U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-454/85002(DRP); 50-455/85001(DRP)

Docket Nos. 50-454; 50-455 License Nos. NPF-37; CPPR-131

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

Facility Name: Byron Station, Units 1 and 2

Inspection At: Byron Station, Byron, IL

Enforcement Conference At: Region III Office, Glen Ellyn, IL

Inspection Conducted: January 1 through March 26, April 6, 9, 10 and 12, 1985

Enforcement Conference Conducted: April 29, 1985

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5/31/85
Date

Inspection and Enforcement Conference Summary

Inspection on January 1 through March 26, April 6, 9, 10 and 12, 1985 and Enforcement Conference on April 29, 1985 (Report Nos. 50-454/85002(DRP); 50-455/85001(DRP))

Areas Inspected: Routine, unannounced safety inspection by resident and regional inspectors of licensee action on previous inspection findings; SER items; Part 21 reports; startup test witnessing; electrical distribution voltage verification; comparison of as-builts with technical specifications and FSAR/SER; nonroutine events; initial criticality witnessing; LERs; operational safety verification; diesel generator surveillance testing; Regional Administrator's tour; plant tours/housekeeping; meetings between NRC and licensee management personnel were held on January 2, 16 and 30 and February 14 and 27, 1985, to discuss Unit 1 facility status and licensee corrective actions for nonroutine events; BDPS actuation reportability and other activities. An enforcement conference was conducted on April 29, 1985, related to those issues addressed in Paragraph 8.b. Criticality on Unit 1 was achieved at 2323 hours on February 2, 1985, and full power Operating License NPF-37 was issued for Unit 1 on February 14, 1985, authorizing power levels up to 100 percent of full power. The inspection consisted of 684 inspector-hours onsite by 12 NRC inspectors including 266 inspector-hours during off-shifts.

Results: In the areas inspected, four items of noncompliance were identified (failure to verify the acceptability of electrical distribution system bus voltages - Paragraph 6; failure to follow ECCS operating procedures - Paragraph 8.a; failure to perform a 50.59 evaluation and submit to the NRC for review and approval and associated violation of GDC 2 - Paragraph 8.b; failure to maintain operability of Overtemperature and Overpower delta T channels - Paragraph 8.b).

DETAILS

1. Persons Contacted

Commonwealth Edison Company

+*R. Querio, Station Superintendent
+*R. Tuetkin, Startup Coordinator
+*R. Ward, Assistant Superintendent, Administrative & Support Services
+*R. Pleniewicz, Assistant Superintendent, Operating
+*L. Sues, Assistant Superintendent, Maintenance
*M. Lohmann, Project Construction Assistant Superintendent
*V. I. Schlosser, Project Manager
*T. Tulon, Operating Engineer
*T. Higgins. Training Supervisor
+*R. Poche, Technical Staff
+*D. St. Clair, Technical Staff Supervisor
+*W. Burkamper, QA Supervisor (Operating)
*S. Barrett, Station Chemist
*G. Stauffer, Station Nuclear Engineer
*S. Dresser, Technical Staff
*P. Anthony, Technical Staff
+*T. Maiman, Manager of Projects
+P. Boyle, Project Engineering Department
+D. Sible, QA Engineering

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

*Denotes those present during one or more of the management meetings on January 2, 16, and 30 and February 14, 27, 1985.

+Denotes those present during the exit interview on February 28, 1985. The inspector conducted a subsequent exit interview with Mr. R. Querio on April 12, 1985, following the evaluation of additional information.

2. Licensee Action on Previous Inspection Findings

a. (Closed) Violation (454/84032-02(DRP); 455/84025-02(DRP)): Material false statement concerning corrective actions taken for equipment supplied by Systems Control Corporation. This item was identified in NRC Inspection Report 454/84032(DRP); 455/84025(DRP) as an unresolved item. Subsequently, a Notice of Violation and Proposed Imposition of Civil Penalty was issued to the licensee for this item on December 4, 1984.

   The licensee's response letter indicated that to avoid further violations of this nature additional training would be conducted for personnel involved in preparing responses to NRC items. This training was to emphasize the individual's responsibility for

assuring that information submitted to the NRC was accurate. The training was also to include a review of circumstances surrounding this time.

The inspector verified by interviews with licensee personnel and a review of training handouts that two training sessions were held on January 15, 1985, for licensee operation and construction personnel. These sessions covered those topics enumerated in the licensee's January 4, 1985, response letter.

b. (Closed) Violation (454/84055-01(DRP); 455/84038-01(DRP)): Failure to account for remote valve position indication inaccuracies in engineered safety features response time measurements. Corrective actions taken by the licensee relative to this item were reviewed and found acceptable in NRC Inspection Report 454/84070(DRP); 455/84048(DRP). This item remained open pending receipt of the licensee's formal written response. The inspector reviewed the licensee's response letter dated December 13, 1984, and found that it accurately described corrective actions previously reviewed and accepted by the inspector.

c. (Closed) Unresolved Item (454/84062-01(DRP)): FSAR Figure 6.3-2 incorrectly indicated that valves 1RH610-1 and 1RH611-2 were motor-operated globe valves. FSAR Amendment 46 was submitted on February 2, 1985, and included a revised Figure 6.3-2 which was previously reviewed and found acceptable by the inspector during an inspection documented in NRC Inspection Report 454/84079(DRP).

d. (Closed) Unresolved Item (454/84062-02(DRP)): Apparent lack of a well-defined program for determining the appropriate capping requirements for test, vent, and drain connections and for ensuring that these requirements are implemented. Examples were: 1) P&ID M-62 showing pipe from drain valve 1ZZ291V capped but pipe was not capped, 2) P&ID M-62 showing pipe from test/vent valve 1RH014A capped but pipe was blocked with a blind flange. A licensee field inspection conducted on January 28, 1985, revealed that the pipe from valve 1ZZ291V had a pipe cap installed as required by the P&ID, but that the pipe from valve 1RH014A had a blind flange installed instead of a pipe cap required by the P&ID.

Sargent and Lundy (S&L) drawing M-2538C, Sheet 2, Revision A, which was approved on May 8, 1980, indicates a pipe cap as the final closure for the pipe from valve 1RH014A. Engineering Change Notice (ECN) 1750 which was approved on August 13, 1980, changed the pipe cap closure to a blind flange closure to comply with ASME Section III, Paragraph NB 3671.3, and S&L Byron Specification F-2739 which does not allow the use of threaded joints on S&L Class A piping. ECN 1805 and Field Change Request 3634 approved on November 17, 1980, revised dimensions and the location so that valve 1RH014A could be used as a test connection and a vent. Revision to the P&ID drawings to reflect the numerous changes to test, vent, and drain connections

resulting from ECN 1750 was accomplished by a change to the P&ID general notes, Revision AH to P&ID M-535 dated March 1, 1985, ECN 24494 which states: "67. Where P&IDs specify a Class A threaded cap for 2" and under connections to Class A piping where no flow restrictor is used, per notes 47, 48, 49, and 50, a new welded cap or a blind flange shall be used. The welded cap or blind flange shall be shown on the as-built piping isometric."

The inspector concluded that the program for revising the physical installation detail and configuration for safety-related and ASME piping is well defined and implemented through the application of approved design changes such as revised drawings, ECNs and FCRs.

e. (Closed) Open Item (454/84066-01): Perform calibration/linearity checks with greater accuracy for process and radwaste effluent monitors by use of sources of sufficient strengths to perform calibration linearity checks of monitors over required ranges. The licensee completed the calibration/linearity checks of these monitors in late October and early November 1984 and provided copies of the calibration procedures and data to the inspector for review. No problems were identified during the review.

f. (Closed) Open Item (454/84066-02): Install heat tracing on sample lines to wide range gas monitor and in containment air sample panel. Completed Nuclear Work Request Nos. 6HT005 and 6HT006 document that the licensee completed the subject installation.

g. (Closed) Open Item (454/84066-03): Complete a commitment analysis for NUREG-0737 Items II.F.1 (Attachments 1, 2, and 3) and II.B.3. The licensee satisfactorily completed this item by: (1) completing the commitment analysis, and (2) submitting to NRR proposed revisions to Appendix E of the FSAR which clarify or modify several licensee commitments to NUREG-0737.

h. (Closed) Open Item (454/84070-01(DRP)): Completion of Auxiliary Building Ventilation system testing to verify compliance with IE Bulletin 80-06. The inspector reviewed preoperational test results for Preoperational Test 2.84.11, "Auxiliary Building HVAC," Sections 9.30, 9.31, 9.32, and 9.33. These test sections included equipment actuation or supply breaker closure from the appropriate engineered safety features actuation system output relay and verification that equipment did not change state (e.g., dampers did not reposition) upon reset of the actuation signal. These test results were approved by the licensee on February 13, 1985.

i. (Closed) Open Item (454/84077-01(DRP)): ECCS valve position audible alarms not installed. FSAR Table 6.3-3 and Section 6.3.2.2 indicated that certain valves in both ECCS trains were provided with visual and audible alarms which would indicate when the valves were not in their normal positions. While visual indication was present and the

valve out-of-position status was recorded by computer, audible alarms were not installed. The licensee issued Amendment 46 to the FSAR which deleted the audible alarm commitment for these valves.

3. Byron Safety Evaluation Report (SER) Items

(Closed) SER Item (454/83000-13): Piping vibration test program. Completion of the test program required by Confirmatory Issue (4) contained in the Byron SER was confirmed during inspections documented in NRC Inspection Reports 454/83013(DE), 454/83019(DE), and 454/84048(DRS). Closure of this Confirmatory Issue was documented by the NRC Staff in Supplement 6 to the Byron SER.

4. 10 CFR Part 21 Reports

a. (Closed) Part 21 Report (454/83001-PP; 455/83001-PP): Intermittent lockup of radiation monitor displays supplied by GA Technologies. The inspector determined by interviews with licensee personnel and review of procurement documents (purchase orders) that the licensee had shipped the RM-23 display consoles originally supplied to the Braidwood facility to the vendor for modifications required to correct the reported defect. These units were returned to the licensee for installation in Byron, Units 1 and 2. The modified RM-23 display console for Byron, Unit 1, has been preoperationally tested and declared operational without experiencing the reported problem. The units originally supplied to Byron were to be modified by the vendor and returned to the Braidwood facility for installation.

b. (Closed) Part 21 Report (454/84005-PP): Failure of Ruskin fire dampers to close under design airflow conditions. The inspector reviewed the licensee's evaluation of this matter with respect to dampers supplied to Byron. The licensee identified 21 dampers installed in Unit 1 and plant common systems potentially affected by the reported failures. Ten of these dampers had been tested under airflow conditions with no failures. The remaining 11 dampers were successfully tested under no airflow. The 10 dampers tested under airflow were shown by analysis to bound the service conditions of the remaining 11 in that the remaining 11 would be subject to lower air velocities and were of smaller sizes than the largest of the 10 tested under airflow conditions.

   Licensee personnel contacted at least five other utilities who also utilized Ruskin fire dampers. Certain of those utilities had experienced damper failures attributable, in whole or in part, to improper installation involving misalignment of the damper assemblies. The licensee earlier became aware of the necessity to maintain proper alignment of the damper assembly in the course of damper installation. Construction and/or preoperational tests were performed by the licensee to verify that the dampers cycled properly and were therefore properly aligned. None of the information obtained by the licensee from contacts with other utilities conflicted with the licensee's evaluation and resolution of the reported deficiency.

c. (Closed) Part 21 Report (454/84007-PP; 455/84007-PP): Potential for overpressurization of the Component Cooling Water (CCW) system. The inspector reviewed Westinghouse letter CAW 7949, dated September 28, 1984, which documented NSSS vendor review and approval of a design change for the Byron Unit 1 and 2 CCW system to resolve the potential overpressurization condition. Attached to the letter was a copy of Westinghouse Design Change Notice (DCN) SET-CCE-043 which illustrated the subject design change. The design change deleted the surge tank relief valves, added loop seals to the relief lines, and provided interconnecting piping for supplying demineralized water to establish the loop seals. The inspector verified by drawing review that Piping and Instrumentation Drawing M-66, Sheet 4, reflected the subject design change. The inspector visually verified that installed piping was per the P&ID and the DCN.

d. Part 21 Report (454/84001-PP; 455/84001-PP): Environmental qualification of viton elastomer seals utilized in hydrogen recombiners manufactured by Rockwell International. As documented in NRC Inspection Reports 454/84028; 455/84020, 454/84055, 455/84038 and 454/84079, 455/84053, the licensee was informed of the reported defect, provided with recommendations for seal replacement, and had issued purchase orders to the replacement seal supplier. At the time of this inspection the licensee had received and installed all but two of the replacement seals.

   Nuclear Work Request (NWR) 6-VQ-025 was written to require replacement of the remaining two seals upon receipt. The inspectors were provided with documentation of evaluations performed by Sargent and Lundy (the Architect Engineer) which concluded that the viton elastomer was qualified for harsher environments than posed by the hydrogen recombiner application and that seal replacement could be deferred until the end of the first manufacturer-recommended 5-year seal replacement interval. The inspectors concluded that the licensee had provided adequate assurance of acceptable hydrogen recombiner performance to support Unit 1 operation. However, this item will remain open pending receipt and installation of the two remaining replacement seals.

5. Startup Test Witnessing and Observation

The inspectors witnessed performance of portions of the following startup test procedures in order to verify that testing was conducted in accordance with the operating license and all procedural requirements, that test results were acceptable, and that the performance of licensee personnel conducting the tests demonstrated an understanding of assigned duties and responsibilities:

2.45.31	Incore Flux Mapping at Low Power
2.47.30	Isothermal Temperature Coefficient Measurement
2.52.34	Reactivity Computer Checkout
2.64.30A	Bank Worth Measurement at Zero Power

2.64.33 Boron Endpoint Determination
2.68.30 Reactor Protection Logic
2.69.30 Pressurizer Spray Heaters and Bypass Flow Adjustment

No violations or deviations were identified.

6. Electrical Distribution System Voltage Verification

The inspector inquired as to whether the licensee had completed preoperational testing necessary to verify that electrical distribution system voltage levels would remain acceptable for the expected full load and minimum load conditions throughout the anticipated range of voltage variations of the offsite power source. A commitment to do such testing prior to fuel load was contained in the Byron FSAR, Table 14.2-11, "Auxiliary Power System (Preoperational Test)." Specifically, testing was to consist of field measurement of bus voltages under various loading conditions, a correlation of these measurements with the results of a computer based analytical model, and use of the validated analytical model to predict bus voltages over the range of anticipated offsite power system voltage levels.

The inspector determined by interview with licensee personnel that field measurements of bus voltage were completed in Preoperational Test 2.5.11, "Bus Loading and Independency." The inspector was provided letters dated January 5, 1984, and September 6, 1984, from the licensee's Station Electrical Engineering Department. These letters documented the acceptable results of a comparison made between measured and calculated bus voltages for the specific offsite power system voltage levels and loading conditions established during the preoperational test. The licensee had not utilized the analytical model or other means to verify acceptable electrical distribution system voltage levels throughout the anticipated range of voltage variations of the offsite power source. This is a violation of 10 CFR Part 50, Appendix B, Criterion XI (454/85002-01(DRP)).

Subsequent to identification of this item, the licensee performed the required analyses and completed evaluations of the results on January 26, 1985. The licensee determined the results to be acceptable. The inspector reviewed the results and discussed them with licensee personnel to obtain clarification of the bases for assumptions used in the analyses. Based upon the results of the analyses and information provided by the licensee during these discussions, the inspector had no further concerns regarding the acceptability of the test results.

Byron SER item 454/83000-15 which was used to track inspection of licensee actions concerning this matter was previously closed in an inspection documented in NRC Inspection Report 454/84079(DRP) based upon validation of the analytical model utilized to predict electrical distribution system voltages. It was the inspector's understanding at that time that the requisite licensee analyses had been conducted.

7. <u>Comparison of As-Built Plant With Technical Specifications and the Byron FSAR/SER</u>

A team of region-based and resident inspection personnel performed comparison of the as-built plant with the Technical Specifications and the Byron FSAR/SER. A large sample of the provisions of individual specifications in Sections 3/4.5 "Emergency Core Cooling Systems," 3/4.6, "Containment Systems," 3/4.7.1, "Turbine Cycle," and 3/4.8, "Electrical Power Systems," were chosen for verification. The method of verification was to compare the wording of individual specifications to the FSAR/SER descriptions and utilize Piping and Instrumentation drawings (P&IDs), Control and Instrumentation Drawings (C&IDs) and other supporting drawings, as necessary, to verify consistency. The technical specification provisions were then verified by physically checking components, instruments, flowpaths, labelings and location to gain assurance that the technical specification provisions were applicable to the Byron as-built plant. Surveillance records were also utilized in some cases (e.g., where accessibility prevented physical verification).

The following specifications and surveillances were examined:

Specification	Surveillance
3/4.5, "Emergency Core Cooling Systems"	
3.5.1.a,b,c,d	4.5.1.1.a,b,c
3.5.2.a,b,c,d,e	4.5.1.2
3.5.3.a,b,c,d	4.5.2.a,c,d,e,f,g
	4.5.3.1
	4.5.3.2
3.5.4.a,b,c,d	4.5.4.a,b,c
3/4.6, "Containment Systems"	
	4.6.1.1.a,b
3.6.1.3.a	4.6.1.3.c
3.6.1.4	4.6.1.4
3.6.1.5	4.6.1.5
3.6.1.7.a,b	4.6.1.7.1
	4.6.1.7.2
3.6.2.1	4.6.2.1.a,b,c.1,c.2,d
3.6.2.2.a,b	4.6.2.2.a,b.1,b.2,c,d.1,d.2
3.6.3 (verified 204 of 235 valves	4.6.3.1
listed in Table 3.6-1)	4.6.3.2.a,b,c
	4.6.3.3
3.6.4.1	4.6.4.1
3.6.4.2	4.6.4.2.a,b.1,b.2,b.3
3.7.1.5	4.7.1.5

Specification	Surveillance
3/4.7.1, "Turbine Cycle"	
3.7.1.1	
3.7.1.2	4.7.1.2.1
	4.7.1.2.2
	4.7.1.2.3
3.7.1.3	4.7.1.3.1
3.7.1.5	
3/4.8, "Electrical Power Systems"	
3.8.1.1.a,b	4.8.1.1.1
	4.8.1.1.2
3.8.1.2	
3.8.1.3	
3.8.2.1	
3.8.2.2	
3.8.3.1	
3.8.3.2	
3.8.4.1	
3.8.4.2 Thermal overloads verified for de-energized valves and spares only since cubicles could not be opened if the breaker was closed.	

Two minor items were identified - one regarding a wording change to Technical Specification 4.5.4.c to more correctly specify heat tracing on the Refueling Water Storage Tank vent line, and one regarding 5 typographical errors in Table 3.6-1 involving a change from I3 and I5 to 13 and 15 where I3 and I5 were actually correct. These items were discussed with the licensee and NRR and were reflected in the final Technical Specifications.

No violations or deviations were identified.

8. Onsite Followup of Nonroutine Events at Operating Reactors

a. Inoperability of Both Intermediate Head Safety Injection (SI) Trains

During execution of Byron Operating Procedure (BOP) SI-9, "Raising Accumulator Level With SI Pumps at all RCS Pressures," Revision 6, on January 11, 1985, while in Mode 3, both trains of intermediate head safety injection were rendered inoperable for approximately 15 minutes due to valve misalignment. The resident inspector interviewed licensee personnel and reviewed BOP SI-9, Revisions 6 and 7, operating logs, Deviation Report 06-01-85-022, Deviation Investigation Report dated January 17, 1985, and Licensee Event Report 454/85011.

Prior to execution of the procedure the SI pumps were in their normal alignment to draw borated water from the Refueling Water Storage Tank (RWST) through a common suction header and individual branch suction lines. The pump discharges were in their normal alignment to inject through individual lines which were cross-tied to a common RCS cold leg injection header downstream of discharge check and motor-operated discharge isolation valves provided for each pump. The SI accumulator fill line which is tied to the SI pump discharges between the 1A SI pump discharge check and motor-operated discharge isolation valve was isolated by a normally closed air operated isolation valve.

The procedure, in part, required opening the SI accumulator fill line isolation valve and closing the 1A SI pump discharge isolation valve. These actions provide a flowpath from the 1A SI pump discharge to the SI accumulators and isolate the 1A SI pump discharge from the RCS cold leg injection header. Execution of this procedure while in Modes 1, 2, or 3 utilizes the provisions of the action statement associated with Technical Specification 3/4.5.2, "ECCS Subsystems - Tavg $\geq$ 350°F," since it renders the 1A SI train inoperable. During execution of the procedure, RCS temperature and pressure were approximately 450°F and 800 psig.

The operator performing the evolution was apparently concerned with the possibility of RCS overpressurization resulting from SI pump operation and reliance on only one isolation valve (the 1A SI pump discharge isolation valve) to prevent injection of water into the RCS. Therefore, the operator closed the 1B SI pump discharge isolation valve. The operator erred in the following respects: (1) closure of the valve was not prescribed by the controlling procedure, and (2) closure of the valve did not provide additional isolation between the 1A SI pump discharge and the RCS. Closure of the valve rendered the 1B SI train inoperable. Approximately 15 minutes after the operator closed the 1B SI pump discharge isolation valve the Station Control Room Engineer noticed that both the 1A and 1B SI pumps were isolated from the cold leg injection header and immediately instructed the operator to open the 1B SI pump discharge isolation valve. The operator opened the valve restoring the 1B SI train to operable status which was within the 1 hour provisions of Technical Specification 3/4.0.

Closing both the 1A and 1B SI pump discharge isolation valves deviated from Procedure BOP SI-9. This is a violation of 10 CFR 50, Appendix B, Criterion V (454/85002-02(DRP)).

Subsequent to this event the licensee issued a Daily Order stressing the importance of procedural adherence. All department heads were rebriefed on the importance of utilizing established administrative controls for processing procedure changes where deviations from procedures are desired. Personnel licensed at the Senior Reactor Operator level reviewed operating procedures involving emergency core cooling systems to assure appropriate technical specification requirements were contained or referenced therein. This review was

completed on January 25, 1985. Comments generated from this review were evaluated and procedures, including BOP SI-9, were revised where deemed necessary prior to the close of this inspection. Inspector followup of this event is complete.

b. <u>Westinghouse 7300 Process Protection System NTC (Temperature Channel Test) Cards</u>

On August 5, 1983, the licensee submitted a 50.55(e) report to Region III concerning, in part, a potential contact bounce problem with certain relays in the Westinghouse (W) 7300 Process Protection System. The potential problem was identified during supplemental seismic testing conducted by W. The relays exhibiting the potential problem were those installed on the temperature channel test (NTC) cards used in the Overtemperature and Overpower delta T channels. There is a total of sixteen of these cards used at Byron - two (one for Tc and one for Th) in each of the four OTΔT channels and the four OPΔT channels. The relays on the cards are only used for periodic testing and are not necessary for normal operation of the channels. The potential problem with the contact bounce was that the intermittent signal resulting from bouncing could cause saturation of downstream RTD amplifier (NRA) cards and possibly prevent a channel trip from occurring on demand. This matter was a subject of IE Information Notice 83-38 which was issued June 13, 1983.

In a May 2, 1984, letter, the licensee submitted to the NRC a justification for interim operation (JIO) concerning, in part, the seismic qualification of the NTC cards. This JIO was revised in an October 16, 1984, licensee letter which states, in part, "Until a permanent resolution is prepared, Field Change Notices have been issued which will provide a method of bypassing these [NTC card] relays when in normal operation." (W issued Field Change Notice (FCN) CAEM-10756, which addresses modification of the NTC cards for normal operation [i.e., channel-on-line] by removing the relays and installing jumper wires in their place. This interim action was determined by RIII to have been completed as documented in NRC Inspection Report 454/84023 dated June 6, 1984.) NRR reviewed the JIO and concluded that the interim modification was an acceptable basis for granting an exemption from General Design Criterion 2 which requires that components important to safety be designed to withstand the effects of natural phenomena such as earthquakes. This conclusion was documented in Section 3.10 of SSER 5 and Paragraph D of Operating License NPF-23.

The modified NTC cards were in place at the time Operating License NPF-23 was issued on October 31, 1984, and remained in place until January 4, 1985. At that time all sixteen of the modified NTC cards were removed and replaced with unmodified cards which had been installed in Unit 2. This action was taken for testing purposes in accordance with a prerequisite of startup test (SUT) 2.47.33, "Incore Thermocouple (Core Exit Thermocouples - CET)," which was added to the procedure via major Test Change Request (TCR) No. 3 approved on

January 4, 1985. A 10 CFR 50.59 safety evaluation was completed in accordance with Byron Administrative Procedure 1310-T19, Revision 0, prior to the incorporation of the TCR into the procedure. Since the OPΔT and OTΔT channels are not required to be operable until Mode 2, substitution of the modified relays with unmodified relays in modes other than Modes 1 and 2 was not contrary to the license provisions.

TCR No. 3 also provided in Step 10.7 for the restoration of the modified cards when SUT 2.47.33 testing was complete. However, that restoration action was not taken. A handwritten note by the shift test engineer (STE) on Page 37a of SUT 2.47.33 at Step 10.7 on January 25, 1985, states "NOTE - this page not performed, see AIR 6-85-031. This AIR tracks proper NTC card replacement." AIR 6-85-031 was initiated on January 25, 1985, for the purpose of tracking the restoration of the modified relays and indicated a completion date of July 1, 1985. Subsequently, the completed test package was reviewed and approved by both the onsite (TRB) and offsite (PED) review groups prior to initial criticality.

During the approach to initial criticality on February 2, 1985, the reactor startup was halted due to a question raised by licensee I&C personnel regarding the lack of seismic qualification data for the installed unmodified NTC cards. The licensee reviewed the matter and concluded that the status of the seismic qualification of the NTC cards was acceptable and under appropriate administrative controls. Based on that conclusion, the approach to initial criticality was resumed and criticality was achieved at 2323 on February 2, 1985.

Both the licensee and the inspectors agreed that the modified NTC cards were required to be installed during "normal operations"; however, the licensee and the inspectors had different understandings as to what constituted "normal operations." The licensee understood the term to mean operations of the plant following completion of the entire startup test program, whereas the inspectors understood the term to mean any time the plant was operated when the OTΔT and OPΔT channels were required by the Technical Specifications to provide a safety function (i.e., Modes 1 and 2). After discussing the different understandings, the licensee acknowledged that its understanding was the least conservative of the two views and the licensee adopted the NRC understanding. Therefore, on February 5, 1985, the licensee removed the unmodified NTC cards and replaced them with modified cards. During the period that the unmodified cards were installed, the plant was not operated above 1% power and Operating License NPF-23 prohibited operation above 5% power.

The inspector identified the following problems with the NTC card issue:

(1) Approval of AIR 6-85-031 and the SUT 2.47.33 test package, which clearly indicated that the unmodified NTC cards were to remain installed during Modes 1 and 2, demonstrated a

lack of understanding of JIOs by both corporate and plant personnel and draws into question the adequacy of the licensee's technical review of test results.

(2) Leaving the unmodified NTC cards installed during Mode 2 operation was contrary to the provisions of the JIO which was used as a licensing basis for the plant. The licensee failed to conduct a 10 CFR 50.59 review of this action which would have revealed that leaving all of the unmodified cards installed during Mode 2 constituted an unreviewed safety question in that the probability of a malfunction of equipment important to safety previously evaluated in the safety analysis report was increased. This action constituted violation of GDC 2 of Appendix A to 10 CFR 50 and 10 CFR 50.59. (454/85002-03(DRP))

(3) The violation of GDC 2 rendered the OTΔT and OPΔT channels inoperable in that they were incapable of performing their specified functions, if required, during a seismic event; therefore, the violation of GDC 2 resulted in a violation of Technical Specification 3.3.1 which requires the OTΔT and OPΔT channels be operable during Mode 2 operations (454/85002-04(DRP)).

(4) The JIO did not clearly address the use of any unmodified cards for testing. A revised JIO was submitted to NRR on March 5, 1985, and NRR approved the submittal in a March 8, 1985, letter to the licensee which allowed limited and controlled use of unmodified cards for testing.

(5) The licensee's approval of the completed test package for SUT 2.47.33 was based, in part, on the provisions of AIR 6-85-031 which controlled the replacement of the NTC cards. This raised a question regarding the level of review that AIRs receive. In the NTC card case, the AIR was issued and reviewed with a test package, but it could have been later revised by test engineers without review by the personnel who approved the test results. Such use of AIRs may not be appropriate for corrective actions involving safety-related items. This is an unresolved item pending the inspector's review of licensee actions regarding AIRs issued to control safety-related items (454/85002-05(DRP)).

The licensee initiated the following corrective actions related to the problems identified:

- Station and corporate personnel were reminded of the requirements of the Byron Startup Manual regarding issuance of TCRs when test steps are eliminated which can be performed.

- Plant personnel who review and approve 50.59 reviews received a JIO listing identifying all JIOs and providing a brief description of the subject matter of each JIO. In addition, personnel were provided with an indoctrination of the JIOs to ensure familiarity with the process of JIO review and approval.

- A checklist was implemented which included a review of JIOs against TCRs during post test review to identify any conflicts.

- Additional administrative controls were implemented for the Unit 1 Startup Test Program which require a checklist to be attached to a 50.59 safety evaluation to ensure the evaluation considers key issues such as the provisions of the FSAR, Technical Specifications, the license, and JIOs for compatibility to the change being prepared.

- A letter was issued to all Station personnel involved in the 50.59 review process which provided direction on how to perform a 50.59 review.

- Corporate personnel involved in the review and approval of test results were reminded of the provisions of all effective JIOs.

- An audit was conducted by the Station QA organization. The audit found that the Station procedure (QP 10-54) regarding transfer of material between units had not been followed for the transfer of the unmodified Unit 2 NTC cards to Unit 1. Additionally, the audit revealed that there was a lack of objective evidence that the cards had been receipt inspected as required by Procedure QP 8-51. The licensee is pursuing resolution of these matters.

There was no apparent technical significance of having the unmodified relays installed during Mode 2 operations at or below 1% power because of (1) the low probability of transient occurring in combination with a seismic event which would have required protective action by the channels during the short time period they were installed, and (2) backup protective instrumentation which was operable that would have precluded any adverse safety effects. It was fortuitous that the licensee had not operated at powers up to 100% with the potentially degraded instrumentation condition since such operation could have involved reduced safety margins during some analyzed transients.

9. <u>Byron Unit 1 Initial Criticality</u>

Byron Unit 1 entered Mode 2 and achieved initial criticality on February 2, 1985. NRC inspectors provided 24 hour-a-day coverage from January 31, 1985 to February 8, 1985.

The inspectors identified all technical specifications and licensee conditions requirements applicable during the initial approach to criticality and verified conformance with these requirements on a sampling basis. The inspectors verified that: startup test procedures were available, in use, and of the proper revision; prerequisities and initial conditions required by test Procedures 2.32.33, "Initial Criticality and Low Power Test Sequence," and 2.52.32, "Initial Criticality," were satisfied prior to execution; nuclear instruments

were properly aligned and operating; shift crew requirements specified in the technical specifications were met; and reviewed inverse multiplication plots were being maintained per procedural requirements.

The inspectors performed daily reviews of operating logs, witnessed several shift turnovers, witnessed several reactor coolant boron concentration analyses, reviewed implementation of radiological protection and personnel access controls for the auxiliary building and Unit 1 containment, and verified that actual critical conditions agreed with predicted conditions within tolerances.

No violations or deviations were identified.

10. Licensee Event Report (LER) Followup

(Closed) LER (454/85011): Inoperability of both intermediate head safety injection trains. Inspector followup of this LER is discussed in Paragraph of 8.a of this report.

11. Operational Safety Verification

The inspector observed control room operations, reviewed applicable logs and conducted discussions with control room operators during the months of January and February. The inspector verified the operability of selected emergency systems, reviewed tagout records, and verified proper return to service of affected components. Tours of containment, auxiliary building and turbine building 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.

These reviews and observations were conducted to verify that facility operations were in conformance with the requirements established under technical specifications, 10 CFR, and administrative procedures.

No violations or deviations were identified.

12. Diesel Generator Surveillance Test History

By letter dated November 20, 1984, from R. E. Querio to J. G. Keppler, the licensee reported diesel generator surveillance test failures in accordance with Byron Unit 1 Operating License NPF-23, Appendix A, Technical Specification 4.8.1.1.3. The letter summarized surveillance test results obtained since completion of preoperational testing utilizing the criteria for determining valid tests and failures contained in NRC Regulatory Guide 1.108, Revision 1, August 1977, Regulatory Position C.2.e. The 1A diesel generator had experienced 10 failures in 34 valid tests. The 1B diesel generator had experienced 2 failures in 22 valid tests. When evaluated on a per-nuclear-unit basis, these results yielded a total of 12 failures in 56 valid tests. The surveillance test frequency required to establish the diesel generator

operability was determined in accordance with Technical Specification 4.8.1.1.2 which adopted the requirements of NRC Regulatory Guide 1.108, Regulatory Position C.2.d. Both the 1A and 1B diesel generators were required to be tested at least once per 3 days.

By letter dated February 8, 1985, from R. E. Querio to J. G. Keppler, the licensee reported that diesel generator surveillance test results had been re-evaluated based upon discussions with personnel from the NRC Office of Nuclear Reactor Regulation concerning 9 of the 10 previously reported failures of the 1A diesel generator. The 9 failures involved fuel oil leaks which resulted from improperly installed fuel supply lines. Just prior to experiencing the failures the fuel supply lines had been replaced. Agreement was reached between the licensee and NRR that 8 of the 9 failures were discovered in the course of troubleshooting. In accordance with Regulatory Guide 1.108, Position C.2.e.(8), tests performed in the course of troubleshooting should not be considered valid tests. Therefore, only 1 of the 9 failures was detected during a valid test and needs to be considered in determining surveillance test frequency. The results of the licensee's re-evaluation in conjunction with additional valid tests performed since November 20, 1984, yielded the following results: the 1A diesel generator experienced 2 failures in 58 valid tests and the 2B diesel generator experienced 2 failures in 47 valid tests. From a nuclear-unit standpoint the results were a total of 4 failures in 105 valid tests or 3 failures in the last 100 valid tests. The surveillance test frequency was therefore reduced to once per 7 days.

On February 14, 1985, Byron Unit 1 full power Operating License NPF-37 was issued. The license contained revised requirements for diesel generator surveillance testing. Specifically, Technical Specification 4.8.1.1.2 was changed to relax the criteria for establishing surveillance test frequencies. Based upon surveillance test results obtained as of February 14, 1985, the test frequencies for each diesel generator were reduced to once per 31 days.

The overall reliability of the 1A and 1B diesel generators since fuel load has been 100%.

13. Regional Administrator's Inspection Tour

On February 7, 1985, NRC Region III Administrator, James G. Keppler accompanied by J. F. Streeter, Director, Byron Project Division, and the Senior Resident Inspector toured the Byron Station including the technical support center, shift engineer's office, control room, auxiliary electrical equipment rooms, Unit 1 containment personnel hatch area, the fuel storage area, primary system pump rooms, remote shutdown panel, and diesel generator 1A room.

14. Plant Tours/Housekeeping

The inspectors conducted plant tours on January 3, 8, 15, 16, 17, 18, 21, 22, 23, 25, 29 and February 5, 12, 19, 25 and 26, 1985. The areas of the plant observed during the tours included Unit 1 and 2 containments, fuel handling and storage areas, auxiliary building areas including the control room, primary system pump cubicles, and diesel generators A and B rooms. Areas were inspected for work in progress, state of cleanliness, overall housekeeping, state of fire protection equipment and methods being employed, and the care and preservation of safety-related components and equipment. The inspectors were accompanied by licensee personnel on portions of the tours for the purpose of identifying areas where additional housekeeping efforts should be concentrated to bring the overall cleanliness state of Units 1 and 2 spaces up to par with the respective stages of construction. Inspector concerns were related to the licensee.

No violations or deviations were identified.

15. Management Meetings

On January 2, 16, and 30 and February 14 and 27, 1985, Regional and NRC resident inspector office personnel met with licensee management and supervisory personnel denoted in Paragraph 1 of this report. These working meetings were held to assess overall facility status, readiness of Unit 1 for criticality (Mode 2) and operation above 5% of rated thermal power, and other areas such as the source range monitor noise problem, diesel generator testing, process radiation monitors, startup testing schedule and delays, and Byron LER actions.

16. Containment Tendon Anchor Head

The recent failures of posttensioned containment tendon anchor heads at Farley Unit 2 were discussed with a licensee representative since the Byron Station uses tendons of the same design manufactured by the same vendor (INRYCO). The Farley problem was the subject of IE Information Notice No. 85-10 dated February 6, 1985, and Supplement 1 to that IN dated March 8, 1985. The licensee representative stated that CECo was aware of the Farley problem and was following developments with that licensee and with Sargent & Lundy. The licensee representative stated that no tendon anchor head failures had occurred at Byron since those in 1979 identified in IN 85-10, and that the normal surveillance program would continue unless future developments in the Farley matter indicated a need for other actions. (Closed - 454/85001-PP; 455/85001-PP.)

17. Jam Nuts on Structural Steel Sliding Connections

The licensee's torquing criterion for jam nuts on structural steel sliding connections inside containment was discussed with licensee representatives since the criterion was different than the criterion used at LaSalle Station which had been reviewed and found acceptable by Region III. (The Byron criterion was snug tight whereas the LaSalle

criterion was a specified amount of bolt tension.) The licensee stated that both criteria were acceptable because the only reason for the jam nut is to provide additional assurance that the bolt will not become loose since the load nut alone is sufficiently tight to prevent loosening. The licensee also stated that the AISC which is the governing code for structural steel connections is silent on the use of jam nuts and, therefore, the licensee has the latitude to develop jam nut torquing criteria in its design specifications as was done for Byron. The licensee's positions on the use of jam nuts on structural steel sliding connections are delineated in a February 17, 1985, letter from CECo to Region III.

In order to demonstrate the adequacy of the licensee's snug tight criterion, the licensee selected more than 100 relatively easily accessible jam nuts inside containment and measured the breakaway torque. The torque values varied from a minimum of 5 ft. lbs. to a maximum of more than 100 ft. lbs. Those results indicated that the snug tight criterion was not resulting in uniform torquing of the jam nuts; however, the licensee reviewed the results and concluded that they indicated the torquing criterion was always resulting in sufficient torque for the intended purpose of the jam nut.

The inspector had no further questions concerning this matter at this time.

18. Electrical Cable Pulling

In Paragraph 267 of the ASLB's Supplemental Initial Decision of October 16, 1984, the ASLB addressed the acceptability of cables installed in conduits COA 6158, COA 6192, and COA 6193. The ASLB noted a paradox related to the cable pull direction and calculated forces for the cables in conduits COA 6192 and COA 6193 and requested that the Staff examine that paradox. In response to the ASLB's request, the licensee in a October 23, 1984, letter to Region III provided related information. The information provided by the licensee indicated that (1) the cable manufacturer's calculations showed that the cables pulled from 1JB261A to 1JB262A through conduit COA 6193 experienced acceptable pulling tensions and sidewall pressures, and (2) the pull records for cables in conduit COA 6192 showed that the pull direction was toward rather than away from 1JB261A and, therefore, the cable manufacturer's position was that with that pull direction those cables experienced acceptable pulling tensions and sidewall pressures. Region III personnel reviewed the information presented by the licensee and concluded that it clarified the basis for the licensee's conclusion that all cables pulled in conduits COA 6158, 6192, and 6193 experienced acceptable pulling tensions and sidewall pressures. Region III had previously evaluated this matter and came to the same conclusion as documented in NRC Inspection Reports 454/84009, Paragraph 3.d, and 454/84027, Paragraph 2.h. Region III has no further questions regarding this matter.

19. Boron Dilution Prevention System (BDPS) Actuation Reportability

The licensee documented 13 occurrences of the initiation of the BDPS resulting from noise spiking of the Source Range Nuclear Instrument Channels in LERs 454/84010, 454/84019, 454/84022 and 454/84031. The inspectors discussed the reportability of these occurrences with the licensee and determined that although the BDPS operates components in an Engineered Safety Feature (ESF) System, the BDPS System is not classified in the Byron FSAR, Section 7.6, as an ESF System. It was therefore concluded, based on similar classifications established in Supplement 1 to NUREG-1022, "Licensee Event Report System," the classification of the BDPS in the Byron FSAR, and discussion with representatives of the NRC AEOD, that inadvertent initiation of the BDPS from noise spiking of the Source Range Nuclear Instrument Channels is not required to be reported. The inspectors requested the licensee to conduct a review to determine if other systems should be included in this classification and the justification for excluding these systems from LER reportability. The licensee provided this information and is included in this report as Attachment 1. The inspectors agreed with the information in Attachment 1.

20. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, items of noncompliance, or deviations. An unresolved item disclosed during the inspection is discussed in Paragraph 8.b.

21. Exit Interview

The inspector met with licensee representatives denoted in Paragraph 1 at the conclusion of the inspection on February 28 and on April 12, 1985. The inspector summarized the purpose and the scope of the inspection and the findings. The inspector also discussed the likely informational content of the inspection report with regard to documents or processes reviewed by the inspector during the inspection. The licensee did not identify any such documents/processes as proprietary.

22. Enforcement Conference

On April 29, 1985, an enforcement conference was conducted in the Region III office between Mr. T. J. Maiman and others of the Commonwealth Edison Company staff and Mr. A. B. Davis and others of the Region III staff. The purpose of the enforcement conference was to discuss (1) the operation of Unit 1 with unmodified NTC cards, and (2) the adequacy of the technical review of test results. The NRC views on these matters as discussed in Paragraph 8.b of this report were presented to the licensee. The licensee presented its views on these matters as summarized below:

- No analyzed event is solely dependent on the OTΔT and OPΔT channels for a reactor trip to mitigate the consequences of the event. Therefore, the reactor trip system as a whole remained capable of performing its intended function with the unmodified NTC cards installed during Mode 2 operations because of reactor trip system functional diversity.

- A 50.59 evaluation of leaving the unmodified NTC cards installed during Mode 2 operations was not performed because of the licensee's understanding of "normal operations."

- The failure to complete a Test Change Request Form for not completing Step 10.7 of SUT 2.47.33 did not constitute a violation of the Startup Manual because the step was deferred to July 1, 1985, and under the control of an AIR and was not eliminated.

- The NTC card issue does not draw into question the adequacy of the technical review of test results. Furthermore, a licensee review of the NTC card issue along with past adverse NRC findings in the test results review area did not reveal any indications of a developing pattern with inadequate test results evaluations.

The NRC representatives indicated that they would consider the information presented by the licensee representatives when assessing the need for further escalated enforcement action. Subsequent to the enforcement conference, Region III concluded that the further escalated enforcement action would not be pursued based on the lack of safety significance. However, Region III also concluded that it was fortuitous that NRC action led to the removal of the unmodified NTC cards before the plant was operated at full power when safety margins could have been reduced during some analyzed transients. Furthermore, Region III concluded that even in the absence of a negative pattern in the quality of technical evaluations of test results, licensee personnel need to be sensitized to the need for thorough, rigorous and completely documented reviews of test results.

Attachment 1: Licensee Positions
on Certain Reportability Matters

ATTACHMENT 1

LICENSEE POSITIONS ON CERTAIN REPORTABILITY MATTERS

A. BDPS

1. How would an actuation be reported?

Contrary to past practice, inadvertent actuations would not be reported pursuant to 50.73(a)(2)(IV) as an ESF/RP actuation, since it is described as "other" in the FSAR, regardless that it does use SSPS. If BDPS actuated due to an actual positive reactivity insertion, then it would be reported as a courtesy.

2. How would a detected failure be reported?

A failure would be reported under 50.73(a)(2)(VII)(A) or (D), since this system is described in the FSAR accident analysis as needed to mitigate the consequences of an accident. This reporting would be dependent on the nature and extent of the failure.

B. VCT Level LoLo Switch to RWST Suction

1. How would an actuation be reported?

Charging pump switch over on lolo VCT level is not discussed in the FSAR under ESF instrumentation, and would not be reported.

2. How would a detected failure be reported?

A failure would be reported under 50.73(a)(2)(VII)(A) or (D). Since 112D, E receive a confirmatory "SI" signal to open, a failure of one or more of these valves could prevent mitigating the consequences of an accident. If the instrument loop failed, this would be reported under 50.73(a)(2)(V) since a possible loss of suction could prevent these pumps from fulfilling their safety function. This reporting would be dependent on the nature and extent of the failure.

C. Hi Pressure Interlock with RH Suction Valves

1. How would a actuation by reported?

An actuation would not be reported pursuant to 50.73(a)(2)(V) since this instrument loop is described as "other" in chapter 7 of the FSAR. The only exception would be an inadvertent isolation where 2 RH trains are required to be operable per Tech Specs (i.e., Mode 5 loops not filled, Mode 6 cavity less than 23', Mode 4 with no RCPs operable).

2. <u>How would a failure be reported?</u>

This instrument loop is designed to protect the low pressure piping of the RH system. A failure of this protection <u>could</u> result in preventing the fulfillment of the safety function of the RH system and as such would be reported pursuant to 50.73(a)(2)(V) (B) or (D). Again, this reporting would be dependent on the nature and extent of the failure.

D. <u>OT, OPΔt Rod Stops</u>

1. <u>How would an actuation be reported?</u>

Rod stops are discussed in Chapter 7.7 of the FSAR, "Control Systems Not Required For Safety," and as such their actuation would <u>not</u> be reported.

2. <u>How would a detected failure be reported?</u>

A detected failure of a rod stop would not be reported, based on their description in the FSAR, and due to the fact that rod stops are backed up by Rx trips.