U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-315/94018(DRP); 50-316/94018(DRP)

Docket Nos. 50-315; 50-316 License Nos. DPR-58; DPR-74

Licensee: Indiana Michigan Power Company
1 Riverside Plaza
Columbus, OH 43216

Facility Name: Donald C. Cook Nuclear Power Plant, Units 1 and 2

Inspection At: Donald C. Cook Site, Bridgman, MI

Inspection Conducted: August 13, through September 23, 1994

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Approved By: Wayne J. Kropp, Chief — 10/20/94 Date
Reactor Projects Section 2A

Inspection Summary:

Inspection from August 13, 1994, through September 23, 1994
(Report Nos. 50-315/94018(DRP); 50-316/94018(DRP))

Areas Inspected: Routine, unannounced safety inspection by the resident inspectors of action on previous inspection findings; operational safety verification; engineered safety feature systems; onsite event follow-up; current material condition and housekeeping; security; radiological controls; licensee event report followup; maintenance activities; surveillance activities; engineering and technical support; and refueling activities.

Results: Of the twelve areas inspected, one violation was identified regarding the failure to remove action request tags from various control panels (paragraph 5.a). One non-cited violation was identified pertaining to an incorrect instrument air piping configuration for a solenoid valve installed in the engineered safety feature ventilation system (paragraph 4). One unresolved item was identified regarding preventive maintenance activities for essential service water system expansion joints (paragraph 5.c). Another unresolved item was identified regarding the licensee's progress on the ferrography program (paragraph 6a).

The following is a summary of the licensee's performance during the inspection period:

Plant Operations:

Overall performance in this area was excellent. Operators exhibited good command and control during the Unit 2 power escalation, reduction, and cooldown evolutions. Good communications and coordination among operating shift personnel were evident during these evolutions. Operator actions in response to level indication discrepancies during a reactor coolant system drain-down evolution reflected a conservative operating philosophy (paragraph 3.a).

Maintenance and Surveillance:

Overall performance in the maintenance and surveillance area was good. The quality of work performed by maintenance personnel was excellent. A violation was identified regarding the licensee's failure to remove action request tags from various control panels after completing corrective maintenance on the associated equipment (paragraph 5.a). The failure to consider replacement of expansion joints in the essential service water system for the emergency diesel generators, reflected weaknesses in the area of preventive maintenance (paragraph 5.c).

Engineering and Technical Support:

Overall performance in this area was mixed. System engineer involvement in the replacement of the regenerative heat exchanger letdown safety valve was considered a strength (paragraph 5.a). The status of implementation of the ferrography program (paragraphs 6.a) was considered a weakness. Strengths were noted in the licensee's erosion/corrosion program, with a large number of piping scheduled for inspection (paragraph 6.b).

Radiological Controls:

Overall performance in this area was good. The licensee took initiatives to reduce the source term using chemical cleaning. Lessons learned from the Unit 1 outage were being applied to reduce overall dose during the Unit 2 outage (paragraph 3.f).

DETAILS

1. Persons Contacted

*A. A. Blind, Site Vice President/Plant Manager
*K. R. Baker, Assistant Plant Manager/Operations Superintendent
*L. S. Gibson, Assistant Plant Manager-Technical
*J. E. Rutkowski, Assistant Plant Manager, Support
*T. P. Beilman, Maintenance Superintendent
P. F. Carteaux, Training Superintendent
*D. L. Noble, Radiation Protection Superintendent
*T. K. Postlewait, Site Engineering Support Manager
*P. G. Schoepf, Materials Management Superintendent
*J. S. Wiebe, Quality Assurance & Control Superintendent
*L. H. Vanginhoven, Project Engineering Superintendent
*G. A. Weber, Plant Engineering Superintendent
A. A. Lotfi, Site Design Superintendent
A. Gort, MOV Coordinator, Plant Engineering

*Denotes those attending the exit interview conducted on September 30, 1994.

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, electrical, mechanical, and instrument maintenance personnel, and contract security personnel.

2. Action on Previous Inspection Findings (92701)

a. (Closed) Violation 50-315/94004-01(DRP): During a Unit 1 reactor coolant system (RCS) drain-down evolution in February of 1994, the inspectors identified that the operations procedure used was inadequate in several areas. First, the procedure did not adequately address the quantity of water to be drained, and did not provide a correlation between RCS level indication and the plant elevation. Secondly, the procedure did not provide adequate instructions regarding the venting of the RCS in a controlled manner. In addition, the inspectors noted that pertinent information regarding the drain-down evolution was not logged in either the control room or the shift supervisor log books.

In response to these problems, the licensee added Figure 3 to the Unit 1 operations procedure, 01-OHP 4021.002.005, Revision 16, "Reactor Coolant System Draining," which correlates RCS volume to plant elevation. Also, Figure 3 was added to the corresponding Unit 2 operations procedure, 02-OHP 4021.002.005, Revision 10. In addition, plant drawings 1-5663 and 2-5663, which contain elevation information for major components in containment, were developed and issued for Unit 1 and 2, respectively.

To address the inspectors' second concern, a caution statement was added after step 19.5 in the subject Unit 1 and 2 operations procedures, which required that the RCS venting be controlled to maintain continuous level indication.

With respect to inadequate log keeping practices, the acting Operations Superintendent issued a memorandum entitled "Control Room Logs," dated April 27, 1994, to all senior licensed operators. This memorandum reminded operators that entries in the log should contain enough information so subsequent shifts can understand what had occurred or why something had happened. The inspectors noted that control room log entries have substantially improved with respect to the details of specific events described.

b. (Open) Unresolved Item 50-315/94004-02(DRP): During their review of the RCS drain-down evolution in February 1994, the inspectors noted that a pre-job briefing was not performed by licensee management. The licensee added precaution 2.2 to the Unit 2 "RCS Draining" procedure, which required that "a shift briefing must be conducted each shift prior to assuming the duties for a unit entering or operating at REDUCED INVENTORY." The licensee plans to add a similar precaution to the Unit 1 "RCS Draining" procedure before the next refueling outage.

c. (Closed) Inspection Follow-Up Item 50-315/94004-05(DRP): During the Unit 1 RCS drain-down evolution in February 1994, the inspectors identified that there was no RCS level indication from the bottom of the pressurizer to the top of the reactor vessel area. The licensee has since installed a temporary mid-loop instrument, 1-NLI-312, which provides level indication from the pressurizer to the half-loop level.

d. (Closed) Unresolved Item 50-315/94014-07(DRP); 50-316/94014-07(DRP): This item concerns failure to remove action request tags upon resolution of the deficiencies documented on the tags. This item is closed based on the issuance of a violation which is discussed in paragraph 5.a of this report.

e. (Open) Unresolved Item (50-315/93006-01(DRS); 50-316/93006-01(DRS)): This item pertains to the methodology for degraded voltage calculations. Degraded voltage calculations performed by the licensee were not performed using the methodology described in GL 89-10 and its supplements. The calculations did not assume the worst case grid voltage as the starting point for evaluating the available voltage at MOV motors. Instead, the licensee used the minimum expected grid voltage that was based on a study of the previous grid history.

The licensee considered the minimum expected value, not the minimum degraded voltage setpoint, as the licensing basis when evaluating the electrical system to ensure adequate component starting and operating voltages were available. However, after

further review by NRR, the NRC position was that licensees use the worst case grid voltage when performing degraded voltage calculations for motor-operated valves (MOV) in the Generic Letter (GL) 89-10 program. The licensee was notified of the NRC position during a teleconference between NRC Region III and the licensee. The licensee committed to evaluate the issue and develop a course of action. Although additional inspection is needed in this area, it was apparent that degraded voltage calculations were being done with the degraded grid setpoint as the starting voltage and the results were used to verify MOV capability. Action was also being taken to incorporate the results of the calculations into the work being planned for the upcoming outage. Any torque switch setpoint changes or modifications needed as a result of the new method for assessing MOV capability were being planned by the licensee. This issue will be reviewed during a future inspection.

f. (Open) Violation 50-315/94009-03(DRS): This item pertained to reviews of MOV test results. The licensee had not yet responded to the violation nor specified the corrective actions, but had implemented changes to test reviews to ensure that complete evaluations are performed and documented. A test package was reviewed during the inspection where a valve was returned to service without an adequate evaluation documented with the acceptance criteria. In the job order package for the valve, the measured thrust had exceeded the allowable thrust, however, the details of the evaluation were not documented in the package. The valve was subsequently tested two years after the initial test and a similar problem occurred. However, a thorough review of the potential overthrust condition was conducted and the results of the review were documented in the work package. There was no problem identified with the valve, and the documented evaluation of potential overthrust condition was adequate. It appeared that the licensee was implementing corrective actions, but had not yet docketed a response. This item will remain open pending NRC review of the violation response.

3. Plant Operations

The licensee operated Unit 1 at full power during the inspection period until September 5 when power was reduced to 50 percent to repair a loose actuator on the No. 13 circulating water pump discharge valve. The licensee returned the unit to full power the following day. The licensee continued to operate Unit 1 at full power until September 9, when power was reduced to 50 percent to perform a clamtrol treatment of lake water systems for zebra mussel infestation. The licensee then reduced power to 8 percent and removed the main turbine from service to add oil to the reactor coolant pumps and replace a turbine trip solenoid. In addition, a steam leak on the "EAST" main feedwater strainer was repaired. The licensee returned Unit 1 to full power on September 15, and operated the unit at that power level for the remainder of the inspection period.

At the beginning of the inspection period, Unit 2 was in coastdown in preparation for the upcoming cycle 9-10 refueling outage. On August 15, the unit tripped from 60 percent power due to a low steam generator level coupled with a steam flow/feed flow mismatch. Details of the trip are discussed in paragraph 3.c of this report. The licensee returned Unit 2 to service on August 17. On September 6, the licensee shut down Unit 2 to begin a scheduled 54-day outage. At the end of this inspection period, Unit 2 was in Mode 6, with the fuel unloaded from the core.

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 effective in ensuring safe operation of the plant.

On a sampling basis, the inspectors verified proper control room staffing and coordination of plant activities; verified operator adherence to 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. The inspectors reviewed applicable logs and conducted discussions with control room operators throughout the inspection period. The inspectors observed a number of control room shift turnovers. The turnovers were conducted in a professional manner and included log reviews, panel walkdowns, discussions of maintenance and surveillance activities in progress or planned, and associated Limiting Conditions for Operation time restraints, as applicable.

The inspectors observed that operating crews exhibited a professional demeanor in the control room. In addition, the inspectors observed that management was present during routine plant operations. Operators used the alarm response procedures for unusual alarms, and communications were generally good and clear among the control room operators. One operating crew was observed using formal repeat backs during normal evolutions.

The use of the task master concept, initiated during the Unit 1 refueling outage, continued during the Unit 2 outage. The "task master" handled requests such as clearances and job orders so that the unit supervisor was able to focus on plant evolutions.

The inspectors observed that pre-evolutionary briefs were thorough and well conducted. This was evidenced in the Unit 2 cool-down brief, which included a presentation by the Shift Technical Assistant on previous problems encountered during the drain-down evolutions at Cook. Management was present at the pre-draindown brief.

The unit supervisor demonstrated good command and control during the cool-down and power reduction evolutions on Unit 1. The operators responded well to problems with the "East" main feedwater pump (MFP). When smoke or steam was reported coming from the "East" MFP, which was supplying feedwater to the steam generators at the time, the operators made a smooth transfer to the "West" MFP. The licensee determined that the smoke was caused by sealant lubrication evaporating from the heat.

The inspectors observed that the operators drained the reactor coolant system to the flange level in a well-controlled manner and that anomalies were properly addressed. For instance, when the operators were unable to obtain an agreement of 2 percent between the pressurizer cold calibrated level instrument and another independent wide range level instrument, 2-NLI-132, the drain-down evolution was stopped until the discrepancy was resolved. The disagreement was caused by the pressurizer cold calibrated instrument needing calibration. The inspectors found that this drain-down evolution was a great improvement over the previous drain-down performed in February of 1994 and discussed in Inspection Report 50-315/94004(DRP); 50-316/94004(DRP).

The inspectors accompanied the auxiliary equipment operators (AEOs) on plant tours, and observed that the non-licensed operators were conscientious and observant during their tours.

The inspectors also observed a requalification dynamic simulator evaluation for an operating crew and found that the crew did not miss any team critical tasks. The inspectors noted that the licensee expected higher standards from their crew and individual operators than those required by NUREG 1021.

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 requirements, 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 position 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 the high pressure charging and the essential service water systems were walked down. No significant discrepancies were noted.

c. Onsite Event Follow-up (93702)

During the inspection period, the licensee experienced several events, some of which required prompt notification of the NRC pursuant to 10 CFR 50.72. The inspectors pursued the events onsite with licensee and/or other NRC officials. In each case, the inspectors verified that any required notification was correct and timely. The inspectors also verified that the licensee initiated prompt and appropriate actions. The specific events were as follows:

1) On August 15, 1994, Unit 2 tripped from 60 percent power. At the time of the trip, the operators were in the process of removing circulating water (CW) pump #21 from service in order to troubleshoot a spurious low voltage alarm on a 4 kV bus. The licensee believes that closing of the CW pump #21 discharge valve and stopping the pump caused debris near the valve to be stirred up and entrained in the circulating water flow. The entrained debris then entered the main feedpump turbine (FPT) condenser waterbox supply lines. The flow restriction in the FPT condenser waterboxes caused a rapid loss of vacuum and the West main feedpump tripped on low vacuum. The reactor subsequently tripped on low feed flow coincident with low level on the 23 steam generator.

   The licensee determined that the root cause of this event was the presence of zebra mussels within the circulating water system. The zebra mussels temporarily blocked cooling flow to the main feedpump condenser waterboxes and caused a main feedpump trip on low vacuum.

   After the reactor trip, all safety systems operated normally. The main feedpump condenser waterboxes were cleaned and inspected. The unit was returned to power on August 16, 1994. The inspectors will review the licensee's LER to ensure that adequate corrective actions will be taken.

2) On September 9, 1994, the licensee made a four hour report pursuant to 10 CFR 50.72, due to the failure of a post accident sample return line check valve, 2-NS-357, to satisfy containment leak rate testing. The licensee discovered that the valve was stuck in the open position and determined that the leakrate exceeded that allowed by TS 3.6.1.2. The inspectors will review the licensee's LER submittal to verify that an adequate root cause investigation was performed and appropriate corrective action was taken.

d. Current Material Condition and Housekeeping (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, and to verify that work requests had been initiated for identified equipment problems. 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 inspectors also monitored the status of housekeeping and plant cleanliness for fire protection and protection of safety-related equipment from intrusion of foreign matter.

The inspectors toured the Unit 2 containment during the current refueling outage and noted that housekeeping was improved compared to that observed during the last Unit 1 outage. However, the inspectors observed that some areas, particularly the annulus, contained excessive amounts of trash and debris. The inspectors discussed these observations with the licensee, and will continue to monitor containment housekeeping throughout the remainder of the outage.

The inspectors also discovered a danger tag for valve 2-RC-102-L4, loop 4 RTD bypass isolation, on the floor of the containment basement. The licensee verified that the tag was active and rehung it. The licensee believed that the tag was inadvertently detached from the valve during installation of shielding on the RTD bypass manifold. The inspectors also found a detached caution tag and a refueling integrity tag. The licensee determined that these tags were not applicable at the time due to plant conditions.

e. Security (71707)

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. In addition, the inspectors observed that personnel and packages entering the protected area were searched by appropriate equipment or by hand.

f. Radiological Controls

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.

The inspectors also reviewed ALARA program performance and initiatives implemented during the on-going refueling outage (U2R94). Selected work areas were reviewed during tours of the auxiliary and containment buildings. Several workers were interviewed to determine their understanding of the job requirements, area dose rates, and ALARA with no problems being identified.

The U2R94 outage has had higher than anticipated general area dose rates. These higher rates are probably a result of several scrams that occurred during the fuel cycle. Initiatives to reduce the source term included chemical cleanup of the reactor coolant system. Also included was a chemical decontamination performed on the Regenerative Heat Exchanger (RHE) and the Resistance Temperature Detector (RTD) loops. Surveys in general areas of Unit 2 indicated that these initiatives had mixed results. The personal dose savings as a result of these initiatives was difficult to quantify. However, the initiatives were effective in removing considerable radioactivity from the reactor systems.

U2R94 was scheduled to be accomplished in about 70 days. In general it appeared the outage was progressing well and to date no significant emergent work had occurred. Lessons learned from the U1R94 outage resulted in improved scheduling of work on the steam generators, and on the installation and removal of scaffolding.

The projected dose goal for the U2R94 outage was about 210 person-rem (2.1 person-Sv), and four weeks into the outage the dose was about 115 person-rem (1.15 person -Sv), which was close to the projected dose goal for that period. The final station goal for 1994 was about 500 person-rem (5 person-Sv).

No violations or deviations were identified.

4. Licensee Event Report (LER) Follow-up (92700)

Through direct observations, discussions with licensee personnel, and review of records, the following event reports were 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 Technical Specifications (TS):

- (Closed) LER 316/93003-LL: ESF ventilation system filter train damper control malfunction due to incorrect solenoid installation. On October 16, 1992, the licensee discovered that the 2-HV-AES-2, Train B engineered safeguards charcoal filter dampers were closed when they should have been open. With 2-HV-AES-1 (Train A) removed from service, the Train B charcoal filter should have automatically been placed in service.

  The licensee determined that the root cause was an incorrect piping configuration of the instrument air supply to solenoid valve XSO-560, which was designed to reposition the dampers upon actuation of a containment isolation phase B signal from Train A or Train A fan out-of-service. The licensee modified the control system for the damper in 1977 to provide the train redundancy. The licensee could not conclusively determine if the piping was installed incorrectly in 1977 or had been changed at a later date. The condition had gone undetected because the cross-train features were not included in the ESF time response test procedure.

  The licensee corrected the piping discrepancy and verified the correct configuration of the other AES system solenoids. The licensee also revised the ESF time response procedures to verify damper operation upon receipt of a safety injection signal from the opposite train.

  This event involved a violation of TS 3.7.6.1; however, the event had minimal safety significance because the inoperability of the Train B exhaust filter would not have significantly contributed to the overall site boundary dose in the event of a design-basis accident. In addition, the licensee properly reported the event and took appropriate corrective action. Therefore, this violation will not be subject to enforcement action because the licensee's efforts in identifying and correcting the violation meet the criteria in Section VII.B(2) of the NRC Enforcement Policy.

- (Closed) LER 316/94001-LL: Unit 2 reactor trip on low-low level in Steam Generator No. 4 as a result of inadequate valve actuator/stroke adjustment procedure. The inspectors reviewed this event and discussed the results of the review in Inspection Report 50-315/94002(DRP); 50-316/94002(DRP).

One non-cited violation was identified. No 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 technical specifications.

The following items were also considered during this review: limiting conditions for operation were met while components or systems were removed from service; 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:

- JO C0024364 "Replace Broken Gauge 2-LPI-262"
- JO C0025436 "Replace 1-SV-51"
- JO C0023527 "Install Unit 2 CD EDG Room Ventilation System Relays"
- AR A0078908 "Repair Unit 1 TDAFW Pump T&TV Limit Switch"
- JO R0014064 "Calibration of Pressure Switch, 2-LPA-67"
- JO C0020990 "Replace 2-BATT-AB Battery Bank"
- JO R0025872 "Refurbish 2-QRV-421 Valve and Actuator"

The inspectors observed activities associated with the replacement of 1-SV-51, regenerative heat exchanger letdown safety valve. The inspectors concluded that the evolution was well-planned and coordinated.

The valve had failed to fully reseat after lifting while a letdown orifice was placed in service in July. The licensee initially attempted to reseat the valve by reducing letdown pressure, but was unsuccessful. Therefore, the licensee operated the unit at reduced letdown pressure and flow to minimize valve leak-by until a plan to replace the valve was prepared.

In order to replace the valve, the licensee secured normal letdown and put excess letdown in service. In addition, since the valve discharge line could not be isolated from the pressurizer relief tank (PRT), the licensee was also required to depressurize and vent the PRT. Following replacement, the licensee used charging flow to refill the isolated section of the letdown line to prevent the potential for water hammer and the injection of positive reactivity upon re-establishing letdown.

The inspectors noted that special procedure "Maintenance of 1-SV-51 While in Mode One," 1 EHP SP.063, prepared to control the evolution was well-written. The inspectors attended the pre-job briefing and observed portions of the evolution and concluded that

the system engineer did an exceptional job of coordinating with the various departments involved. The licensee successfully completed the replacement and returned the plant to normal configuration without incident.

b. Action Request (AR) Tags

The inspectors previously identified an unresolved item (50-315/94014-07(DRP); 50-316/94014-07(DRP)) regarding AR tags that remained attached to components, despite resolution of the deficiencies documented on the tags.

In response to the inspector's concern identified during the previous inspection period, as documented in Inspection Report 50-315/94014(DRP);50-316/94014(DRP), the licensee performed an audit of all tags located on the control room panels. The audit resulted in the removal of a total of 20 tags from both control rooms due to either corrective action that was completed or ARs that were rejected.

The inspectors reviewed results of the licensee's QA audits and surveillances performed in 1993 and noted that similar discrepancies were documented, including failure to remove AR tags from components in the auxiliary and turbine buildings as well as the control rooms.

During the current inspection period, the inspectors identified two more tags which required removal. On September 26, 1994, the inspectors identified that, although a problem with the Unit 2 turbine-driven auxiliary feedwater (TDAFW) pump trip and throttle valve (T&TV) had been corrected, the tag remained attached to the switch in the control room. Two days later, the inspectors identified a tag that required removal from a local control panel located in the Unit 2 "CD" emergency diesel generator (EDG).

The inspectors were concerned that failure to remove AR tags may inhibit personnel from initiating new ARs when similar equipment problems occur. Also, the failure to remove out-dated AR tags could result in an inaccurate assessment by the reactor operators and others in the plant of the condition of plant components.

Upon further review of this issue, and after identifying more examples during the current inspection period, the inspectors concluded that the licensee was not implementing the requirements of procedures regarding the removal of AR tags. Paragraph 5.2.1.B.4 of "Nuclear Plant Maintenance System Process Instruction," NPM-02CM, Revision 4, requires that all AR tags be removed when the AR is determined to be unacceptable and is rejected during initial review. Paragraph 5.13.3.G of NPM-02CM requires that tags be removed upon successful completion of the corrective maintenance. Failure of the licensee to properly implement the requirements of this procedure is considered a

violation of Technical Specification 6.8.1. (50-315/94018-01(DRP);50-316/94018-01(DRP)).

c. Essential Service Water (ESW) Expansion Joints

The inspectors performed an inspection of the various piping expansion joints in the essential service water pump tunnel after an expansion joint, 2-XJ-74, developed a 100 gallons per minute (gpm) leak on September 14, 1994. The leak in expansion joint, 2-XJ-74, was not safety-significant, because it was installed in the non-essential service water (NESW) return piping from containment ventilation units. However, previously on July 18, 1992, a rupture of an expansion joint caused flooding in the NESW tunnel which caused operators to secure essential service water to both Unit 1 emergency diesel generators (EDGs) until the source of the of the flooding was determined.

In response to the July 18, 1992, event, the licensee identified six expansion joints that were candidates for periodic replacement and planned to replace these during the Unit 1 and Unit 2 1994 refueling outages. The licensee initiated Action Requests (AR) in 1993 to replace these expansion joints during these outages. The inspectors found that most of the expansion joints in the plant had been recently replaced. However, the inspectors identified two expansion joints, 1-XJ-56CD and 2-XJ-56AB, which were not yet replaced. These expansion joints are installed in the ESW return piping from the Unit 1 "CD" and the Unit 2 "AB" EDGs respectively. The inspectors discussed this concern with the system engineer, who performed an independent inspection and found no deteriorating condition with the expansion joint. However, the engineer did initiate ARs A80290 and A80292 to replace the expansion joints, 1-XJ-56 CD and 2-XJ-56 AB respectively.

Based on past expansion joint failures, the licensee's failure to replace these expansion joints, 1-XJ-56CD and 2-XJ-56A, after initiating ARs in 1993 was considered a weakness. The licensee's planned maintenance activities regarding these two expansion joints is considered an Unresolved Item pending further review by the NRC (50-315/94018-03(DRP); 50-316/94018-03(DRP)).

d. Surveillance Activities (61726)

During the inspection period, the inspectors observed technical specification required surveillance testing and verified that testing was performed in accordance with adequate procedures, that test instrumentation was calibrated, that results conformed with technical specifications 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:

- 2 OHP 4030.STP.027AB, "AB Diesel Generator Operability Test," Revision 6
- 1 OHP 4030.STP.018, "Steam Generator Stop Valve Dump Valve Surveillance Test," Revision 11
- 01-OHP 4030 STP.015, Full Length Control Rod Operability Test," Revision 6

One violation was identified. No deviations were identified.

6. Engineering & Technical Support (37700 and 49001)

The inspector monitored engineering and technical support activities at the site including any support from the corporate office. The purpose was to assess the adequacy of these functions in contributing properly to other functions such as operations, maintenance, testing, training, fire protection, and configuration management.

a. Ferrography Program

The inspectors reviewed the licensee's ferrography program as described in plant engineering office guide, PLE.OFF.GDE.023.007, Revision 0, to determine its scope, to what extent it was implemented, and the type of problems being detected by the program. The ferrography program involves wear particle analysis, and is a predictive maintenance tool used by the plant to determine mechanical wear by analyzing lubrication oil.

The licensee had initiated this program because of numerous oil-related problems with the pumps in the auxiliary feedwater (AFW) system. The inspectors had raised concerns with the licensee not being aware of degraded oil conditions for the AFW pumps in previous NRC inspection reports 50-315/93011(DRP); 50-316/93011(DRP), and 50-315/93016(DRP); 50-316/93016(DRP).

The inspectors found that although the licensee had included most safety-related and selected non-safety-related pumps in the program, the oil had not yet been sampled or analyzed for the majority of these pumps. For example, no oil samples had been taken from the safety injection or the service water pumps. However, the inspectors found that for certain equipment, such as the AFW pumps, numerous samples had been taken.

Most pumps in the program had a sampling periodicity of 12 weeks, but some pumps, such as the containment spray and the reactor coolant pumps, had a sampling periodicity of 6 months and every refueling outage respectively. Also, oil from the reactor coolant pumps was already being analyzed under a separate chemistry program.

The inspectors learned that the licensee had initiated job orders to have the oil samples taken for those pumps which have not been sampled to date. At the end of the inspection period, these job orders were in the process of being scheduled. Additionally, the licensee informed the inspectors of their intention to add the residual heat removal pump to the ferrography program.

The inspectors also reviewed selected oil analysis results from the ferrography program. Through this review, and discussion with the responsible engineer, the inspectors found that there were several analyzed oil samples from the Unit 2 "East" AFW pump bearings that were categorized as "critical." The inspectors were initially concerned that the oil samples may indicate a potentially degraded pump condition. The system engineer stated that the Unit 2 "East" AFW pump was operable based on review of the following: the oil data, maintenance history on the pump, vibration and bearing temperature information, and the pump hydraulic performance.

The inspectors also noted that oil analyses which were categorized as "critical" were not always forwarded to the system engineer for review. In addition, the inspectors were concerned that there were no documented engineering evaluations to support the operability determination of pumps with oil analyses categorized as "critical." Discussion with the engineer responsible for the ferrography program indicated that these evaluations were being performed informally.

Although the inspectors were informed by the AFW system engineer that he had requested all oil sample results to be forwarded to him for review in the future, the licensee's ferrography program does not require such actions. Currently, the ferrography program is still being developed and the program description is in the form of an engineering office guide. The licensee intends to document the scope and proposed schedule for full implementation of the ferrography program in November 1994.

The inspector's review of the licensee's progress for implementation of the ferrography program will be an unresolved item (50-315/94018-02(DRP); 50-316/94018-02(DRP)).

b. Erosion/Corrosion Program (49001)

The licensee began their Erosion Corrosion (E/C) program in 1982. In 1986, formalized procedures and administrative controls were established to ensure continued long term implementation of an E/C monitoring program for piping and components. The licensee subsequently implemented the Electric Power Research Institute's (EPRI) CHEC, CHECMATE, CHECNDE computer software programs for control of Erosion/Corrosion in susceptible piping and component systems.

The EPRI CHECWORKS program is in the process of being implemented. CHECWORKS is the most recent upgrade of the EPRI Flow Accelerated Corrosion (FAC) replacing the CHEC-mate, NDE, programs for E/C. This program is compatible with the previous CHEC programs and procedures.

The inspectors reviewed the current revisions of the E/C procedures for selection of components subject to FAC, grid application and inspection technique, evaluation of inspection data, analysis of degraded components for repair, replacement, and re-inspection criteria.

The inspectors observed a visual walkdown of cross-under piping, which exhibited wear in isolated areas. These areas were further examined using ultrasonic examination for thickness. Areas which exhibit high wear rates and excessive wall loss are being repaired by weld cladding with 309L stainless steel material. The licensee previously applied stainless steel welded clad to the cross under piping and no further degradation has been observed in these areas. (Stainless steel is extremely resistant to E/C)

The inspectors also observed the examination of several components using ultrasonic examination with a grid layout procedure and electronic recording data loggers. The examinations are performed in permanently identified areas of the component (GRID) to assure repeatability of the data from inspection to inspection. This is necessary to predict wear rates of the material for reinspection and replacement criteria.

The inspectors reviewed three E/C component inspections (UT) data reports and engineering calculations for remaining life of the respective components and the reinspection schedules as determined by the calculated wear rates. The engineering calculations are performed by the EPRI CHECWORKS computer program and verified by hand calculations prior to the unit returning to service.

Safety related piping whose examination reveals a wall thickness less than the material standard/code minimum wall thickness or a predicted wall thickness of less than the standard/code minimum wall prior to the next refueling outage are evaluated by the Nuclear Design Group for continued operation prior to restart.

The review and observations of the NRC inspector concluded that the licensee's E/C program is implemented in accordance with the EPRI CHECMATE/CHECWORKS, NRC Generic Letter 89-08, Bulletin 87-01, and the licensee's E/C procedures. The E/C examination program appears to be conservatively implemented with a representative number of components inspected each outage. (200 large bore components were scheduled for examination this outage.)

Observations of examinations and review of data analysis determined that the inspection and data processing provided the accuracy and conservatism to prevent catastrophic failure of E/C susceptible piping.

c. Generic Letter 89-10 Issues

The inspectors found that the differential pressure (DP) testing acceptance criteria were being changed to incorporate concerns noted during this and a previous inspection (IR 50-315/94009(DRP); 50-316/94009(DRP)). The licensee was also evaluating methods for incorporating motor-operated valve (MOV) test data into programmatic assumptions by the scheduled program completion date.

Concerns identified in inspection report 50-315/94009(DRP); 50-316/94009(DRP) were:

- The acceptance criteria for VOTES dynamic tests did not ensure that there was adequate margin between torque switch trip (TST) (VOTES point C14) and the extrapolated flow cutoff (C10) to account for torque switch repeatability (TSR) and degradation. With insufficient margin between the torque switch trip setpoint thrust and the thrust observed at the extrapolated flow cutoff point, the MOV may not fully close under design-basis conditions.

- The OATIS test data was not completely evaluated to compare torque switch settings to extrapolated thrust requirements due to the limitations of the data. For those MOVs that were tested at less than full design basis differential pressure, this analysis is necessary in order to determine the ability of the MOV to function at full differential pressure.

The inspectors determined that the licensee was revising the MOV testing acceptance criteria to address the concerns and the planned corrective actions were considered adequate. The licensee was changing the acceptance criteria to evaluate the margin between TST and extrapolated flow cutoff and to ensure that there was adequate margin to account for torque switch repeatability and degradation. However, margins for load sensitive behavior and degradation were applied incorrectly to the overall stem thrust measurement (calculated to determine the acceptance criteria). However, the overall magnitude of these errors was insignificant. The licensee planned to correct the problems noted with the margin calculation.

Additionally, the licensee was evaluating the OATIS data to compare the test results, with appropriate diagnostic equipment inaccuracies, with the assumptions used in the design equations. However, the inspectors concluded that the OATIS data may not

provide an accurate measure of valve performance parameters that could be used to justify the design assumption of valves with smaller margins. The licensee was evaluating methods for incorporating MOV test data into programmatic assumptions by the scheduled program completion date. To address this concern, the licensee was considering performing additional differential pressure testing using the VOTES equipment to measure the various MOV performance characteristics.

The inspectors discussed concerns of a possible delay in completion of the requirements in Generic Letter 89-10. The inspectors stressed the importance of maintaining progress in this area in order to avoid potential operability concerns with MOVs and to ensure timely closure of GL 89-10.

The inspectors will review the licensee's resolution to these concerns in future motor-operated valve inspections.

Two unresolved items were identified. No violations or deviations were identified.

7. Refueling Activities (60710)

During the refueling outage, the inspectors observed the licensee's fuel handling operations and discussed refueling operations with plant operators and fuel handling personnel. The licensee used approved procedures for fuel accountability and movements. Communications between the control room and fuel handlers were established and effective. The inspectors witnessed fuel handling operations during several shifts from the control room, in the fuel building, and in containment.

During this Unit 2 outage, all of the fuel was unloaded from the reactor and moved to the spent fuel pool. The refueling activity was initiated on schedule, completed essentially on schedule, and proceeded with no significant problems.

No violations or deviations were identified.

8. 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 5.c and 6.a.

9. Meetings and Other Activities

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 September 30, 1994. 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.

The licensee agreed to periodically meet with the resident inspectors to discuss the progress of their ferrography program. In addition, the licensee noted that it had assembled a team to investigate the issue regarding the failure to remove the action request tags. The team was in the process of developing a draft report which would include recommendations for preventative actions.