U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-315, 50-316
License Nos:	DPR-58, DPR-74
Report No:	50-315/96006; 50-316/96006
Licensee:	Indiana Michigan Power Company
Facility:	Donald C. Cook Nuclear Generating Plant
Location:	1 Cook Place
Dates:	May 26 - July 13, 1996
Inspectors:	B. L. Bartlett, Senior Resident Inspector D. J. Hartland, Resident Inspector C. N. Orsini, Resident Inspector R. Lerch, Reactor Inspector, RIII
Approved by:	W. J. Kropp, Chief Reactor Projects Branch 3

Executive Summary

D. C. Cook Units 1 and 2
NRC Inspection Report 50-315/96006, 50-316/96006

This integrated inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a 6-week period of resident inspection; in addition, it includes the results of announced inspections and the follow-up to issues identified during an Integrated Performance Assessment documented in inspection report 50-315/316-96003.

Operations

- Operator performance at the controls was observed to be good, with excellent shift turnover, good communications, and professional performance. One exception was noted in the identification of a degraded condition that did not receive a timely operability evaluation (Section O1.2).

- The inspectors observed licensed operator performance during the failure of a controller and determined that there was a prompt and professional response. Good attention to the boards identified the event early, resulting in additional operator response time (Section O4.1).

- Weaknesses were identified in the timeliness of identification and the quality of evaluations regarding operability of plant equipment (Sections E1.1 and E1.2)

Maintenance

- The inspectors found the work performed under these activities to be generally professional and thorough. One exception was the self-identified improperly performed replacement of a fuel rack arm on the Unit 1 CD D/G (Section M1.1).

- The licensee exhibited a conservative approach by deciding to replace a degraded but operable Unit 2 train A Reactor Trip Breaker (RTB). The inspectors also noted that the licensee's planning, coordination, and communications between the different departments was very thorough (M1.2).

Engineering

- Three examples of failure to follow procedure were identified for not performing an operability evaluation of degraded and potentially non-conforming conditions in a timely manner (Sections E1.1.b.1 and E1.2).

- The inspectors review of the licensee's operability evaluations determined that they were generally weak and some were lacking in detail in a number of areas (Section E1.1.b.2).

- The inspectors identified one example of a licensee corrective action program that had been initiated prior to GL 91-18 whose operability determination process had not been modified after GL 91-18 (the Large Bore Piping Reconstitution Program) and this appeared to affect the evaluation of degraded pipe supports identified through other mechanisms (Section E1.1.b.3).

- The inspectors reviewed the D. C. Cook Integrated Performance Assessment (IPAP) - Final Analysis (inspection report 50-315/316-96003), and identified inspection issues documented by the IPAP team. Various paragraphs and comments were given individual item numbers. Those item numbers which rose to the level of violations, unresolved items, or inspector follow up items are so identified in this report (Section E8.2).

Report Details

Summary of Plant Status

Unit 1

Unit 1 began this inspection period at 100 percent power. Reactor power was decreased to 57 percent Reactor Thermal Power (RTP) June 6, 1996 to remove the West Main Feed Pump from service to facilitate steam supply leak repairs. Reactor power was restored to 100 percent RTP June 8, 1996.

Reactor power was decreased to 93 percent RTP June 29, 1996, due to main transformer thermal limitations as a result of increasing ambient temperature conditions. Reactor power was restored to 100 percent RTP on June 30, 1996.

Unit 2

Unit 2 entered and exited this reporting period in Mode 1 at 100 percent RTP. There were no unit shutdowns or significant power reductions.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was professional and safety-conscious; specific events and noteworthy observations are detailed in the sections below. In particular, the inspectors noted the good operator performance during the loss of a pressure controller. Good operator turnover for a relief occurred and good attention to the unit enabled an early identification of the instrument failure.

O1.2 Control Room Observations

a. Inspection Scope (71707)

The inspectors performed routine observations of control room activities, shift relief and turnover, procedural usage and adherence, response to alarms and plant conditions, and supervisory command and control including compliance with the following procedures:

- Operations Department Head Instruction (OHI) - 2000, "Operations Department Guidance Policy".

- OHI - 2211, "Maintenance of Operations Department Logs".
- OHI - 4011, "Conduct of Operations (Shift Staffing)".
- OHI - 4012, "Conduct of Operations (Shift Turnover)".

b. Observations and Findings

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 LCO time restraints, as applicable. Procedural usage and adherence was noted to be good with appropriate questioning of the adequacy of the procedures for use during plant evolutions.

The operators exhibited good teamwork within the shift and were observed to communicate when necessary with other departments to resolve equipment problems. An exception to this good communications is discussed further in paragraph E1.1 and concerned the untimely initiation of an operability evaluation for the leaking Unit 2 West Essential Service Water (ESW) strainer discharge check valve. A leaking check valve was properly identified by an auxiliary equipment operator and an action request was issued, however, an operability evaluation was not requested of engineering.

c. Conclusions

Operators acted and reacted to various plant evolutions in a prompt and professional manner. One example was identified where a degraded condition was not evaluated for operability in a timely manner. This issue is discussed further in section E1.1.

O4 Operator Knowledge and Performance

O4.1 Prompt Operator Response To A Pressure Controller Failure (Unit 2)

a. Inspection Scope (93702)

The inspectors assessed the performance of the licensed operators during the failure of main steam header pressure controller 2-UPC-101. This controller affected the operation of the main feedwater pumps and prompt operator actions were necessary to prevent the unnecessary shutdown of Unit 2.

b. Observations and Findings

On June 13, 1996, Unit 2 was stable at 100 percent RTP. Pressure controller 2-UPC-101 failed low without any warning. This caused the secondary control system to sense a false low steam pressure. As a result a separate controller which compared feedwater pressure to steam pressure then indicate a high differential pressure. This controller

sent a demand signal to the two main feedwater pumps to reduce speed in order to reduce the indicated high differential pressure. As speed was reduced, feedwater flow was reduce resulting in lowering steam generator water levels.

The balance of plant reactor operator had requested a break from the controls and a relief operator took over after a brief turnover. The relief operator observed the drop in steam generator levels prior to the steam generator level deviation annunciators actuating. He announced the unexpected indications to the rest of the control room operators and began checking his panels for possible causes.

The unit supervisor directed the operator to take manual control and then he requested additional assistance from the Unit 1 control room personnel. The control room operators then restored levels and after the pressure controller was repaired, automatic control was re-established.

The inspectors entered the control room and began observations of the operating crew approximately half-way through this event. The inspectors observed:

- Effective command and control was being effected by shift supervision. None of the SROs were at the panel but instead the unit supervisor (US) was several feet behind the ROs providing guidance. The shift supervisor (SS) and the assistant shift supervisor (ASS) were at the US's desk maintaining a broad overview and ensuring that the reactor operators were not distracted.

- Two of the four steam generators did eventually have level deviation alarms annunciate. As directed by the US, the ROs took manual control of the feedwater regulating valves and restored level. This action was promptly and efficiently performed.

- The US and the SS held a crew briefing immediately following the restoration of the level controllers in automatic. The briefing covered:

    - Why two of the steam generators received level deviation alarms and the other two steam generators levels had smaller swings. It was determined that a feedwater regulating valve was operating slowly. An action request was written and subsequently a valve's controller was tuned.

    - The operators discussed any additional actions which might be needed, applicable technical specifications and the sequence of events.

    - A plan of repair was discussed and each crew member was asked for input concerning the event.

c. <u>Conclusions</u>

The operating crew and supervision reacted promptly and professionally to the failure of main steam header pressure controller. Effective monitoring of control panels and good relief turnover were also demonstrated by the operators.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. <u>Inspection Scope (62703)</u>

The inspectors observed all or portions of the following work activities:

- 1-IHP 4030.SMP.111 — Pressurizer Pressure Set 1 Surveillance Test
- 2-IHP 4030.SMP.120 — Steam Generator 2 & 4 Mismatch Channel II Surveillance Test
- 2-OHP 4030.STP.018 — Steam Generator Stop Valve Dump Valve Surveillance Test
- 2-IHP 4030.STP.510 — Train "A" Reactor Protection System and Engineered Safety Features Reactor Trip Breaker and Solid State Protection System Automatic Trip/Actuation Logic Functional Test.
- JO C0036842 — Replace Solenoid for 2-MRV-232
- JO R0059010 — Replace a fuel injection pump on the 1 CD D/G
- JO R0059013 — Replace a fuel injection pump on the 1 CD D/G
- 2-IHP.SP.C36477 — Administrative Control Procedure for Replacement of 2-52-RTA (Unit 2, train A reactor trip breaker).
- AR A0118729 — Unit 2 West ESW pump strainer discharge check valve sticking open.

b. Observations and Findings

The inspectors found the work performed under these activities to be generally professional and thorough. One exception was the self-identified improperly performed replacement of a fuel rack arm on the 1 CD D/G. This resulted in the inability of the D/G to take the 100 percent load requirement. This was self-identified during the post maintenance testing prior to the restoration of the D/G to operable. The worker error was documented in a condition report and the licensee's corrective action will depend on the results of the CR assessment.

c. Conclusions

Maintenance activities were generally completed thoroughly and professionally with the proper procedures at the work site and in active use. One exception was the improper replacement of a fuel rack arm on the 1 CD D/G that prevented the D/G from reaching 100 percent load.

M1.2 Reactor Trip Breaker (RTB) Replacement (Unit 2)

a. Inspection Scope (62703 and 61726)

On June, 10, 1996 while performing monthly surveillance procedure 2-IHP 4030.STP.510, "Train 'A' RPS and ESF Reactor Trip Breaker and SSPS Automatic Trip/Actuation Logic Functional Test," the licensee was unable to close RTB A from the control room. The licensee determined that the inability to close the breaker remotely did not affect breaker operability. The breaker was manually closed and remained in service until June 22, 1996, when the breaker was replaced.

The inspectors reviewed the licensee's basis for operability and observed the initial troubleshooting efforts including the breaker replacement.

b. Observations and Findings

During performance of STP.510, the unit was in a two hour action statement for TS 3.3.2.1 while the reactor trip bypass breaker was closed. When RTB A would not close, the licensee needed to quickly determine the extent of the problem, the effect on breaker operability, and whether or not repairs could be made without exceeding the action statement time limits.

The inspectors verified the licensee's conclusion that the RTB's only safety function was to open on a reactor trip signal. The licensee determined that the problem was limited to the closing circuit, which was electrically isolated from the opening circuit. The breaker was manually closed and verified to open as required. The breaker was then declared operable and the LCO was exited. The inspectors observed troubleshooting activities, assessed the licensee's basis for operability and did not identify any concerns.

Although RTB A remained operable, the licensee wanted to replace the breaker as a conservative measure because the root cause of the problem had not been identified. Due to the time constraints involved with the LCO, and the coordination of several work groups, (Operations, I&C, electrical maintenance, and engineering) the licensee wrote a special procedure, 2-IHP.SP.C36477, "Administrative Control Procedure for Replacement of 2-52-RTA," specifically for this evolution.

The inspectors observed the replacement and associated troubleshooting efforts on June 22, 1996. At this time the problem could not be repeated, and during testing the breaker was successfully closed from the control room. The licensee proceeded with the installation and testing of the replacement breaker within the time constraints of the LCO.

Following removal, the licensee conducted further testing on the malfunctioning breaker to determine the root cause. The inability to close was repeated on an intermittent basis during bench testing. The problem was isolated to the closing control relay which did not fully close on each demand. The relay was scheduled to be replaced and the breaker will be utilized as a spare.

The licensee also determined that the malfunction of the closing control relay was not a generic concern as:

- This particular breaker had been in service since 1982 without exhibiting problems and
- No other breakers on site had exhibited this problem.
- A review of industry experience with similar breakers (Westinghouse DB-50) did not identify similar concerns.

c. <u>Conclusions</u>

The licensee exhibited a conservative approach by deciding to replace RTB A with it degraded but operable. The inspectors also noted that the licensee's planning, coordination, and communications between the different departments was very thorough. This was important due to concerns with TS time constraints and personnel safety, involved with working on the reactor trip equipment.

III. Engineering

E1 Conduct of Engineering

E1.1 Assessment of Operability Evaluations

a. Inspection Scope (37551)

The inspectors reviewed procedures, condition reports (CR), and action requests (AR) to assess the licensee's capability to evaluate degraded and potentially non-conforming conditions. The inspectors intent was to verify that the licensee could ensure that appropriate operability requirements were satisfied.

b. Observations and Findings

The inspectors observed that generally the licensee was able to properly assess identified conditions against license and regulatory requirements to ensure that the licensing basis and operability requirements were maintained. The inspectors also determined that the licensee's timeliness in performing these assessments and the quality of these assessments appeared contrary to NRC Generic Letter (GL) 91-18, "Information To Licensees Regarding Two NRC Manual Sections On Resolution Of Degraded and Nonconforming Conditions And On Operability".

In addition to the guidance contained within GL 91-18 the licensee's procedure for documenting and addressing degraded and potentially non-conforming conditions gives requirements for the timeliness and quality for performing operability evaluations (Plant Managers Instruction (PMI) 7030, "Corrective Action"). PMI-7030 is the licensee's primary mechanism by which degraded and potentially non-conforming conditions are evaluated. PMI-7030 requires the originator to initiate a condition report (CR) for known or suspected adverse conditions or events (step 6.9.a). PMI-7030 also defines an adverse condition/event as "A non-conformance, deficiency, deviation, discrepancy, or adverse trend of items, services and/or administrative systems that, if left uncorrected, could adversely impact safety, quality, or operability" (step 5.1). In step 5.31, PMI-7030 states, in part, "Prompt Operability Determination - This determination must be made expeditiously following identification of a potentially degraded condition that has the potential to impact SSC operability."

Unfortunately these requirements while strong for timeliness were not specific and did not give guidance for the quality of the evaluations. For example the requirements for timeliness were "promptly" or "expeditiously". This can be clear for major issues but was less clear for more subtle problems. The licensee had recognized this due to previous inspector comments and was in the process of revising the ambiguous procedure to add more specific requirements and to give additional guidance for the quality of the operability evaluations. This procedure had not been issued at the close of this inspection. During this assessment period, the licensee gave additional temporary

guidance to plant personnel in form of a standing order in response to the issues identified below (Standing Order 173, issued July 16, 1996).

1) Timeliness Issues

GL 91-18 contained recommendations as to the timeliness of performing prompt operability determinations and for the performance of backup operability determinations. The recommended time for performing an operability determination in GL 91-18 was about 24 hours with a few exceptional cases taking longer. In addition, a recommended timeliness of the technical specification (TS) allowed outage times (AOT) was given for those components covered by the TS.

The following list gives examples of where the licensee exceeded those recommended guidelines:

AR 0118729

The Unit 2 West Essential Service Water (ESW) discharge check valve was leaking-by sufficient to cause reverse pump rotation. The West ESW pump was running and the licensee swapped to the East ESW pump. During the swap over the motor driven discharge valves of the West pump were momentarily open while the East ESW pump was running. During this time an auxiliary equipment operator observed the West pump reverse rotation, which indicated excessive discharge valve leakage and wrote an action request (AR).

This was identified on May 3, 1996, however an operability evaluation was not performed. This was identified when the inspectors requested a copy of the evaluation on July 9, 1996 and it couldn't be located. The licensee subsequently performed an evaluation and the evaluation determined that the ESW system was operable. After a review of the data and discussions with plant personnel, the NRC inspectors agreed with the licensee's determination.

The failure to perform a prompt operability assessment expeditiously following the identification of a potentially degraded condition that had the potential to impact Structure System Component (SSC) operability is a violation of TS 6.8.1. This failure to follow a required procedure is example (b) of Notice of Violation 50-315/316-96006-01.

CR 96-0022

The Unit 1 CD emergency diesel generator (D/G) neutral grounding resistor was identified by licensee personnel to be incorrectly configured (nominally 6 ohms but it was wired such that it was actually 2.3 ohms).

The problem was identified on December 27, 1995, the CR and subsequent prompt operability evaluation were not written until January 5, 1996. The backup operability evaluation was written January 8, 1996. The timeliness of the prompt evaluation was inadequate to meet licensee procedures. The evaluation which was subsequently performed determined that the D/G was still operable. The inspectors review of the quality of the evaluation did not identify any concerns.

The failure to perform a prompt operability assessment expeditiously following the identification of a potentially degraded condition that had the potential to impact Structure System Component (SSC) operability is a violation of TS 6.8.1. This failure to follow a required procedure is example (c) of Notice of Violation 50-315/316-96006-01.

<u>CR 96-0335</u>

With the reactor at full power, hydraulic fluid from the Unit 2 containment jib crane spilled into the reactor cavity during testing. An evaluation was performed which determined that the fluid did not affect the operability of emergency core cooling system.

The spill occurred on March 8, 1996 and the prompt operability evaluation was performed on March 9, 1996. The backup operability evaluation was performed on March 13, 1996. The licensee's procedures for the performance of operability evaluations did not clearly address the timeliness requirements of the backup operability requirements. In the inspectors' opinion the delay until March 13, 1996, to perform the backup operability assessment was excessive but was not a violation.

<u>CR 96-0622</u>

D/G Cam Follower springs were discovered failed during testing of the Unit 2 CD D/G. The licensee determined that the potential failure was applicable to both units. An evaluation was performed which determined that all four D/Gs were operable.

The event occurred on Unit 2 on April 13, 1996. In response to inspector questioning an operability evaluation was again performed and documented on June 25, 1996. Additional inspector questioning resulted in the licensee supplementing the evaluation on June 26, 1996. This issue is discussed in more detail in paragraph E1.2.

The failure to perform a prompt operability assessment expeditiously following the identification of a potentially degraded condition that had the potential to impact Structure

System Component (SSC) operability is a violation of TS 6.8.1. This failure to follow a required procedure is example (a) of Notice of Violation 50-315/316-96006-01.

2) <u>Quality Of Evaluations</u>

The inspectors review of the licensee's operability evaluations determined that they were generally weak and some were lacking detail in a number of areas.

<u>CR 96-1097</u>

Unit 2 West Essential Service Water (ESW) discharge check valve leaking-by sufficient to cause the pump to rotate backwards referenced above as AR 0118729. After the inspectors brought this issue to the licensee's attention CR 96-1097 was written and a prompt operability was performed.

The inspectors reviewed the prompt operability determination contained in the CR and agreed with the licensee's decision that the ESW system was still operable. However, one of the arguments used by the licensee took credit for manual operator action. Specifically the evaluation stated that if the check valve stuck open enough to divert a large amount of flow, the determination took credit for the operators manually closing the train cross-tie valves upon ESW header low pressure annunciation.

This credit for prompt manual operator action in order to restore ESW to operable was inappropriate in that it had not been previously established as part of the licensing review of the plant. The rest of the evaluation supplied appropriate justification that operability was established without taking credit for manual action.

<u>CR 96-0127</u>

With the reactor at full power, the Unit 2 containment jib crane spilled hydraulic fluid into the reactor cavity during testing.

The prompt operability determination relied upon a valid engineering judgement argument, however the backup operability determination also relied upon engineering judgement. Several weeks after the backup operability was performed the licensee performed a reportability determination. The reportability determination was more technical in nature and supported the prompt and backup operability determinations.

A lack of engineering rigor was demonstrated through the reliance on engineering judgement for both the prompt and backup operability evaluations.

CR 96-0472

The Unit 1 AB D/G before and after lube oil pump was found to have its discharge check valve improperly installed such that it would not have closed when needed to prevent reverse flow. This condition was identified while the D/G was inoperable and corrected prior to restoring the D/G to operable. No operability determination was required for operating under this condition, however an operability determination was required in order to determine past operability and thus reportability.

The licensee's prompt operability determination was based strictly on engineering judgement. Normally the backup operability determination would be expected to provide more engineering rigor, however none was performed. There was a reportability determination performed with much more detail than the prompt operability determination concerning the lube oil pump check valve and failure modes, however it too only contained engineering judgement.

A lack of engineering rigor was demonstrated through the reliance on engineering judgement for both the prompt and backup operability evaluations.

CR 96-0335

With the reactor at full power, the Unit 2 containment jib crane spilled hydraulic fluid into the reactor cavity during testing.

Both the prompt and backup operability evaluations utilized only engineering judgement to assess the acceptability of the oil in reactor cavity or the reactor coolant system. The backup operability evaluation assessed post accident environmental conditions but did not address the oil's interaction with nuclear fuel or other internal reactor vessel components.

Following the initiation of the refueling outage several weeks later, the licensee realized that the operability determinations did not address the oil's affects on refueling operations. Another determination was performed which did address refueling operations but it too only relied upon engineering judgement and did not specifically address the oil's affect upon the fuel bundles.

Again, a lack of engineering rigor was demonstrated through the reliance on engineering judgement for both the prompt and backup operability evaluations.

3) <u>Large Bore Piping Reconstitution Program (LBPRP) and The Identification of Degraded Pipe Supports</u>

The inspectors identified one example of a licensee corrective action program that had been initiated prior to GL 91-18 whose operability determination process had not been modified after GL 91-18 (the LBPRP) and this appeared to affect the evaluation of degraded pipe supports identified through other mechanisms.

In the late 1980's licensee and NRC personnel identified situations where as-found piping and piping supports did not meet the original FSAR design requirements. This was documented in NRC inspection reports and licensee documents. The licensee began a program to identify, assess, and where appropriate to correct these deficiencies. The program was committed to and documented in correspondence to the NRC.

In licensee letter AEP:NRC:1100A, issued February 16, 1990, the licensee committed that "When these or similar reviews reveal discrepancies between the as-found and the as-designed condition, an evaluation of the acceptability and reportability of the condition is conducted."

The inspectors determined that the licensee was not in fact performing specific calculations on each identified discrepancy or relying upon bounding calculations but was instead relying upon the results of series of walkdowns in order to assess operability of the supports. The walkdowns had been performed on a sampling basis and any identified discrepancies were evaluated using interim acceptance criteria. The results of these walkdowns were used to justify the operability of safety related piping systems in their existing configurations.

In teleconferences with resident inspectors and Region III personnel, the licensee stated that licensee letter AEP:NRC:1100C, dated March 20, 1995, documented this practice, that NRC had been a party to teleconferences in which this operability practice had been discussed and that NRC inspection reports had accepted this practice. A detailed review of the referenced letter by the resident staff and NRC region III personnel cognizant of this issue identified a reference to results of the sample walkdowns being acceptable, but no statement could be found which stated the licensee's practice of only relying upon the walkdowns for operability determinations of discrepancies. Interviews with NRC piping experts and their management determined that none remembered any such discussions. A review of inspection report (50-315/316-91028) showed that a review of two systems was indeed performed and the licensee's operability determinations were found to be acceptable. However, the review was limited to just those two systems and the acceptability was also limited to just the discrepancies identified on those two systems. No blanket acceptability of the practice of relying upon the walkdown samples was meant or implied. This was confirmed during interviews with the lead NRC inspector for the referenced inspection report.

The LBPRP was discussed previously in inspection report 315/316-95012 and an inspector follow-up item was issued regarding resolution of the licensee's commitment to perform specific reviews (50-315/316-95012-02(DRP)). This item will remain open pending the assessment of the licensee's response to the request for information discussed in the cover letter.

Examples of piping support discrepancy whose operability evaluation appeared not to meet GL 91-18 are discussed below:

<u>CR 96-0395</u>

During a walkdown on March 20, 1996, a U-Bolt on 2-AFW-L944 was found to not conform to the design drawing. The prompt operability determination relied upon AEPSC Guideline 5700-13 which documents the licensee's operability determination practice as discussed above.

<u>CR 94-1124</u>

During an examination of a pipe support for an unrelated reason, on June 6, 1994, support number 2-GC-R39 was found to not conform to the design sketch. The criteria contained within AEPSC Guideline 5700-13 was relied upon for a prompt operability determination.

<u>CR 96-0180</u>

During a walkdown with licensee personnel of the plant, NRC inspectors identified 14 discrepancies on piping supports for various safety related and non-safety related systems. The inspection was documented in report 50-315/316-96003 (IPAP). The LBPRP was not intended by the licensee to address non-safety related systems, but for those safety related support discrepancies identified by the inspectors the licensee relied upon the guidance contained with AEPSC 5700-13. The separate issue of the timeliness of initiating CR 96-0180 is addressed elsewhere in this report as a Notice of Violation.

We were concerned that the operability assessments performed as a part of the LBPRP and support discrepancies identified through other mechanisms did not appear to comply with NRC Generic Letter 91-18. A request for a response concerning the licensee's operability assessments for pipe supports was discussed on the front cover of this report.

c. <u>Conclusions</u>

The licensee generally failed to implement the timeliness guidelines of GL 91-18 for performing operability evaluations. In addition, examples of the quality of the operability evaluations not meeting GL 91-18 were identified concerning piping support discrepancies. A Notice of Violation with three examples was issued for failing to meet licensee

procedural requirements for timeliness. A request for information concerning the apparent lack of piping supports to meet Gl 91-18 requirements was issued.

E1.2 Issuance of A Report Required by 10 CFR Part 21 - Both Units

a. Inspection Scope (37551)

The inspectors performed routine followup activities in response to a licensee issued report required by 10 CFR Part 21. The inspectors independently assessed the licensee's operability assessment for the emergency diesel generators and the details contained within the Part 21 report.

b. Observations and Findings

Initial Identification of Failed Component

On June 20, 1996, at 9:45 am EDT the licensee called the NRC Headquarters Operations Officer via the Emergency Notification System and made a report as required by 10 CFR Part 21. The licensee reported that a failure of the emergency diesel generator (D/G) cam follower spring which occurred on April 13, 1996, represented a substantial safety defect and was reportable under 10 CFR Part 21.

On April 13, 1996, Unit 2 was in a refueling outage with the reactor defueled. While troubleshooting for a speed control problem on the 2 CD engine a loud knocking was heard. During followup to that knocking the licensee discovered that one cylinder had a failure of its cam follower spring. The licensee performed appropriate followup activities and identified one other broken spring on the 2 CD D/G.

One of the two broken springs resulted in its associated cylinder in not being able to produce power. The other broken spring was not as severely damaged and its cylinder was still able to produce power.

Licensee's Initial Root Cause Analysis and Corrective Actions

The licensee performed acoustic monitoring of the cylinders on the other three D/Gs (two on Unit 1 and the other one on Unit 2) and did not identify any other failed springs. One spring on the 2 AB D/G was removed and inspected in response to noise on one cylinder, however, no problems were identified.

The licensee had also observed that the set screws for the spring cover plate had been found loose on the spring first identified as failed and ensured that the other three D/Gs had tight setscrews.

Licensee management had discussed with the inspectors their bases for three D/Gs being operable following the April 13, 1996, failure. This basis for operability included all the information discussed previously in this section. The 2 CD D/G was repaired and tested prior to being declared operable. The inspectors had no significant concerns with the licensee's discussion on their basis for operability.

Issuance of A Report Required By 10 CFR Part 21

The licensee determined that the D/G spring failure met Part 21 reporting requirements on June 19, 1996. The report was made on June 20, 1996. This met the two day reporting requirements of Part 21. The narrative appeared to meet the reporting requirements, however it did fail to supply important, pertinent information. For example the report:

- Failed to discuss the basis for reportability (it represented a substantial safety hazard).

- Failed to discuss the past and current operability of the four D/Gs in detail sufficient to inform the reader of the present operability status of the D/Gs.

Failure to Document The Basis For Operability

Following the issuance of the 10 CFR Part 21 report discussed above, the inspectors attempted to review the licensee's basis for operability for the other three D/Gs. This review was to ensure that no new information was revealed in the Part 21 which invalidated the previous basis for operability. The licensee's requirements for performing operability evaluations was implemented through Plant Managers Instruction (PMI)-7030, "Corrective Action" as was discussed in E1.1.

CR 96-0622 was written on April 17, 1996, to document the failure of the 2 CD D/G cam follower springs. This CR did not contain a prompt operability determination required in PMI-7030 as it only addressed 2 CD D/G and it had been declared inoperable for maintenance (thus it wasn't required to be operable). However the inspectors could not locate any documented operability evaluation for the other D/Gs. Subsequently the licensee confirmed that no operability evaluation had been documented.

The licensee was required to perform and document a prompt operability evaluation for the remaining three D/Gs following the spring failure on April 13, 1996. The licensee's failure to comply with PMI-7030 is a violation (example (a) of 50-315/316-96006-01(DRP)) (this violation is also discussed in paragraph E1.1.b.1 above).

c. Conclusions

The licensee's Part 21 report was accurate but lacked certain desired information. The licensee failed to ensure that an operability evaluation was documented however this issue was address in E1.1 above.

E8 Miscellaneous Engineering Issues (92902)

E8.1 <u>(Closed) Inspector Follow-up Item 50-316/93020-02:</u> Loss of turbine driven auxiliary feedwater (TDAFW) pump flow retention due to inaccurate flow measurements. This item concerned the fact that the flow sensing device which initiated a flow retention signal for the Unit 2 TDAFW pump was reading only 78 percent of actual flow. The instrument inaccuracy was corrected by a modification, installed in 1994, which moved the flow orifice to a straight run of piping. This modification eliminated oscillations and turbulence across the orifice which resulted in more accurate flow measurements. The inspector reviewed the licensee's post modification tests to ensure that the flow instruments that initiated a flow retention signal were accurately indicating actual flow rates. This item is closed.

E8.2 <u>(Open) Integrated Performance Assessment Program (IPAP) Issues</u>

The inspectors reviewed the D. C. Cook Integrated Performance Assessment (IPAP) - Final Analysis (NRC Inspection Report Nos. 50-315/316-96003), and identified inspection issues documented by the IPAP team. Various paragraphs and comments were given individual item numbers. Those item numbers which rose to the level of violations, unresolved items, or inspector follow up items are so identified in the below list. Some items concerned issues that were either the same item or were similar in nature. Those issues are referenced whenever possible in the list of items below. It should be noted that the section numbers referenced below are the section numbers from inspection report 50-315/316-96003 and are not from this inspection report.

<u>Item No.</u>

01 Condition reports (CRs) were either not initiated or not done so in a timely manner. (Section 1.1, "Safety Assessment and Corrective Action") Untimely identification and resolution of conditions adverse to quality is a violation of 10 CFR 50, Appendix B, Criterion XVI "Corrective Action." (50-315/316-96006-02) Specific examples are addressed in other items below.

Three examples were given; these and others are addressed in more detail later in the report:

01A A CR was initiated 4 days after the team and the system engineer identified possible auxiliary feedwater system piping support deficiencies. (Section 1.1) See item 62.

01B A CR was not initiated when licensee identified that boric acid heat trace instrumentation, used to verify compliance with TS surveillance requirements, was not included in plant calibration program. (Section 1.1) See item 44.

01C A CR was not initiated when foreign material was found in interior of feedwater heater level control valve 2-HRV-651 during maintenance of the valve. (Section 1.1) See item 60.

02 Documented operability determinations were delayed. (Section 1.1) See paragraph E.1.1.b.1 of this report.

03 QA audits and surveillance findings appeared to be programmatic in nature and fairly narrow in scope. (Section 1.1) This issue and item 12 are an IFI. (50-315/316-96006-04)

04 CR causal determinations associated with issues not requiring a formal root cause evaluation were narrowly focused, did not address potential generic aspects, and contributed to inadequate corrective actions. (Section 1.2) See items 07 and 08.

05 A large number of CRs were assigned to generic root cause categories, which resulted in little trending value. (Section 1.2) This issue is an IFI. (50-315/316-96006-05)

06 Ferrography identified by lab analysis, (EDG) governor oil sample marginal due to high particulate count. Subsequently, the governor failed due to contaminants in oil. (Section 1.2) See item 77.

07 Corrective actions taken in response to identified plant problems were not always effective. Problems recurred due to inadequate and/or timely follow-up corrective actions. (Section 1.3) This is a violation of 10 CFR 50 Appendix B, Criterion XVI, "Corrective Action." (50-315/316-96006-02) This includes item 08 below. The specific examples are addressed in other items.

08 Corrective actions tended to be narrowly focused. (Section 1.3) This is a portion of the issue identified in item 07.

09 Repeated Component Cooling Water pump discharge check valve slamming events due to failure to install vendor recommended stop plates. (Section 1.3) See item 48.

10 Unit 2 reactor/turbine trip due to actuation of moisture separator reheater high level switch. Root cause not determined. (Section 1.3) This issue was reviewed in inspection report 50-315/316-95010.

11 Numerous foreign material exclusion control related issues. (Section 1.3 and 2.2) The specific issues were reviewed in inspections reports. See item 75 for the general issue.

12 Line organization responses to QA findings tended to be program oriented and narrowly focused. (Section 1.3) See item 03.

13 The team noted lack of programmatic controls that would preclude subsequent revision or elimination of the corrective actions by the line organization. (Section 1.3) This issue is an IFI. (50-315/316-96006-06).

14 Corrective actions associated with rework CRs were narrow in scope. Root cause was not effectively determined in several cases and corrective actions to prevent recurrences appeared inadequate. (Section 1.3) See item 67.

15 Licensee's response to NRC generic communications were narrowly focused, and relied upon actions already in place. Licensee did not fully address the issues. (Section 1.3) This issue is an IFI. (50-315/316-96006-07)

16 NRC Generic Letter 91-18 provided specific guidance for determining operability of piping with degraded supports. The licensee did not incorporate any of the GL 's specific guidance into existing programs. (Section 1.3) This issue is discussed in section E.1.1.b.3 of this report and is being tracked by IFI 50-315/316-95012-02.

OPERATIONS

17 Inconsistencies between the functioning of the five operating crews were noted. (Section 2.1) This issue is an IFI. (50-315/316-96006-08)

18 Administrative activities were distracting shift supervision from their oversight responsibilities. (Section 2.1) This issue is an IFI. (50-315/316-96006-09)

19 Technical operating guidance was promulgated to shift supervisors without indication that it had operations management approval for implementation. (Section 2.1) This issue is an IFI. (50-315/316-96006-10)

20 Lack of a questioning attitude was observed in some operators. (Section 2.1) This was based on limited observations by the team, and is an element normally reviewed during routine operations inspections. No further tracking is required.

21 Elevated EDG lube oil temperatures were identified in an August 1994 QA audit, but had not been effectively corrected. (Section 2.1) See item 03.

22 Cumbersome nature of the work control system did not facilitate effective control of the status of other equipment. (Section 2.1) This issue is an IFI. (50-315/316-96006-11) See items 34 and 55.

23 Operations management and supervision rarely used QA assessment or trend results. (Section 2.2) See items 03 and 05 regarding the weaknesses in QA assessments and corrective action trending.

24 Correction of some longstanding deficiencies such as procedure inadequacies, work practices, and equipment clearance errors was ineffective. (Section 2.2) The licensee's action to address these concerns will be tracked under their response to violation 50-315/316-96006-02. Specific examples are addressed in other items of this report.

25 Despite procedure changes, performance problems with inadequate control of Reactor Coolant System draining. (Section 2.2) This issue is an IFI. (50-315/316-96006-12)

26 Instances of operators' not responding promptly to alarms. (Section 2.3) This was based on limited observations by the team, and is an element normally reviewed during routine operations inspections. No further tracking is required.

27 Weaknesses in system knowledge in a few operators. (Section 2.3) This issue was addressed in the inspection report reviews of specific events and was a comment on minor discrepancies observed by the team.

28 Observation of new fuel receipt and inspection revealed instances of weak work practices. (Section 2.3) This issue is an IFI. (50-315/316-96006-13)

29 Recent inspection reports and the team's observations indicated that coordination and communication with other site groups was often ineffective. (Section 2.3) This is an element normally reviewed during routine operations inspections. No further tracking is required.

30 Many normal operating and surveillance procedures were of lesser quality. (Section 2.4) See items 31 and 33.

31 The overall quality of administrative procedures also varied greatly. (Section 2.4) See items 30 and 33.

32 Poor corrective action was taken in response to problems with poor procedures. (Section 2.4) The role of specific procedures in specific events was reviewed in inspection reports. This issue is another example of lack of adequate corrective action which was a violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action." addressed with specific examples in other items of this report.

33 Slowed implementation of procedural improvements. (Section 2.4) Items 30, 31, and 33 are an IFI. (50-315/316-96006-14)

34 Both the work control and the clearance control processes were cumbersome, imposing a burden on the unit supervisors. (Section 2.4) See item 22.

35 Cryptic equipment nomenclature made work schedule readability difficult (i.e., poor human factoring). (Section 2.4) See item 22.

36 Scheduling system did not easily support adjusting work activity schedules if difficulties arose with a job. (Section 2.4) See item 22.

37 Unit supervisors' administrative burden was increased with multiple work schedules containing similar information. (Section 2.4) See item 22.

ENGINEERING

38 Management involvement was not evident in the handling of deficiencies identified by the "As Found Reportable" (AFR) program. (Section 3.1) This issue is related to the effectiveness of the corrective action process addressed in item 07 and violation 50-315/316-96006-02.

39 Management involvement was not evident in the handling of operability/reportability of the auxiliary feedwater (AFW) pump instantaneous overcurrent trips. (Section 3.1) This issue is related to the effectiveness of corrective actions addressed in item 07 and violation 50-315/316-96006-02.

40 The "As Found Reportable" program was intended to identify Technical Specifications related instruments not in the calibration program. At some date prior to January 1996, the licensee had identified that TS-related boric acid system temperature instruments were not in the calibration program and, as of February 5, 1996, a condition report (CR) had not been written. (Section 3.1) Once this was noted by inspectors, a condition report was not initiated until two days later. Failure to enter this deficiency in the corrective action program was an example of a violation of 10 CFR 50, Appendix B, criterion XVI. "Corrective Action." which required that conditions adverse to quality promptly identified and corrected. (example (a) of 50-315/316-96006-02)

41 In two instances, the Corrective Action Group (CAG) incorrectly designated CR 95-1204 for the safety-related motor-driven auxiliary feedwater pump (MDAFW) motor as not safety related. (Section 3.1) This issue is addressed with item 42.

42 Inspection report 50-315/316-95010 section 3.5 identified that the Unit 1 west motor-driven auxiliary feedwater pump (MDAFWP) had a history of instantaneous overcurrent trips. The IPAP team noted that the overcurrent protection circuit tripped the pump within the design operating range of the bus voltage, thus there was a possibility for the pump to trip at any time when required to start, during normal operation or an accident condition. (Section 3.1) Only one pump of three (another 50 percent capacity motor-driven pump and a 100% capacity turbine-driven pump) was affected by the pump trip point at approximately 4285 volts on a nominally rated 4160 volt bus. The effect of this condition on pump and system operability is an unresolved item (50-315/96006-15) pending further NRC review.

43 Delayed and narrow-focused use of the condition reporting process to identify/capture problems was considered a weakness. Example:CRs relating to a CCW system temporary modification (TM). (Section 3.2) See items 07 and 51.

44 The licensee did not promptly initiate condition reports to document the various problems, (ie) CRs written for boric acid system high temperatures and uncalibrated instrumentation were written two days after the issue were identified. (Section 3.2) The timeliness of documented operability determinations was also influencing and influenced by the timing of CR initiations. It appeared that the initiation of a CR was being delayed until a formal documented operability determination could be prepared, leaving the immediate operability issue unaddressed in the interim. Prompt identification of a condition adverse to quality was a requirement of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," which stated, in part, that conditions adverse to quality are to be promptly identified and corrected. The failure to initiate corrective action in the past and to promptly initiate a condition report once these issues were identified by the inspectors were examples of a violation of 10 CFR 50 Appendix B (50-315/316-96006-02). The issue of the uncalibrated boric acid system temperature instruments is addressed in item 40. The high temperature issue is addressed in item 45.

45 A condition report for the boric acid system high heat trace temperatures adverse condition had not been written by operations or engineering until two days after inspectors questioned the system status. The high temperature alarm condition of the temperature instruments could have been identified on previous periodic operator rounds. (Section 3.2) Failure to take prompt corrective action for a condition adverse to quality was an example of a violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," which required that conditions adverse to quality be promptly identified and corrected. (example (c) of 50-315/316-96006-02)

46 Unit 1 CCW flow balance surveillance did not meet the Updated Final Safety Analysis Report (UFSAR) 240 gpm minimum flows listed on UFSAR table 9.5-2 for sample coolers. (Section 3.2) The Unit 1 flow balance procedure EHP 4030 STO.248 completed on 9/28/95 listed an objective to achieve 195 gpm flow to the sample coolers. The recorded combined flows of sample coolers and the blowdown cooler flow was 142 gpm. This item is an IFI (50-315/316-96006-03).

47 Weaknesses were also noted in the area of problem resolution. Several recurring issues were not resolved in a timely manner. (Section 3.2) The specific issues have been reviewed in previous inspection report 50-315/316-95010. No additional inspector follow-up action was required.

48 CCW check valve slamming root cause not addressed. Failure to resolve the slamming issue in a timely manner and failure to address the implementation of vendor recommendations were considered to be a weakness with the licensee's resolution of the check valve slamming

issue. (Section 3.2) This issue was addressed in NRC inspection report 50-315/316-95010.

49 Motor Driven AFW Pump instantaneous over current trips narrowly addressed. The narrow scope of the corrective actions was considered a weakness in the resolution of this issue. (Section 3.2) See item 42.

50 The inspectors reviewed the licensee's operability determination for high temperatures on the boric acid system. Based on missing temperature profile data, missing NPSH calculations, a lack of basis for adequate pressure in the line to prevent boiling and the lack of discussion of the high temperature effect on the process fluid, the operability determination was considered to be inadequate. (Section 3.3) The inspectors concluded that the system was operable; no further inspector follow-up action is required. The quality of the licensee's operability determinations is discussed further in section E.1.1.b.2 of this report.

51 Inspectors reviewed the installation of a "Cosmos" system analysis apparatus controlled by a CCW system temporary modification (TM). Several deficiencies were identified with the TM. (Section 3.3)

- The safety evaluation failed to address the effect of flow through the equipment on the overall CCW flow balance. Flow balance values were listed in the UFSAR. The TM redirected approximately 10 gpm from the other sample coolers including post-accident sample stations. The total CCW flow to the sample coolers was already less than described in the UFSAR. See item 46.

- The use of tygon tubing connections was not specified in the TM and its design requirements were not evaluated. The licensee initiated CR 96-0179 for this issue. The tubing was replaced with tubing of a higher pressure/temperature rating. No further action was required, the safety evaluation did address the potential consequences of a leak.

- Review by the Plant Nuclear Safety Review Committee (PNSRC) was marked "N/A" although requirements specified that when a procedure was initiated which had a full safety evaluation, PNSRC review was required. The licensee initiated condition report CR 96-0210 and issued revision 2 to procedure PMP 1040.SES.001 to clarify the requirements for PNSRC reviews. No further action was required.

- Following installation, but prior to placing a TM in operation, the completed package was required to be returned to the control room and placed in the TM log. The unit had been in service for about 30 days, however, the package had not been returned to the control room, and operators were not aware that the unit was in service. This did not meet the requirements of the temporary modification procedure PMP 5040 MOD.001; however, no condition report was written to address this issue. This was

another example of a violation of 10 CFR Appendix B for the prompt identification and correction for a condition adverse to quality. (50-315/316-96006-02)

52 Some weaknesses were noted in that system engineers were not reviewing work requests. (Section 3.4) This was a comment on engineering performance which may be reviewed under normal inspection activities. No further follow-up tracking required.

53 Other programs that warranted further review included post maintenance testing which was to receive substantially reduced engineering review beginning in April 1996, ferrography (lube analysis) program which was not fully established at the time of the onsite assessment, and the backlog of modification package indicated in the performance trend report. (Section 3.4) Post maintenance testing was addressed in violation 50-315/95009-03. The implementation of the ferrography program was addressed under IFI 50-315/94018-02. The backlog of modification packages is an IFI (50-315/316-96006-16).

54 The team noted few self assessment activities were ongoing or planned in the engineering area. (Section 3.4) This was a comment on engineering performance which may be reviewed under normal inspection activities. No further follow-up tracking required.

55 Boric Acid surveillance procedure 12 OHP 4030.STP.023 was considered weak because it did not provide acceptance criteria for maximum system temperatures or guidance on what to do. (Section 3.4) This issue is an IFI. (50-315/316-96006-17)

56 CCW flow balance surveillance, I-EHP 4030 STP.248 was considered to be weak because the "Acceptance Criteria" data sheet did not contain the sample coolers and the data sheets did not list acceptance criteria. (Section 3.4) See item 46.

<u>MAINTENANCE</u>

57 Voluntary LCO entries frequently exceeded their estimated time for the system to be returned to service. (Section 4.1) This issue was covered under URI 50-315/316-94022-02.

58 The corrective maintenance work backlog had steadily risen and had approximately doubled since March 1995. (Section 4.1) This was a comment on the performance of maintenance which may be reviewed under normal inspection activities. No further follow-up tracking required.

59 The time for "completion of a priority 30" maintenance activity had increased significantly. (Section 4.1) This was a comment on the performance of maintenance which may be reviewed under normal inspection activities. No further follow-up tracking required.

60 The team was concerned with the licensee's failure to recognize the need to initiate a condition report to evaluate the as-found damage of secondary valve 2-HRV-651 internals and the presence of foreign material in the system. (Section 4.2) This is another example of weakness in reporting conditions as discussed in item 44.

61 Equipment had been returned to service without an evaluation of the foreign material in the system. (Section 4.2) See item 75.

62 Piping support deficiencies. The team considered the licensee's failure to recognize the need to promptly initiate condition reports to be a weakness. (Section 4.2) This issue is another example of the issue discussed in item 44 and is considered a violation of licensee procedures (example (b) of 50-315/316-96006-02).

63 The team was concerned with the licensee's timely completion of operability determinations. (Section 4.2) This issue was discussed in item 44.

64 The maintenance department was not effective at preventing the recurrence of previously identified deficiencies. (Section 4.2) See item 7.

65 The team identified a rework condition on the turbine room sump pump, 12-PP-25-1, that had not been identified by the licensee. (Section 4.2) See item 66.

66 Weaknesses existed in the licensee's process for identifying rework. (Section 4.2) This issue is an IFI. (50-315/316-96006-18)

67 The majority of condition reports written for rework were narrow in scope and were not effective at determining the root cause for the rework or identifying appropriate preventive actions. (Section 4.2) See item 66.

68 Maintenance department self-evaluations were programmatic and were not in-depth or critical. (Section 4.2) This was a comment on the performance of maintenance which may be reviewed under normal inspection activities. No further follow-up tracking required.

69 The team was concerned with the licensee's apparently high threshold for the identification of material condition problems. (Section 4.3) See item 44.

70 The team was concerned with the licensee's lack of timeliness with initiating condition reports when appropriate. (Section 4.3) See item 44.

71 U-1 W centrifugal charging pump was found to be inoperable from March 15, 1996 through September 12, 1995. (Section 4.4) This item was addressed in violation 50-315/95014-01.

72 U-1 main transformer was damaged on July 16, 1995, due to the improper installation of a main generator voltage potentiometer. (Section 4.4) This issue was previously discussed in NRC inspection report 50-315/316-95009. No further review is required.

73 U-1 East motor driven auxiliary feedwater pump was damaged on December 30, 1994, as a result of inadequate maintenance. (Section 4.4) This item was tracked by LER 94015.

74 The team was concerned that licensee management appeared not to have recognized commonalities between the causes for the events discussed in items 71, 72, and 73. This issue will be addressed in item 71, in response to violation 50-315/95014-01.(Section 4.4)

75 The foreign material exclusion practices was considered a weakness. (Section 4.4) This issue is an IFI. (50-315/316-96006-19) See item 61.

76 The licensee failed to replace EDG quick exhaust valve diaphragms at the scheduled interval. (Section 4.5) This issue is an IFI. (50-315/316-96006-20)

77 The team considered the ferrography program ineffective.4.5 This issue was tracked by URI 94-018-02 which is here re-designated as an IFI.

78 Procedural adherence or inadequate maintenance procedures were identified as contributing causes to equipment failures by both the NRC and the licensee. (Section 4.5) This issue is an IFI. (50-315/316-96006-21) See item 74.

PLANT SUPPORT

79 Inadequate management involvement to address the number of unnecessary alarms. (Section 5.1) This issue was reviewed in inspection report 50-315/316-96004 under open item IFI 50-315/316-95012-03

80 The PASS continued to have material condition deficiencies.(Section 5.2) This issue was reviewed further in inspection report 50-315/316-96004.

81 PASS QC records revealed significant weaknesses in the program implementation. (Section 5.2) This issue was further reviewed in inspection report 50-315/316-96004 and a violation 50-315/316-96004-02 was issued.

82 Weaknesses were evident in the chemistry staff's ability to identify and resolve performance issues. (Section 5.2) This issue was further reviewed in inspection report 50-315/316-96004 and a violation 50-315/316-96004-02 was issued.

83 1995 exercise weakness (verbal communication). Indicating a lack of issue resolution. (Section 5.2) This issue was further reviewed in inspection report 50-315/316-96004 under open item IFI 50-315/316-95007-02.

84 Improper donning of protective clothing. (Section 5.3) The report identified isolated occurrences noted as an indicator of level of performance. Additional inspection of this area was documented in inspection report 50-315/316-96004.

85 Chemistry technicians (CTs) did not perform radiation surveys of reactor coolant system (RCS) samples or sample areas during routine sampling. The reliance of an ED as a survey instrument was considered a weakness. (Section 5.3) This issue is an IFI. (50-315/316-96006-22)

86 Boron samples (November and December 1995) required by PASS QC procedures were discarded by the chemistry department before their analyses. (Section 5.3) This issue was further reviewed and violation 50-315/316-96004-02a was issued.

87 Boron analytical comparisons for September 1995 were not properly documented. (Section 5.3) This issue was further reviewed and violation 50-315/316-96004-02a was issued.

88 The licensee failed to take required action when the acceptance criteria in 12 THP 6020 PAS.016 were not met. (Section 5.3) This issue was further reviewed and violation 50-315/316-96004-02b was issued.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

*A. Blind, Site Vice President
*K. Baker, Assistant Plant Manager
*D. Noble, Radiation Protection Superintendent
*T. Postlewait, Site Engineering Support Manager
*L. VanGinhoven, Material Management Department
*J. Allard, Maintenance Superintendent
*B. Gillespie, Operations Superintendent
*M. Mierau, Operations - Shift Technical Advisor Supervisor
*P. Schoepf, Supervisor, Safety Related Systems
*D. Morey, Chemistry Superintendent
*J. Kobyra, Manager Nuclear Engineering
*C. Freer, Scheduling
*M. Depuydt, Licensing
*T. Quaka, Project Management & Inst. Services
*A. Barker, Plant Performance Assurance
*P. Russell, Plant Protection

INSPECTION PROCEDURES USED

IP 37551	On-site Engineering
IP 61726	Surveillance Observations
IP 62703	Maintenance Observation
IP 71707	Plant Operations

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-315/316-96006-01	VIO	Failure to perform a prompt operability assessment
50-315/316-96006-02	VIO	Failure to identify 10CFR50 Appendix B Criterion XVI "corrective actions" in a prompt manner.
50-315/316-96006-03	IFI	No written 10 CFR 50.59 evaluation.
50-315/316-96006-04	IFI	QA audit and surveillance findings appeared to be programmatic and narrow in scope.
50-315/316-96006-05	IFI	A large number of CR's were assigned generic root cause categories, therefore of little trending value.
50-315/316-96006-06	IFI	No programmatic control to preclude revisions or elimination of corrective actions.

50-315/316-96006-07	IFI	Responses to NRC generic communications was narrowly focused and did not fully address the issues.
50-315/316-96006-08	IFI	The operating crews did not function the same.
50-315/316-96006-09	IFI	Administrative activities were distracting shift supervision from their oversight responsibilities.
50-315/316-96006-10	IFI	Technical operating guidance was promulgated to shift supervisors without indication that it had operations management approval for implementation.
50-315/316-96006-11	IFI	Cumbersome nature of the work control system did not facilitate effective control of the status of other equipment.
50-315/316-96006-12	IFI	Despite procedure changes, performance problems with inadequate control of Reactor Coolant System draining.
50-315/316-96006-13	IFI	Observation of new fuel receipt and inspection revealed instances of weak work practices.
50-315/316-96006-14	IFI	Slowed implementation of procedural improvements.
50-315/316-96006-16	IFI	Post maintenance testing which was to receive substantially reduced engineering review beginning in April 1996, ferrography (lube analysis) program which was not fully established at the time of the onsite assessment, and the backlog of modification packages in the performance trend report.
50-315/316-96006-17	IFI	Boric Acid surveillance procedure 12 OHP 4030.STP.023 was considered weak because it did not provide acceptance criteria for maximum system temperatures or guidance on what to do.
50-315/316-96006-18	IFI	Weaknesses existed in the licensee's process for identifying rework.
50-315/316-96006-19	IFI	The foreign material exclusion practices was considered a weakness.
50-315/316-96006-20	IFI	The licensee failed to replace EDG quick exhaust valve diaphragms at the scheduled interval.

50-315/316-96006-21	IFI	Procedural adherence or inadequate maintenance procedures were identified as contributing causes to equipment failures by both the NRC and the licensee.
50-315/316-96006-22	IFI	The reliance of an ED as a survey instrument was considered a weakness.
50-315/94-018-02	IFI	URI (same number) re-designated as a IFI.

<u>Closed</u>

50-316/93020-02	IFI	Loss of turbine driven auxiliary feedwater(TDAFW) pump flow retention due to inaccurate flow measurements.

<u>DISCUSSED</u>

50-315/96006-15	UDI	Inspection report 50-315/316-95010 section 3.5 identified that the Unit 1 west motor-driven auxiliary feedwater pump (MDAFWP) had a history of instantaneous overcurrent trips. The IPAP team noted that the overcurrent protection circuit tripped the pump within the design operating range of the bus voltage, thus there was a possibility for the pump to trip at any time when required to start, during normal operation or an accident condition.