U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-454/92008(DRP); 50-455/92008(DRP)

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

Licensee: Commonwealth Edison Company
Opus West III
1400 Opus Place
Downers Grove, IL 60515

Facility Name: Byron Station, Units 1 and 2

Inspection At: Byron Site, Byron, Illinois

Inspection Conducted: March 24, 1992 through May 5, 1992

Inspectors: W. J. Kropp
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Approved By: Anthony H. Hsia 5/15/92
A. H. Hsia, Acting Chief Date
Reactor Projects Section 1A

Inspection Summary

Inspection from March 24, 1992 through May 5, 1992 (Report Nos. 50-454/92008(DRP); 50-455/92008(DRP)).
Areas Inspected: Routine, unannounced safety inspection by the resident inspectors of action on previous inspection findings, operational safety verification, current material condition, housekeeping and plant cleanliness, radiological controls, security, reactor startup, verification of containment integrity, licensee event reports, maintenance activities, surveillance activities, installation and testing of modifications, onsite reviews, degraded voltage, hydrogen monitors, and report review.
Results: In the sixteen areas inspected no violations, one open item pertaining to a source range monitor noise problem (3.h) and four unresolved items that pertained to a missed action statement (2.c), hydrogen recombiners (3.i), recording of valve manipulations during surveillances (5.b) and the containment flood level (6.d) were identified. The following is a summary of the licensee's performance during this inspection period.

Plant Operations

The licensee's performance in this area during this inspection period was considered good. Shift briefings were conducted for either high risk or abnormal plant evolutions. The Operating Engineers continue to provide a good channel for communications between the various station departments. Overall, the Operating Department maintained good command and control in the control room during the recently completed Unit 2 refueling outage.

Safety Assessment/Quality Verification

The licensee's performance in this area was not assessed due to the limited activities reviewed by the inspectors. The one Licensee Event Report reviewed was considered to have adequate corrective action identified to preclude a similar event in the future. However, the inspectors did identify a concern with one Deviation Report that documented a spurious start of the 2A Auxiliary Feedwater pump. The preliminary description of the event was not adequately described by the system engineer.

Maintenance and Surveillance

The licensee's performance in the maintenance area was considered good. However, performance in the surveillance area was considered mixed. One surveillance was not performed which was required by a Technical Specification Action Statement. Also, during the observation of the performance of surveillances, the inspectors noted two instances where steps were not performed in accordance with the surveillance procedures. The inspectors also noted that a surveillance had to be exited because a valve was out of service that prevented the completion of the surveillance. During the performance of another surveillance, a valve manipulation (not defined in the surveillance procedure) was performed to allow the correct repositioning of another valve. There is a previous licensee commitment to identify all valve manipulations not authorized by a procedure in the surveillance packages. Based on the licensee's performance in the surveillance area since September 1991, surveillance activities need increased management attention.

Engineering and Technical Support

The licensee's overall performance in this area was considered good. The onsite reviews examined were considered thorough and technically sound. The system engineer's involvement in the minor modification for changing the 480V unit substation transformer taps resulted in the identification of a potential problem with the overvoltage trip on the AC input breaker for the instrument inverters. Excellent teamwork between the corporate and station technical organizations allowed for timely resolution of a potentially degraded voltage problem. Problems were noted with a 1982 calculation that was the basis for determining the containment flood level during a design base loss of coolant accident. The problems pertained to a mathematical error and the use of a non-conservative assumption.

DETAILS

1. Persons Contacted

Commonwealth Edison Company (CECo)

*R. Pleniewicz, Station Manager
*K. Schwartz, Production Superintendent
*M. Wallace, Vice President, PWR Operations
*M. Burgess, Technical Superintendent
*D. St. Clair, ENC Project Manager
*P. Johnson, Technical Staff Supervisor
*J. Kudalis, Services Director
*W. Pirnat, Regulatory Assurance
*M. Snow, Unit 0 Operating Engineer
*E. Zittle, NRC Coordinator
*W. Grundmann, NQP Superintendent
*T. Tulon, Assistant Superintendent, Maintenance
*T. Gierich, Assistant Superintendent, Planning
*W. Dean, Nuclear Safety
*W. Dijstelbergen, Site Engineering Supervisor
*S. Barrett, Radiation Protection Supervisor

*Denotes those attending the exit interview conducted on May 5, 1992.

The inspectors also had discussions with other licensee employees, including members of the technical and engineering staffs, reactor and auxiliary operators, shift engineers and foremen, and electrical, mechanical and instrument maintenance personnel, and contract security personnel.

2. Action on Previous Inspection Findings (92701 & 92702)

a. (Closed) Open Item 454/90017-01; 455/90017-01(DRP): The licensee's review of Westinghouse setpoint methodology could affect other setpoints. The licensee has completed the review of Westinghouse's setpoint methodology. The review was thorough and concluded that even though ten setpoints had negative margins there were no significant safety issues.

b. (Closed) Violation 454/91007-01; 455/91007-01(DRP): Three examples of failure to follow procedures during the repair of a emergency diesel generator fire door; the control of station keys; and the control of overtime. The inspectors reviewed the licensee's corrective action and actions to avoid further violations documented in a letter to Region III dated April 29,1991. The inspectors have no further concerns in this area.

c. (Closed) Open Item 454/91007-02(DRP): Valve 1CV8479A was found not locked because the chain was not properly secured. The licensee had operating engineers review the key log for six months. There were no problems noted with the keys. In addition the inspectors have noted no other problems with locked valves. The inspectors have no further concerns in this area.

d. (Closed) Open Item 454/91007-05; 455/91007-04(DRP): The inspectors will monitor the interface between site and corporate ENC staffs. Previous results of ENC corporate reviews of calculations had not been transmitted to the site ENC organization. The inspectors have monitored the interface between corporate and site engineering organizations and have no further concerns in this area. The teamwork exhibited during the minor modification installation for changing the 480V unit substation transformer taps, described in paragraph 6.c of this report, was an example of good interface between corporate and station engineering.

e. (Closed) Open Item 454/91008-01; 455/91008-02(DRP): The licensee's non-routine/conditional surveillances would be monitored by the inspector. The licensee performed a detailed review of 1990 and 1991 Deviation Reports, Licensee Event Reports, QA findings and NRC Violations. The review focused on procedure related items and included the categories of surveillance procedures, conditional surveillances, bad procedures and external department communications or involvement. The results of the review showed that the majority of problems were in the communication and work practice areas. The licensee's actions included a revision to procedures, a new trending program and a review by each station department of non-routine surveillances. The inspectors have no further concerns with non-routine or conditional surveillances identified in the Technical Specification (TS). However, on April 3, 1992, the licensee failed to implement a TS Action Statement for Limiting Condition of Operation (LCO) 3.8.1.1 when the Unit 2 to Unit 1 4kV Engineered Safety Feature (ESF) crosstie breaker 2414 was taken out of service (OOS) for maintenance. With breaker 2414 OOS, Unit 1 had one inoperable offsite circuit. Action statement 3.8.1.1.a was applicable and required the performance of surveillance 4.8.1.1. within 1 hour and at least once per 8 hours thereafter. Otherwise surveillance 4.8.1.1.a was required to be performed on Unit 1 in accordance with the TS once per 7 days with the unit in Modes 1-4 . The surveillance verified that the required independent circuits between the offsite transmission network and the onsite Class 1E distribution system were operable by verifying correct breaker alignments and indicated power availability. On April 3, 1992, while performing the 7 day surveillance, 1BOS 8.1.1.1a-1, the Unit 1 Nuclear Station Operator (NSO) observed that there was no control power indication on breaker 2414. Further investigation by the NSO determined the breaker was racked out and partially disassembled; LCO 8.1.1-1.a was entered. A spare 4kV breaker was placed in the breaker cubicle for the 2414 breaker and the LCO was exited after successful completion of surveillance 1BOS 8.1.1.1.a-1. The failure to enter TS Action Statement 3.8.1.1.a and perform the required surveillance is considered an Unresolved Item pending further NRC review (455/92008-01(DRP)).

f. (Closed) Violation 454/91021-01; 455/91021-01(DRP): Technical Specification 3.3.1 was violated due to the potential of saturation of the reactor protection system overtemperature delta temperature (OT/delta T) protection cards at temperatures above 597 degrees F. The licensee implemented corrective actions, both administrative and to the hardware, which provided OT/delta T protection throughout the operating temperature range as prescribed by the accident analysis. The licensee's actions were aggressive and were implemented in an expedited manner. The licensee provided details of the corrective actions to the NRC in the response to the violation dated December 6, 1991. This violation is considered to be closed.

g. (Closed) Violation 454/91027-01(DRP): Mode 4 was entered with both Unit 1 containment spray pumps inoperable which was contrary to the TS requirements. The inspectors reviewed the licensee's corrective actions and actions to avoid further violations documented in a letter to Region III, dated February 6, 1992. The corrective actions included the development of a table top scenarios on mode changes; the identification of infrequently performed tasks for implementation into the 1992 training program; team training that focused on team skills; and a review of operating procedures and flowcharts for clarity. The inspectors reviewed and witnessed mode changes that occurred during the recent Unit 2 refueling outage. No problems were noted. Based on these reviews, the inspectors concluded that the licensee's corrective actions to this violation were effective. This violation is considered closed.

3. Plant Operations

Unit 1 operated at power levels up to 100% in the load following mode since January 30, 1992.

Unit 2 was synchronized to the grid on April 30, 1992 at 2:39 a.m. following a 62-day refueling outage that commenced on February 28, 1992.

a. Operational Safety Verification (71707)

The inspectors verified that the facility was being operated in conformance with the licenses and regulatory requirements, and that the licensee's management control system was effectively carrying out its responsibilities for safe operation.

On a sampling basis, the inspectors verified proper control room staffing and coordination of plant activities; verified operator adherence with procedures and technical specifications; monitored control room indications for abnormalities; verified that electrical power was available; and observed the frequency of plant and control room visits by station management.

After entering Mode 3, the licensee took Unit 2 to Mode 5 to repair leaks on a reactor coolant pump (RCP) seal, a conoseal, and the reactor head vent valves. During a review of the Unit 2 logs maintained by the Nuclear Station Operator (NSO), the inspectors noted a log entry documenting that the Unit 2 NSO was relieved from the unit. Discussions with on shift personnel determined that the NSO had been relieved as a result of his being uncomfortable with plans to drain the the reactor coolant system. The concern was that the hydrogen concentration could exceed that allowed by procedure. Through review of records and interviews, the inspectors determined that a temporary change (92-0-106) was in place at approximately the time the Unit 2 NSO was relieved, which stated that draining of the RCS would be performed with less than 5 cc/kg hydrogen in the RCS or that the RCS hydrogen concentration would be determined acceptable by the chemistry department and would not create an exp sive mixture. Also, the licensee initiated action to ensure the work stations were sampled for explosive mixtures prior to and during the work activities.

b. Current Material Condition (71707)

The inspectors performed general plant as well as selected system and component walkdowns to assess the general and specific material condition of the plant, to verify that Nuclear Work Requests had been initiated for identified equipment problems, and to evaluate housekeeping. Walkdowns included an assessment of the buildings, components, and systems for proper identification and tagging, accessibility, fire and security door integrity, scaffolding, radiological controls, and any unusual conditions. Unusual conditions included but were not limited to water, oil, or other liquids on the floor or equipment; indications of leakage through ceiling, walls or floors; loose insulation; corrosion; excessive noise; unusual temperatures; and abnormal ventilation and lighting. The material condition of Unit 1 was considered good with the main control board annunciators being dark for most of the inspection period. Material condition of Unit 2 was not assessed since the unit was in a refueling outage.

c. Housekeeping and Plant Cleanliness

The inspectors monitored the status of housekeeping and plant cleanliness for fire protection and protection of safety-related equipment from intrusion of foreign matter. Housekeeping in the Unit 1 area was considered good.

d. Radiological Controls (71707)

The inspectors verified that personnel were following health physics procedures for dosimetry, protective clothing, frisking, posting, etc. and randomly examined radiation protection instrumentation for use, operability, and calibration.

f. Security

Each week during routine activities or tours, the inspectors monitored the licensee's security program to ensure that observed actions were being implemented according to the approved security plan. The inspectors noted that persons within the protected area displayed proper photo-identification badges and those individuals requiring escorts were properly escorted. The inspectors also verified that vital areas were locked and alarmed. Additionally, the inspectors also observed that personnel and packages entering the protected area were searched by appropriate equipment or by hand.

h. Reactor Startup (71707)

On April 27, 1992, at 6:22 p.m. the licensee entered Mode 2 and commenced a Unit 2 reactor startup after completing a scheduled refueling outage. The licensee approached criticality by the dilution method. The reactor achieved criticality at 6:54 a.m. on April 28, 1992. During the startup the inspectors noted that source range N-32 was indicating lower counts than the other source range, N-31. When the reactor startup commenced source range N-31 indicated 154 counts and channel N-32 indicated 89 counts. At 6:53 a.m., just prior to deenergizing the source ranges N-31 indicated 5840 counts and N-32 3753 counts. Discussion with licensee personnel determined that during the outage, source range N-32 had the discriminator voltage raised due to noise problems. The higher discriminator voltage resulted in the lower N-32 counts during the startup. The licensee stated that an investigation will be performed to determine the resolution to the ongoing noise induced interference with the N-32 source range channel. This matter is considered an open item pending further review by the licensee and NRC (455/92008-02(DRP)).

I. Verification of Containment Integrity (61715)

The inspectors verified through local observation the proper positioning of the electrical and mechanical barriers and isolation valves associated with the following valves:

2CV8160, RCS Letdown
2FC009, Spent Fuel Pool Cleaning
2OG057A, Hydrogen Recombiner
2OG079, Hydrogen Recombiner
2OG080, Hydrogen Recombiner
2PS9355A, Primary Process Sampling
2PS9356A, Primary Process Sampling
2PS9357A, Primary Process Sampling
2RE9157, Reactor Building Equipment Drains
2RE9160A, Reactor Building Equipment Drains.
2RHR8701A, RH Hot Leg Suction
2SA033, Service Air

2SI 8871, Accumulator Fill
2WO056A, Chilled Water
2WO056B, Chilled Water

During the walkdown of containment for verifying containment integrity, the inspectors identified a concern with the hydrogen recombiners (HR). The concern pertained to the location of one set of suction and discharge lines that penetrated the containment through penetration P-13. The suction and discharge lines through P-13 terminated in the containment within approximately 8 feet of each other. The motor operated (MOV) containment isolation valves for this penetration P-13, OG079 and OG080 (discharge line) and OG082 and OG084 (suction line) were supplied from ESF bus 212. The other suction and discharge lines penetrated the containment at two different penetrations, P-23 and P-69. The MOVs for the containment isolation valves associated with P-23 and P-69 were powered from ESF bus 211. The inspectors were concerned that with a loss of ESF bus 211 after a design basis loss of coolant accident, the HR would only have one suction and discharge line available that were approximately 8 feet apart. This could result in inadequate processing of the containment atmosphere to eliminate the presence of any hydrogen. Pending further review of this matter by the NRC this matter is considered an unresolved item (455/92008-03(DRP)).

No violations or deviations were identified.

4. Safety Assessment/Quality Verification (40500, 90712, 92700)

a. Licensee Event Report (LER) Follow-up (90712, 92700)

Through direct observations, discussions with licensee personnel, and review of records, the following event report was reviewed to determine that reportability requirements were fulfilled, that immediate corrective action was accomplished, and that corrective action to prevent recurrence had been or would be accomplished in accordance with the TSs:

(Closed) 455/92001-LL: While performing a planned reactor shutdown, the 2D steam generator level increased to greater than the high-high level feedwater isolation setpoint. This resulted in a P-14 signal and feedwater system isolation. The turbine had been previously tripped. The D-5 steam generators installed in Unit 2 were sensitive to level instabilities at low power levels due to the location of the instrument taps. The licensee relocated the instrument taps during the recent Unit 2 refueling outage. The modification should result in the D-5 steam generators responding in the same manner as the Unit 1 D-4 steam generators which exhibit no level instabilities at low power levels.

In addition to the foregoing, the inspector reviewed the licensee's Deviation Reports (DVRs) generated during the inspection period. This was done in an effort to monitor the conditions related to plant or personnel performance, potential trends, etc. DVRs were also reviewed to ensure that they were generated appropriately and dispositioned in a manner consistent with the applicable procedures and the QA manual. The inspectors did have one concern with issuance of DVR 6-2-92-021. This DVR was issued to document the spurious start of the 2A auxiliary feedwater (AFW) pump on April 22, 1992, while performing the modification testing described in procedure, SPP 92-041. The "Description of Event" block of the DVR did not completely describe the cause of the event. The DVR stated the spurious start of the 2A AFW pump was caused by a short circuit due to a malfunctioning strip chart recorder. The inspectors were present during the spurious start of the 2A AFW pump and identified, along with the system engineer, that the two leads which had been previously connected to the strip chart recorder were no longer connected to the recorder, but were lying on the floor. The leads were shorted together with the other end of the leads still connected across contacts of the 2A AFW main control board control switch. When the auxiliary oil pump for the 2A AFW pump was started in preparation to start the 2A AFW pump, the start circuit became energized due to the contact on the control switch being shorted by the leads previously connected to the strip chart recorder. The spurious start of the 2A AFW was not caused by a malfunction of a strip chart recorder but rather by leads that had been inadvertently disconnected from the recorder and had fallen on the floor shorting out the control switch for the 2A AFW pump on the main control board.

No violations or deviations were identified.

5. Maintenance/Surveillance (62703 & 61726)

a. Maintenance Activities (62703)

Routinely, station maintenance activities were observed and/or reviewed to ascertain that they were conducted in accordance with approved procedures, regulatory guides and industry codes or standards, and in conformance with TSs.

The following items were also considered during this review: approvals were obtained prior to initiating the work; functional testing and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; and activities were accomplished by qualified personnel.

Portions of the following maintenance activities were observed and reviewed:

B89779 - Replace station air compressor first stage bearing.

B91429 - Change grease in condensate booster pump coupling.
B92545 - Replace 2A AFW pump suction transmitter.
B99714 - Repack heater drain vent isolation valves.

b. Surveillance Activities (61726)

During the inspection period, the inspectors observed TS required surveillance testing and verified that testing was performed in accordance with adequate procedures, that test instrumentation was calibrated, that results conformed with TSs and procedure requirements and were reviewed, and that any deficiencies identified during the testing were properly resolved.

The inspectors also witnessed portions of the following surveillances:

- 2BOS 3.1.1-21 - "Unit 2 Train B Solid State Protection System Bi-Monthly Surveillance"
- 2BOS 3.1.1-32 - "Analog Channel Operation Test of Source Range Channel N32"
- 2BOS 3.2.1-800 - "ESFAS Instrumentation Slave Relay Surveillance (Train A Automatic Safety Injection - K602, K647)"
- 2BOS 3.2.1-844 - "ESFAS Instrumentation Slave Relay Surveillance (Train A Containment Isolation Phase A-K613)"
- 2BOS 3.2.1-853 - "ESFAS Instrumentation Slave Relay Surveillance (Train B Containment Isolation Phase A-K612)"
- 2BOS 3.2.1-960 - "ESFAS Instrumentation Slave Relay Surveillance (Train A Automatic Valve Actuation on RWST LO-2 Level-K 648)"
- 2BOS 10.5-1 - "Special Test Exceptions Rod Position Indication system Daily Surveillance Prior to and During Rod Drop Testing"
- 2BOS SR-U1 - "Unit 2 Containment Evacuation Alarm"
- 2BVS 4.6.2.2-1 - "Reactor Coolant System Pressure Isolation Valve Leakage and Cold Leg Injection Isolation Valve Surveillance"

During the review and performance of the above surveillances the inspectors identified the following observations:

- Surveillance 2BOS 3.1.1-21 - The operator performed step 10.e.4, the resetting of the Train B recirculation sump isolation valve prior to step 10.e which was the resetting of Train B SI. The performance of these steps out of sequence did not adversely impact the plant.

- Surveillance 2BOS 3.1.1-32 - The operator did not subtract the background counts from the observed N-32 source range counts as required by steps 5.e, 5.g, and 5.c. The operator did not perform the subtraction because the background counts were insignificant and would not impact the surveillance results. The licensee should evaluate the surveillance procedure to determine if a revision was required to clarify the intent of the surveillance.

- Surveillance 2BOS 3.2.1-960 - The portion of the surveillance that pertained to measuring voltage across contacts associated with valve 2SI8811A could not be performed since valve 2SI8811A was out of service and deenergized. As a result, the operators exited the surveillance.

- 2BVS 4.6.2.2-1 - When valve 2SI8871 would not remain open to meet paragraph F.2, step 2.7, the nuclear station operator opened 2SI8878D, the accumulator make up valve, to apply accumulator pressure to open 2SI8871. The manipulation of valve 2SI8878D was not noted in the surveillance package. Procedure BAP 1400-1, Revision 7, " Byron Station Surveillance Program", step C.1.K, states that any authorized valve manipulations, during the surveillance performance, shall be documented in an approved procedure or in the remarks section of the surveillance data package cover sheet. Since the inspectors have not noted other recent instances where the licensee has failed to document other valve manipulations, the inspectors consider this matter unresolved pending further NRC review (455/92008-04(DRP)).

- 2BOS 10.5-1 - During the performance of step 4.b in paragraph F, shutdown bank B, control bank B and control bank D could not be withdrawn to 228 steps due to logic card failures in the rod control cabinet. The logic cards were replaced and the surveillance was successfully completed .

No violations or deviations were identified.

6. <u>Engineering & Technical Support (37700)</u>

a. <u>Installation and Testing of Modifications (37828)</u>

The inspector witnessed the installation of modification M6-2-89-033 that pertained to the relocation of the Unit 2 steam generator narrow range lower level taps. The purpose of the modification was to improve the level control characteristics of the Westinghouse D5 steam generators to be consistent with the Unit 1 D4 steam generators. An LER (455/91005-LL) related to this modification was reviewed and closed in report 50-454/455-91029(DRP). The modification consisted of relocating the tap connection for the lower narrow range sensing line (sixteen narrow range transmitters) from elevation 438' 2-3/8" to 429' 5-1/4". The new location increases the upper tap to lower tap distance from 128 inches to 233 inches. In addition to witnessing the installation of the modification, the inspector reviewed the modification package for the inclusion of testing requirements and performed a walkdown of the accessible portions of the installed tap connections.

b. Onsite Reviews

The inspectors reviewed Onsite Review (OSR) 92-038, "Diesel Generator Operability, Jacket Water Piping" and OSR 92-049, "Installation of M-6-2-92-032". OSR 92-038 addressed a concern about the potential impact of the failure of non-safety related piping on the diesel generator (DG) jacket water system. Preliminary investigation showed that the demineralized water piping for filling and draining the jacket water system was not seismically qualified. OSR 92-038 documents the station's review of the licensee's Nuclear Engineering Department (NED) evaluation which concluded that the piping in question would be capable of withstanding stresses associated with a postulated seismic event. The conclusion by NED was based on a preliminary analysis performed by Sargent & Lundy (S&L) OSR 92-038 concluded that the DGs were operable.

OSR 92-049 pertained to a minor change, M6-2-92-032, that provided direction for the station to change transformer taps at the 231x and 232x 480 volt safety related buses and at the 120 volt buses on motor control centers 231 x 1(2)(3) and 232 x 1(2)(3). The minor change is discussed in the next paragraph of this report. The purpose of OSR 92-049 was to discuss the purpose and installation of minor change M6-2-92-032. The OSR included a risk assessment by work planning and a list of affected equipment for each bus outage. The OSR also reviewed the engineering calculations and requested an addendum letter for the tap change modification to provide a 2.5% voltage reduction at the inverter. The 2.5% reduction will increase the margin between the nominal AC voltage input to the inverter and the over voltage trip setpoint on the inverter AC input breaker.

c Degraded Voltage

As a result of a degraded voltage issue at another licensee's nuclear plant, corporate engineering has been in the process of reviewing Byron's degraded voltage setpoint calculations. Based on the preliminary stages of the review, corporate engineering recommended changing the taps on the Class 1E 480V Unit Substation to provide a 2.5% boost of the transformer secondary voltage and a 2.5% reduction at the 120-volt level. The tap changes were identified by the licensee as a minor modification in a letter dated April 10, 1992 which included a 50.59 evaluation and referenced the supporting S&L calculation. The minor modification letter was subsequently revised on April 14, 1992 to include changing the instrument inverters' (211 through 214) power supply transformer taps. This revision was required when the system engineer noted that the increased 480V bus voltage caused a decrease in margin to the overvoltage trip setpoint for the AC input breaker to inverters 211 through 214. These inverters were powered from the 480V motor control centers. The inspectors considered the licensee's actions in implementing modification MG-2-92-632 as very good with excellent teamwork between corporate engineering departments as well as between the station's technical staff and corporate engineering. The S&L calculations to evaluate the acceptability of a 2.5% boost in the 4160-480V unit substation transformer secondary voltage were considered good. The calculation concluded that the expected unit substation voltage with the proposed 2.5% boost would be 503.1 V. The calculation was based on a switchyard voltage of 354kV and no transformer losses or line losses from the transformer secondary to the loads. The calculation clearly identified the purpose, scope, assumptions and input data. To assist corporate engineering in evaluating the possible affects on equipment with the higher 480V bus voltage, the station supplied corporate engineering with portions of the vendor technical manuals for equipment powered from the Class 1E 480V bus.

d. Hydrogen Monitors (HMs)

During walkdowns of the Unit 2 containment the inspectors identified several concerns with the HMs. The concern with the HMs pertained to the location of the HM suction lines. The suction for Train A of the HM system was located approximately 5 feet 7 inches above the containment floor outside of the shield wall. The inspectors were concerned that the water level in containment could go above the 5 feet 7 inches after a design basis loss of coolant accident. The Updated Final Safety Analysis Report (UFSAR) in Appendix D, paragraph D3.6.1.2, stated the maximum flood level was conservatively predicted to be 5 feet 2 inches above the floor. Paragraph D3.61.1 further stated that the calculated flood level followed a limiting set of conservative assumptions that included: 1) break occurs in the lowest point of the reactor coolant loops; 2) pressurizer was assumed solid; 3) entire available volume of the refueling water storage tank (RWST) was injected into the reactor vessel and 4) certain areas of limited accessibility, such as the reactor cavity and annulus, were assumed to remain dry. Since the calculated flood level was within 5 inches of the Train A suction for the HM system, the inspectors requested a copy of the calculation that was the basis of the UFSAR 5 feet 2 inches flood level. The inspectors reviewed the S&L calculation, RAS-FL-1, prepared on July 21, 1982. The review identified the following concerns:

- The volume used for the RWST was 410,000 gallons which corresponded to the minimum level (89%) required by Technical Specifications. However, the available volume could be as high as 450,000 gallons which corresponds to a high level of 97%.

- When calculating the entrained volume of the safety injection (SI) sumps, there was a mathematical error of approximately 400 cubic feet. The S&L calculation identified 2256 cubic feet of entrained water in the SI sumps instead of the correct volume of approximately 1850 cubic feet.

- The calculated free space in the containment at the floor level was 78% based on the reduction of the floor space caused by the reactor cavity, shield wall, reactor containment fan coolers and miscellaneous walls. However, the calculation did not assume reductions of floor space for other items such as the reactor coolant drain tank, pressurizer relief tank, reactor coolant loop piping, the hot leg suction piping, structural steel and instrument racks. The calculation did not identify if these other reductions in free space were offset by the assumption that the reactor cavity and annulus remained dry during the LOCA.

Following discussion of the above concerns with the licensee, the inspectors were informed that new calculations to determine or reaffirm the maximum flood level in the containment would be performed. Pending review of the new calculations, this matter is considered an Unresolved Item (455/92008-05(DRP)).

No violations or deviations were identified.

7. <u>Report Review</u>

During the inspection period, the inspector reviewed the licensee's Monthly Performance Reports for December and January, 1992. The inspector confirmed that the information provided met the requirements of Technical Specification 6.9.1.3 and Regulatory Guide 1.16. The inspector also reviewed the licensee's Monthly Plant Status Reports for January, February and March 1992.

No violations or deviations were identified.

8. Open Items

Open items are matters which have been discussed with the licensee, which will be reviewed 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.h.

9. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, violations, or deviations. Unresolved items disclosed during the inspection are discussed in paragraphs 2.c, 3.i, 5.b and 6.d.

10. Meetings and Other Activities

a. Management Meetings (30702)

On March 27, 1992, The Chairman toured the Byron plant and training facilities. The Chairman met with licensee management to discuss plant performance maintenance and the Individual Plant Evaluation Process. The Chairman at the conclusion of the visit conducted a press conference at the Byron Training Building which was attended by local news organizations.

On April 21 and 22, 1992, Mr. Brent Clayton toured the Byron plant and met with licensee management to discuss plant performance and plant material condition. Also, on May 5, 1992, Mr. A. Bert Davis, Regional Administrator accompanied by Mr. Marty Farber, Section Chief 1A, met with licensee management to discuss plant performance. Messrs. Davis and Farber also presented operator licenses to recently licensed individuals.

b. Exit Interview (30703)

The inspectors met with the licensee representatives denoted in paragraph 1 during the inspection period and at the conclusion of the inspection on May 5, 1992. The inspectors summarized the scope and results of the inspection and discussed the likely content of this inspection report. The licensee acknowledged the information and did not indicate that any of the information disclosed during the inspection could be considered proprietary in nature.