May 9, 2000

Mr. R. P. Powers
Senior Vice President
Nuclear Generation Group
American Electric Power Company
500 Circle Drive
Buchanan, MI 49107-1395

SUBJECT: REVIEW OF FOUR PRELIMINARY ACCIDENT SEQUENCE PRECURSOR ANALYSES OF OPERATIONAL EVENTS AT D. C. COOK NUCLEAR PLANT

Dear Mr. Powers:

By letters dated August 12 and November 9, 1999, the NRC transmitted the draft preliminary results of an analysis of the significance of issues that were identified at D. C. Cook Nuclear Plant, Units 1 and 2, between August 1997 and January 1999. By letter dated September 27, 1999, the NRC transmitted a preliminary Accident Sequence Precursor (ASP) analysis of an operational condition which was discovered at D. C. Cook Nuclear Plant, Units 1 and 2 on July 15, 1998. The analysis is being performed to support our ongoing ASP analysis program, which evaluates operational events at nuclear power plants to determine the risk-significance of events or conditions. This analysis is consistent with the new reactor oversight process for analyzing the safety significance of inspection findings.

Enclosed for your review and comment are copies of four preliminary ASP analyses of operational conditions which were discovered at D. C. Cook Nuclear Plant, Units 1 and 2 (Attachments 1 through 4) during the 1999 calendar year. These conditions were reported in Licensee Event Reports (LERs), NRC inspection reports and a licensee condition report. The results of our preliminary analyses indicate that these conditions may be precursors for 1999.

In assessing operational events, an effort was made to make the ASP models as realistic as possible regarding the specific features and response of a given plant to various accident sequence initiators. We realize that licensees may have additional systems and emergency procedures, or other features at their plants that might affect the analysis. Therefore, we are providing you an opportunity to review and comment on the technical adequacy of each preliminary ASP analysis, including the depiction of plant equipment and equipment capabilities. Upon receipt and evaluation of your comments, we will revise the conditional core damage probability calculations where necessary to consider the specific information you have provided. The object of the review process is to provide as realistic an analysis of the significance of each event as possible.

In order for us to incorporate your comments, perform any required reanalysis, and prepare the final report of our analyses of these events in a timely manner, you are requested to complete your review and to provide any comments within 60 calendar days of receipt of this letter. We have streamlined the ASP Program with the objective of significantly improving the time after an event in which the final precursor analysis of the condition is made publicly available. As soon as our final analyses of these conditions have been completed, we will provide for your information the final precursor analyses of the conditions and the resolution of your comments.

We have also enclosed several items to facilitate your review. Attachment 5 contains specific guidance for performing the requested review, identifies the criteria which we will apply to determine whether any credit should be given in the analysis for the use of licensee-identified additional equipment or specific actions in recovering from the event, and describes the specific information that you should provide to support such a claim. Attachments 6 through 10 are copies of the LERs, NRC inspection reports, and the licensee conditions report, which documented the conditions.

In May 2000, we will provide you with the draft preliminary results of individual and integrated analyses of the significance of the 141 issues that were identified at D. C. Cook Nuclear Plant, Units 1 and 2, between August 1997 and December 1999.

Please contact me at (630) 829-9700 if you have any questions regarding this request. This request is covered by the existing OMB clearance number (3150-0104) for NRC staff follow up review of events documented in LERs. Your response to this request is voluntary and does not constitute a licensing requirement.

Sincerely,

/RA/

John A. Grobe, Director
Division of Reactor Safety

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

Attachments:
1. Preliminary ASP analysis: "Lack of Procedure For Manually Backwashing the ESW Pump Discharge Strainers."
2. Preliminary ASP analysis: "High Energy Line Break Programmatic Inadequacies Result in Unanalyzed Conditions."
3. Preliminary ASP analysis: "Valve Required to Operate Post-Accident Could Fail to Open Due to Pressure Locking/Thermal Binding."
4. Preliminary ASP Analysis: "Potential Seismic Deficiencies (Block Wall)."
5. Guidance For Licensee Review of Preliminary ASP Analysis.
6. LER 315/99-026, "High Energy Line Break Programmatic Inadequacies Result in Unanalyzed Conditions," November 19, 1999.
7. LER 315/99-031, "Interim–Valves Required to Operate Post-Accident Could Fail to Open Due to Pressure Locking/Thermal Binding," January 31, 2000.
8. NRC Inspection Report 50-315/97-024; 50-316/97-024, dated January 23, 1998.
9. NRC Inspection Report 50-315/99-010; 50-316/99-010, dated June 11, 1999.
10. D. C. Cook Condition Report P-99-14004.

See Attached Distribution

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7. LER 315/99-031, "Interim–Valves Required to Operate Post-Accident Could Fail to Open Due to Pressure Locking/Thermal Binding," 1/31/00.
8. NRC Inspection Report 50-315/97-024; 50-316/97-024, dated 1/23/98.
9. NRC Inspection Report 50-315/99-010; 50-316/99-010, dated 6/11/99.
10. D. C. Cook Condition Report P-99-14004.

See Attached Distribution
DOCUMENT NAME: G:DRS\DCC OPERATIONAL EVENT DRS.WPD
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M. Rencheck, Vice President, Nuclear Engineering
R. Whale, Michigan Public Service Commission
Michigan Department of Environmental Quality
Emergency Management Division
MI Department of State Police
D. Lochbaum, Union of Concerned Scientists

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Attachement 8

January 23, 1998

EA 97-0592

Mr. E. E. Fitzpatrick
Executive Vice President
Nuclear Generation Group
American Electric Power
500 Circle Drive
Buchanan, MI 49107-1395

SUBJECT: NOTICE OF VIOLATION AND NRC INSPECTION REPORT NO. 50-315/97024(DRP); 50-316/97024(DRP)

Dear Mr. Fitzpatrick:

On December 27, 1997, the NRC completed an inspection at your D. C. Cook 1 and 2 reactor facilities. The enclosed report presents the results of that inspection. During the seven-week period covered by this inspection report, the inspectors observed that the plant was operated in a safe manner, and radiological work practices were properly followed.

Based on the results of this inspection, two violations of NRC requirements were identified by the NRC. The violations are cited in the enclosed Notice of Violation (Notice), and the circumstances surrounding them are described in detail in the subject inspection report. The first violation involved a failure to perform 10 CFR 50.59 safety evaluations for the removal of annunciators from service. The second violation involved a failure to provide procedural controls for the essential service water (ESW) pump discharge strainers.

You are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response. The NRC will use your response, in part, to determine whether further enforcement action is necessary to ensure compliance with regulatory requirements.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosures, and your response will be placed in the NRC Public Document Room.

Sincerely,

Original signed by
Marc L. Dapas for
Geoffrey E. Grant, Director
Division of Reactor Projects

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

Enclosures:
1. Notice of Violation
2. Inspection Report No. 50-315/97024(DRP); 50-316/97024(DRP)

cc w/encls:
John Sampson, Site Vice President
A. A. Blind, Vice President Nuclear Engineering
Douglas Cooper, Plant Manager
Richard Whale, Michigan Public Service Commission
Michigan Department of Environmental Quality

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosures, and your response will be placed in the NRC Public Document Room.

Sincerely,

/s/Marc L. Dapas for

Geoffrey E. Grant, Director
Division of Reactor Projects

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

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Michigan Department of Environmental Quality

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NOTICE OF VIOLATION

Indiana Michigan Power Company
Donald C. Cook Nuclear Power Plant

Docket No. 50-315; 50-316
License No. DPR-58; DPR-74

During an NRC inspection conducted from November 8 through December 27, 1997, two violations of NRC requirements were identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," NUREG-1600, the violations are listed below:

1. 10 CFR 50.59, “Changes, Tests, and Experiments,” requires, in part, that the licensee shall maintain records of changes in the facility as described in the Safety Analysis Report. These records must include a written safety evaluation which provides the basis for the determination that the change does not involve an unreviewed safety question.

   Contrary to the above, on November 16, 1997, the inspectors identified a failure to maintain records which contained a written safety evaluation for three control room annunciators. The three annuciators were physically or electronically blocked, preventing them from operating, constituting a change to the facility as described in Chapters 7.5 and 10.3 of the Safety Analysis Report.

   This is a Severity Level IV violation (Supplement I).

2. 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” requires, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings.

   Contrary to the above, on December 18, 1997, the inspectors identified that a procedure of a type appropriate to the circumstances did not exist for an activity affecting quality, the manual backwashing of the ESW pump discharge strainers, a support system necessary to ensure ESW system operability.

   This is a Severity Level IV violation (Supplement I).

Pursuant to the provisions of 10 CFR 2.201, Indiana Michigan Power Company is hereby required to submit a written statement or explanation to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555 with a copy to the Regional Administrator, Region III, and a copy to the NRC Resident Inspector at the facility that is the subject of this Notice, within 30 days of the date of the letter transmitting this Notice of Violation (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation" and should include for each violation: (1) the reason for the violation, or, if contested, the basis for disputing the violation, (2) the corrective steps that have been taken and the results achieved, (3) the corrective steps that will be taken to avoid further violations, and (4) the date when full compliance will be achieved. Your response may reference or include previously docketed correspondence, if the correspondence adequately addresses the required response. If an adequate reply is not received within the time specified in this Notice, an order or a Demand for Information may be issued as to why the license should not be modified, suspended, or revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time.

Because your response will be placed in the NRC Public Document Room (PDR), to the extent possible, it should not include any personal privacy, proprietary, or safeguards information so that it can be placed in the PDR without redaction. If personal privacy or proprietary information is necessary to provide an acceptable response, then please provide a bracketed copy of your response that identifies the information that should be protected and a redacted copy of your response that deletes such information. If you request withholding of such material, you must specifically identify the portion that you seek to have withheld and provide in detail the bases for your claim of withholding (e.g., explain why the disclosure of information will create an unwarranted invasion of personal privacy or provide the information required by 10 CFR 2.790(b) to support a request for withholding confidential commercial or financial information). If safeguards information is necessary to provide an acceptable response, please provide the level of protection described in 10 CFR 73.21.

Dated at Lisle, Illinois
this 23th day of January 1998

U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No.	50-315, 50-316
License No.	DPR-58, DPR-74
Report No.	50-315/97024(DRP); 50-316/97024(DRP)
Licensee:	Indiana and Michigan Power 500 Circle Drive Buchanan, MI 49107-1395
Facility:	Donald C. Cook Nuclear Generating Plant
Location:	1 Cook Place Bridgman, MI 49106
Dates:	November 8, 1997, through December 27, 1997
Inspectors:	B. L. Bartlett, Senior Resident Inspector B. J. Fuller, Resident Inspector J. D. Maynen, Resident Inspector
Approved by:	Bruce L. Burgess, Chief Reactor Projects Branch 6

EXECUTIVE SUMMARY

D. C. Cook Units 1 and 2
NRC Inspection Report No. 50-315/97024(DRP); 50-316/97024(DRP)

This inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a seven-week period of resident inspection and includes the followup to issues identified during previous inspection reports.

Operations

- The inspectors identified a violation in which the licensee had been removing control room annunciators from service without maintaining records which contained a written safety evaluation as required by 10 CFR 50.59 (Section O3.1).

Maintenance

- Licensee personnel identified a blocked hydrogen skimmer connection to a steam generator enclosure. The blockage of this line, coupled with failure of the opposite train skimmer, could have resulted in an excessive buildup of hydrogen gas in the steam generator enclosure following a postulated loss of coolant accident. This issue is considered an unresolved item pending the results of testing the individual flow connections from each containment enclosure (Section M1.2).

- During periodic maintenance on the Unit 2 upper containment airlock, licensee mechanics found that the “O” ring seal material installed on the inner bulkhead interlock shaft was Teflon packing rather than the specified EPDM elastomer. This is considered an unresolved item pending the results of the root cause assessment and a determination of the safety significance of the use of Teflon seals (Section M1.3).

- The licensee’s efforts to modify the Unit 2 AB diesel generator (D/G) reflected a weakness in design control in that multiple changes were made to engine components without a thorough understanding of the interrelations of proposed modifications. The engine timing change, performed to reduce cylinder pressure, in conjunction with the fuel line changes, resulted in several other engine parameter changes which were not anticipated by the licensee. The troubleshooting and analyses required to correct the engine parameters resulted in a significant delay in the licensee’s restoration of the 2 AB D/G to service (Section M2.3).

- A non-cited violation was issued when licensee personnel identified that non-safety-related parts were used during maintenance activities on the Unit 2 AB diesel generator. The licensee looked for other instances where non-safety-related parts could have been used and identified one other example (Section 4.1).

Engineering

- The inspectors identified a violation in which the licensee failed to treat the manual backwashing of the ESW strainers in accordance with quality standards commensurate with the importance of the safety functions to be performed. The licensee committed to complete the corrective actions necessary prior to placing either unit in Mode 4, Hot Shutdown (Section E1.1).

Plant Support

- No discrepancies were noted.

Report Details

Summary of Plant Status

Unit 1 remained in Mode 5, Cold Shutdown, during this inspection period. The unplanned outage was in response to NRC and licensee concerns with the operability of the containment recirculation sump and other engineering issues.

Unit 2 was in Mode 6, Refueling, at the beginning of this inspection period. On December 5, 1997, the licensee entered Mode 5, Cold Shutdown. The Unit remained in Mode 5 throughout the remainder of the inspection period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707 , 60710, and 86700)

Using the referenced inspection procedures, the inspectors conducted frequent reviews of ongoing plant operations. Maintaining both Units in Mode 5 for a prolonged period and the recovery from the Unit 2 refueling outage were properly handled by the operators. Specific events and noteworthy observations are detailed in the sections below.

Of special note was that on December 18, 1997, an Operations Shift Manager (SM) challenged the conservatism of an engineering calculation that was done in support of an operability decision. The SM was concerned that the calculation did not properly account for some essential service water (ESW) flow and that some ESW flow could be diverted from safety-related components during a design basis event. The calculation was subsequently reviewed by engineering to ensure that the concern was appropriately resolved. The SM's challenge of the calculation was appropriate and timely.

O2 Operational Status of Facilities and Equipment

O2.1 Engineered Safety Feature System Walkdowns (Both Units)

In addition to routine plant inspections, the inspectors used Inspection Procedure 71707 to walk down selected portions of the residual heat removal, condensate tank, refueling water storage tank, and containment recirculation sump systems for both units. No operability concerns were identified.

O3 Operations Procedures and Documentation

O3.1 Removing Control Room Annunciators From Service Without a Safety Evaluation (Both Units)

a. Inspection Scope (71707 and 37001)

During a routine tour of the control rooms, the inspectors questioned the licensee's practice of removing annunciators from service. The inspectors performed routine followup and reviewed the following documents:

- Operations Head Instruction (OHI) - 2211, Revision 20, "Maintenance of Operations Department Logs"
- 02-Operations Head Procedure (OHP) 4024.221, Revision 4, "Annunciator Panel Number 221 - Generator"
- 02-OHP 4024.222, Revision 4, "Annunciator Panel #222 Response: Plant Service"
- UFSAR Sections 7.5, 10.3
- Condition Report (CR) 97-3314, Operations procedure does not require that a 10 CFR 50.59 review be performed prior to blocking an alarm.

b. Observations and Findings

On November 16, 1997, during a routine tour of the control rooms, the inspectors questioned the licensee's method of removing control room annunciators from service. The licensee's procedures allowed the blocking [by physically or electronically preventing operation] of annunciators without a safety review as required by 10 CFR 50.59, "Changes, tests, and experiments."

The licensee's existing program, described in Procedure OHI-2211, stated that a technical review must be performed prior to the removal of an alarm from service. However, the technical review, performed by a Senior Reactor Operator, focused on TS requirements and required compensatory actions. The technical review was not intended to meet the requirements of 10 CFR 50.59.

The inspectors reviewed the blocked alarm log and determined that the following annunciators had been blocked since at least July 5, 1996:

- Unit 1 Annunciator Panel #121, Drop 17, "Stator Winding Rec[order] High"
- Unit 2 Annunciator Panel #222, Drop 81, "Ice Condenser Recorded Ice Temp[erature] Hi or Lo"
- Unit 2 Annunciator Panel #221, Drop 16, "Stator Winding Rec[order] High"

The function of these annunciators was described in the Updated Final Safety Analysis Report Chapters 7.5 and 10.3. All three annunciators provided an alarm in the control room if the temperature setpoints were exceeded; however, none of them provided an equipment control function or required immediate operator action. The actual safety consequences of blocking the annunciators was minor; however, the regulatory significance of blocking safety-related annunciators without performing a proper safety review per 10 CFR 50.59 was significant.

10 CFR 50.59, "Changes, tests and experiments," required, in part, that the licensee shall maintain records of changes in the facility as described in the safety analysis report. These records must include a written safety evaluation which provides the basis for the determination that the change does not involve an unreviewed safety question. On December 15, 1997, an NRC 10 CFR 50.59 panel reviewed the circumstances surrounding the removal of annunciators from service without maintaining a written safety evaluation. The failure to maintain records which contained a written safety evaluation for three blocked control room annunciators which constituted a change to the facility as described in the safety analysis report is considered a violation of 10 CFR 50.59 (50-315/97024-01a(DRP)); (50-316/97024-01b,c(DRP)).

c. Conclusions

The inspectors identified a violation in which the licensee had been removing control room annunciators from service without maintaining records which contained a written safety evaluation as required by 10 CFR 50.59.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62707 and 61726)

Portions of the following maintenance job orders, action requests, and surveillance activities were observed or reviewed by the inspectors:

- A150778, Inspect and repair the Unit 2 main and auxiliary transformers isophase transition box
- A0149089, Repair of insulation and coatings in Unit 2 containment
- A0153671, Unit 1 CD diesel generator fuel oil leak at base of injector
- **02-OHP 4030. Surveillance Test Procedure (STP).027AB, Revision 10, "AB Diesel Generator Operability Test (Train B)"
- 12 Engineering Head Procedure (EHP) 4050.Fuel Handling Procedure (FHP).301, Revision, "Core Reload"
- Job Order (JO) C29866, Replace 2-CD battery bank

- 12 Instrumentation and Controls Head Procedure (IHP) 5021. Electrical Maintenance Procedure (EMP).006, Revision 2, “Battery Cell Replacement”

- **02 OHP 4030.STP .038, Revision 5, “Leak Rate Test of Liquid Systems”

- Job Order R72312, 2 AB D/G, perform 18 month diesel surveillance

b. Observations and Findings

The inspectors concluded that most of the observed work activities were performed in a quality manner with procedures present and in use; however, some maintenance activities continued to challenge the licensee. Specifically, problems were identified concerning two previous maintenance activities: a plugged hydrogen skimmer line (discussed in Section M1.2) and Teflon packing rings in Unit 2 upper containment airlock (discussed in Section M1.3). Two maintenance problems concerning the 2 AB emergency diesel generator were also identified: weak design control regarding engine modifications (discussed in Section 2.1) and improper fasteners used to secure engine components (discussed in Section M4.1).

M1.2 Inadvertently Plugged Hydrogen Skimmer Suction Line (Unit 2)

a. Inspection Scope (62707)

On November 26, 1997, licensee maintenance personnel identified a blockage of the Steam Generator (S/G) #3 enclosure Train B hydrogen skimmer suction piping. The inspectors performed walkdowns of the hydrogen skimmer system in Unit 2 containment and observed the licensee's investigation, short-term corrective actions, and long-term corrective actions. Licensee procedures and documentation reviewed included:

- **12 THP Technical Head Procedure (THP) 6040 PER. 098

- JO C006665, Replace heaters in upper compartment quadrant 3 ventilation unit

b. Observations and Findings

Portions of safety-related piping for the hydrogen skimmers had been removed to facilitate the replacement of non-safety-related heaters inside Unit 2 upper containment. During the foreign material exclusion inspection, licensee maintenance personnel identified blockage of the Steam Generator (S/G) #3 enclosure Train B hydrogen skimmer suction piping to the air recirculation/hydrogen skimmer fan, 2-HV-CEQ-1. The discovery of material blocking the skimmer suction piping was an indication that the licensee’s efforts to improve identification of foreign material was beginning to produce results.

The hydrogen skimmer system functions to minimize accumulated hydrogen in the upper portions of the S/G and pressurizer enclosures following a loss of coolant accident. Two subsystems of hydrogen skimmer are available in containment. Each hydrogen skimmer subsystem has connections to each S/G enclosure, so that each pair of S/Gs has a total of four suction connections. Each S/G hydrogen skimmer line was required to pass a nominal 250 standard cubic feet per minute (SCFM) of air flow when the associated hydrogen skimmer fan was in service.

The Updated Final Safety Analysis Report (UFSAR) stated that if hydrogen skimmer flow were as low as 455 SCFM from a paired S/G enclosure, the hydrogen concentration would not exceed the 4 volume percent flammability limit inside the paired S/G enclosure. Train A connections to the S/G #2 and S/G #3 enclosure were open and would have provided the required flow of at least 455 SCFM. However, assuming a single failure and the loss of the Train A fan during a LOCA, only degraded Train B would have been available to meet the required flow.

The system engineer postulated that the hydrogen skimmer piping may have been blocked during restoration work from the Unit 2 steam generator replacement project (SGRP) in 1989. The concrete roof of each S/G enclosure had been removed to permit S/G repairs. The area where the skimmer piping penetrated the roof was not to be disturbed during the repair but was close to the chip back line specified for concrete replacement. When the forms were built prior to the concrete pour for the steam generator enclosure, the penetration may have been inadvertently covered. A contributing cause for the licensee's failure to identify the blocked hydrogen skimmer piping was the lack of testing of the skimmer system. No test of the hydrogen skimmer system had been scheduled because the suction lines were in an area that was not part of the SGRP.

Flow balancing of the skimmer system in Unit 2 was last performed in October 1985 using test Procedure **12 THP 6040 PER.098. The as-left flowrates for 17 of the 19 test points were not within the acceptable flow as specified on the Final Air Flow Tabulation data sheet. Although all 17 points were left higher than the maximum allowed by the procedure, they were still outside the acceptance criteria. No disposition existed for the flows that were outside acceptable limits. The 1985 as-left combined flows for the S/G #2 and S/G #3 enclosure were greater than the nominal 455 SCFM stated in the UFSAR. Due to physical constraints in the S/G #2 and S/G #3 enclosure, individual skimmer line flow tests were not performed.

The licensee's failure to have a valid surveillance test to verify that individual line flow rates for this system met the UFSAR stated values is considered a significant weakness. Pending the results of the flow testing for the individual flow connections in each steam generator enclosure, this will remain an Unresolved Item (50-316/97024-03(DRP)).

Licensee personnel removed the concrete grout which was plugging the S/G #3 enclosure connection and performed hydrogen skimmer system flow verifications. Based on the results of the flow verifications, licensee personnel determined that the remaining hydrogen skimmer connections were free from blockage. The inspectors subsequently performed an independent verification of the skimmer connections and agreed with the licensee's determination.

c. Conclusions

Licensee personnel identified a blocked hydrogen skimmer connection to a steam generator enclosure. The blockage of this line coupled with failure of the opposite train skimmer could have resulted in an excessive buildup of hydrogen gas in the steam generator enclosure following a postulated loss of coolant accident. This issue was determined to be an unresolved item pending the results of testing the individual flow connections from each containment enclosure.

M1.3 Teflon Packing Rings in Upper Containment Airlock (Unit 2)

a. Inspection Scope (62707)

On December 7, 1997, maintenance personnel discovered Teflon packing installed in the Unit 2 upper containment airlock instead of the specified EPDM elastomer. The inspectors interviewed the system engineer and observed the licensee's investigation, including the development of both short-term and long-term corrective actions.

b. Observations and Findings

During periodic maintenance on the Unit 2 upper containment airlock, licensee mechanics found that the “O” ring seal material installed on the inner bulkhead interlock shaft was Teflon packing rather than the specified EPDM elastomer. The “O” ring seals were designed to prevent a leakage path from containment into the airlock compartment and from the airlock compartment into the auxiliary building. The inspectors were concerned because Teflon will degrade significantly in high radiation fields, such as would exist inside containment following a postulated loss of coolant accident, and deterioration of the seal rings in the airlock could result in a leakage path from the containment to the airlock compartment.

Periodic maintenance on the airlock is done on a five-year nominal cycle to look for wear in the “O” ring seals and other parts. The periodic maintenance had been last performed in 1992 for this airlock. The licensee stated that because the wording in the job order was limited to a statement requiring only the replacement of EPDM seals, the mechanics performing the work may have interpreted the instructions to mean that the Teflon seals did not need to be replaced.

The original specifications for the airlock did not specify the “O” ring seal material. The airlock as supplied by the vendor was fitted with Teflon seals. A major refurbishment program for the airlocks was conducted over a period of three years commencing in 1988. As a result of NRC and industry concerns with the lifespan of sealing materials, natural rubber seals were initially replaced by Grafoil type seals. Subsequently, due to difficulties with the installation of the Grafoil seals, a switch to the EPDM seals was initiated. The job orders directed changing the seals on the handwheel hub and interlock mechanism on the interlock door to EPDM seals. The licensee stated that during performance of the work, it appeared that only the seals on the hubs were changed. The licensee further speculated that the work instructions were not explicit in calling out part numbers for the interlock mechanism and that the mechanics may have misinterpreted the instructions as only pertaining to the mechanism on the door itself.

The licensee’s assessment of the root causes and of the safety significance was continuing at the end of the inspection period. Pending the results of the root cause assessment and a determination of the safety significance, this will remain an Unresolved Item 50-316/97024-04(DRP)).

c. Conclusions

During periodic maintenance on the Unit 2 upper containment airlock, licensee mechanics found that the “O” ring seal material installed on the inner bulkhead interlock shaft was Teflon packing rather than the specified EPDM elastomer. This was

considered an unresolved item pending the results of the root cause assessment and a determination of the safety significance of the use of Teflon seals.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Weak Design Control for Modifications on the AB D/G (Unit 2)

a. Inspection Scope (62707)

During the 18-month surveillance on the Unit 2 AB diesel generator (2 AB D/G), modifications were carried out to change the high pressure fuel lines and engine timing. Following these modifications, unanticipated effects on D/G performance were experienced. The inspectors followed the licensee's modification and testing efforts and reviewed the following documents:

- UFSAR Section 8.4, "Emergency Power System"
- Component Evaluation No. CE-96-0293, Replace emergency diesel generator fuel injection tubing
- CR 97-3110, On November 4, 1997, while operating the 2 AB D/G for a maintenance run, the high pressure fuel line at #1 front bank failed.
- CR 97-3157, On November 6, 1997, during the operation of the 2 AB D/G, the new #4 rear bank stainless steel high pressure fuel line lifted out of the compression nut and ferrule.
- CR 97-3175, On November 7, 1997, during inspections performed on 2AB D/G fuel lines, it was determined that the line ends and ferrules were not being set properly.
- CR 97-3176, On November 8, 1997, 2 A/B D/G #3 rear bank fuel injection line mechanical connection failed at the injector end.
- CR 97-3264, On November 12, 1997, after 2 AB D/G was started and loaded for the 24-hour maintenance run, the air chest high pressure alarm unexpectedly came in.
- CR 97-3263, On November 13, 1997, 2 AB D/G blew a fuel line off #4 rear injector.
- CR 97-3277, On November 15, 1997, 2 AB D/G #3 front high pressure fuel oil line developed a pin hole leak while running at full load.

b. Observations and Findings

Due to high peak cylinder pressure on the 2 AB D/G, the licensee evaluated engine performance enhancements which might reduce the peak cylinder pressure. The two

selected enhancements involved changing the high pressure fuel lines and retarding the engine timing by several degrees.

Fuel Line Problems

The component evaluation for replacing diesel generator fuel injection tubing (CE-96-0293) concluded that stainless steel lines of a larger inner diameter would be acceptable replacements for the installed carbon steel fuel injection lines. The licensee added the fuel injection line replacement to the refueling outage maintenance on the 2 AB D/G after two fuel line through wall failures occurred in October and November 1997. A new installation procedure was developed which provided more specific guidance for installing the fuel line connections and avoiding reliance on the "skill of the craft." The installation of stainless steel fuel injection lines coupled with the use of new compression fittings and proceduralized assembly instructions initially resulted in difficulties in obtaining satisfactory connections for the fuel lines. Problems with the installation and testing of the new fuel lines were documented in the condition reports listed above.

The licensee sent several fuel lines, ferrule fittings, and connecting nuts to an offsite laboratory for testing to determine the most probable failure mechanism. After reviewing fuel line test results and consulting with the fuel line vendor, the licensee's engineering staff found that the fuel line connection problems could be attributed, in part, to the following:

- The connecting nuts provided with the new stainless steel high pressure fuel lines were received from the vendor incorrectly machined. These nuts may have damaged the ferrule fittings, resulting in connection failure at normal operating pressure.

- The new installation procedure required using the connection nut torque prescribed by the D/G vendor technical manual instead of ferrule fitting compression to determine connection tightness. The 2 AB D/G 18-month maintenance was the first time when this new installation procedure was used.

To resolve the connection problems, the incorrectly machined connecting nuts were replaced with properly machined connecting nuts. Concurrently, a high pressure fuel line installation procedure based on ferrule fitting compression rather than connecting nut torque was developed with the fuel line vendor's concurrence. Following these corrective actions, the licensee did not identify any other fuel line connection problems. The inspectors concluded that the licensee's troubleshooting efforts, including consultation with the fuel line vendor and offsite testing of several connections, were aggressive and thorough.

Engine Timing Changes

As a part of the 18-month maintenance, the 2 AB D/G timing was retarded by three degrees to reduce peak cylinder pressure. The inspectors noted that, although the

timing change did have the desired result of reducing cylinder pressures, many other engine parameters also changed. At D/G full load, the air chest pressure alarm annunciated, causing the operators to reduce load and subsequently terminate the reliability run. The licensee's engineering staff also noted that the new stainless steel high pressure fuel lines had a larger inner diameter than the carbon steel lines which were replaced. The effect of the larger diameter was similar to retarding the engine timing by 3 percent. During several attempts at completing a 24-hour reliability run on the 2 AB D/G, the licensee identified several unexpected engine parameter changes:

- Air chest pressure was higher than expected.
- The dynamic loading characteristics of the diesel engine were slightly changed.
- The fuel oil consumption rate increased.
- Fuel rack maximum travel was reduced.

The licensee consulted the D/G vendor concerning the engine parameter changes. With the vendor's concurrence, the air chest pressure alarm and trip set-points were raised, and the test was repeated. Two additional set point changes were required before the 2 AB D/G could be run at full load without receiving an air chest high pressure alarm. In addition, the installed air chest pressure gauge was replaced with a gauge with a higher range to accommodate the higher alarm set point.

Additionally, the licensee's engineering staff evaluated the dynamic load characteristics, limited fuel rack travel, and increased fuel consumption of the 2 AB D/G. The licensee's engineering staff concluded that, even with the limited fuel rack travel and increased fuel consumption, the 2 AB D/G would still be able to properly sequence on safety-related loads following a design basis accident and run at full load for one week with the minimum amount of fuel required by TSs in the fuel oil tank. The inspectors reviewed the licensee's evaluation of the 2 AB D/G and had no additional concerns.

c. Conclusions

The licensee's efforts to modify the Unit 2 AB diesel generator (D/G) reflected a weakness in design control in that multiple changes were made to engine components without a thorough understanding of the interrelations of proposed modifications. The engine timing change, performed to reduce cylinder pressure, in conjunction with the fuel line changes, resulted in several other engine parameter changes which were not anticipated by the licensee. The troubleshooting and analyses required to correct the engine parameters resulted in a significant delay in the licensee's restoration of the 2 AB D/G to service.

M2.2 (Open) Inspection Followup Item (50-316/97018-05): 2 AB diesel generator poor material condition. The 2 AB D/G had been placed on an accelerated surveillance frequency following the second valid test failure in August 1997. Condition Report 97-2810 was issued on October 14, 1997, to document the third functional failure of the 2 AB D/G over a two year period. This functional failure resulted in the licensee placing the 2AB D/G in maintenance rule category (a)(1).

In addition to moving the 2 AB D/G to maintenance rule category (a)(1), the licensee also elected to implement a material condition outage. All outstanding maintenance work requests were evaluated; those that did not involve a major tear down of the D/G were worked. This resulted in many minor oil and water leaks being repaired.

This item will remain open until the licensee has issued their corrective actions for the 2 AB D/G and the inspectors have had an opportunity to review the corrective actions.

M2.3 (Open) Unresolved Item 50-315/97018-06; 50-316/97018-06: Diesel Generator Exhaust Manifold Brackets (Both Units). On October 19, 1997, while running the 2 AB D/G for an eight-hour surveillance test, the flywheel end exhaust manifold bracket failed. The licensee speculated that missing jam nuts may have allowed the bracket bolt to come loose, resulting in a fatigue failure of the bracket; however, the minor modification package paperwork indicated that the jam nuts had been installed. The licensee began an investigation into the root cause of the bracket failure, but the investigation was not completed at the end of this report period. This unresolved item remains open pending a review of the licensee's investigation into the root cause of the bracket failure.

M4 Maintenance Staff Knowledge and Performance

M4.1 Non-Safety-related Capscrews and Nuts Used in a Safety-related Application (Unit 2)

a. Inspection Scope (62707)

On December 2, 1997, the licensee identified that some of the capscrews used to hold the 2 AB D/G combustion air turbocharger air aftercoolers were drawn from stock spares rather than from safety-related stores. The inspectors followed up on this finding. The following documents were reviewed:

- **12 Maintenance Head Procedure (MHP) 5021.032.015, Revision 2, "Emergency Diesel Engine Intake Air Aftercooler Maintenance"
- JO R36576; Open, inspect, clean, and close 2 AB D/G north combustion aftercooler
- JO R37665; Open, inspect, clean and close 2 AB D/G south combustion aftercooler
- CR 97-3461, Non-certified bolts installed on 2 AB D/G aftercoolers
- CR 97-3496, Non class 30 nuts installed on 2 AB D/G crankcase covers
- CR 97-3494, Potential adverse trend relative to control of contractors

b. Findings

On December 2, 1997, a contract worker performing the 18-month maintenance work on the 2 CD D/G told a licensee supervisor that some of the capscrews used to replace

the 2 AB D/G intake air aftercoolers had been drawn from open stock spares rather than from safety-related stores. The licensee inspected the capscrews and found that 32 of 84 capscrews were drawn from open stock spares. The 2 AB D/G was declared inoperable, and the appropriate TS action statements were entered.

Several capscrews from the open stock spares were tested for material composition and strength. The results of this testing and analysis indicated that the installed capscrews exceeded the American Society for Testing and Materials (ASTM) A574 standard. The licensee's engineering staff also conducted an analysis assuming worst-case ASTM A307 capscrews were installed. This analysis showed that even if lower standard capscrews were installed, the vertical restraint spring cans and the remaining correct capscrews would have prevented the aftercooler from coming loose during operation or a design basis earthquake. Therefore, no operability question existed with the 2 AB D/G. The 2 AB D/G was declared operable, and the TS action statements were exited. The inspectors reviewed the testing and analysis results and had no additional concerns.

While performing follow up on the capscrews, licensee personnel identified that non-certified nuts had also been installed to hold crankcase covers in place on the 2 AB D/G. The non-certified nuts had been installed by the same contractor personnel who installed the non-safety-related capscrews. The crankcase covers are designed to relieve internal crankcase pressure which would not challenge the structural integrity of the crankcase cover nuts and studs. The licensee determined that the use of non certified parts would have no operability impact.

The work on the aftercoolers was performed under job orders R36576 and R37665 which were marked as safety-related. These Job Orders referred the workers to Procedure **12 MHP 5021.032.015 for instructions on how to perform the aftercooler maintenance and reinstallation. This procedure specified that the capscrews meet the ASTM standard A574; however, no documentation existed which indicated that the open stock spare capscrews met this standard. Title 10 CFR Part 50, Appendix B, Criterion VIII, required, in part, that measures shall be established for the identification and control of materials, parts, and components, including partially fabricated assemblies. These identification and control measures shall be designed to prevent the use of incorrect or defective material, parts, and components. The two examples of failure to utilize the required parts were a violation of 10 CFR Part 50, Appendix B, Criterion VIII, in that no measures were in place to prevent contractor personnel from using non-certified parts drawn from open stock spares in a safety-related application. This non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation (NCV), consistent with Section VII.B.1 of the NRC Enforcement Policy (50-316/97024-05).

c. Conclusions

A non-cited violation was issued when licensee personnel identified that non-safety-related parts were used during maintenance activities on the Unit 2 AB diesel generator. The licensee looked for other instances where non-safety-related parts could have been used and identified one other example.

M8 Miscellaneous Maintenance Issues

M8.1 (Closed) Violation 50-315/97004-02b: Spiral wound gasket material in the reactor coolant system and the reactor vessel (Unit 1). On March 12, 1997, during Unit 1 core off-load, the licensee found spiral wound gasket material on the bottom of several fuel assemblies and the lower core plate. The source of this material was later determined to be from the spiral wound gaskets on the residual heat removal (RHR) heat exchanger outlet valves, 1-IRV-310 and 1-IRV-320. Additional material may also have remained in the reactor coolant system from an earlier failure of the spiral wound gasket on the RHR heat exchanger bypass valve, 1-IRV-311. The spiral wound gaskets on these three valves were replaced with compressed fiber gaskets, and the spiral wound gasket material was removed from the reactor coolant system.

A similar inspection for debris on the fuel assemblies and lower core plate was performed during the Unit 2 core off-load. No spiral wound gasket material was noted. As discussed in the licensee's response to Inspection Report No. 50-315/97004, letter AEP:NRC:1260C, dated June 5, 1997, the corresponding Unit 2 RHR heat exchanger valves, 2-IRV-310, 2-IRV-320, and 2-IRV-311 had their spiral wound gaskets replaced with compressed fiber gaskets prior to or during the Unit 2 1996 refueling outage.

The inspectors reviewed portions of the licensee's Unit 2 reactor vessel internals and fuel assembly inspection records and had no additional concerns. The Unit 2 reactor vessel inspection results supported the licensee's conclusion that the spiral wound gasket replacements on 1[2]-IRV-310, 1[2]-IRV-320, and 1[2]-IRV-311 have prevented the introduction of gasket material into the reactor coolant system and reactor vessel. The inspectors had no further concerns. This violation is closed.

III. Engineering

E1 Conduct of Engineering

E1.1 (Closed) Unresolved Item 50-315/96007-03; 50-316/96007-03; Operability of Essential Service Water (ESW) With Inoperable Pump Discharge Strainers (Both Units)

a. Inspection Scope (37551)

As documented in Inspection Report No. 50-315/96007, during routine control room observations, the inspectors observed that an ESW pump discharge strainer had been removed from service without the associated ESW train being declared inoperable. The inspectors questioned the adequacy of the licensee's basis for the strainers not being a support system required for ESW system operability. Pending additional information from the licensee the issue remained an Unresolved Item (50-315/316-96007-03).

The licensee supplied additional information to the inspectors, and the inspectors requested that the Office of Nuclear Reactor Regulation (NRR) review the licensee's design basis and reach a conclusion as to the need for operable strainers to support an operable ESW train.

b. Observations and Findings

The inspectors reviewed the operating history of the ESW system for the past several years and found no instances where an ESW strainer had been removed from service for longer than 72 hours, the TS limit for inoperability of an ESW system train.

The ESW strainer backwash system was classified as a non-safety-related system. However, it was possible for the strainers to be manually backwashed if the air system or the relays were to fail in order to support the continued operability of the ESW system. In their response to the inspectors' request to review this issue, NRR stated that the licensee should consider any procedures for manually backwashing the strainers to be safety-related. The licensee should also ensure that the emergency procedures for responding to a loss of offsite power contain appropriate actions to take if the automatic strainer backwash capability was lost. However, a procedure to manually backwash the strainers did not exist, the evolution would require tools, and the operators were not trained in how to perform a manual backwash of the ESW strainers.

Technical Specification basis 3/4.7.4 for the ESW system stated, in part, "The OPERABILITY of the essential service water system ensures that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions." [Original emphasis retained.] Title 10 CFR Part 50, Appendix B, Criterion V, "Instructions, procedures, and drawings," required, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures or drawings.

Based upon the above information, the licensee failed to comply with Criterion V in that no procedures existed for the ESW pump discharge strainers manual backwash capability which was necessary to support the operability of the ESW system. The licensee did not have the procedures, training, and tools necessary for manual backwashing. This was considered a violation of 10 CFR Part 50, Appendix B, Criterion V (50-315/97024-02(DRP)); (50-316/97024-02(DRP)).

c. Conclusions

The inspectors identified a violation in which the licensee failed to treat the manual backwashing of the ESW strainers in accordance with quality standards commensurate with the importance of the safety functions to be performed. The licensee committed to complete the corrective actions necessary prior to placing either unit in Mode 4, Hot Shutdown.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls (71750)

During the resident inspection activities, routine observations were conducted in the areas of radiological protection and chemistry controls using Inspection Procedure 71750. No discrepancies were noted.

S1 Conduct of Security and Safeguards Activities (71750)

During normal resident inspection activities, routine observations were conducted in the areas of security and safeguards activities using Inspection Procedure 71750. No discrepancies were noted.

F1 Control of Fire Protection Activities (71750)

During normal resident inspection activities, routine observations were conducted in the area of fire protection activities using Inspection Procedure 71750. No discrepancies were noted.

X1 Exit Meeting

The inspectors presented the inspection results to members of the licensee management at the conclusion of the inspection on December 29, 1997. The licensee had additional comments on some of the findings presented. No proprietary information was identified by the licensee.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

#M. Ackerman, Supervisor, Nuclear Licensing
#K. Baker, Manager, Production Engineering
#S. Brewer, Director, Regulatory Affairs
#S. Delong, Management Information
#S. Farlow, Supervisor I&C Engineering
#J. Fryer, Radiation Protection
#R. Mankowski, Materials Management
#D. Morey, Chemistry Superintendent
#A. Olvera, Nuclear Licensing
#F. Pisarsky, Supervisor, Mechanical Component Engineering
#T. Postlewait, Manager, Design Engineering
#P. Russell, Supervisor, Plant Protection
#J. Sampson, Plant Manager
#P. Schoepf, Supervisor, Safety-related Mechanical Systems
#J. Stubblefield, Supervisor, Scheduling
#T. Szymanski, Plant systems
#G. Tollas, Assistant Operations Superintendent

#Denotes those present at the December 29, 1997 exit meeting.

INSPECTION PROCEDURES USED

IP 37001	10 CFR 50.59 Safety Evaluations
IP 37551	On-site Engineering
IP 60710	Refueling Outage
IP 61726	Surveillance Observations
IP 62707	Maintenance Observation
IP 71707	Plant Operations
IP 71750	Plant Support Activities
IP 86700	Spent Fuel Pool Activities

ITEMS OPENED and CLOSED and DISCUSSED

ITEMS OPENED

50-315/97024-01 50-316/97024-01	VIO	Failure to maintain written safety evaluation
50-315/97024-02 50-316/97024-02	VIO	Failure to implement quality assurance commensurate with safety function
50-316/97024-03	URI	Failure to have a valid surveillance test which proved operability of a TS required system
50-316/97024-04	URI	Root cause and safety significance of the wrong containment airlock door seals
50-316/97024-05	NCV	Failure to utilize the required safety-related parts

ITEMS CLOSED

50-315/96007-03 50-316/96007-03	URI	Operability of ESW with inoperable discharge strainers
50-315/97004-02b	VIO	Spiral wound gasket material in reactor vessel
50-316-97024-05	NCV	Failure to utilize the required safety-related parts

ITEMS UPDATED

50-316/97018-05	IFI	Poor material condition of the 2 AB D/G
50-315/97018-06 50-316/97018-06	IFI	D/G exhaust manifold brackets

LIST OF ACRONYMS

AEP	American Electric Power
ASTM	American Society for Testing and Materials
bcc	blind carbon copy
cc	carbon copy
CFR	Code of Federal Regulations
CR	Condition Report
DCC	Donald C. Cook
DCP	Design Change Package
D/G	Diesel Generator
DRP	Division of Reactor Projects
DPR	Demonstration Power Reactor
ECCS	Emergency Core Cooling System
EDT	Eastern Daylight Time
EHP	Engineering Head Procedure
ESF	Engineered Safety Feature
ESW	Essential Service Water
FME	Foreign Material Exclusion
IFI	Inspection Follow Up Item
IR	Inspection Report
JO	Job Order
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
ME	Mechanical Engineering
MHP	Maintenance Head Procedure
MI	Michigan
NCV	Non-Cited Violation
NOV	Notice of Violation
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulator
OHI	Operations Head Instruction
OHP	Operations Head Procedure
OSO	Operations Standing Order
PDR	Public Document Room
PMP	Plant Manager’s Procedure
RHR	Residual Heat Removal
SE	Safety Evaluation
SI	Safety Injection
SM	Shift Manager
SRO	Senior Reactor Operator
SCFM	Standard Cubic Feet per Minute
STP	Surveillance Test Procedure
S/G	Steam Generator
SGRP	Steam Generator Replacement Project
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item

Attachment 9

June 11, 1999

Mr. R. P. Powers
Senior Vice President
Nuclear Generation Group
American Electric Power Company
500 Circle Drive
Buchanan, MI 49107-1395

SUBJECT: D. C. COOK INSPECTION REPORT 50-315/99010(DRP); 50-316/99010(DRP)

Dear Mr. Powers:

On May 27, 1999, the NRC completed an inspection at your D. C. Cook Units 1 and 2 reactor facilities. The inspection was an examination of activities conducted under your license as they relate to compliance with the Commission rules and regulations and with the conditions of your license. Areas reviewed included Operations, Maintenance, Engineering, and Plant Support. Within these areas, the inspection consisted of selective examinations of procedures and representative records, interviews with personnel, and observations of activities in progress. The enclosed report presents the results of that inspection.

Your staff successfully restored the Unit 2 AB diesel generator to an operable condition along with the associated train of boration control resulting in an increased ability to address postulated reactor coolant dilution events. In addition, the continued effort to place both units on electrical back feed indicated an increased focus on reactor core safety issues. We also noted that during the conduct of the Expanded System Readiness Review process, your staff demonstrated a critical questioning attitude by effectively identifying technical issues related to the Containment Spray System.

While an increased focus on reactor core safety issues was evident, several examples were identified by the inspectors where your staff failed to consistently respond in a manner commensurate with the potential impact of the degraded condition on current plant configuration. The examples included your staffs' response to degraded and inoperable Essential Service Water pump discharge strainers, degraded 4 kV breakers, and source range instrument issues. In response to the inspectors' concerns, your staff took prompt and appropriate actions, including the initiation of compensatory measures when warranted. These actions ensured that equipment which could be required to support maintaining the reactor in a cold shutdown condition were available or returned to service in an expeditious manner.

During the inspectors review of previously identified regulatory issues, two violations of NRC requirements were identified. The first violation, identified by the inspectors in 1998, was due to an inappropriate surveillance procedure for the engineered safeguards ventilation system. The surveillance procedure did not direct the operators to restore the system to an operable configuration. The second violation, identified by your staff in 1995, involved the failure to

restore several main steam safety valves to operable status prior to exceeding the Technical Specification Limiting Condition for Operation time limit.

These Severity Level IV violations are being treated as Non-Cited Violations (NCVs). Appendix C of the Enforcement Policy requires that for Severity Level IV violations to be dispositioned as NCVs, they be appropriately placed in the licensee's corrective action program. Implicit in that requirement is that the corrective action program be fully acceptable. The plant corrective action program was not adequate and has been the focus of significant attention by your staff to improve the program. While your staff and the NRC have not yet concluded that the corrective action program is fully effective, the corrective action program improvement efforts are underway and captured in the Restart Plan which is under the formal oversight of the NRC through the NRC Manual Chapter 0350 Process, "Staff Guidelines for Restart Approval." Consequently, these issues will be dispositioned as NCVs.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be placed in the NRC Public Document Room.

Sincerely,

/s/ J. A. Grobe

John A. Grobe, Director
Division of Reactor Safety

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

Enclosure: Inspection Report 50-315/99010(DRP);
50-316/99010(DRP)

cc w/encl: A. C. Bakken III, Site Vice President
T. Noonan, Acting Plant Manager
M. Rencheck, Vice President, Nuclear Engineering
R. Whale, Michigan Public Service Commission
Michigan Department of Environmental Quality
Emergency Management Division
MI Department of State Police
D. Lochbaum, Union of Concerned Scientists

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-315; 50-316
License Nos:	DPR-58; DPR-74
Report No:	50-315/99010(DRP); 50-316/99010(DRP)
Licensee:	Indiana and Michigan Power 500 Circle Drive Buchanan, MI 49107-1395
Facility:	Donald C. Cook Nuclear Generating Plant
Location:	1 Cook Place Bridgman, MI 49106
Dates:	April 17, through May 27, 1999
Inspectors:	B. L. Bartlett, Senior Resident Inspector B. J. Fuller, Resident Inspector J. D. Maynen, Resident Inspector K. A. Coyne, Project Engineer - Region II
Approved by:	A. Vegel, Chief Reactor Projects Branch 6 Division of Reactor Projects

EXECUTIVE SUMMARY

D. C. Cook Units 1 and 2
NRC Inspection Report 50-315/99010(DRP); 50-316/99010(DRP)

This inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a 6-week period of resident inspection activities and includes follow-up to issues identified during previous inspection reports.

Operations

- Overall, plant operations were performed using approved operating procedures and reflected good operating practices. The inspectors observed an operator conduct in-plant rounds and determined that the operator was knowledgeable of system status and operation, observed proper radiological controls, and appropriately communicated with the control room. (Section O1.1)

- During a routine tour of the control rooms, the inspectors determined that the control room operators were not fully cognizant of the status of the configuration of the source range nuclear instruments. The source range instrument alarms were treated inconsistently between the units and the licensed operators were not knowledgeable of the differences or of the reasons for the differences. (Section O1.2)

- Several examples were identified by the inspectors where the licensee failed to consistently respond in a manner commensurate with the potential impact of the degraded condition on the current plant operational condition. The examples included degraded and inoperable Essential Service Water pump discharge strainers, and degraded 4 kV breakers and source range nuclear instruments. Licensee management personnel recognized the need to prioritize degraded material condition issues in order to focus on items important to reactor core safety in Mode 5, but did not always ensure the corrective actions were focused towards Mode 5 items first. (Section O1.2)

Maintenance

- The inspectors concluded that the maintenance and surveillance activities observed were performed in accordance with procedures. The current revision of the appropriate procedures were in use at the work sites, and appropriate radiological protection practices were noted. (Section M1.1)

- Plant material condition continued to be identified including problems with the ESW pump discharge strainers. The licensee's response to the degraded ESW strainers lacked a sense of urgency commensurate with their importance to maintaining reactor core safety. Following NRC inspector observations on the need to re-evaluate the corrective actions on the ESW strainers, the licensee's corrective actions were appropriate. (Section M2.1)

Engineering

- The inspectors observed that engineering personnel provided effective support to maintenance personnel in an effort to resolve the containment spray system problems in a timely manner. As appropriate, the problem scopes were expanded and/or re-assessed to ensure adequate technical resolutions were achieved. (Section E7.1)

- Significant progress had been made by the licensee in the identification of technical issues related to the Containment Spray System. At the end of the inspection report period, the system remained inoperable pending resolution of the identified issues. Case Specific Checklist item 10 remained open at the end of the inspection period. (Section E7.1)

Plant Support

- Delay in the placement of plant equipment into an appropriate lay-up condition contributed to the degradation of some plant safety and nonsafety-related equipment. The licensee had recognized the need for an effective lay-up program and had taken action to place equipment in lay-up and to develop planning for lay-up during future outages. (Section R2.1)

Report Details

Summary of Plant Status

The licensee maintained both Unit 1 and Unit 2 in Mode 5, Cold Shutdown, throughout the inspection period. During this inspection period, the licensee continued with the Expanded System Readiness Reviews (ESRR). The Unit 2 AB emergency diesel generator was returned to an operable status following HFA relay calibrations, which allowed the licensee to declare the Unit 2 west charging pump operable. In addition, work continued on restoring the other emergency diesel generators and the chemical and volume control system to an operable status. The licensee informed the NRC on April 30, 1999, that Unit 2 was the lead unit for restart work.

The licensee was pursuing placing both units on electrical back feed through the main transformers to improve connectivity to off-site power supplies. Various technical and material condition issues with the main transformers required resolution prior to placing the units on back feed.

I. Operations

O1 Conduct of Operations

O1.1 General Comments

The inspectors conducted frequent observations of control room and in-plant operation of equipment during the extended outage of both reactor units. Overall, plant operations were performed using approved operating procedures and reflected good operating practices. Specific events and noteworthy observations are detailed in the sections below.

On May 11, 1999, the inspectors questioned the licensee about which deficiencies would require correction to support Unit 2 entry into Mode 4 (reactor coolant system temperature greater than 200°F but less than 350°F). The licensee stated that a comprehensive list of Unit 2 Mode 4 constraints did not exist and that the current tracking processes did not capture all Mode 4 constraints. Condition Report 99-09835, written on April 29, 1999, had already documented this problem. The inspectors identified several Unit 1 Technical Specifications (TSs) required to be satisfied when Unit 2 was in Modes 1, 2, 3, or 4. These Unit 1 TS requirements were not tracked on the Unit 2 TS open items index. The licensee stated that the Unit 1 TS required equipment would also be added to the Unit 2 Mode 4 constraints in response to the inspectors comments.

On May 26, 1999, the inspectors accompanied a non-licensed operator on the Unit 2 Auxiliary Building Tour conducted in accordance with procedure 02-OHP [Operations Head Procedure] 5030.001.001, “Operations Plant Tours,” Revision 14. The operator was knowledgeable of system status and operation, observed proper radiological controls, appropriately communicated with the control room, and conducted a thorough

tour. The inspectors observed minimal amounts of debris and transient combustibles in the auxiliary building. The inspectors noted that the reference information section of the operator rounds procedure incorrectly referenced the normal system condition of the 2-SYS3-NESW [Non-Essential Service Water] fire detection panel. However, the inspectors observed that the operator appropriately verified the condition of the 2-SYS3-NESW panel. The licensee initiated Condition Report (CR) 99-13653 to document this minor procedure deficiency.

O1.2 Licensee Focus on Reactor Core Safety

a. Inspection Scope (71707)

The inspectors identified several technical issues and noted that the licensee's initial response to these issues lacked a sense of urgency commensurate with managements expectations that corrective actions should be prioritized based on the potential impact on core safety. The inspectors reviewed the licensee's follow up to the recently identified technical issues and previously documented issues in order to perform an assessment of the licensee's focus on reactor core safety.

b. Observations and Findings

Since the licensee shutdown both units on September 8, 1997, various licensee efforts to enhance reactor core safety have been evident. Within the last 6 months, the licensee's improved focus on reactor core safety resulted in increased attention to emergent issues related to maintaining the core in a safe shutdown condition. Examples included the decision to perform the initial Expanded System Readiness Reviews (ESRR) on those systems necessary for reactor core safety in Mode 5, the efforts to increase electrical connections from the grid by going on main transformer back feed, the establishment of a core safety priority safety list, and the efforts to restore the emergency diesel generators and boron injection flow paths to an operable status.

Despite the improved performance, the NRC inspectors identified three examples where the licensee demonstrated an inadequate sense of urgency in prioritizing corrective actions to resolve issues involving degraded equipment. The first example involved the poor material condition of the Essential Service Water (ESW) pump discharge strainers, the second example involved the lack of a comprehensive preventive maintenance program on 4 kilovolt breakers, and the third example involved operator knowledge of the condition of the reactor vessel source range instruments. The licensee's initial response to correct these examples lacked a sense of urgency commensurate with the function of the affected systems in the current mode of operation.

b.1. ESW Pump Discharge Strainers

The licensee identified several operability and degraded material condition issues on all four (two per unit) ESW strainers. As issues were identified, the licensee performed operability evaluations as necessary for each individual issue and concluded that the ESW system remained operable. (The specific operability and material condition issues

are discussed below in Section M2.1.) However, an aggregate operability evaluation of these issues was not performed until after questions had been raised by the inspectors. Although the Technical Specifications for ESW did not require the system to be operable in Mode 5, the ESW system was required as a support system for RHR, Component Cooling Water, and the emergency diesel generators which are systems required in Mode 5.

After the inspectors questioned the licensee's response to the questions of operability and material condition, the licensee:

- increased operator tours of the ESW system,
- tracked ESW strainer differential pressures,
- made contingency plans for the failure of an additional ESW strainer,
- reviewed loss of ESW abnormal operating procedures,
- reviewed the performance of strainer manual backwash procedure,
- requested vendor assistance, and
- performed an operability determination for the overall system degradation in order to ensure the ESW system could continue to support the removal of core decay heat.

Though the licensee was prompted by the inspectors, the licensee's subsequent response and corrective actions were adequate to compensate for the degraded material condition of the ESW system.

b.2. Safety-Related 4 Kilovolt (kV) Breakers

The licensee had identified that their 4 kV breakers were in a degraded material condition due to an inadequate preventive maintenance program. In response, an NRC inspection was performed and documented in Inspection Report 50-315/316-99011. As documented in that report, the licensee did not prioritize their refurbishment program to consider those breakers necessary to operate equipment needed for Mode 5, until after questions had been raised by the NRC inspectors.

b.3. Source Range Nuclear Instruments

During routine control room walkdowns, the inspectors observed that all four (two per unit) normal source range instrument channels were operable, and that all post accident source range detectors (referred to as the Gamma-Metrics detectors) had their high flux alarms disabled except for Unit 2 detector 2-NRI-21. Source range instruments were required for reactor core safety in order to monitor the shutdown status of the reactor core. The inspectors interviewed the unit supervisors and I&C personnel and

determined that the normal licensee practice was to enable the Gamma-Metrics source range detector alarms only when the normal source range instruments were inoperable.

Unit 2 had experienced problems with their source range instruments in early February 1999, and the operators had enabled the alarm on Gamma-Metrics source range detector 2-NRI-21. Following the restoration of the normal source range instruments, the high flux alarm had not been disabled on 2-NRI-21.

The inspectors determined that the licensed operators were unaware of the status of the high flux alarms, the reasons for the current status of the alarms, or the desired alarm status. Even though the safety significance of the inconsistent enabling of the ex-core source range detectors high flux alarm was minimal, the occurrence of this issue indicated that the operators were not fully cognizant of the configuration of plant equipment, in this case the source range instruments.

Additional issues previously identified by the NRC inspectors included:

- The failure of licensed operators to understand which controlling procedures they were utilizing for maintaining the plant in a cold shutdown condition (Inspection Report 50-315/316-98008, Section O1.2).

- The failure of the licensed operators to know the time necessary for the core to reach boiling conditions in the event of a loss of all core cooling (Inspection Report 50-315/316-98016, Section O1.2).

- The failure of the licensed operators to identify erratic flow indications in the Unit 1 Residual Heat Removal (RHR) system. Following the inspectors' identification of the erratic flow, licensee personnel performed a detailed walk down of the RHR system and identified flow cavitation issues (Inspection Report 50-315/316-99001, Section O2.1).

- The failure of the licensed operators to recognize that reactor coolant system temperature changes while in cold shutdown also resulted in reactivity changes (Inspection Report 50-315/316-99004, Section O1.2).

- The failure of the licensee to restore fencing and other barriers around the Unit 1 condensate storage tank and the Unit 1 refueling water storage tank (RWST) following removal for the moving of the spare main transformer (Inspection Report 50-315/316-99004, Section O1.1).

In public Manual Chapter 0350 meetings, licensee and NRC personnel had discussed plant material condition. It had been recognized that efforts to identify the extent of the design and licensing issues would cause resources for corrective maintenance to be below normal levels and that this reduced resource availability would impact negatively upon plant material condition. The NRC had also discussed the importance of the licensee monitoring plant material condition and responding promptly to degraded and potentially non-conforming equipment issues that impacted equipment necessary for

reactor core safety. The issues identified by the NRC in this inspection period showed that the licensee efforts in this area have been inconsistent.

b.4. Corrective Actions

The licensee initiated condition reports for the ESW strainer issues (CR 99-13076) and the control of the source range instrument high flux alarm set point (CR 99-14123). Resources were increased on the repair of the Unit 2 West strainer, and corrective actions were planned to address the specific material condition issues on all four ESW strainers. The 4 kV breakers had a root cause analysis performed and a vendor was brought on site to refurbish breakers. Additional investigations and corrective actions related to other licensee electrical component issues were continuing. The issues listed above that were discussed in other inspection reports had previously been addressed in CRs.

c. Conclusions

During a routine tour of the control rooms, the inspectors determined that the control room operators were not fully cognizant of the status of the configuration of the source range instruments. The source range instrument alarms were treated inconsistently between the units and the licensed operators were not knowledgeable of the differences or of the reasons for the differences.

Several examples were identified by the inspectors where the licensee failed to consistently respond in a manner commensurate with the potential impact of the degraded condition on the current plant operational condition. The examples included degraded and inoperable Essential Service Water pump discharge strainers, degraded 4 kV breakers, and source range nuclear instruments. Licensee management personnel recognized the need to prioritize degraded material condition issues in order to focus on items important to reactor core safety in Mode 5, but did not always ensure the corrective actions were focused towards Mode 5 items first.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (61726 and 62707)

The inspectors performed routine observations of maintenance and surveillance activities in progress. The inspectors observed procedure use and adherence, and radiological control practices.

b. Observations and Findings

The inspectors observed all or part of the following maintenance activities:

- 01-OHP [Operations Head Procedure] 4030.STP [Surveillance Test Procedure].027AB, AB Diesel Generator Operability Test (Train B), Revision 14
- 02-OHP 4030.STP.027AB, AB Diesel Generator (D/G) Operability Test (Train B), Revision 12
- Job Order (JO) C0048865, Unit 2 AB Emergency Diesel Generator, replace damaged oil line at 3R cylinder
- JO C0047947, Perform checks of HFA relays on Unit 2 AB D/G
- JO R0073261, Clean oil/air separator and crankcase blower
- JO R0084700, Sample and change the oil in the governor to Unit 2 AB D/G
- Action Request (AR) A179380, Unit 2 East ESW Supply fan number 1 has higher vibrations than the other fans.
- AR A183629, Unit 2 West ESW strainer lost power, perform troubleshooting activities.
- AR A183169, Unit 2 East ESW strainer basket backwash valve 2-WRV-773 operates in a “jerky” fashion.

The inspectors concluded that the observed work was performed in accordance with procedures. The current revision of the appropriate procedures were in use at the work sites, and proper work safety and radiological protection practices were noted. Inspector observations of work activities associated with the ESW pump discharge strainers are documented in Section M2.1.

M2 Material Condition of Facilities and Equipment

M2.1 Essential Service Water Pump Discharge Strainers Degraded Material Condition

a. Inspection Scope (62707 and 71707)

Plant operation and maintenance activities were impacted by the material condition of the plant. The inspectors followed up on several activities which were affected. The licensee’s responses to material condition issues on various system components were discussed in Section O1.2, above. The inspectors assessed the material condition of the ESW pump discharge strainers as part of the continued evaluation plant material condition.

b. Observations and Findings

Each of the two Units has two ESW pumps. On the discharge of each pump is a duplex strainer. During normal operation, the strainer uses nonsafety-related equipment and based on a set differential pressure, automatically swaps sides and initiates a backwash of the side that had previously been in service. Previous NRC inspection reports identified that the licensee had considered the ESW strainers as a support system not required for operability of the ESW system (Inspection Report 50-315/316-96007) and a Notice of Violation had been issued for the licensee's failure to have procedures for the performance of manual back washing of the ESW system (Inspection Report 50-315/316-97024). In response to questions raised during the ongoing Expanded System Readiness Reviews (ESRRs), the licensee's position on the need for the strainers was being re-evaluated, but had not yet formally changed. As material condition issues on the ESW strainers were identified by the licensee, the issues were evaluated, and the importance of the strainers for support of the systems necessary for the safe shutdown operation of the units were recognized.

The licensee identified several operability and degraded material condition issues on the ESW strainers in addition to known, pre-existing issues already identified on the strainers. As the issues were identified, the licensee performed operability evaluations as necessary for each individual issue and maintenance personnel began corrective maintenance activities. However, an aggregate operability evaluation was not performed until after questions had been raised by the inspectors. Although the Technical Specifications for ESW did not require the system to be operable in Mode 5, the ESW system was required as a support system for RHR, component cooling water, and the emergency diesel generators.

On May 19, 1999, the Unit 2 West ("B" Train) strainer failed to complete a timed swap and backwash. At the time the Unit 1 East ("A" Train) strainer was out of service for troubleshooting and additional corrective maintenance for a previous failure of the inlet gate to operate. The Unit 1 East strainer was restored to an available status and troubleshooting begun on the Unit 2 West Strainer.

Other operability or material condition issues existing on the four ESW strainers at that time included:

2. Failure of the Unit 1 West left strainer to backwash due to a failed backwash valve

- Degraded gate seal to the inlet gate of the Unit 1 East strainer
- Rounded key on the motor operator to the inlet gate of the Unit 1 East strainer
- Cracked support pads for both of the Unit 1 strainers
- Improperly supported air lines to the backwash valves of all four ESW strainers
- Improperly supported instrument lines to all four ESW strainers

- Jerky operation of Unit 2 East ESW strainer basket backwash valve 2-WRV-773

Following the inspectors' observations that there was a lack of a sense of urgency to initiate corrective actions and compensatory measures, commensurate with the importance to safety, the licensee significantly increased the focus and resources on the ESW strainers. There had been discussions by members of the licensee's management on the need to increase attention on the material condition and to initiate precautions such as discussed in the Section O1.2 above, but these discussion had not resulted in actions.

Condition Reports related to the ESW strainers were listed in Section O1.2. Corrective actions included:

- Regular focus meetings between maintenance supervisors, engineers, schedulers, operations department representatives, and the shift manager to track, trend, discuss, and resolve ESW strainer issues.

- Meetings with a representative of the ESW strainer vendor to resolve questions on the causes of the degraded material conditions and the necessary corrective actions. For example, the bolts holding the strainer slide gates to the operating shafts had backed out, loosened, or failed on the Unit 2 West strainer inlet and outlet gates. The licensee held discussions with vendor representatives to determine the need for longer bolts, the types of bolts, the types of nuts, torque values, and the advisability of using locking compound during re-installation.

- A schedule was drafted for the performance of corrective maintenance on all ESW strainers in order to return them to their original design conditions. At the end of the assessment period, the schedule was still in the planning stage.

- Maintenance procedures were being reviewed in order to determine necessary modifications, additions, and deletions.

c. Conclusions

Plant material condition continued to decline as evidenced by the licensee identified problems with the ESW pump discharge strainers. The licensee's response to the degraded ESW strainers lacked a sense of urgency commensurate with their importance to maintaining reactor core safety. Following NRC inspector observations on the need to re-evaluate the corrective actions on the ESW strainers, the licensee's corrective actions were appropriate.

M3 Maintenance Procedures and Documentation

M3.1 (Closed) EEI 50-315/98021-03: Surveillance procedure did not direct the operators to restore the AES system to a configuration included in the normal operating procedure or enter the appropriate TS limiting condition for operation action statement. On October 28, 1998, the inspectors identified that Surveillance Procedure **01-OHP 4030.STP.025A, "Engineered Safety Features Fan No. 1 (1-HV-AES-1) Ventilation

Exhaust Air Filter Train Test," Revision 3, was inappropriate to the circumstances in that it did not direct the operators to restore the AES system to a configuration included in the normal operating procedure or enter the appropriate TS limiting condition for operation action statement. 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings, required, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. The inspectors considered the failure of the surveillance procedure to return the AES system to an operable lineup to constitute an apparent violation of 10 CFR Part 50 Appendix B, Criterion V. This apparent violation remained open to allow the licensee a reasonable time to develop corrective actions. On December 22, 1998, the licensee completed a review of the AES surveillance procedures. In addition to the deficiency described above, Condition Report 98-08328 documented other apparent deficiencies in the AES surveillance procedures. The licensee planned to revise the procedures to correct the identified problems.

This Severity Level IV violation is being treated as a Non-Cited Violation (NCV). Appendix C of the Enforcement Policy requires that for Severity Level IV violations to be dispositioned as NCVs, they be appropriately placed in the licensee's corrective action program. Implicit in that requirement is that the corrective action program be fully acceptable. The plant corrective action program was not adequate and has been the focus of significant attention by your staff to improve the program. While your staff and the NRC have not yet concluded that the corrective action program is fully effective, the corrective action program improvement efforts are underway and captured in the Restart Plan which is under the formal oversight of the NRC through the NRC Manual Chapter 0350 process, "Staff Guidelines for Restart Approval." Consequently, this issue will be dispositioned as an NCV (50-316/99010-01(DRP)). This EEI is closed.

M8 Miscellaneous Maintenance Issues

M8.1 (Closed) Licensee Event Report 50-315/95002-00: Nine Unit 1 main steam safety valves had lift setpoints above the Technical Specification allowed values. In June 1995, with the unit at approximately 55 percent power, the licensee exercised the Unit 1 main steam safety valves (MSSVs). Nine MSSVs were found to be above the 3 percent lift setpoint tolerance allowed by Technical Specification (TS) 3.7.1.1. These valves were not reset to within 1 percent of the nominal lift setpoint until after the setpoints were questioned by the inspectors. This event was discussed in Inspection Report 50-315/95009. Technical Specification 3.7.1.1 required, in part, that a safety valve shall be reset to the nominal value ± 1 percent whenever found outside the ± 1 percent tolerance. Contrary to the above, the licensee did not reset the MSSV setpoints to within 1 percent of the nominal lift setpoint until after questioned by the inspectors. The inspectors considered the failure to reset the MSSV lift setpoints to constitute a violation of TS 3.7.1.1. The licensee implemented more frequent MSSV exercising, and valve seat refurbishment on MSSVs found out of tolerance. Condition Report 98-07823 was initiated to address MSSV testing and refurbishment issues.

This Severity Level IV violation is being treated as an NCV. Appendix C of the Enforcement Policy requires that for Severity Level IV violations to be dispositioned as

NCVs, they be appropriately placed in the licensee's corrective action program. Implicit in that requirement is that the corrective action program be fully acceptable. The plant corrective action program was not adequate and has been the focus of significant attention by your staff to improve the program. While your staff and the NRC have not yet concluded that the corrective action program is fully effective, the corrective action program improvement efforts are underway and captured in the Restart Plan which is under the formal oversight of the NRC through the NRC Manual Chapter 0350 process, "Staff Guidelines for Restart Approval." Consequently, this issue will be dispositioned as an NCV (50-315/99010-02(DRP)). This LER is closed.

M8.2 (Closed) Licensee Event Report 50-315/97004-00: Main steam safety valve exceeds allowable lift setpoint due to setpoint drift. On February 28, 1997, during main steam safety valve (MSSV) testing, the licensee identified that MSSV 1-SV-2A-3 exceeded its allowable lift setpoint by greater than three percent. The licensee's investigation determined that the cause of the setpoint change was setpoint drift. The inspectors reviewed the licensee's logs and determined that the valve lift setpoint was reset and that the MSSV was restored to operable within 4 hours. The Limiting Condition for Operation for Technical Specification 3.7.1 was met; therefore, no violation of Technical Specifications occurred. Condition Report 98-07823 was initiated to address MSSV testing and refurbishment issues. This LER is closed.

III. Engineering

E1 Conduct of Engineering

E1.1 General Engineering Comments

The licensee's staff continued with the discovery phase of the ESRRs. The ESRRs comprised a significant portion of the licensee's restart effort. In accordance with the NRC Inspection Manual Chapter 0350 inspection plan, the NRC established an inspection team to provide oversight of the ESRR process. The NRC oversight team will document their findings in a separate inspection report.

E7 Quality Assurance in Engineering Activities

E7.1 Case Specific Checklist Item 10, "Resolution of Containment Spray System Operability Issues"

a. Inspection Scope (37551 and 71707)

During this inspection period the inspectors performed routine follow up on Manual Chapter 0350, Case Specific Checklist (CSC) Item 10, regarding resolution of the Containment Spray System (CTS) Operability Issues. These operability issues were identified by NRC, third party, and licensee personnel. The issues were documented in Licensee Event Report 50-315/980020, 022, 027, 030, and 034; Inspection Reports 50-315/98004, 005, and 009 and in numerous licensee Condition Reports (CRs). At the end of this assessment period, CSC item 10 remained open.

b. Observations and Findings

The licensee's efforts to identify and correct the CTS operability issues were focused primarily on three different areas:

- The rotation of the Unit 1, West CTS heat exchanger to its correct configuration and the problems identified during this evolution.

- The ESRR findings including the incorporation of NRC and third party assessments.

- The ESRR findings from other system assessments that impacted upon the CTS system.

The licensee's ESRR on the CTS system had recently been completed and the corrective actions were still being developed and prioritized at the end of this inspection report period. The findings by the ESRR on the CTS system included the following items:

- CR 99-5921: During a walk down of the CTS system, the ESRR team observed that the top 5 percent of the containment was not covered by the CTS sprays. This was contrary to an assumption used by a vendor to calculate the off-site and control room dose calculations.

- CR 99-5939: During a walk down of the CTS system, the ESRR team observed that several CTS upper containment nozzles had partially obstructed spray patterns from nearby lighting or lighting supports.

- CR 99-5934: During a walk down of the CTS system, the ESRR team observed that the fall height of the CTS spray in lower containment was significantly shorter than assumed by a vendor in dose calculations.

- CR 99-6013: During a walk down of the CTS system, the ESRR team observed that the spray pattern of the CTS was partially blocked by the licensee's practice of parking the polar crane above the air lock doors.

The inspectors have generally observed that the findings from the ESRR were indicative of a detailed assessment by personnel with good questioning attitudes. The inspectors will perform additional assessments of the problems identified on the CTS system during continued reviews of the licensees corrective actions in regard to the issues tracked by CSC item 10.

Findings by other ESRR teams that impacted upon the operability of the CTS included:

- CR 99-6389: The two CTS spray additive tank outlet valves on each unit were to have their actuator torque switches replaced in response to a 10 CFR Part 21 notification. The ESRR identified that the work had been deferred for five years, without adequate justification.

- CR 99-6012: An ESRR team identified that non-seismic class I lighting and supports were above the refueling canal drains that lead to the recirculation sump. During a postulated accident, the lights could fail and clog the drains potentially reducing the return of water to the recirculation sump.

- CR 99-7853: Two of the upper containment pressure transmitters and two of the lower containment pressure transmitters were identified as improperly mounted. The pressure transmitters were anchored to both the containment and the auxiliary buildings. Differential movement of the buildings during a seismic event could cause loads to exceed allowable limits. The lower containment pressure transmitters are used to automatically actuate the CTS system on a high containment pressure.

The licensee had included the ESRR findings listed above into their restart data base and were in the process of prioritizing and assessing the corrective actions to the these and other findings. While the inspectors did not perform a detailed assessment of the ESRR teams regarding the CTS system, the broad overview did not identify any significant concerns.

The inspectors performed a more detailed oversight of the rotation of the CTS heat exchanger and the problems identified during that rotation. Following the re-installation of the Unit 1, West CTS heat exchanger, the licensee performed routine post maintenance pressure testing. During that testing, the licensee identified several small pressure boundary leaks.

During the assessment of the pressure boundary leaks, several heat exchanger tubes were found to be leaking. The licensee performed eddy-current testing of the Unit 1, West heat exchanger and identified several dozen leaking or thin walled tubes. The eddy-current testing was appropriately expanded to the other three similar CTS heat exchangers. The licensee determined that all four CTS heat exchangers (two per nuclear unit) had flaw indications.

The flaw indications consisted primarily of outside diameter cracks and outside diameter pits. Several tubes were pulled and compared to the eddy-current testing results. Good comparisons were found for the pits; however, the cracks had significant non-conservative discrepancies between the test results and the pulled tubes. The licensee believed that the discrepancies were due to the use of a flat bottom hole standard and began manufacturing an axial notch standard. Prior to the use of the new standard, an industry expert group recommended the use of different frequencies and using new

computer models and manipulations got agreement between the eddy-current tests and the pulled tubes within 2 percent.

At the end of this inspection period, the licensee's root cause analysis was continuing. All of the crack indications had been identified in the centerline weld of the tubes. Additional testing and contingency planning were continuing. The licensee had determined that no other safety-related heat exchangers had been procured from the manufacturers that made either the heat exchangers or the tubes used in the heat exchangers.

c. Conclusions

Significant progress had been made by the licensee in the identification of operability issues with the Containment Spray System. At the end of the inspection report period, the system remained inoperable pending resolution of the identified issues. Case Specific Checklist item 10 remained open at the end of the inspection period.

The inspectors observed that engineering personnel provided effective support to maintenance personnel in an effort to resolve the containment spray system problems in a timely manner. As appropriate, the problem scopes were expanded and/or re-assessed to ensure adequate technical resolutions were achieved.

E8 Miscellaneous Engineering Issues

E8.1 Review of Licensee's Readiness for Year 2000

The inspectors conducted an abbreviated review of Year 2000 (Y2K) activities and documentation using Temporary Instruction (TI) 2515/141, "Review of Year 2000 Readiness of Computer Systems at Nuclear Power Plants." The review addressed aspects of Y2K management planning, documentation, implementation planning, initial assessment, detailed assessment, remediation activities, Y2K testing and validation, notification activities, and contingency planning. The inspectors used NEI/NUSMG 97-07, "Nuclear Utility Year 2000 Readiness," and NEI/NUSMG 98-07, "Nuclear Utility Year 2000 Readiness Contingency Planning," as the primary references for this review. The results of the review were discussed with licensee management. The results of this review will be combined with the results of other reviews at other NRC licensees in a summary report to be issued by letter this year.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls (71750)

During normal resident inspection activities, routine observations were conducted in the area of radiological protection and chemistry controls using Inspection Procedure 71750. No uncontrolled releases of radioactive material were identified.

R2 Status of RP&C Facilities and Equipment

R2.1 Plant Equipment Lay-up Program

a. Inspection Scope (71750)

The inspectors reviewed the status of the licensee's lay-up program for plant equipment. The inspectors interviewed Chemistry Department personnel, reviewed condition reports and walked down equipment to assess the adequacy of the plant lay-up program.

b. Observations and Findings

The licensee performed a dual unit shutdown in September 1997, due to operability issues raised during an NRC Architect Engineer inspection. Plant equipment and system chemistry were maintained to support a near term return to power operation. As the return to operation was delayed to address emergency issues, the licensee did not perform a comprehensive lay-up of equipment.

As a consequence of not laying up equipment for the extended outage, evidence of equipment degradation due to corrosion and corrosion products became apparent:

- The Unit 1 west containment spray heat exchanger was hydrostatically tested after pressure boundary welds were made. The heat exchanger hydro failed due to internal leakage later identified as tube leakage. Analysis of pulled tubes by an independent laboratory revealed evidence of microbiologically induced corrosion (MIC) as well as other tube failure mechanisms. A likely cause of the MIC degradation of the tubes was that the equipment was not placed in lay-up during the extended outage (CR 98-7066).

- Failure of heat exchanger tubes in other equipment has occurred during the extended outage of both units. The Unit 1 number 1 reactor coolant pump (RCP) motor cooler (CR 98-8299) and Unit 1 west component cooling water (CCW) heat exchanger (CR 99-0278) failures may be attributed to improper lay-up. Root cause analyses were underway to further refine the cause of these failures.

- In June 1998, failure of tubes in the Unit 2 main turbine lube oil cooler caused a release of 780 gallons of lubricating oil to Lake Michigan. The licensee stated that the probable cause of the tube degradation was the coolers had been left with standing NESW water and the water had aggressively attacked the tube metal. As part of the corrective actions for that failure, the licensee planned to perform an assessment of their equipment lay-up program for long-term shutdown conditions.

In February 1999, an industry organizations assist visit for Chemistry Department reviewed the plant program for lay-up of equipment. The assist team identified that an effective lay-up program for plant equipment did not exist. Chemistry Department personnel developed an action plan to develop procedures and logic trees for placing

equipment in lay-up during outages. Equipment was being procured to allow introduction of warm, dry air into secondary systems for corrosion prevention during outages.

The inspectors observed that changes in unit priority and delays in the restart schedule had an adverse impact on placing equipment in lay-up for the extended outage. Licensee senior management made implementation of a comprehensive plant lay-up program a priority.

c. Conclusions

Delay in the placement of plant equipment into an appropriate lay-up condition contributed to the degradation of some plant safety and nonsafety-related equipment. The licensee had recognized the need for an effective lay-up program and had taken action to place equipment in lay-up and to develop planning for lay-up during future outages.

S1 Conduct of Security and Safeguards Activities (71750)

During normal resident inspection activities, routine observations were conducted in the area of security and safeguards activities using Inspection Procedure 71750. No discrepancies were noted.

F1 Control of Fire Protection Activities (71750)

During normal resident inspection activities, routine observations were conducted in the area of fire protection activities using Inspection Procedure 71750. No discrepancies were noted.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of the licensee management at the conclusion of the inspection on May 27, 1999. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

#R. Antonow, Outage Manager
#J. Arias, Compliance Manager
#C. Bakken, Site Vice President
#P. Barrett, Performance Assurance
#D. Cooper, Plant Manager
#D. Garner, Plant Engineering
#M. Marano, Director Business Services
#T. O'Leary, Radiation Chemistry Manager
#F. Poppell, Regulatory Affairs
#M. Rencheck, Vice President, Nuclear Engineering
#M. Skow, Performance Assurance
#T. Taylor, Regulatory Affairs
#K. VanDyne, Regulatory Affairs
#L. Weber, Operations
#B. Yockey, Performance Assurance
#T. Zemo, Engineering

# Denotes those present at the May 27, 1999, exit meeting.

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 92700:	Onsite Review of LERs
IP 92901:	Followup - Operations
IP 92902:	Followup - Maintenance

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-315/99010-01	NCV	Surveillance procedure did not direct the operators to restore the AES system to a configuration included in the normal operating procedure or enter the appropriate TS limiting condition for operation action statement.
50-315/99010-02	NCV	Nine Unit 1 main steam safety valves had lift setpoints above the Technical Specification allowed values.

Closed

50-315/95002-00	LER	Nine Unit 1 main steam safety valves had lift setpoints above the Technical Specification allowed values.
50-315/97004-00	LER	Main steam safety valve exceeds allowable lift setpoint due to setpoint drift.
50-315/98021-03	EEI	Surveillance procedure did not direct the operators to restore the AES system to a configuration included in the normal operating procedure or enter the appropriate TS limiting condition for operation action statement.
50-315/99010-01	NCV	Surveillance procedure did not direct the operators to restore the AES system to a configuration included in the normal operating procedure or enter the appropriate TS limiting condition for operation action statement.
50-315/99010-02	NCV	Nine Unit 1 main steam safety valves had lift setpoints above the TS allowed values.

LIST OF ACRONYMS

ASM	Assistant Shift Manager
CCP	Centrifugal Charging Pump
CCW	Component Cooling Water
CFR	Code of Federal Regulations
CR	Condition Report
CSC	Case Specific Checklist
CTS	Containment Spray System
CVCS	Chemical and Volume Control System
DRP	Division of Reactor Projects
ESRR	Expanded System Readiness Review
ESW	Essential Service Water
I & C	Instrumentation and Controls
IHP	Instrument Head Procedure
IMP	Instrument Maintenance Procedure
JO	Job Order
LCO	Limiting Condition for Operation
LER	Licensee Event Report
MC	Manual Chapter
MHP	Maintenance Head Procedure
MOV	Motor Operated Valve
MSSV	Main Steam Safety Valve
N/A	Not Applicable
NCV	Non-cited Violation
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
OHI	Operations Head Instruction
OHP	Operations Head Procedure
PMI	Plant Manager’s Instruction
PMP	Plant Manager’s Procedure
PMSO	Plant Manager’s Standing Order
PMT	Post Maintenance Testing
PPA	Plant Performance Assurance
PDR	Public Document Room
PORV	Power Operated Relief Valve
STP	Surveillance Test Procedure
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VIO	Violation