U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Reports No. 50-454/91007(DRP); 50-455/91007(DRP)

Docket Nos. 50-454; 50-455 Licenses No. 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: February 12, 1991 through March 22, 1991

Inspectors: W. J. Kropp
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3-29-91
Date

Inspection Summary

Inspection from February 12, 1991 through March 22, 1991 (Reports No. 50-454/91007(DRP); No. 50-455/91007(DRP)).

Areas Inspected: Routine, unannounced safety inspection by the resident inspectors of action on previous inspection findings, operational safety, engineered safety systems, onsite event follow-up, current material condition, radiological controls, security, management command and control, onsite nuclear safety, essential service water Train B outage, maintenance problems analysis program, surveillance activities, chemical and volume control suction piping, onsite reviews, Safety Evaluation TI-91-0045 and nuclear engineering.

Results: Of the sixteen areas, one violation was identified with three examples of failure to follow procedures (Paragraphs 2, 3a, and 3d). Four open items were identified that pertained to the locked valve program (Paragraph 3b), the Initial Notification program (Paragraph 4b), periodic monitoring of the diesel generator ventilation system (Paragraph 5c) and interface between site and corporate Engineering and Construction (ENC) staffs (Paragraph 6c). The following is a summary of the licensee's performance during this inspection period.

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Plant Operations

The licensee's overall performance in this area was considered good during this inspection period. There were several examples of failures to follow procedures. However, the operating shifts response to the loss of two offsite power sources was considered good. The licensee continues conservative operations as demonstrated by immediately walking down all four emergency diesel generators (DG) when a second offsite power source was lost. Also, the inspectors considered the licensee plans for performing a surveillance on the 1A DG prior to draining essential service lines instead of 24 hours later, which was allowed by technical specification, as another example of conservative operations.

Safety Assessment/Quality Verification

The licensee's overall performance in this area was considered good during this inspection period. Plant tours by key management personnel and the utilization of the Onsite Nuclear Safety group to review the Unit 1 refueling activities (September - October 1991) for high risk activities were examples of good management involvement.

Maintenance and Surveillance

The licensee's overall performance in this area was considered good during this inspection period. Management involvement in planning for the maintenance activities on Train B of the Unit 1 Essential Service Water (SX) system was evident. The planning of the maintenance activities, such as tools, parts and personnel availability was good. The maintenance problem analysis program was reviewed using recent failures of a Unit 2 air operated valve for cooling of the diesel driven auxiliary feedwater pump and a Unit 1 pressurizer power operated relief valve. Based on the review, the program appears to be an effective management tool.

Engineering and Technical Support

The licensee's overall performance in this area was considered mixed during this inspection period with improvement noted in the station's Onsite Review (OSR) process. The station's assessment of a concern with ECCS piping identified at another licensee station was timely and well documented. Also, the guidelines furnished to the Nuclear Station Operators (NSO) by the station's nuclear engineers for a Unit 1 ramp from 100% to 20% reactor power for maintenance was considered a good example of providing technical support. The guidelines addressed ramp rate, affects of Xenon on the core, dilution operations, etc. The guidelines were beneficial for the NSOs since Unit 1 core was at end of life. The OSR performed by station personnel for the planned maintenance activities on the Unit 1 Train B SX system addressed most of the necessary salient points. However, the OSRs did not address the assessment of the risk of the maintenance activities especially since the required out of services would result in inoperability of several key components. Also, the licensee had a calculation to support a abnormal valve lineup during the maintenance activities performed by an engineering consultant to determine if Train A components would receive sufficient SX flow. The calculation did not use actual SX flow data or account for system variances (i.e. pressure drops, actual friction factors etc.) and used engineering judgement exclusively. The calculation concluded that there would be sufficient SX flow to Train A. However, the OSRs did not require verification of proper SX flows to the Train A ECCS room coolers when valves in the SX system were to be repositioned for the abnormal valve lineup. The new Safety Evaluation (SE) process implemented in January 1991, was reviewed with no problems noted. The effectiveness of the new program was not assessed due to lack of implementation time. However, concerns were identified with the interface between the licensee's ENC organization on site and offsite organizations. The interface between the site ENC staff and the engineering consultant (S&L) needs improvement in the documentation of assumptions used in calculations. The interface between the site ENC staff and the corporate ENC staff needs improvement in the distribution of results of reviews of S&L calculations performed by the corporate ENC staff. The results of the reviews could be a useful tool for the site ENC organization in ascertaining if a review of a calculation would be prudent rather than just a review of the calculation assumptions.

DETAILS

1. Persons Contacted

   Commonwealth Edison Company (CECo)

   R. Pleniewicz, Station Manager
   *K. Schwartz, Production Superintendent
   *R. Ward, Technical Superintendent
   *J. Kudalis, Service Director
   D. Brindle, Regulatory Assurance Supervisor
   T. Didier, Operating Engineer, Unit 1
   T. Gierich, Assistant Superintendent, Work Planning
   T. Higgins, Assistant Superintendent, Operating
   *J. Schrock, Operating Engineer, Administrative
   M. Snow, Operating Engineer, Unit 0
   D. Prisby, Quality Control Supervisor, Quality Control
   *D. St. Clair, Project Manager, ENC
   *P. Johnson, Technical Staff Supervisor
   *T. Tulon, Assistant Superintendent, Maintenance
   *D. Winchester, Quality Assurance Superintendent
   M. Rauckhorst, PWR Projects Principal Engineer
   W. Kouba, Operating Engineer, Unit 2
   E. Zittle, Regulatory Assurance Staff

   *Denotes those attending the exit interview conducted on March 22, 1991, and at other times throughout the inspection period.

   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)

   (Closed) Unresolved Item 455/90023-03; Lack of documentation for authorized overtime. A review of hours worked for the 7 day per[illegible], September 20-26, 1990 determined that the Fuel Handling Foreman (FHF) worked 82.5 hours. BAP 100-7, Revision 4, "Overtime Guidelines for Personnel That Performed Safety Related Functions", establishes overtime guidelines that included no more than 72 hours in any 7 day period. The procedure required that instances where the guideline was exceeded shall be documented on BAP 100-7T1, "Overtime Deviation Authorization". The licensee could not provide to the inspector a completed BAP-100-7T1 for the FHF for the week of September 20-26, 1990. The failure to complete form BAP 100-7T1, is an example of a Violation of 10 CFR 50, Appendix B, Criterion V and is the basis for closing this Unresolved Item (454/91007-1a(DRP); 455/91007-1a(DRP)).

3. Plant Operations

Unit 1 operated at power levels up to 100% in the load following mode.

Unit 2 operated at power levels up to 100% in the load following mode.

a. Operational Safety (71707)

During the inspection period, the inspectors verified that the facility was being operated in conformance with the licenses and regulatory requirements and the licensee's management responsibilities were effectively carried out for safe operation. Verification was based on routine direct observation of activities and equipment performance, tours of the facility, interviews and discussions with licensee personnel, independent verification of safety system status and limiting conditions for operation action requirements (LCOARs), corrective action, and review of facility records.

On a sampling basis the inspectors verified proper control room staffing and access, operator professionalism and coordination of plant activities with ongoing control room operations; verified operator adherence with the latest revisions of procedures for ongoing activities; verified operation as required by Technical Specifications (TS); including compliance with LCOARs, with emphasis on engineered safety features (ESF) and ESF electrical alignment and valve positions; monitored instrumentation recorder traces and duplicate channels for abnormalities; verified status of various lit annunciators for operator understanding, off-normal condition, and compensatory actions; examined nuclear instrumentation (NI) and other protection channels for proper operability; reviewed radiation monitors and stack monitors for abnormal conditions; verified that onsite and offsite power was available as required; observed the frequency of plant/control room visits by the station manager, superintendents, assistant operations superintendent, and other managers; and observed the Safety Parameter Display System (SPDS) for operability.

On February 6, 1991, during a tour of the auxiliary building, the inspector identified an uncontrolled key, #451 in the Unit 2 Train A Safeguards Test Cabinet (STC) panel, 2PA11J, located in the Auxiliary Electric Equipment Room (EER). The panel door was slightly ajar and no plant personnel were in the area. The inspector determined through discussion with the Unit 2 Nuclear Station Operator (NSO) that no surveillance activities were currently in progress, and no surveillances were scheduled. The inspector informed the NSO and extra NSO of an uncontrolled key in the STC Train A panel and that the panel door was ajar. The extra NSO informed the shift engineer (SE) of the incident and checked the Station Key Control Log (KCL), BAP 330-5T1, to ascertain the current status of key. BAP 330-5, Revision 4, "Lock and Key Control", required the person that requested and authorized release of a key to enter in the KCL the time and date of issuance of the key from the key control cabinet (KCC) in the SE's office. Contrary to the above, a review of the KCL revealed that no entry had been made by the individuals that requested or authorized the release of the key. Further review of the KCL indicated that January 31, 1991, was the last day that the key was checked out. In addition, BAP 330-5, also requires that upon return of the key, that the date/time return section of the KCL be completed by the individual who requested the key. Earlier the same day, key #489/160 was checked out and the proper entries were entered in the KCL. However, when the key was returned to the SE's office and replaced back in the KCC, there was no entry that identified the date/time the key was returned. The control of keys #451 and #489/160 was not in accordance with procedure, BAP-330-5, Revision 4, "Lock and Key Control, and is considered another example of a Violation of 10 CFR 50, Appendix B, Criterion V (454/91007-1b(DRP); 455/91007-1b(DRP)).

b. Engineered Safety Feature (ESF) Systems (71710)

During the inspection, the inspectors selected accessible portions of several ESF systems to verify status. Consideration was given to the plant mode, applicable Technical Specifications, Limiting Conditions for Operation Action Requirements (LCOARs), and other applicable requirements.

Various observations, where applicable, were made of hangers and supports; housekeeping; whether freeze protection, if required, was installed and operational; valve positions and conditions; potential ignition sources; major component labeling, lubrication, cooling, etc.; whether instrumentation was properly installed and functioning and significant process parameter values were consistent with expected values; whether instrumentation was calibrated; whether necessary support systems were operational; and whether locally and remotely indicated breaker and valve positions agreed. During the inspection, the accessible portions of Train B of the Unit 1 Safety Injection and Chemical Volume Control System were walked down. The inspectors identified that on March 8, 1991, the isolation valve, 1CV8479A, in the Chemical and Volume Control (CV) mini-flow line for pump 1A was found not in a locked open condition. The valve was open with a closed lock and chain wrapped around the valve handle. However, the chain was not secured tightly. The inspector was able to remove the lock and chain from the valve handle due to the slack in the chain around the handle. A review of the key control log identified that the key for valve 1CV8479A (key #1B72) was last issued and returned on September 6, 1990, for the purpose of a return to service of the 1A CV pump. The licensee took immediate action to securely lock the valve. The inspectors will continue to monitor the status of locked valves. This matter is considered an Open Item pending further NRC review (454/91007-02(DRP)).

c. Onsite Event Follow-up (93702)

On March 12 and 13, 1991, the licensee had voltage spikes on various radiation monitors that caused ESF actuations of control room ventilation, fuel building ventilation and containment ventilation isolation (valves already closed). The voltage spikes were caused when the offsite power sources (345 kV) tripped open due to what appeared to be "galloping". Galloping was caused by ice on the 345 kv transmission lines and high winds that resulted in momentarily shorting a phase to phase. At one time, the licensee had two offsite lines disconnected from the switchyard ring buss which left two offsite power sources available for the station. The operating shift on duty, when a loss of 345 kV line 15501 resulted in only two offsite sources available to the station, (line 0624 already disconnected from ring bus) initiated a walkdown of all four Emergency Diesel Generators (1A, 1B, 2A and 2B) to ensure operability. Both lines 15501 and 0624 were restored to the ring bus in the afternoon on March 13, 1991. The inspectors will review the associated LER for this event for proper corrective action and root cause.

d. 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 (NWRs) 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 and Unit 2 was considered good with the licensee pursuing repairs on various steam leaks in the Turbine building.

During a tour of the Auxiliary building, on January 23, 1991, the resident inspector observed that the 2B emergency diesel generator (EDG) fire door, #732, had been removed. The door had been removed on January 21, 1991, under NWR B88221. The door had been previously repaired in June 1989 under blanket NWR B99706 release 94 to repair a lock assembly. At the same time another blanket NWR (B99706 release 98) was written to replace the door due to holes in the inside part of the door. A new door was ordered. In June 1989, the licensee followed procedure, BAP 1100-3, Revision 8, "Fire Protection Systems, Fire Rated Assemblies, Radiation, Ventilation, and Flood Seal Impairments", Paragraph F.1.c, which required a Fire Protection Impairment Permit (FPIP) to repair the 2B EDG fire door. The intent of the FPIP was to ensure that all compensatory actions were implemented to meet the Fire Protection Program requirements while a barrier was impaired. All requirements of the FPIP were met that included a security review and approval, a shift engineer review and approval, and the performance of applicable tests. After repairing the lock assembly the door was declared operable on October 2, 1989, after test results of BOS 7-11-2.a-1, "Fire Rated Assemblies Fire Door Monthly Surveillance," were determined satisfactory. The surveillance verified only operability of the door alarm. Blanket NWR 99706 release 98 was not accomplished since a replacement door had not yet been received.

When NWR B88219 was written on January 21, 1991, to replace EDG fire door #732, the maintenance personnel did not initiate a FPIP as required by BAP 1100-3. Maintenance personnel thought that the FPIP that was initiated for NWR B99706 release 94 in June 1989 was still in effect. Since a FPIP was not completed, no compensatory actions were taken to ensure compliance. Limiting Condition for Operation Administrative Requirement (LCOAR) 3.7.11 states that for an inoperable fire rated assembly and/or sealing device, within 1 hour either establish a continuous fire watch on at least one side of the affected assemble or verify the operability of fire detectors on at least one side of the inoperable assemble and establish an hourly fire watch control. The licensee's corrective action included entering the LCOAR until the required action for the LCOAR was accomplished. The failure to initiate a Fire Protection Impairment Permit on January 21, 1991 during the replacement of the 2B EDG door is considered another example of a Violation of 10 CFR 50, Appendix B, Criterion V (454/91007-1c(DRP); 455/91007-1c(DRP)).

e. 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 (81064)

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 checked vital areas were locked and alarmed. Additionally, the inspectors also verified that observed personnel and packages entering the protected area were searched by appropriate equipment or by hand. The inspectors performed a walkdown of the Central Alarm Station and Secondary Alarm Station with plant management. The housekeeping and material condition appeared to be good.

One violation was identified.

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

a. <u>Management Command and Control</u>

To assess management's command and control, the inspector selected areas of the plant toured by management personnel. The inspector reviewed the January ingress and egress records for the control room and auxiliary building for the Plant Manager, Production Superintendent, Technical Superintendent, Services Director, Operating Assistant Superintendent, Operating Engineers and Master Maintenance Personnel (IM, EM and MM). The inspector concluded that management's plant tours for the month of January were sufficient to contribute positively to management's command and control function. However, the plant tours by the Maintenance Masters needed further management review. Maintenance Memo, 1200-02 "Management Field Inspections", provides guidelines and direction to manage the day to day activities of the Maintenance Department. The memo states field inspections should take place at least weekly.

b. <u>Onsite Nuclear Safety</u> (ONS)

The inspector reviewed the activities of the ONS group onsite. The ONS group consist of three individuals with approximately 18 years of Byron ONS experience. The ONS has recently been requested by the plant manager to perform a qualitative assessment of the next Unit 1 refueling outage activities (August - September 1991) for identifying what activities have a high risk. The assessment was scheduled for completion in May 1991 and the results will be reviewed by the inspectors. Other recent activities performed by the ONS in addition to the normal duties described in the Technical Specification included a review of the new station procedures for the 10 CFR 50.59 process to assess compatibility and compliance with corporate directive, NOD-Ts.11, "10 CFR 50.59 Safety Evaluation Process".

The inspector also discussed with the ONS group the event at the licensee's Quad Cities station on January 24, 1991. The ONS group stated that the new Lesson Learned Group in the corporate offices had issued a "Lessons Learned Initial Notification" on February 8, 1991, but the notification failed to reach the station. The Initial Notification program was a new program established by the licensee's corporate office. The inspector will assess the program in the future for effectiveness. The assessment of the Initial Notification program is considered an Open Item (454/91007-03(DRP); 455/91007-02(DRP)).

No violations or deviations were identified.

5. Maintenance/Surveillance (62703 & 61726)

a. Essential Service Water (SX) Train "B" Outage

The inspector reviewed various licensee documentation for a planned maintenance outage of Train B of SX system on Unit 1. The maintenance was planned for February 13, 1991. The licensee met with the inspectors on February 11, to discuss the controls established for the 1B SX Train outage. The licensee had previously completed successful outages on Train A of Unit 1 SX during January 9-11 and January 14-20, 1991 (see Inspection Report 454/91002; 455/91002). The maintenance on Train B was similar to the maintenance activities on Train A performed on January 9-11, 1991 except that the Unit 1 SX system configuration would be different for the maintenance on the 1B SX pump discharge valve, 1SX143B. Since the 1A containment chiller was out of service (OOS), the licensee decided to open normally closed valves, 1SX104A and 1SX105A, to allow cross train flow of SX from the 1A SX train to the 1B Reactor Containment Fan Cooler (RCFC) coils and the 1B containment chiller. All other train 1B SX loads would be isolated. The licensee performed a 10 CFR 50.59 review, TI-91-0045, to assess the proposed Unit 1 SX valve lineup with normally closed valves 1SX104A and 1SX105A open. The inspector reviewed TI-91-0045 and other engineering activities associated with the planned SX Train B outage. The results of the review are documented in paragraph 6.c of this report. The inspector also reviewed OnSite Reviews that pertained to the outage with the results documented in paragraph 6.b of this report. Overall, the inspector concluded that management involvement was evident and at a level commensurate with the scope of the maintenance activities. The planned maintenance activities on the 1B SX train were subsequently postponed by the licensee to further evaluate the scope of the out of services.

b. Maintenance Problem Analysis Program

Due to the failure on February 19, 1991, of the SX inlet valve (1SX0173) to the 1B diesel driven auxiliary feedwater pump (AFW) to open during the monthly surveillance and the failure on March 4, 1991, of pressurizer power operated relief valve (PORV) 1RY456, to open during a surveillance, the inspectors performed a review of the Maintenance Problem Analysis Program (MPAP). The MPAP was designed to identify and correct repetitive equipment problems, equipment misapplications, calibration problems, or preventative maintenance problems through the issuance of a Problem Analysis Data Sheet (PADS). One of the criteria for issuance of a PADS was the occurrence of at least three failures recorded in the Total Job Maintenance (TJM) program during a 12 month interval. The inspectors reviewed the TJM for all Unit 1 and Unit 2 pressurizer PORVs and the inlet and outlet SX valves to the 1B and 2B diesel driven AFW pumps. The review determined that the licensee had already issued corrective actions to prevent reoccurrence of PORV diaphragm failures. The subsequent failure on March 4, 1991, of the 1RY456 PORV diaphragm could not have been prevented as the corrective actions were not in place for the Unit 1 PORVs during the last refueling outage. The licensee also had issued a PADS for the inlet and outlet SX valves to the 1A and 1B diesel driven AFW pumps on March [illegible], 1991. The failure of 1SX0173 on February 19, 1991, was already addressed in Deviation Report 1-91-012. The inspectors concluded based on a review of the problems with the pressurizer PORVs and the SX valves to the diesel driven AFW pumps that the licensee's MPAP has been effective in resolving reoccurring equipment problems.

c. Surveillance Activities (61726)

The inspectors observed or reviewed surveillance tests required by Technical Specifications during the inspection period and verified that tests were performed in accordance with adequate procedures, test instrumentation was calibrated, limiting conditions for operation were met, removal and restoration of the affected components were accomplished, results conformed with Technical Specifications and procedure requirements and were reviewed by personnel other than the individual directing the test, and any deficiencies identified during the tests were properly reviewed and resolved by appropriate management personnel.

The inspectors also witnessed portions of the following activities:

1 BVS 6.2.1.b-2, "ASME Surveillance Requirements for the 1B Containment Spray Pump".

2 BOS 8.1.2.2.a-1, "2A Diesel Generator Operator Monthly and Semi-Annual Surveillance".

2 BVS 3.3.2-1, "Moveable Incore Detectors' Operability Check".

While observing 2 BOS 8.1.1.2.a-1 "2A Diesel Generator Operability Monthly and Semi-Annual Surveillance", on March 6, 1991, the inspectors noted that the diesel generator (DG) room and day tank room ventilation systems status was not required to be checked by the surveillance. The DG ventilation vent fan auto-starts when the DG auto-starts. Updated Final Safety Analysis Report (UFSAR) Section 9.4.5.2.1.4 states that the DG ventilation system should be monitored during periodic testing of the diesel-generator units. The inspectors discussed the UFSAR commitment with the technical staff engineers. This matter is considered an Open Item pending further review by the licensee and the NRC (454/91007-04(DRP); 455/91007-03(DRP)).

No violations or deviations were identified.

6. Engineering & Technical Support (37700)

a. Chemical and Volume Control Suction Piping

On February 14, 1991, the licensee informed the Resident Inspectors that piping tables for some ECCS piping identified the design pressure as 75 psig even though the piping could be subjected to higher pressures. This issue had been identified at the licensee's Braidwood Station during an OnSite Nuclear Safety (ONS) review of overpressure protection for the Chemical and Volume Control (CV) system. The ONS review identified that the design pressure of 75 psig given in the line list for the subject lines was inconsistent with the 220 psig setpoint for the CV pumps suction relief valve. The relief valve setpoint of 220 psig was adequate from an overpressure protection standpoint and was consistent with anticipated pressures under a small break Loss of Coolant Accident (LOCA) scenario where the CV pumps are aligned to take suction from the residual heat removal pump discharge. The licensee's engineering consultant has performed a preliminary review and has ascertained that the installed piping (stainless steel schedule 40) and valves were capable of performing the intended design function. However, since the installed piping and valves had originally been hydrostatic tested based on the incorrect 75 psig criteria, additional hydrostatic testing of the lines is required. The licensee plans to perform these additional hydrostatic tests during the next outage of sufficient length. The licensee will receive the consultant engineer's final assessment by March 15, 1991. The licensee has also instructed the consultant engineer (Sargent & Lundy) to determine the cause of using the wrong design pressure criteria in the original plant construction and to determine if other plant systems were affected. The inspector's reviewed OnSite Review (OSR) 91-023 dated February 13, 1991, that pertained to this issue. Based on the preliminary engineering assessment, that the installed piping would maintain pressure boundary integrity, the CV system was considered operable.

b. Onsite Reviews

The inspector reviewed the OSRs 91-010 and 91-022 that pertained to maintenance on Train B of the Unit 1 SX system. OSR 91-010, dated February 5, 1991, addressed the maintenance activities that pertained to isolation of the 1B SX pump. The isolation of the 1B SX pump would allow maintenance activities on the pump discharge valve, 1SX143B, the discharge strainer, strainer drain line isolation valve, 1SX150B, and other SX maintenance activities. The OSR 90-010 addressed the following salient points:

* equipment that would become inoperable during the 1B SX pump isolation.

* requirement of a shift briefing to advise the shift personnel of plant conditions prior to isolating the 1B SX trains.

* an evaluation of the operability of the 1A Diesel Generator (DG) when the normally locked closed valves, 1SX104A and 1SX105A were opened. These valves would be opened to enable Train A of SX to supply the 1B Reactor Containment Fan Coolers (RCFCs) and the 1B Containment Chiller to assist in maintaining containment temperature.

* requirement to verify operability of the 1A SX train and ensure that the train was in a good state of repair with no outstanding Limiting Condition of Operations or major deficiencies.

OSR 91-010 also stated that the reason for the repairs to the 1B SX train in Mode 1 rather than during a refueling outage was to upgrade the system status at the earliest opportunity. Waiting for an outage, further degradation could occur and may not have been readily apparent. Also, by performing the maintenance prior to an outage, the remainder of the system will be verified to have integrity.

The maintenance was originally scheduled for February 13, 1991. The licensee briefed the resident inspector on February 11, 1991 of the plans for the maintenance. The inspector had the following comments on OSR 91-010:

* The OSR did not clearly identify that Unit 2 SX pumps would not be available for Unit 1, if needed.

* The OSR did not address the licensee's assessment of the risk involved in the maintenance.

Even though the licensee would have been in compliance with Technical Specification Limiting Condition of Operations, the maintenance activities on the 1B SX train would have resulted in inoperative equipment such as:

* 1B Auxiliary Feedwater Pump (diesel driven)

* 1B Emergency Diesel Generator (DG)

* Train B of Emergency Core Cooling System

* Unit 0 Component Cooling Heat Exchanger

The inspector also reviewed OSR 91-022 that was performed by the station to evaluate the abnormal valve lineup of opening the normally locked closed 1A and 1B DG Jacket Water Cooling SX water crosstie valves 1SX104A and 1SX105A. The crosstie valves were to be opened so the 1B containment chiller and 1B RCFCs could be supplied by the 1A SX train during the OOS of the 1B SX train. Since the 1A containment chiller was OOS for maintenance, the licensee wanted the 1B containment chiller available for containment temperature control. OSR 91-022 referenced letters from the licensee's Engineering and Construction (ENC) organization at the site and from the licensee's engineering consultant, S&L. The engineering aspects of the ENC and S&L letters are discussed in the next paragraph (6.c). The inspector had the following comments on OSR 91-022:

* OSR 91-022 identified that a 10 CFR 50.59 safety evaluation was required. However, the OSR did not reference the safety evaluation number, TI-91-0045.

* The S&L letter dated February 11, 1991, states that the 1A train components would receive sufficient SX flows. However, the letter further stated that the computer program (calculation MAD-91-0012), used to determine SX flows was not completely benchmarked against SX system flow data to account for variances in actual friction factors, equipment pressure drops etc. The letter further stated that based on engineering judgement, the differences of actual flow data would not significantly change the conclusions of the calculation. Since the conclusion that the SX flow to the 1A train components would be sufficient was based on 1) a calculation which did not use SX flow data based on variances and 2) engineering judgement, the OSR could have required verification of sufficient SX flow to train A components (i.e. room coolers) when the 1A DG was run for operability with the SX DG crosstie valves open prior to the actual SX maintenance work. The performance of the 1A DG surveillance run prior to draining of the SX lines for the maintenance activities was considered a conservative approach. The Technical Specifications required the surveillance on the 1A DG within 24 hours after the 1B DG was declared inoperable. The licensee elected to perform the 1A DG surveillances prior to any SX line draining activities.

In conclusion, the inspector considered the OSRs performed for the 1B SX train maintenance work as above average with most salient issues addressed. However, the maintenance planned for the 1B SX train was extensive and required valves to be placed OOS that required entry into several LCOs, causing several Train B components to be inoperable. OSR 91-010 could have been enhanced by documenting the results of the risk assessment discussed by station personnel during the OSR and clearly stating that the Unit 2 SX pumps would not be available for the 1A SX train. OSR 91-022 also could have been enhanced by requiring verification of adequate SX flow to train A components when the 1A DG was run with the normally closed DG SX cooling water crosstie valves 1SX104A and 1SX105A open.

c. <u>Safety Evaluation TI-91-0045</u>

The inspector reviewed safety evaluation (SE) TI-91-0045 that was performed as a result of a Abnormal Valve Lineup required for the planned 1B SX Train maintenance activities. The normally locked close valves, 1SX104A and 1SX105A were to be opened to allow cross train flow of SX from the 1A SX train to the 1B RCFC coil and containment chiller. The SE referenced S&L letter dated February 11, 1991, that documents the results of a S&L computerized flow evaluation (MAD-91-012). The inspector had one observation that pertained to ENC's review process. The February 11, 1991 S&L letter to the Byron onsite ENC identified five assumptions used in calculation MAD-91-012. The inspector requested a copy of S&L calculation MAD-91-012 which had not been reviewed by the ENC onsite group. ENC procedures did not require a review of the calculation but did require a review of the assumptions used in calculations. The S&L calculation identified nine assumptions. In discussions with the ENC engineer who performed the SE, he stated that he had verbally discussed all the assumptions with S&L. The ENC engineer presented handwritten notes to the inspector that also identified three assumptions used in the calculation but were not identified in the February 11, 1991 S&L letter. The assumptions that were not identified in the February 11, 1991 S&L letter were:

* Unit 1 Train A RCFC valves were throttled to a design flow of 1330 gpm per set of five coils.

* Unit 1 Train B RCFC valves were wide open.

* Unit 2 was operating under normal conditions with the CC heat exchanger throttled to 8000 gpm. The Unit 2 RCFC valves were throttled to receive the same flows as in the normal operating condition.

A corporate ENC representative committed to instruct S&L via a letter to include all assumptions used in calculations in correspondence with the licensee's ENC organization. The inspector expressed a concern with the lack of documentation of onsite ENC personnel reviews of S&L assumptions used in calculations. Documenting the review of assumptions would facilitate a method for corporate management to measure the effectiveness of the engineering overview of an Architect/Engineer activities. In discussions with corporate ENC personnel the inspector determined that corporate ENC offices have been sampling S&L calculations for adequacy. However, the results of the reviews have not been transmitted to the site ENC organizations. This matter of interface between site and corporate ENC staffs is considered an Open Item (454/91007-05(DRP); 455/91007-04(DRP)).

d. Nuclear Engineering

On March 4, 1991, the Nuclear Engineering group in the Technical Staff issued a memo to the shift engineers that provided guidelines to the operators for a Unit 1 load reduction to 20% reactor power to perform maintenance on feedwater isolation valve, 1FW009D. The memo provided a desired ramp rate; affects of Xenon on the core, dilution operations, and control of delta flux. The memo was attached to a Daily Order that discussed the various maintenance activities planned after the load reduction.

No violations or deviations were identified.

7. 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. Open Items disclosed during the inspection were discussed in Paragraphs 3b, 4b, 5c and 6c.

8. Meetings and Other Activities

a. Management Meetings (30702)

On February 11 - 12, 1991, Mr. H. J. Miller, Director, Division of Reactor Projects, toured the Byron plant and met with licensee management to discuss plant performance and plant material condition.

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 March 22, 1991. 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.