U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-454/88009(DRP); 50-455/88009(DRP)

Docket Nos. 50-454; 50-455 License Nos. NPF-37; NPF-66

Licensee: Commonwealth Edison Company
Post Office Box 767
Chicago, IL 60690

Facility Name: Byron Station, Units 1 and 2

Inspection At: Byron Station, Byron, Illinois

Inspection Conducted: May 17 - June 30, 1988

Inspectors: P. G. Brochman
N. V. Gilles
J. M. Ulie

Approved By: J. M. Hinds, Jr., Chief
Reactor Projects Section 1A

07.11.88
Date

Inspection Summary

Inspection from May 17 - June 30, 1988 (Report Nos. 50-454/88009(DRP); 50-455/88009(DRP))

Areas Inspected: Routine, unannounced safety inspection by the resident inspectors and a region-based inspector of licensee action on previous inspection findings; licensee event reports; bulletins; generic letters; operations summary; training; spent fuel storage racks; surveillance; maintenance; operational safety; and event followup.

Results: Of the 10 areas inspected, no violations or deviations were identified in 9 areas; 2 violations were identified in the remaining area (failure to establish and implement adequate procedures for the Fire Protection Program - paragraph 3.a; failure to maintain an auxiliary feedwater pump operable during operational mode changes - paragraph 3.b). However, in accordance with 10 CFR 2, Appendix C, Section V.G.1, a Notice of Violation was not issued for the second violation.

DETAILS

1. Persons Contacted

Commonwealth Edison Company

*R. Pleniewicz, Station Manager
T. Joyce, Production Superintendent
R. Ward, Services Superintendent
*W. Burkamper, Quality Assurance Superintendent
*T. Tulon, Assistant Superintendent Operating
*G. Schwartz, Assistant Superintendent, Maintenance
*L. Sues, Assistant Superintendent, Technical Services
*D. St. Clair, Assistant Superintendent, Work Planning
T. Higgins, Operating Engineer, Unit 0
J. Schrock, Operating Engineer, Unit 1
D. Brindle, Operating Engineer, Unit 2
T. Didier, Operating Engineer, Rad-Waste
M. Snow, Regulatory Assurance Supervisor
*R. Flahive, Technical Staff Supervisor
S. Barrett, Radiation/Chemistry Supervisor
P. O'Neil, Quality Control Supervisor
S. Wilson, Station Chemist
W. Bielasco, Station Health Physicist
*W. Pirnat, Regulatory Assurance Staff
E. Zittle, Regulatory Assurance Staff
*G. Stauffer, Regulatory Assurance Staff
K. Sullivan, Technical Staff
W. Walter, Assistant Technical Staff Supervisor
*F. Hornbeak, Nuclear Safety
*D. Freeman, Regulatory Assurance Staff

The inspector also contacted and interviewed other licensee and contractor personnel during the course of this inspection.

* Denotes those present during the exit interview on June 30, 1988.

2. Action on Previous Inspection Findings (92701)

(Open) Unresolved Item (454/88006-01(DRP); 455/88006-01(DRP)): Appropriateness of using Whitman General, J-505 pressure switches in environmentally qualified applications. On March 27, 1988, a problem was identified with the qualification of Whitman General, J-505 pressure switches. These switches are used on several safety-related components in an environmentally qualified application. The licensee declared some of these components inoperable and followed the appropriate Technical Specification Action Requirements, and prepared a Justification for Continued Operation (JCO) for those switches left in service. Subsequently, the licensee has developed information which it believes demonstrates that the J-505 pressure switches always were environmentally qualified. This information was provided to the NRC staff for review. This item will remain open pending the NRC's review of this information.

3. Licensee Event Report (LER) Followup (92700)

(Closed) LERs (454/87011-1L; 454/88002-LL; 455/87019-1L; 455/88004-LL; 455/88005-LL; 455/88006-LL; 455/88007-LL): Through direct observation, discussions with licensee personnel, and review of records, the following LERs were reviewed to determine that the reportability requirements were fulfilled, that immediate corrective action was accomplished, and that corrective action to prevent recurrence had been accomplished in accordance with Technical Specifications.

LER No.	Title
Unit 1	
454/87011-1	Carbon dioxide system inoperable due to mispositioned valve.
454/88002	Reactor trip due to rod drop during manual control rod motion.
Unit 2	
455/87019-1	Reactor trip from Hi-Hi steam generator level and subsequent loss of offsite power.
455/88004	Main feedwater pump trip due to improper isolation of electrohydraulic control fluid supply resulting in reactor trip.
455/88005	Operational mode changes made while auxiliary feedwater pump was inoperable due to level switch failure.
455/88006	Reactor trip due to control rod drop caused by intermittent component failure in the rod drive system.
455/88007	Two Feedwater isolations on Hi-Hi steam generator level due to a feedwater valve failing to open

The events described in LER 454/88002 were discussed in Inspection Report No. 454/88007. The events described in LER 455/87019-01 were discussed in Inspection Report No. 455/87038. The supplemental report was issued to provide additional information on the failure of the feedwater regulating valve and to document completion of corrective actions. The events described in LER 455/88004 were discussed in Inspection Report No. 455/88007. The events described in LERs 455/88006 and 455/88007 are discussed further in Paragraph 12.c.

a. With regard to LER 454/87011, this LER describes an event in which the carbon dioxide (CO_2) fire suppression system for the station was inoperable due to a mispositioned valve. On April 15, 1987, at approximately 1:30 pm, during the performance of the 18-month surveillance (1BHS 7.10.3.2.B.1-3) on the CO_2 fire suppression system for the diesel-driven auxiliary feedwater (AFW) pump room, the licensee discovered that the low pressure CO_2 system

was inoperable. During the actuation test no CO_2 flowed from the spray nozzles in the AFW pump room. The licensee initiated a nuclear work request to troubleshoot and repair the CO_2 system for the AFW pump room. In addition, the Limiting Condition For Operation Action Requirement for an inoperable AFW CO_2 system was entered.

On April 16, 1987, at approximately 5:00 pm, while troubleshooting the AFW pump room CO_2 system problem, the system engineer (non-licensed) and maintenance personnel discovered a CO_2 storage tank vapor pilot valve to be in the closed position. Upon discovery, the valve was immediately opened. This valve provides CO_2 (as a motive force) through the electro-manual pilot cabinets to open the pilot-operated master selector valves. The CO_2 tank is located within a locked cage in the turbine building, and the vapor pilot valve is located inside the tank's cowling, which is also locked. The master selector valves pressurize the various plant CO_2 headers. With the vapor pilot valve closed, the motive force to operate all three master selector valves was removed. Consequently, the CO_2 fire suppression system would not have been capable of performing its design function, should a fire have occurred in any of the approximately 30 rooms that the system protects.

There are approximately 22 rooms that use CO_2 as the primary means of fire suppression, of which approximately 10 rooms contain redundant shutdown equipment. Due to construction activities in progress in the 8 upper cable spreading rooms, the primary automatic Halon fire suppression systems were also out of service for personnel safety. However, continuous and/or hourly fire watch patrols were in place between April 4 and April 16, 1987. The inspector reviewed the fire watch patrol sheets to verify this practice. However, the inspector noted that these compensatory actions were primarily as a result of other degraded fire protection features and were not knowingly put in place by the licensee in response to an inoperable CO_2 system. On April 20, 1987, Surveillance Procedure 1BHS 7.10.3.2.B.1-3 was successfully reperformed, demonstrating the operability of the AFW pump room CO_2 system and the master selector valves.

During a review of this event, the licensee determined that on April 4, 1987, the vapor pilot valve had been demonstrated to be open when an inadvertent CO_2 actuation occurred in the Unit 2 cable tunnel area. After this inadvertent actuation, during the tank refilling operation, a switching valve line adjacent to the vapor pilot valve was found to be leaking. This leaking valve was in close proximity to the vapor pilot valve. The licensee believes that the vapor pilot valve was inadvertently closed to isolate this leak. From the time of the CO_2 tank recharging on April 4, until the AFW pump room CO_2 surveillance failed, no documented work was performed in the locked CO_2 supply tank cage. The licensee believes this explanation to be the most probable reason for the mispositioning of the vapor pilot valve, and based on inspector review, this explanation is considered to be plausible.

The inspector determined that prior to this event, the licensee's procedures had failed to specifically require surveilling the proper position of the CO_2 system tanks' vapor pilot valves. Technical Specification 6.8.1.h requires that written procedures be established, implemented, and maintained for activities involving the Fire Protection Program.

The failure to include the vapor pilot valves in appropriate procedures as described in the Notice of Violation is considered a violation of Technical Specification 6.8.1.h (454/88009-01(DRS); 455/88009-01(DRS)). The procedural inadequacies were a result of the design drawings not showing the two CO_2 System vapor pilot valves. In addition, these deficiencies are attributable in part to the vapor pilot valves being a part of the CO_2 tank skids, and not a part of the engineering specifications.

The licensee's corrective actions for this event included the following:

* Other fire protection skid-mounted components were immediately reviewed to determine if any other valves were overlooked. The only other valve found was the identical vapor pilot valve on the river screen house CO_2 tank. The licensee immediately checked this valve and found it to be open as required. On January 19, 1988, the inspector visited the river screen house and also verified that the installed CO_2 tank vapor pilot valve was locked in the open position.

* Both vapor pilot valves were given unique identification numbers and locked in the open position. The valves were added to the station's "Locked Valve Surveillance." On January 19, 1988, the inspector confirmed that the CO_2 tank vapor pilot valve located in the turbine building was locked open. As mentioned previously, the river screen house CO_2 tank vapor pilot valve was also verified to be in the locked open position. In addition, the inspector was provided the monthly CO_2 system valve position Surveillance Procedure OBOS 7.10.3.1-1, Revision 2, approved on July 20, 1987, which now includes both CO_2 tanks' vapor pilot valves identified as "Master Vapor Pilot Valves" numbered 0C05002 and 0C05006.

* Drawing change requests have been submitted to add these valves to the design drawings. On January 19, 1988, the inspector confirmed that drawing nos. M-58, Revision AD, dated June 2, 1987, and M-58, Revision J, dated June 2, 1987, now include each of the required vapor pilot valves.

* The System Valve Lineup Procedures have been updated to include the vapor pilot valves. On January 19, 1988, the inspector verified that System Valve Lineup Procedures BOP CO-M1, Revision 5, approved on July 17, 1987, and BOP CO-M2, Revision 3, approved on August 13, 1987, include these vapor pilot valves.

The inspector considers the licensee's corrective actions to be adequate, and this item is therefore considered closed.

As a result of CO_2 system problems identified during this event, the inspector is concerned about the design reviews which were performed on other fire protection systems, and whether procedures for operation of fire protection systems are adequate. Therefore, the licensee is requested to take the necessary additional steps to ensure that appropriate design reviews have been performed to determine if any other procedural revisions for other fire protection systems are necessary, so as to assure the operability of fire protection systems. This is considered an open item (454/88009-02(DRS); 455/88009-02(DRS)) pending NRC review of licensee actions to ensure that appropriate design reviews have been performed.

b. With regard to LER 455/88005, this LER describes an event in which operational mode changes were made at 11:55 pm on May 6, 1988, and at 1:11 am on May 7, while the 2B diesel-driven AFW pump was inoperable due to its fuel oil day tank level being below the Technical Specification limit. The root cause of this event was the failure of the 2B AFW pump fuel oil day tank low level switch to actuate a main control room annunciator. A contributing cause to the length of time the condition existed was the fact that two non-licensed Equipment Attendants (EAs), who had noted the out-of-tolerance condition during their rounds and had circled the out-of-tolerance value on their round sheets, did not recognize the significance of the low level condition and did not notify senior control room personnel. The reason the EAs did not recognize the importance of the low level condition was a placard affixed to the day tank that specified that the level be maintained greater than 50%, leading the EAs to excuse the out-of-tolerance condition as indicated by their round sheets. At 10:20 am on May 8, a third EA reviewed the logs from the previous shift and noted the out-of-tolerance condition which had been recorded on the previous shift and informed the Reactor Operator (RO). The RO directed the EA to immediately fill the day tank to a level greater than the Technical Specification limit.

Technical Specification 3.7.1.2 requires that one direct-driven diesel auxiliary feedwater pump be operable and capable of being powered from a direct-drive diesel engine and an operable Diesel Fuel Supply System consisting of a day tank containing a minimum of 420 gallons of fuel. This specification is applicable in Modes 1, 2, and 3. With one auxiliary feedwater pump inoperable, the Technical Specification Action Requirement allows 72 hours to restore the pump to an operable status. The licensee did not exceed the 72-hour time limit; however, Technical Specification 3.0.4 prohibits entry into an operational mode unless the conditions for the Limiting Condition for Operation are met without reliance on provisions contained in the Action Requirements.

The changing of operational modes while relying on provisions contained in the action requirements of Technical Specification 3.7.1.2 is a violation of Technical Specification 3.0.4 (455/88009-03(DRP)). However, this violation meets the tests of 10 CFR 2, Appendix C, Section V.G.1; consequently, no Notice of Violation will be issued, and this matter is considered closed.

Because the operational mode changes were made before the EA's daily check of the AFW pump fuel oil day tank level, the violation would have occurred even if the EA had recognized the level was below the Technical Specification limit. However, eight separate reviews of the rounds sheets were performed by six different licensed individuals (three ROs and three Senior Reactor Operators [SROs]); all of the individuals failed to recognize the out-of-tolerance condition, which was circled in red and clearly indicated that the day tank level was below the Technical Specification limit, and signed off on the round sheets for their shifts. The inspectors are seriously concerned about this breakdown in management oversight and review of the status of safety-related systems by licensed individuals.

The licensee's corrective actions included replacement of the day tank low level switch and a calibration check of the local level meter. A new operating procedure (BOP AF-1) will be implemented to require verification of adequate diesel-driven AFW pump day tank level, along with other parameters important to AFW pump operability. Procedures which require the operation of the diesel-driven AFW pump will be revised to require the performance of BOP AF-1. The placard affixed to the day tank has been revised to clarify the level requirements. Finally, the "Equipment Daily Logs Administrative Procedure," (BAP 350-5) is being revised to require that all (emphasis original) out-of-tolerance readings be brought to the attention of the operating shift supervisor.

One violation was identified.

4. NRC Compliance Bulletin Followup (92701)

a. (Closed) Bulletin (454/88001-BB; 455/88001-BB): Defects in Westinghouse Circuit Breakers. The NRC staff has reviewed the licensee's response to this bulletin and concluded that it is acceptable, in accordance with a letter from L. N. Olshan to H. Bliss, dated April 22, 1988. Based on this review, this bulletin is considered closed.

b. (Closed) Bulletin (454/88003-BB; 455/88003-BB): Inadequate Latch Engagement in HFA Type Latching Relays Manufactured by General Electric (GE) Company. The inspector has reviewed the licensee's response to Bulletin 88-03. The licensee has completed its review pursuant to the request outlined in Bulletin 88-03 for Byron. Byron Station does not utilize HFA type latching relays that are subject to the bulletin, and no further actions are required. Based on this review, this bulletin is considered closed.

No violations or deviations were identified.

5. Generic Letters (GLs) (92701)

a. (Open) GL (454/88003-HH; 455/88003-HH): Potential for disabling auxiliary feedwater pumps due to steam binding. The licensee has submitted a response for this GL, which is being reviewed by the NRR staff. This GL will remain open pending the completion of the staff's review.

b. (Open) GL (454/88005-HH; 455/88005-HH): Boric acid corrosion of carbon steel reactor coolant system pressure boundary components. The licensee has submitted a response for this GL, which is being reviewed by the NRR staff. This GL will remain open pending the completion of the staff's review.

No violations or deviations were identified.

6. Summary of Operations

Unit 1 operated at power levels up to 98% until 12:16 am on May 28, 1988, when the unit was shut down to repair a tube leak in the 1A steam generator (see paragraph 12.a). The unit was restarted at 4:01 am on June 11, 1988, and was synchronized to the grid at 7:30 am on the same day. The unit operated at power levels up to 98% for the rest of the report period.

Unit 2 operated at power levels up to 94% until 6:40 am on June 2, 1988, when the unit tripped on a high negative neutron flux rate (See paragraph 12.b). The unit was restarted at 12:44 pm on June 3 and was synchronized to the grid at 8:41 am on June 4. The unit operated at power levels up to 95% until 4:54 pm on June 23, when the turbine was taken off the line due to secondary chemistry problems (see paragraph 12.c). The unit was synchronized to the grid at 1:48 pm on June 24 and operated at power levels up to 95% for the rest of the report period.

7. Training (41400 & 41701)

The effectiveness of training programs for licensed and non-licensed personnel was reviewed by the inspectors during witnessing of the licensee's performance of routine surveillance, maintenance, and operational activities and during review of the licensee's response to events which occurred during May and June 1988. Personnel appeared to be knowledgeable of the tasks being performed, and nothing was observed which indicated ineffective training.

No violations or deviations were identified.

8. Spent Fuel Storage Racks (50095)

The licensee has submitted a request to amend the operating licenses for Units 1 and 2 to increase the storage capacity of the spent fuel

pit (SFP). This is to be accomplished by replacing the existing fuel storage racks with high density racks, which hold a larger number of spent fuel assemblies per given volume. The NRC staff has been reviewing the licensee's request and has requested additional information on reracking the SFP. In anticipation of the NRC's approval of the amendment, the licensee had previously removed most of the old spent fuel racks from the SFP before they had become contaminated. The SFP presently contains the discharged portion of the Unit 1, Cycle 1, reactor core. However, there is an inadequate amount of storage space to store the discharged reactor cores from the upcoming Unit 1 and 2 refuelings. Consequently, the licensee has reinstalled three of the old spent fuel racks. The licensee has received most of the new (higher density) spent fuel racks; however, they cannot be installed until the license amendment is issued.

The inspector reviewed the licensee's procedures for reinstalling the old spent fuel racks. The inspector verified that requirements for lifting heavy loads over the SFP were met and that mechanical stops and limit switches were in place on the SFP building bridge crane. The inspector verified that the installation procedures specified the torquing requirements for the spent fuel rack hold down bolts.

The inspector observed installation of one of the old fuel racks and the activities of the diver in the SFP. The inspector observed the health physics and radiation protection activities related to sending a diver into the SFP.

The inspector met with the licensee's staff to review the progress of the SFP activities. The licensee believes that activities performed in the fuel handling building to support the two upcoming refueling outages would interfere with the removal of the old fuel racks and installation of the new fuel racks. Consequently, the licensee does not plan on installing any new fuel racks before spring 1989, should the license amendment be issued.

No violations or deviations were identified.

9. Monthly Surveillance Observation (61726)

Station surveillance activities of the safety-related systems and components listed below were observed or reviewed to ascertain that they were conducted in accordance with approved procedures and in conformance with Technical Specifications.

1A auxiliary feedwater pump monthly test
1B diesel generator monthly test
Unit 2 incore flux map monthly surveillance
Deep well pumps 0A and 0B surveillance test

The following items were considered during this review: the limiting conditions for operation were met while affected components or systems were removed from and restored to service; approvals were obtained prior

to initiating the testing; testing was accomplished in accordance with approved procedures; test instrumentation was within its calibration interval; testing was accomplished by qualified personnel; test results conformed with Technical Specifications and procedural requirements and were reviewed by personnel other than the individual directing the test; and any deficiencies identified during the testing were properly documented, reviewed, and resolved by appropriate management personnel.

No violations or deviations were identified.

10. Monthly Maintenance Observation (62703)

Station maintenance activities of the safety-related systems and components listed below were observed or reviewed to ascertain that they were conducted in accordance with approved procedures, regulatory guides, and industry codes or standards, and in conformance with Technical Specifications.

Eddy current examination of the 1A, 1B, and 1C steam generator u-tubes

The following items were considered during this review: the limiting conditions for operation were met while components or systems were removed from and restored to service; approvals were obtained prior to initiating the work; activities were accomplished using approved procedures and were inspected as applicable; functional testing and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; radiological controls were implemented; and fire prevention controls were implemented. Work requests were reviewed to determine the status of outstanding jobs and to assure that priority is assigned to safety-related equipment maintenance which may affect system performance.

No violations or deviations were identified.

11. Operational Safety Verification (71707, 71709, & 71881)

The inspectors observed control room operation, reviewed applicable logs and conducted discussions with control room operators during May and June 1988. During these discussions and observations, the inspectors ascertained that the operators were alert, cognizant of plant conditions, and attentive to changes in those conditions, and that they took prompt action when appropriate. The inspectors verified the operability of selected emergency systems, reviewed tagout records, and verified the proper return to service of affected components. Tours of the auxiliary, fuel-handling, rad-waste, and turbine buildings were conducted to observe plant equipment conditions, including potential fire hazards, fluid leaks, and excessive vibrations, and to verify that maintenance requests had been initiated for equipment in need of maintenance.

The inspectors verified by observation and direct interviews that the physical security plan is being implemented in accordance with the station security plan.

The inspectors observed plant housekeeping/cleanliness conditions and verified implementation of radiation protection controls. The inspectors also witnessed portions of the radioactive waste system controls associated with rad-waste shipments and barreling.

The observed facility operations were verified to be in accordance with the requirements established under Technical Specifications, 10 CFR, and administrative procedures.

No violations or deviations were identified.

12. Onsite Follow-up of Events at Operating Reactors (93702)

The inspectors performed onsite follow-up activities for events which occurred during May and June 1988. These follow-ups included reviews of operating logs, procedures, Deviation Reports, Licensee Event Reports (where available), and interviews with licensee personnel. For each event, the inspector developed a chronology, reviewed the functioning of safety systems required by plant conditions, and reviewed licensee actions to verify consistency with procedures, license conditions, and the nature of the event. Additionally, the inspector verified that the licensee's investigation had identified the root causes of equipment malfunctions and/or personnel errors and that the licensee had taken appropriate corrective actions prior to restarting the unit. Details of the events and the licensee's corrective actions developed through inspector follow-up are provided in paragraphs a through c below:

a. Unit 1 - Steam Generator (SG) 1A U-tube Leak

At 12:16 a.m. on May 28, 1988, the unit was taken off line to repair a u-tube leak in the 1A SG. The leakage rate was measured at 125 gallons per day (gpd). The Technical Specification limit for u-tube leakage is 500 gpd. Unit 1 was previously shut down on March 11, 1988, due to a u-tube leak in the 1D SG.

The licensee performed eddy current testing on all row 1 u-tubes and on all u-tubes which had indications of cracks from the previous refueling outage eddy current tests in the 1A, 1B, and 1C steam generators. The leaking tube was located at row 1, column 2 of the 1A SG. The leak was located at the apex of the tube, identical to the location of the leak in the 1D SG. No other through-wall leaks were identified. However, other indications were identified, and the licensee plugged an additional 24 tubes in the 1A SG and 1 tube in the 1C SG.

The unit was returned to service at 7:30 am on June 11, 1988. The licensee has used approximately 16% of the available tube plugging limit per the current safety analysis. The licensee is evaluating

whether to perform stress relieving on the row 1 tubes for all four Unit 1 SGs or to plug the tubes now. The inspectors will review the licensee's course of action.

b. Unit 2 - Unit Taken Off Line Due To Secondary Chemistry Excursion

At 10:45 am on June 23, 1988, the licensee entered Byron Abnormal Operating Procedure (BOA) SEC-2, "Steam Generator High Conductivity," when steam generator blowdown samples indicated a cation conductivity of approximately 340 micromhos per centimeter and a sulfate concentration of approximately 2000 ppb. The excursion was caused by a leaking acid valve in the condensate makeup demineralizer system which allowed acid to leak into the makeup system for approximately 10 minutes, until the leak was discovered and isolated. Makeup water was being added to the main condenser at the time, allowing a path for the acid to enter the condensate and feedwater system. The leaking valve had not closed completely following the acid portion of the demineralizer regeneration process due to the wire valve tag getting caught up in the valve.

BOA SEC-2 identifies action levels associated with steam generator chemistry. The criterion for entering Action Level 3 (highest level) for cation conductivity is greater than 7 micromhos per centimeter. The criterion for entering Action Level 2 for sulfates is greater than 100 ppb (there is no Action Level 3 for sulfate concentration). At 10:56 am, the licensee began a controlled power reduction in accordance with BOA SEC-2, which requires that the unit be taken to hot standby (Mode 3) within 6 hours of entering Action Level 3 on any chemistry parameter. The licensee reduced power to approximately 10%, reduced Tave to its no-load value, and at 4:54 pm, tripped the main turbine to satisfy the intent of BOA SEC-2, while remaining in Mode 1. While this action was not in accordance with the licensee's procedures, remaining in Mode 1 allowed faster cleanup of secondary chemistry due to increased steam generator blowdown rates. Station management made the decision to remain in Mode 1 after discussions with the corporate chemist and corporate management. The licensee is in the process of revising BOA SEC-2 to allow operation in Mode 1 with the unit off line and Tave at or below its no-load value when in Action Level 3 on steam generator secondary chemistry.

The licensee exited Action Level 2 on cation conductivity at 7:00 a.m. on June 24, and exited Action Level 2 on sulfates at 10:20 a.m. the same day. This allowed the licensee to increase Tave and to bring turbine power to 25%. At 1:48 p.m. on June 24, the unit was synchronized to the grid, and turbine power was increased to 25%. At 2:40 a.m. on June 25, the licensee exited all action levels for steam generator chemistry and began ramping up in power.

The licensee believes that no short term effects on steam generator integrity will be seen from the chemistry excursion. This is based on the expeditious cleanup of the secondary coolant, the corresponding small amount of time that the contaminants remained in the steam generators, and on the metallurgical and design characteristics of the D-5 steam generators installed in Unit 2. This steam generator design is not expected to be as susceptible to the effects of "denting," which is one of the major concerns with contaminants entering the steam generators. Denting occurs when the gap between a tube and support plate increases during cold plant conditions due to differential expansion. Corrosion products deposit in the hole in the support plate. When the unit is heated, the differential expansion closes the gap. Since the hole is now smaller due to the corrosion products, the tube can actually be dented, and its integrity threatened. To minimize this effect, the D-5 model of steam generators are designed with machined "quatrefoil" openings in the support plate. These openings combine the tube support holes and the steam flow holes. Only a small portion of the opening between tube and plate is close to the tube. Also, since there is more flow around the tube, there is less probability of corrosion products being deposited. This model of steam generator is also less susceptible to corrosion damage because of the use of stainless steel support plates, versus the carbon steel support plates used in older model SGs.

The licensee is planning a 24-hour hold point at 350 degrees F during the shutdown for the upcoming Unit 2 refueling outage (January 1989). The purpose of the hold point is to allow any sulfates which may be "hiding out" in crevices in the steam generators to come out, which is most likely to happen at this temperature. The licensee is also planning a hideout study in July 1988, in which a small, known quantity of sulfates will be injected into the steam generators to determine how long it takes for all of the sulfates to be removed. The licensee and the industry hope to gain a better understanding of how sulfates behave in the environment found in steam generators from these types of studies. Based on its observations, the licensee does not believe that this incident will have any serious effect on the integrity of the steam generators.

c. Unit 2 - Reactor Trip due to Dropped Control Rods and Feedwater Isolations During Startup

At 6:40 a.m. on June 2, 1988, with reactor power at 94%, a reactor trip occurred on high negative flux rate on the power range nuclear instruments. The negative flux rate trip was caused by control rods dropping into the reactor core. All systems functioned normally following the trip, except that the RO manually reenergized the source range instruments when one of the intermediate range channels appeared to be undercompensated. He thought the undercompensation would delay automatic reenergization. However, the intermediate range channel was later determined to be properly

compensated, and the P-6 permissive that automatically reenergizes the source range instruments actuated shortly after the manual reenergization.

Immediately following the reactor trip, the rod drive (RD) power cabinet fuses were inspected for blown fuse indications. The licensee determined that rods dropped from the 1AC rod drive power cabinet, initiating the event, and that three stationary gripper phase fuses were blown during the event. Other stationary gripper phase fuses remained intact and were capable of maintaining all control rods in their withdrawn positions. Therefore, the three blown fuses alone could not have caused multiple dropped rods. The rod drive motor generator (MG) sets' protective relays were checked for targets indicating trouble, and none were found. The RD bus duct was checked for shorts, but no shorts were found. The rest of the stationary phase fuses were checked, and the licensee discovered 23 stationary phase fuses to be either cracked or electrically unacceptable; therefore, all stationary phase fuses in all power cabinets were replaced. The fuses leading out to the control rod drive mechanism (CRDM) coils were resistance checked and the fuse clips tightened. Fourteen fuses were found to be outside the acceptance criteria, but none had degraded enough to have caused rods to drop. All 14 fuses were replaced. The cables to the stationary coils on the reactor head package from RD power cabinet 1AC were checked for short circuits, and none were found. At 3:07 a.m. on June 3, the RD system was energized and reset, but an urgent failure alarm remained actuated on RD power cabinet 1CDE. After troubleshooting and swapping out the associated firing circuit card and the signal processing circuit card, the urgent alarm was cleared and determined to be due to a loose card edge connector on the stationary gripper firing circuit card. A cracked solder connection on a capacitor was fixed, and the card edge connectors tightened. Troubleshooting efforts failed to determine a root cause for the dropped rods.

The licensee exercised the control rods to verify proper operation, and Unit 2 was taken critical at 12:44 pm on June 3, 1988. At 1:27 p.m. a feedwater isolation and turbine trip occurred form approximately 2% power while operators were controlling the feedwater system in manual during the startup. The isolation occurred on a Hi-Hi level in the 2D steam generator. The isolation was caused by a rapid swell in steam generator levels which occurred when the operator could not open the preheater bypass valve for the 2C steam generator. Levels in the 1A, 1B, and 1D steam generators increased while the 1C steam generator level decreased. The preheater bypass valve was opened by an operator locally, but the 1D steam generator level reached the Hi-Hi level setpoint, causing the automatic feedwater isolation and turbine trip. During the recovery from this feedwater transient, another feedwater isolation signal occurred due to Hi-Hi level in the 1A steam generator. Levels were restored, the feedwater isolation signal was reset, and the plant startup was continued. The unit was synchronized to the grid

at 8:41 a.m. on June 4, after the licensee identified a problem with one of the generator output breakers which was causing the turbine governor valves to cycle, and subsequent level and pressure oscillations in the steam generators. The licensee synchronized the unit using the other generator output breaker and initiated repairs to the faulty output breaker.

No violations or deviations were identified.

13. Open Items

Open items are matters which have been discussed with the licensee, which will be reviewed further by the inspector, and which involve some action on the part of the NRC or licensee or both. An open item disclosed during the inspection is discussed in paragraph 3.a.

14. Violations for which a "Notice of Violation" Will Not Be Issued

The NRC uses the Notice of Violation as a standard method for formalizing the existence of a violation of a legally binding requirement. However, because the NRC wants to encourage and support a licensee's initiatives for self-identification and correction of problems, the NRC will not generally issue a Notice of Violation for a violation that meets the tests of 10 CFR 2, Appendix C, Section V.G.1. These tests are: (1) the violation was identified by the licensee; (2) the violation would be categorized as Severity Level IV or V; (3) the violation was reported to the NRC, if required; (4) the violation will be corrected, including measures to prevent recurrence, within a reasonable time period; and (5) it was not a violation that could reasonably be expected to have been prevented by the licensee's corrective action for a previous violation. A violation of regulatory requirements identified during the inspection for which a Notice of Violation will not be issued is discussed in paragraph 3.b.

15. Exit Interview (30703)

The inspectors met with the licensee representatives denoted in paragraph 1 at the conclusion of the inspection on June 30, 1988. A telephone exit was held with licensee representatives on June 21, 1988, to discuss the inspector's findings on LER 454/87011 (see paragraph 3.a). The inspectors summarized the purpose and scope of the inspection and the findings. The inspectors also discussed the likely informational content of the inspection report, with regard to documents or processes reviewed by the inspectors during the inspection. The licensee did not identify any such documents or processes as proprietary.