U. S. NUCLEAR REGULATORY COMMISSION
REGION I

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Report No. 84-04

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: J. A. Fitzpatrick Nuclear Power Plant

Inspection At: Scriba, New York

Inspection Conducted: March 1-31, 1984

Inspectors: W. Lazarus for 5/4/84
L. T. Doerflein, Senior Resident Inspector date

date

date

Approved by: Samuel J. Collins 5/4/84
S. J. Collins, Chief, Reactor Projects Section 2C date

Inspection Summary:
Inspection on March 1-31, 1984 (Report No. 50-333/84-04)
Areas Inspected: Routine and reactive inspection during day and backshift hours by one resident inspector (109 hours) of licensee action on previous inspection findings, licensee event report review, operational safety verification, surveillance observations, maintenance observations, engineered safety feature system walkdown, followup on plant trips, followup on IE Bulletin 79-14, and review of periodic and special reports.

Results: No violations were observed in seven of nine areas inspected. Two violations were observed in two areas (Exceeding the Technical Specification Heatup rate limit, details paragraph 4a; and failure to perform adequate post maintenance testing, paragraph 6c).

Region I Form 12
(Rev. February 1982)

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DETAILS

1. Persons Contacted

*R. Baker, Technical Services Superintendent
R. Burns, Vice President, Nuclear Support-BWR
T. Butler, Outage Coordinator
V. Childs, Assistant to the Resident Manager
*R. Converse, Superintendent of Power
M. Cosgrove, Quality Assurance Superintendent
M. Curling, Training Superintendent
*W. Fernandez, Maintenance Superintendent
*H. Keith, Instrument and Control Superintendent
D. Lindsey, Assistant Operations Superintendent
*R. Liseno, Operations Superintendent
C. McNeill, Resident Manager
E. Mulcahey, Radiological & Environmental Services Superintendent
T. Teifke, Security & Safety Superintendent

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

*Denotes those present at the exit interview.

2. Licensee Action on Previous Inspection Findings

(Closed) Inspector Followup Item (333/82-01-02): The inspector reviewed procedures no. F-AOP-18, Loss of 10500 Bus, Revision 0, dated February 3, 1982 and no. F-AOP-19, Loss of 10600 Bus, Revision 0, dated February 3, 1982 and verified that, to prevent recurrence of the low voltage condition on the 24 VDC Battery System which supplies the Source Range and Intermediate Range Monitors, the licensee has implemented procedures which require that the 24 VDC battery voltage and specific gravity be monitored and consideration be given to a temporary power supply for the 24 VDC battery chargers if the 10600 or 10500 bus is lost or removed from service for a period of greater than one hour.

(Closed) Inspector Followup Item (333/82-12-05): The inspector reviewed Flow and Machinery drawing FM-23A, Revision 16, and the system drawing and valve lineup list in Operating Procedure No. 14, Core Spray System, Revision 8, and verified that valves CSP-791A, CSP-1060A and CSP-1060C were added to the drawings and valve lineup list. As discussed in paragraph 7. of this report, the inspector performed a complete walkdown of the Core Spray System and did not identify any additional discrepancies with the drawings or valve lineup list.

(Closed) Inspector Followup Item (333/83-28-07): The licensee replaced the motor actuator on the Residual Heat Removal Suppression Pool Cooling Outboard Isolation Valve (10-MOV-39B) with a Limitorque type SMB-0-40 actuator. The licensee changed the gear ratio of the actuator, under direction of the vendor, so that it would provide sufficient torque to operate the valve under design conditions. The inspector reviewed modification package M1-84-001 and noted that the safety evaluation for the actuator replacement was reviewed and approved by the Plant Operating Review Committee. The inspector reviewed Material Receiving Report No. 60869 and verified that the replacement operator was purchased as a QA Category I item. The inspector also reviewed work request no. 10/11159 and the accompanying Quality Control Inspection Report and verified that the actuator installation was performed in accordance with approved procedures and was witnessed by Quality Control personnel.

(Closed) Inspector Followup Item (333/83-29-02): The inspector reviewed the results of an evaluation in which the licensee determined that, using actual valve parameters from the vendor (Wm. Powell Co.) and the Limitorque selection procedures, the incorrect actuator installed on the Residual Heat Removal Suppression Pool Cooling Outboard Isolation Valve (10-MOV-39B) was capable of meeting the design limits of the valve. The inspector noted that the licensee revised LER 83-60 to indicate that valve 10-MOV-39B was operable while the incorrect actuator was installed and to indicate that a fully qualified replacement actuator had been installed on the valve. The inspector had no further questions on this item.

3. Licensee Event Report (LER) Review

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's 84-03*, 84-04*, 84-05, 84-06*, and 84-08* were reviewed.
*LER's selected for onsite followup.

LER 84-03 reported that while the High Pressure Coolant Injection System was out of service for planned maintenance, the Reactor Core Isolation Cooling System was made inoperable as the result of personnel error. Details of this event are described in paragraph 7.b.(2) of inspection report no. 50-333/84-02.

LER 84-04 reported that while the High Pressure Coolant Injection System was out of service for planned maintenance, the Reactor Core Isolation Cooling (RCIC) System was inadvertently made inoperable for approximately thirty minutes when the DC control power to the RCIC inverter was momentarily interrupted during the performance of a ground isolation procedure.

Based on discussions with the licensee personnel involved with the event, the inspector determined that an inadequate ground isolation procedure and the inexperience of the operator performing the procedure resulted in a failure to recognize that the RCIC inverter had to be manually reset once the power was interrupted. After the operating shift determined that the RCIC inverter would not reset automatically, a manual reset was performed. The inverter was recharged and RCIC was declared operable. The inspector noted that the licensee has revised procedure no. F-AOP-22, A DC Power System Ground Isolation, instructing the operator to manually reset the RCIC inverter when the RCIC Control and Logic Circuit breaker is cycled. The inspector also noted that a copy of the LER was placed in the night orders to ensure all operators were aware of the event.

LER 84-06 reported that the high level trip setpoint of Reactor Water Level Indicating Switch 02-3-LIS-101D was found above the Technical Specification (TS) limit. This switch operates in conjunction with level switch 02-3-LIS-101B, in a series logic, to provide the high reactor water level High Pressure Coolant Injection (HPCI) turbine trip. Thus with level switch 02-3-LIS-101D above the TS limit, the entire HPCI turbine trip on high reactor water level function was above the TS limit. The licensee has had a history of problems with this level switch and based on an evaluation believes that the cause of the problem is a bending of switch backing plates, during tightening of the "switch lock", which results in excessive friction between the switch actuator cam and actuator arm. Based on discussions with licensee personnel the inspector determined that the setpoints on the other reactor water level switches (02-3-LIS-101A, 02-3-LIS-101B, and 02-3-LIS-101C) and the low level trip setpoint on switch 02-3-LIS-101D, which provides a reactor scram signal, have not been affected with setpoint drift. However, the licensee has noted similar problems in a identical spare level switch which has a sequential serial number with level switch 02-3-LIS-101D. The licensee has sent this spare level switch to the vendor for analysis and has increased the surveillance frequency on level switch 02-3-LIS-101D until it can be replaced. The inspector will review the results of the vendor evaluation during a subsequent inspection. (333/84-04-01)

LER 84-08 reported that during a normal reactor startup on March 13, 1984, the heatup rate exceeded the Technical Specification limit of $100^{O}F$ per hour. Details of this event are described in paragraph 4.a. of this report.

4. Operational Safety Verification

a. Control Room Observations

Daily, the inspector verified selected plant parameters and equipment availability to ensure compliance with limiting conditions for operation of the plant Technical Specifications. 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. The inspector observed shift turnovers biweekly to ensure proper control room and shift manning. The inspector directly observed the operations listed below to ensure adherence to approved procedures:

-- Routine Power Operation

-- Reactor Shutdown on March 2, 1984

-- Reactor Startups on March 13 and 26, 1984

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

During a normal reactor startup on March 13, 1984, the licensee exceeded the Technical Specification heatup rate limit of 100°F per hour. The inspector reviewed data from the process computer alarm printer and from surveillance test F-ST-26J, Heatup and Cooldown Temperature Checks, Revision 3, dated May 26, 1982, and noted that the reactor coolant temperature change at fifteen minute intervals between 6:30 P.M. and 7:30 P.M. were:

Time	Temperature Change
6:45	15.86°F
7:00	34.56°F
7:15	35.36°F
7:30	19.10°F

Based on discussions with licensee personnel, including operators involved with the event, the inspector determined that the cause of the excessive heatup rate was a lack of adequate supervision over the inexperienced operators conducting the heatup, an apparent overreliance by the operators on the process computer fifteen minute temperature change (ΔT) for heatup rate information, and the incorrect reading of this data. At fifteen minute intervals during the startup the process computer prints the last four fifteen minute ΔT's with the latest ΔT in the left hand column. The operator reading the printout had read the right hand column. The operators in the control room failed to recognize the other indications of an excessive heatup rate such as the reactor water level control problems they were experiencing. When the operators recognized the excessive heatup rate they fully inserted control rod 18-27 from notch 40. This resulted in a 15 minute ΔT between 7:30 P.M. and 7:45 P.M. of 10.38°F per hour and reduced the heatup rate to less than 100°F per hour. Subsequently, an engineering evaluation was performed by General Electric which demonstrated that the event did not have any effect on reactor vessel life.

The inspector noted that this event was similar to those reported in LER 81-66 and 82-07. During startups on August 16, 1981 and March 6, 1982, the licensee exceeded the Technical Specification heatup rate limit by 6°F. Following each event the licensee counselled the individuals involved and following the second event the licensee revised the startup and shutdown procedure to administratively limit the heatup/cooldown rates to 60°F per hour. It appears that these corrective actions were not adequate. During the startup on March 13, 1984, between 6:30 P.M. and 7:30 P.M. the heatup rate was 104.88°F per hour. The inspector informed the licensee that this was a violation of Technical Specification 3.6.A.1 which requires that the heatup rate not exceed 100°F per hour. (333/84-04-02)

b. Shift Logs and Operating Records

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.

No violations were identified.

c. Plant Tours

During the inspection period, the inspector made observations and conducted tours of the plant. 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 valves were not mechanically blocked. The inspector also checked fire protection, housekeeping/cleanliness, radiation protection, and physical security conditions to ensure compliance with plant procedures and regulatory requirements.

No violations were identified.

d. Tagout Verification

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

-- PTR 840375 on the "B" and "D" Emergency Diesel Generators.

-- PTR's 840426 and 840427 on the Containment Atmosphere Sampling System.

No violations were identified.

e. Emergency System Operability

The inspector verified operability of the following systems by ensuring that each accessible valve in the primary flow path was in the correct position, by confirming that power supplies and breakers were properly aligned for components that must activate upon an initiation signal, and by visual inspection of the major components for leakage and other conditions which might prevent fulfillment of their functional requirements:

-- Emergency Diesel Generator Fuel Oil and Air Start Systems

-- Standby Gas Treatment System

-- Low Pressure Coolant Injection System

No violations were identified.

5. Surveillance Observations

The inspector observed portions of the surveillance procedures listed below to verify that the test instrument 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-1B, MSIV Fast Closure, Revision 5, dated December 14, 1983, performed on March 2, 1984.

-- F-ST-39B, Type "B" and "C" LLRT of Containment Penetrations, Revision 10, dated May 11, 1983, performed March 12, 1984 on Main Steam Isolation Valves 29-AOV-80D and 29-AOV-86D and performed March 13, 1984 on valve 27-SOV-125B.

-- F-ST-5R, RBM Upscale and Downscale Instrument Functional Check, Revision 5, dated May 19, 1982, performed March 15, 1984 on the "B" Rod Block Monitor.

-- F-ST-1I, Main Steam Isolation Valves Limit Switch Instrument Functional Test, Revision 5, dated May 19, 1982, performed on March 23, 1984.

-- F-ST-26J, Heatup and Cooldown Temperature Checks, Revision 3, dated May 26, 1982, performed on March 26, 1984.

The inspector also witnessed all aspects of the following surveillance test to verify that the surveillance procedure conformed to technical specification requirements and had been properly approved, limiting conditions for operation for removing equipment from service were met, testing was performed by qualified personnel, test results met technical specification requirements, the surveillance test documentation was reviewed, and equipment was properly restored to service following the test.

-- F-ST-3J, Core Spray Subsystem Logic Functional Test, Revision 10, dated February 23, 1983, performed on March 27, 1984.

No violations were identified.

6. Maintenance Observations

a. The inspector observed portions of various safety-related maintenance activities to determine that 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, and equipment was properly tested prior to returning it to service.

b. During this inspection period, the following activities were observed:

-- WR 00/25352 on the Induction Heating Stress Improvement of Recirculation System Welds.

-- WR's 03/18520 and 03/28294 on the replacement of Control Rod Drive Mechanisms No. 22-19, 34-15 and 14-23.

-- WR 27/20015 on the modification of the seal in logic for the Post Accident Sampling System solenoid operated valves.

-- WR 27/23283 on the repair of Containment Atmosphere Sampling System isolation valve 27-SOV-125B.

-- WR 29/25125 on the modification to Main Steam Isolation Valve 29-AOV-86D.

During the March 2-13, 1984 maintenance outage the licensee performed a demonstration of Induction Heating Stress Improvement (IHSI) on the following eleven recirculation system welds that were particularly susceptible to Intergranular Stress Corrosion Cracking (IGSCC):

Weld No.	Description
28-02-2-48	A recirculation pump suction pipe to safe-end weld
28-02-2-49	A recirculation pump suction pipe to elbow weld
22-02-2-22	A recirculation loop manifold end cap weld
12-02-2-8	A recirculation loop riser pipe to elbow weld
12-02-2-15	A recirculation loop riser pipe to sweepolet weld
12-02-2-18	A recirculation loop riser pipe to elbow weld
12-02-2-20	A recirculation loop riser pipe to sweepolet weld
28-02-2-106	B recirculation pump suction pipe to safe-end weld
28-C2-2-107	B recirculation pump suction pipe to elbow weld
12-02-2-75	B recirculation loop riser pipe to safe-end weld
12-02-2-76	B recirculation loop riser pipe to elbow weld

For each weld the licensee performed a baseline ultrasonic examination, the IHSI, and a post treatment ultrasonic examination.

No IGSCC indications were found during the baseline or post IHSI ultrasonic examination for ten of the eleven welds treated. One indication, believed to be IGSCC, was discovered in the heat affected zone of weld no. 28-02-2-48 during the baseline ultrasonic examination. The circumferential indication was reported to be one inch long and approximately 10-15% through wall. Following the IHSI on this weld, and using various crack sizing techniques, the licensee reported the indication had an estimated length of 2.875 inches and a maximum depth of 17% through wall. These results were used in a fracture mechanics analysis of the indication. Based on this analysis, NRR, in a letter dated March 12, 1984, concluded that the above crack, without repair, did not reduce the original structural design margin of the piping nor would it adversely affect the margin of safety for the remainder of the present operating cycle. Further details of the procedure used in sizing the crack and the review of the ultrasonic data of the indication in weld no. 28-02-2-48 are discussed in Inspection Report No. 50-333/84-03.

As a result of the IHSI demonstration program, the licensee also determined that the indication in weld no. 22-02-2-22, which was reported as IGSCC in letter JAFP 83-880, dated August 24, 1983, was actually due to geometry. The licensee plans to submit a formal change to their earlier analysis of this indication following further review of construction documentation.

c. During the March 2-13, 1984 maintenance outage the licensee replaced the control rod drives for control rods 02-23, 06-19, 06-27, 10-47, 14-07, 14-11, 14-23, 14-31, 22-19, 26-19, 34-45, and 38-19. On March 28, 1984, the inspector discovered, during a review of this maintenance, that none of these twelve control rods had been scram time tested following the reactor startup on March 13, 1984. When the inspector questioned this, the licensee stated that he had planned to perform the scram insertion time testing on these control rods during the next scheduled scram time test required, at eight week intervals, by Technical Specification (TS) 4.3.C.2. The inspector pointed out that Technical Specifications 3.3.C.1, 3.3.C.2, and 3.3.C.3 require that the licensee be able to demonstrate that: the average scram insertion time at notch positions 46, 38, 24, and 04 of all operable control rods during power operation be no greater than 0.338, 0.923, 1.992, and 3.554 seconds respectively; the average of the scram insertion times at notch positions 46, 38, 24, and 04 for the three fastest operable control rods of all groups of four control rods in two-by-two array be no greater than 0.361, 0.977, 2.112, and 3.764 seconds respectively; and the maximum scram insertion time for 90 percent insertion of any operable control rod not exceed 7.0 seconds. This implies that new data must be obtained for control rods on which maintenance has been done. This position is supported by the Standard General Electric Technical Specifications which specifically requires scram time testing after performing control rod drive system maintenance which could affect a control rod's scram insertion time. The inspector also pointed out that Technical Specification 6.8(A) requires that written procedures and administrative policies be established, implemented and maintained that meet or exceed the requirements and recommendations of Section 5 "Facility Administrative Policies and Procedures" of ANSI 18.7-1972. Section 5.3.5(3), Post Maintenance Check Out and Return to Service, of ANSI 18.7-1972, requires that, when returning equipment to service, operating personnel place the equipment in operation and verify and document its functional acceptability. This is implemented through procedure no. WACP 10.1.1, Procedure for Control of Maintenance, Revision 8, dated October 4, 1983, which requires, in section 7.2.6.1, that the Shift Supervisor determine and perform sufficient post work testing to meet the Technical Specifications. The inspector informed the licensee that failure to perform scram time testing as part of the post maintenance testing on the twelve control rods, whose control rod drives were replaced during the March 2-13, 1984 outage, to verify that the scram insertion times met the requirements of Technical Specifications 3.3.C.1, 3.3.C.2, and 3.3.C.3 was a violation of Technical Specification 6.8(A) and procedure no. WACP 10.1.1. (333/84-04-03)

The licensee subsequently performed the control rod scram time testing on these twelve control rods on March 28, 1984. The inspector reviewed this data and verified that the testing was performed in accordance with procedure no. RAP 7.3.10, Control Rod Scram Time Evaluation, Revision 10, dated September 8, 1983 and that the results met the scram insertion time requirements of Technical Specifications 3.3.C.1, 3.3.C.2, and 3.3.C.3.

7. Engineered Safety Feature (ESF) System Walkdown

The inspector verified the operability of the following ESF system by performing a complete walkdown of accessible portions of the system to confirm that system lineup procedures match plant drawings and the as-built configuration, 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.

-- Core Spray System

No violations were identified.

8. Followup on Plant Trips

a. At 7:44 A.M. on March 22, 1984, the reactor scrammed from approximately 67% power on low reactor vessel water level. The cause of the low reactor water level was a loss of feedwater flow. At the time of the event the unit was operating with only the "B" Reactor Feed Pump (RFP) as the "A" RFP was undergoing maintenance to correct a previously identified vibration problem. The licensed operators on watch during the event stated that at the time of the reactor trip they noted that there was no indicated feedwater flow and that the "B" RFP had dual indication on the hydraulic coupling while the RFP turbine speed was approximately 4500 RPM. The operators had thought the "B" RFP turbine had uncoupled from the pump and manually tripped the RFP turbine after the scram. Following the scram,reactor water level dropped to approximately 115 inches above the Top of Active Fuel. The High Pressure Coolant Injection (HPCI) and the Reactor Core Isolation Cooling (RCIC) Systems automatically initiated and injected to restore reactor water level when level dropped to the double low level setpoint. During the event reactor pressure peaked at 1000 psig. There was no radioactive release associated with this trip. All Emergency Core Cooling Systems functioned properly during the event however, a subsequent investigation revealed that the HPCI gland seal condenser gasket was blown. The licensee declared HPCI inoperable during the cooldown following the trip and isolated the system to stop and repair the leaking gasket. The inspector attended the critique of the event and reviewed the process computer alarm printout, the post trip log, various chart recorders, and the completed data sheets for procedure No. ODSO 23, Post Trip Evaluation, and determined that the plant responded as designed and that the licensee's review of the trip was adequate.

During the investigation into the problem with the "B" RFP, the licensee found a wiped inboard journal bearing on the feed pump. At approximately 5:30 A.M., March 22, 1984, the licensee began experiencing higher than normal vibration readings on this bearing. About this time, the operators also received a momentary high temperature alarm on the feed pump outboard journal bearing. This high temperature alarm was actually on the feed pump inboard journal bearing as the licensee later found that the thermocouple leads for the feed pump inboard and outboard journal bearings were reversed. The licensee believes that the wiped bearing probably applied enough additional torque on the feed pump so that the feed pump discharge pressure dropped below reactor pressure, thus stopping feedflow, and the reactor tripped on low level before the feed pump turbine could increase speed to compensate for the decreasing level. The licensee commenced a reactor startup on March 24, 1984, using only the "A" RFP while the "B" RFP was being repaired.

b. At 4:23 A.M., March 25, 1984, during a plant startup, the reactor scrammed from approximately 18% power on low reactor vessel water level. The low reactor water level was caused by a loss of feedwater flow when the operating "A" Reactor Feed Pump (RFP) tripped. The unit was operating with only one RFP at the time as the "B" RFP was undergoing maintenance due to the damaged bearing noted above. There was no Emergency Core Cooling System actuation and no radioactive release associated with this trip. Reactor water level dropped to approximately 135 inches above the Top of Active Fuel and reactor pressure remained at approximately 940 psig. The High Pressure Coolant Injection (HPCI) System was manually started and used to restore reactor water level. Subsequently, the licensee noted that the HPCI gland seal condenser gasket started leaking again. The licensee declared HPCI inoperable and isolated it to stop and repair the leak. The inspector reviewed the process computer alarm printout, the post trip log, various chart recorders, and the completed data sheets for procedure No. ODSO 23, Post Trip Evaluation, and determined that the plant responded as designed and that the licensee's review of the trip was adequate.

During the investigation into the loss of the "A" RFP, the licensee determined that the RFP turbine tripped on loss of control oil to the High Pressure and Low Pressure Stop Valves when the control oil line parted at a compression fitting. Based on discussions with maintenance personnel, the inspector noted that the compression fitting failed because it had not been tightened properly. The maintenance personnel also indicated that this fitting had not been broken nor was it in a location where it could have been accidently jarred during the recent maintenance on the "A" RFP and that this condition probably had existed for some time. The licensee repaired the parted control oil line and checked all other oil lines on the "A" RFP for loose fittings. No additional problems were found. The licensee commenced a reactor startup at 5:55 P.M. on March 25, 1984, using only the "A" RFP as the "B" RFP was still undergoing repairs.

9. Followup on IE Bulletin 79-14, Seismic Analysis for As-Built Safety-Related Piping Systems

On March 13, 1979, as a result of significant discrepancies observed between the original piping analysis computer code used to analyze earthquake loads by the architect-engineer and the then currently acceptable computer codes developed for that purpose, the licensee was ordered to shutdown and to show cause why they should not remain shut-down pending reanalyses of the facility piping systems and pending completion of any modifications indicated by the reanalyses. In letter JAFP 79-352, dated July 9, 1979, in response to IE Bulletin (IEB) 79-14, Seismic Analysis for As-Built Safety-Related Piping Systems, the licensee took the position, acknowledged by the NRC, that the requirements of the bulletin were being met by the seismic analyses program established for the show cause order. This seismic analyses program consisted of: a field verification of the as-built condition by the licensee of 96 piping system problems involving 17 safety related systems and 989 piping supports; the seismic reanalysis of these problems by Stone and Webster Engineering Corporation (SWEC), the architect-engineer, using the as-built information; and the evaluation of adequacy and the modification by Target Technology Limited (TTL) of supports identified by SWEC, utilizing loads supplied by SWEC.

The order suspending facility operation was lifted on August 14, 1979, after the licensee had: completed the reanalyses for all 96 piping problems; completed all analyses and modifications on those pipe supports located in inaccessible areas; completed the required modifications identified to date on the accessible pipe supports; committed to complete the analysis of the remaining accessible pipe supports within 60 days from the date of plant startup; and committed to make a 24 hour notification if it was determined that any of the remaining analyses resulted in declaring a support inoperable. Prior to the order lifting the suspension of facility operation, the inspector noted that inspection no. 333/79-11, conducted at the request of NRR, confirmed that deficient pipe supports, located in inaccessible areas, were being properly repaired or modified in accordance with applicable engineering disposition. Subsequent to this, the inspector noted that inspections no. 333/81-12 and 333/83-24 also confirmed that pipe support deficiencies had been properly corrected. The licensee resumed power operation on September 3, 1979. In letter JPN-79-71, dated November 2, 1979, the licensee indicated that, as committed to, the reanalysis of the accessible pipe supports was complete. The inspector reviewed LER's 79-79, 79-80, 79-81, 79-85, 79-86, and 79-87 and verified that the licensee made the prompt notifications, also committed to, when a support was determined to be inoperable and that repairs/modifications were completed within seven days. In letter JPN-79-78, dated December 3, 1979, the licensee indicated that the field verification required by IEB 79-14 of all safety related pipe lines two and a half inches and larger in diameter, which were not computer analyzed and therefore not included in the pipe stress program in response to the Show Cause Order, had also been completed and identified modifications were in progress. In letter JAFP-80-773, dated October 7, 1980, the licensee summarized the status of IEB 79-14 and indicated that one hundred eighteen supports requiring modification were identified and that these modifications had been completed. This letter also noted, based on additional reviews, that incorporation of the Control Rod Drive (CRD) system into the IEB 79-02 and 79-14 programs may have been inadequate and that this was still being evaluated.

Inspection no. 333/81-12 examined licensee action on IEB 79-14 and left the bulletin open pending verification of the seismic analysis for for the CRD piping. As a result of the IEB 80-17 program, the licensee determined that the CRD insert and withdrawal lines, which were less than 2½ inches in diameter but computer analyzed, and the Scram Discharge Volume (SDV) headers, Scram Discharge Instrument Volume (SDIV), and portions of their vent and drains, which had been overlooked, were subject to the requirements of IEB 79-14. The program for the CRD piping was the same as it was during the pipe stress shutdown. That is, the licensee performed the field verification, SWEC performed the seismic reanalyses using as-built data; and TTL evaluated the adequacy and modified supports identified by SWEC and using loads supplied by SWEC. The inspector reviewed modification packages no. F1-81-08 on the SDV, SDIV and vent and drain pipe supports, and F1-81-22 on the CRD insert and withdrawal pipe supports, including their respective safety evaluations (no. JAF-SE-81-34 and JAF-SE-81-59), and noted that although all the seismic reanalysis and support modifications have been completed, neither modification package was closed out. Both modification packages are still open pending completion of the drawing update which is still in progress. The inspector will verify that modification packages FI-81-08 and FI-81-22 are properly closed out during a subsequent inspection. (333/84-04-04)

During a review of the licensee's actions with respect to IEB 79-14, the inspector noted that the licensee did not have a formal written procedure identifying the inspection elements used to verify the as-built condition. This discrepancy had been previously identified by United Engineers and Constructors (UE&C), a consultant retained by the licensee as an independent third party to investigate allegations regarding pipe support deficiencies. In letter JPO-83-74, dated October 31, 1983, the licensee sent UE&C the guidance provided for the field verification. This guidance included checks of the support location, function, orientation, condition, and dimensions which were important to the reanalysis effort. Based upon a review of several marked up isometric drawings used in the seismic reanalysis, a review of several work requests generated as a result of the field verification, and discussions with an individual involved in the system walkdowns, the inspector concluded that this guidance was followed.

In addition, the inspector noted that inspections 333/79-06 and 333/79-09 confirmed the effectiveness of the licensee's program to verify the as-built condition. However, during a November 1983 detailed field investigation, which checked support member sizes, weld size and length, and bolting, UE&C identified dimensional discrepancies on thirteen of eighteen supports examined. These discrepancies included undersized welds, missing welds, and steel member size differences. The licensee examined these same supports and similarly identified several deviations from the as-built drawings. These deviations were included in Deficiency and Corrective Action Reports (DCAR) which were sent to SWEC for evaluation. SWEC determined that for each support, the discrepancies found did not represent any safety concern and that the subject as-installed piping systems were acceptable for all normal and seismic loading. As a result of the findings by UE&C, the licensee is developing a program to inspect pipe supports against the as-built drawings in order to identify, evaluate and correct any discrepancies such as those noted above. Since the as-built drawings were used in the piping seismic reanalysis, this item is unresolved pending completion of the licensee's program. (333/84-04-05)

The inspector also examined ten pipe supports in the Residual Heat Removal and High Pressure Coolant Injection Systems to verify that the drawings reflected the as-built condition and that the supports were not visibly damaged. The inspector selected two supports, no. H 23-23 and H 23-36, which had not been modified; four supports, no. PFSK1939, and PFSK1944, PFSK1947, PFSK1959, which were modified during the 1979 pipe stress shutdown; and four supports, no. H 23-49, H 23-50, H 23-53, and H 23-54, which have been identified by UE&C as having dimensional discrepancies. For the first six supports the inspector verified that the supports were not damaged and that the drawings accurately reflected the as-built condition. For the last four supports the inspector verified that the supports were not damaged and that the deficiencies noted between the drawings and as-built condition were accurately reflected in DCAR's 83-101, 83-93, 83-98, and 83-99 respectively. These are the DCAR's used by SWEC to verify that the supports were still acceptable as installed. The inspector concluded that the licensee's program to verify, evaluate and resolve the UE&C findings was adequate.

With the exception of the two issues noted above, which will be reviewed during subsequent inspections, the inspector determined, based on his review, that the licensee satisfied the requirements of IEB 79-14 and considers this bulletin closed.

10. Review of Periodic and Special Reports

Upon receipt, the inspector reviewed periodic and special reports. The review included the following: Inclusion of information required by the NRC; test results and/or supporting information consistent with design predictions and performance specifications; planned corrective action for resolution of problems, and reportability and validity of report information. The following periodic report was reviewed:

-- February, 1984 Operating Status Report, dated March 8, 1984.

11. 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 item identified during this inspection is discussed in paragraph 9.

12. 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 April 2, 1984, the inspector met with licensee representatives (denoted in paragraph 1) and summarized the scope and findings of the inspection as they are described in this report.