reviewed to verify that the signed off position of the valve is the normal position. Exceptions such as missing locks or caps, which are not identified on the VLU list, may not be corrected prior to startup. Valves RHR 45C and RHR 250C, which were in a position other than that signed off on the VLU, are another example of exceptions to the VLU which may not be corrected prior to startup. Failure to provide adequate controls to ensure valves are properly aligned prior to startup is considered a violation of ANSI 18.7-1972, Section 5 and Technical Specification 6.2(A). (333/82-06-04)

As part of the corrective action to ensure the Residual Heat Removal and other safety systems were properly aligned prior to startup on March 6, 1982, the licensee performed new valve lineups on the Residual Heat Removal, High Pressure Coolant Injection, Core Spray, Reactor Core Isolation Cooling and Containment Atmosphere Dilution Systems. Quality Assurance personnel had already verified the VLU's on Standby Liquid Control, Emergency Diesel Generators and portions of the Emergency Service Water Systems. The licensee also stated that the RHR valve checkoff list and P&ID would be corrected to accurately reflect the system status. The inspector will review these revisions to verify completion in a subsequent inspection. (333/82-06-09)

b. Unit Startup Following Refueling

The inspector witnessed portions of the plant startup conducted March 6-8, 1982 to verify that:

-- The control room withdrawal sequence was available.

-- All surveillance tests required to be performed prior to the startup were satisfactorily completed.

-- The startup was performed in accordance with approved procedures.

-- Startup activities were conducted in accordance with Technical Specification requirements.

While observing the startup on March 6, 1982, the inspector found that the licensee exceeded the 25°F per 15 minute heatup rate allowable by surveillance test F-ST-26J, Heatup and Cooldown Temperature Checks, Revision 2, dated December 1, 1980 during three of the four 15 minute intervals between 9:15 p.m. and 10:15 p.m. as listed below.

Time	Heatup Rate
9:30 p.m.	26.25°F
9:45 p.m.	17.18°F
10:00 p.m.	32.57°F
10:15 p.m.	30.48°F

The licensed operators on watch explained and the inspector observed from the alarm printer that group 3 rods were pulled a total of approximately 60 notches with each rod being at either notch 4 or notch 6 between 9:45 p.m. and 10:00 p.m. They were surprised that these deep rods gave them such a high heatup rate. They decided not to pull any other rods between 10:00 p.m. and 10:15 p.m. anticipating that the heatup rate would drift below 25°F during the interval. When the heatup rate remained above 30°F between 10:00 p.m. and 10:15 p.m., the licensed operators drove in group 3 rods a total of approximately 40 notches between 10:15 p.m. and 10:30 p.m. which resulted in a heatup rate of 5.59°F. Between 9:15 p.m. and 10:15 p.m. the heatup rate was 106.48°F per hour. This is a violation of Technical Specification 3.6.A.1 which requires that the heatup rate not exceed 100°F per hour. (333/82-06-10)

8. Followup on a Plant Trip

At 6:16 a.m. on March 10, 1982, during a plant startup, the reactor scrammed from approximately 30% power. No plant problems were encountered after the scram. Reactor pressure peaked at 981 psi and reactor water level only decreased to approximately one inch before water level was restored using feed pumps. No Emergency Core Cooling Systems were actuated. It appeared the scram was caused by a Turbine Stop Valve Fast Closure Trip which occurred during surveillance testing of the Turbine Control Valves. The licensee believes that testing the Turbine Control Valves imposed a pressure transient on the Electro Hydraulic Control oil system which, coupled with a clogged oil filter in No. 2 Turbine Stop Valve servo control valve, was sufficient to allow No. 2 Turbine Stop Valve to start drifting shut. Since all the other Turbine Stop Valves are slaved to No. 2 Turbine Stop Valve, they all started drifting shut. When they reached less than 90% full open, a Turbine Stop Valve Fast Closure trip occurred. The Turbine Stop Valves did not fully close as the turbine was manually tripped after the scram.

The exact sequence of events remains unclear because of electronic component failures in the computer input cards for the turbine stop and control valves. During the subsequent startup the licensee unsuccessfully tried to reproduce the event by testing turbine stop and control valves at 20%, 25% and finally when required at greater than 30% reactor power.

12. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, violations or deviations. The unresolved items identified during this inspection are discussed in paragraph 3.

13. Exit Interview

At periodic intervals during the course of this inspection, meetings were held with senior facility management to discuss inspection scope and findings. On March 31, 1982, the inspectors met the licensee representatives (denoted in paragraph 1) and summarized the scope and findings of the inspection as they are described in this report.