August 4, 2000

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 50-315/2000016(DRP); 50-316/2000016(DRP)

Dear Mr. Powers:

This refers to the inspection conducted on May 28, 2000, through July 15, 2000 at the 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 inspectors also reviewed observations and findings as they related to the NRC Manual Chapter 0350 Case Specific Checklist for D.C. Cook. The enclosed report documents the closure of NRC restart issues which were considered in our determination that your staff's performance improvement initiatives have been sufficiently effective to support the restart of D.C. Cook Unit 2. The NRC Inspection Manual Chapter 0350 Oversight Panel conclusions were documented separately in a letter to you dated June 13, 2000.

During this inspection period, increased inspection focus was placed on assessing your activities related to the return of Unit 2 to power operation. Based on our extensive observations of Unit 2 restart activities, we concluded that the restart evolution was performed in a controlled and deliberate manner. Specifically, we observed that operators responded conservatively to equipment problems, and when issues were raised, the restart evolution was stopped and the problems were appropriately resolved prior to recommencement of the power ascension.

However, we did note a lack of attention to detail in the engineering and maintenance areas which resulted in several violations of NRC requirements. The failure to account for instrument and analytical uncertainties during pre-startup calibrations of the nuclear instrumentation resulted in non-conservative reactor trip setpoints for the reactor protection system. The failure to consider a common mode failure mechanism for auxiliary feedwater pump room coolers resulted in repeated Technical Specification entries. A lack of attention to detail during walkdowns conducted prior to Mode ascension resulted in the failure to identify degraded high energy line break doors and scaffolding interferences with safety related equipment.

Based on the results of this inspection, the NRC has determined that five violations of NRC requirements occurred involving the failure to meet minimum operable channel requirements for the nuclear instruments, failure to establish proper low power trip setpoints during control rod testing, failure to demonstrate operability of an offsite power source following loss of power to the “A” train buses, inadequate control of high energy line break barriers, and failure to appropriately control scaffolding in the vicinity of safety related equipment. These violations are being treated as Non-Cited Violations (NCV), consistent with Section VI.A of the Enforcement Policy. These NCVs are described in the subject inspection report. If you contest the violations or severity level of these NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001, with copies to the Regional Administrator, Region III; and the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, D.C. 20555-0001.

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Sincerely,

/RA/

John A. Grobe, Director
Division of Reactor Safety

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

Enclosure: Inspection Report 50-315/2000016 (DRP);
50-316/2000016(DRP)

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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:	50-315/2000016(DRP); 50-316/2000016(DRP)
Licensee:	American Electric Power Company 1 Cook Place Bridgman, MI 49106
Facility:	D. C. Cook Nuclear Generating Plant
Location:	1 Cook Place Bridgman, MI 49106
Dates:	May 28, 2000 through July 15, 2000
Inspectors:	B. L. Bartlett, Senior Resident Inspector K. A. Coyne, Resident Inspector J. D. Maynen, Resident Inspector M. F. Kurth, Resident Inspector, Duane Arnold P. F. Prescott, Senior Resident Inspector, Duane Arnold R. A. Langstaff, RIII Inspector K. S. Green-Bates, RIII Inspector R. G. Quirk, Consultant N. Shah, RIII Inspector A. Dunlop, RIII Inspector D. McNeil, RIII Inspector
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 50-315/2000016(DRP); 50-316/2000016(DRP)

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

Operations

- The inspectors concluded that the Unit 2 reactor startup and power ascension were well controlled and performed in accordance with the appropriate procedures. Operations personnel responded conservatively to several equipment problems which were identified during preparations for starting the Unit 2 reactor. (Section O1.2)

- On June 8, 2000, both units lost power to their “A” Train buses due to an apparent switching error. The inspectors determined that the operators had appropriately entered the loss of offsite power procedure and that the operators were monitoring key plant parameters to ensure that Unit 2 reactor and spent fuel pool safety were maintained. (Section O1.3)

- A non-cited violation (NCV) was identified for the failure to demonstrate the operability of the remaining offsite power source within one hour after the loss of “A” train buses as required by Technical Specifications (TS). The inspectors noted that the operators had appropriately entered abnormal operating procedures which included steps to restore power to both electrical trains if necessary. Therefore, the inspectors concluded that the safety significance of the missed surveillance was low. (Section O1.3)

- Between July 4, 2000, and July 8, 2000, repeated failures of the auxiliary feedwater pump room coolers occurred due to inadequate essential service water (ESW) flow. Operators implemented appropriate actions to restore operability of the auxiliary feedwater pump room coolers, closely monitored room cooler performance, and effectively communicated concerns with cooler operation to engineering and maintenance personnel. (Section O2.1)

- An NCV for the failure to follow High Energy Line Break (HELB) barrier control procedural requirements was identified. During a routine plant tour, the inspectors twice identified a HELB door that was not in its required position. Subsequent inspector and licensee followup identified three other degraded but operable HELB doors, weak HELB barrier procedural controls, and missing HELB door barrier labels. (Section O2.2)

Maintenance

- 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 personnel exhibited proper work safety and radiological protection practices. Work items were appropriately scheduled in the plan of the day. (Section M1.1)

- An NCV for the failure to follow scaffolding installation procedure requirements was identified. During a routine plant tour, the inspectors identified three non-seismically qualified scaffolds in the main steam enclosures and an auxiliary feedwater pump room that could have interfered with the proper operation of equipment. The scaffolding was in well traveled areas yet was not identified during plant tours by licensee personnel.(Section M1.2)

- The inspectors determined that the material condition of the Unit 2 containment was good and ready for restart of the Unit. The containment closeout surveillance performed by the licensee was of good quality and was effectively performed. (Section M2.1)

Engineering

- The inspectors identified an Unresolved Item regarding single failure vulnerability of relays in the Safeguards Test Cabinet. The Safeguards Test Cabinet was installed to permit online testing of Engineered Safety features actuating circuits beyond the slave relay coils. Failures of relays may go undetected during plant operation. (Section E1.1)

- The inspectors identified an NCV of TS 3.3.1.1 when the Unit 2 reactor entered Mode 2 on June 22, 2000, and continued operation in Mode 1 through June 26, 2000, with one intermediate range channel and two power range channels exceeding the allowable reactor trip setpoint of TS 2.2.1. This condition resulted in the failure to meet the minimum operable channel requirements of TS 3.3.1.1. Because the safety analysis bound the actual trip setpoints, the safety significance was minimal. (Section E2.2)

- The inspectors identified an NCV of TS 3.10.3.b when the licensee conducted control rod worth verification testing during the period June 23, 2000 through June 24, 2000. TS 3.10.3.b required that the trip setpoints for the operable intermediate range, neutron flux, and the power range, neutron flux, low setpoint, be set at less than or equal to 25 percent of rated thermal power. Because the safety analysis bound the actual trip setpoints, the safety significance was minimal. (Section E2.2)

- The inspectors concluded that engineering personnel did not adequately consider a potential common cause failure mechanism for the auxiliary feedwater (AFW) room coolers. Consequently, degradation of flow in the ESW cooling lines, a common cause failure mechanism, resulted in repeated failures of the AFW room coolers. Additionally, plant procedures did not adequately reflect the station blackout analysis initial condition for turbine driven auxiliary feedwater pump (TDAFWP) room temperature. The lack of understanding of TDAFWP room cooler control circuit operation by engineering personnel resulted in unnecessary additional time with an out-of-service TDAFWP. (Section E4.1)

- The inspectors determined that the licensee performed an inadequate engineering analysis supporting the reduction in the resistance temperature detector (RTDs) bypass manifold low flow alarm setpoint. A low flow condition in the bypass manifold could have resulted in longer time response for the loop hot and cold leg RTDs or inoperability of reactor trip and engineered safeguards functions associated with loop temperature. The licensee performed additional analysis and revised the affected alarm setpoints prior to ascension to Mode 2 (Startup). (Section E4.2)

Report Details

Summary of Plant Status

Unit 1 remained defueled throughout the inspection period. The licensee continued containment restoration following steam generator replacement. Licensee restart efforts have been re-focused from Unit 2 to Unit 1. Major activities this inspection report period included ice condenser work and a “B” Train electrical bus outage.

At the beginning of the inspection period, Unit 2 was in Mode 5. Unit 2 entered Mode 4, Hot Shutdown on June 6, 2000, and Mode 3, Hot Standby, on June 12, 2000. The mode ascension continued to Mode 2, Startup, on June 21, 2000 and Mode 1, Power Operations, on June 24, 2000. On July 5, 2000, Unit 2 reached 100 percent power and remained at 100 percent power for the remainder of the inspection period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments

The inspectors conducted frequent observations of control room activities and equipment operation. Overall, plant operations were performed using approved operating procedures and reflected good operating practices. Noteworthy observations and findings are detailed below and in the report sections which follow.

- The inspectors reviewed several of the licensee’s operability determination evaluations (ODEs) to support Unit 2 entry into Mode 2. The inspectors found that the corrective actions which were required for Mode 2 entry had been completed, and that licensee’s resolution for each ODE was appropriate.

- On June 7, 2000, during performance of surveillance test Unit 2 Instrument Head Procedure (IHP) 6030.IMP.276, “RTD [resistance temperature detector] Cross-Calibration,” the operators failed to anticipate a reduction in steam generator (S/G) levels. Operators did not observe the decreasing S/G levels caused by performance of the test. The operators later identified that S/G levels had lowered during routine logging of control room parameters. Although the minimum wide range S/G levels required by TS 3.4.1.3, “Reactor Coolant Loops and Coolant Circulation, Hot Shutdown,” were maintained, the inspectors concluded that this failure to closely monitor plant parameters was an example of a human performance error. The licensee wrote CR 00-8237 to document this issue.

O1.2 Observations of Operations Activities During Reactor Startup and Power Ascension (Unit 2)

a. Inspection Scope (71707)

On June 22, 2000, the licensee brought the Unit 2 reactor critical. The inspectors observed the operators approach to criticality, low power physics testing, main turbine startup, and power ascension.

b. Observations and Findings

The inspectors determined that the reactor startup and power ascension were performed in a controlled, deliberate manner. Good command and control of reactivity changes and clear communications were evident. Dedicated operators were assigned to tasks such as reactivity management and steam generator level control. The operators conducted a pre-job brief prior to each complex evolution in accordance with the licensee's procedures for conducting infrequently performed evolutions. Control room staffing exceeded TS minimums throughout the approach to criticality, low power physics testing, and power ascension. Licensee management and Performance Assurance department personnel provided good oversight during the startup and power ascension. The Unit Supervisor (US) and reactor operators (ROs) were aware of plant status, and additional personnel were brought in to assist when necessary. When questioned by inspectors, the ROs were able to explain the reasons for alarms and out of service equipment.

On several occasions during surveillance testing of reactor plant instrumentation, the inspectors noted that an instrumentation and control (I&C) technician would acknowledge the alarms brought in as a result of the testing. Plant Managers Procedure 4043.EQC.001, "Equipment Control," allowed I&C technicians to acknowledge control room alarms which were caused by I&C surveillance testing. In several instances, the inspectors observed that the control room ROs would not look up at the panel to verify that only the expected alarm had come in when an alarm was brought in as a result of the surveillance testing. The inspectors discussed this observation with operations management. Operations management subsequently established an expectation that only control room operators could acknowledge control room annunciators regardless of the cause of the alarm. The inspectors subsequently observed that the control room ROs followed the new expectation and acknowledged each control room annunciator.

The inspectors noted that plant equipment required to startup the Unit 2 reactor performed as designed. Several equipment issues were identified prior to startup, including an incorrect RTD bypass manifold flow alarm setpoint and a rod sequence logic error. The inspectors determined that operators made conservative decisions to stop or delay reactor startup when equipment problems were identified.

c. Conclusions

The inspectors concluded that the Unit 2 reactor startup and power ascension were well controlled and performed in accordance with the appropriate procedures. Operations personnel responded conservatively to several equipment problems which were identified during preparations for starting the Unit 2 reactor.

O1.3 Partial Loss of Offsite Power (Both Units)

a. Inspection Scope (71707, 92700)

On June 8, 2000, both units lost offsite power to the “A” Train buses. The inspectors observed and assessed the licensee’s response to the loss of power.

b. Observations and Findings

On June 8, 2000, the licensee was performing an electrical switching evolution in the plant switchyard. At 9:31 a.m., the feeder breaker to the “A” Train reserve feed transformers opened, causing both units’ “A” Train buses to lose power. At the time of the event, Unit 1 was defueled and supplying spent fuel pool cooling, and Unit 2 was in Mode 4 (Hot Shutdown).

b.1 Plant and Operator Response to the Partial Loss of Offsite Power

After the “A” Train buses lost power, both “A” Train emergency diesel generators (D/Gs) started, and all four Unit 2 reactor coolant pumps (RCPs) tripped. Unit 2 decay heat removal remained available by natural circulation through the steam generators. The safety-related electrical buses automatically shed load, and the safety-related equipment sequenced onto the buses after the D/Gs had restored power to the buses. Because both units’ spent fuel pool cooling pumps receive power from the “A” Train buses, spent fuel pool cooling was lost at the outset of the event when the buses lost power.

The operators entered abnormal Operating Procedure 01[02]-OHP 4022.001.005, “Loss of Offsite Power With the Reactor Shutdown,” for both units. After verifying that power was available to the “A” Train buses from the D/Gs, and that the D/G loading was such that non-critical loads could be added, the Unit 1 operators restored spent fuel pool cooling 22 minutes after the partial loss of offsite power. During that time, the spent fuel pool temperature rose from 84°F to 85°F. Offsite power was restored at 10:19 a.m., and at 10:47 a.m., the operators started the Unit 2, loop 4 RCP which restored forced circulation on Unit 2. Due to low decay heat and the loss of the RCP heat input during the 76 minutes that Unit 2 was in natural circulation, the Unit 2 reactor coolant system temperature dropped from 335°F to 315°F. At 11:34 a.m., the operators secured the Unit 2 “A” Train D/G and exited the Unit 2 loss of offsite power procedure. The Unit 1 “A” Train D/G was secured and the operators exited the Unit 1 loss of offsite power procedure at 12:20 p.m.

The operators identified that, when the ESW pumps sequenced onto the D/G buses, an ESW pressure transient resulted. The ESW pressure transient caused the ESW relief valve on the both the Unit 1 and Unit 2 East Containment Spray (CTS) heat exchangers to lift, but the Unit 2 relief valve failed to reseat. The operators isolated ESW to the Unit 2 CTS heat exchanger and the Unit Supervisor declared the Unit 2 East CTS train inoperable. The valve was replaced and successfully tested on June 9, 2000, and the

Unit 2 East CTS train was declared operable. The licensee wrote CR 00-8378 to evaluate the cause of the relief valve failure to reseat.

Condition Report 00-8384 was written to document the occurrence of the partial loss of offsite power event. The licensee investigated the event and attempted to recreate the conditions which led to the partial loss of offsite power. The licensee's troubleshooting did not reveal any equipment problems; therefore, the licensee concluded that a switching error occurred during the breaker switching evolution. The licensee's conclusion was documented in Licensee Event Report (LER) 50-315/2000004-00. The licensee also concluded that, with the exception of the ESW relief valve on the CTS heat exchanger, the plant responded as expected, and that the safety impact of the event was minimal.

The inspectors observed the operators' response to the partial loss of offsite power. The inspectors determined that the operators had appropriately entered the loss of offsite power procedure and that the operators were monitoring key plant parameters to ensure that Unit 2 reactor core and spent fuel pool safety were maintained. The inspectors reviewed the licensee's event evaluation and determined that the licensees follow up investigation of this event was timely and comprehensive.

b.2 Missed Technical Specification Surveillance on Remaining Offsite Power Source

At the time the "A" Train feeder breaker opened, Unit 2, which was in Mode 4, entered the action statement for TS 3.8.1.1, "A.C. Power Sources, Operating." This action statement required that the remaining offsite power source be demonstrated operable within one hour. However, the licensee identified that the operability of the remaining offsite power source was not verified until 2 hours and 39 minutes into the event. The licensee documented the failure to comply with TS 3.8.1.1 in CR 00-8397.

Technical Specification 3.8.1.1 required, in part, two physically independent circuits between the offsite transmission network and the onsite Class 1E distribution system. TS 4.8.1.1.a required that, with an offsite circuit of the required A.C. electrical power sources inoperable, the operability of the remaining offsite source be demonstrated within one hour by verifying the correct breaker alignments and indicated power availability. Contrary to the above, on June 8, 2000, with one independent circuit between the offsite transmission network and the onsite Class 1E distribution system inoperable due to the "A" Train feeder breaker opening, the licensee failed to demonstrate the operability of the remaining offsite powers source within one hour. The failure to demonstrate the operability of the remaining offsite power source was a violation of TS 3.8.1.1. This Severity Level IV violation is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as CR 00-8397 and as part of LER 50-315/2000004-00 (NCV 50-316/2000016-01).

The inspectors determined that the safety significance of the Unit 2 operators' failure to verify the operability of the remaining offsite power source within one hour was low. When the TS surveillance requirement was completed, Unit 2 operators determined that the remaining offsite power source was operable. In addition, both units' control room operators appropriately entered the loss of offsite power abnormal operating procedure at the outset of the event. These procedures contained steps to restore power to both electrical trains if necessary. Therefore, had the remaining power source been inoperable, the abnormal operating procedures which the Unit 2 operators were using would have provided the appropriate steps to provide power to equipment necessary to ensure reactor safety. Because Unit 1 was defueled at the time of the event, neither TS 3.8.1.1 nor TS 3.8.1.2 were applicable to Unit 1.

b.3 (Closed) Licensee Event Report 50-315/2000004-00: Partial loss of off-site power results in start of emergency diesel generators. The inspectors reviewed the LER which was issued as a result of the partial loss of off-site power. As a short-term corrective action, the licensee issued an Operations Standing Order which required an operator or electrician to accompany any personnel working in the switchyard and verify that any switching operations were done correctly. The licensee planned to modify the switchyard agreement between the Cook Nuclear Plant and the corporate transmission and distribution organization to incorporate the provisions of the Operations Standing Order. The LER did not identify any new issues, and the inspectors determined that the licensee's corrective actions appeared appropriate to prevent recurrence. This LER is closed.

c. Conclusions

On June 8, 2000, both Units lost power to their "A" Train buses due to an apparent switching error. The inspectors determined that the operators had appropriately entered the loss of offsite power procedure and that the operators were monitoring key plant parameters to ensure that Unit 2 reactor and spent fuel pool safety were maintained.

A NCV was identified for the failure to demonstrate the operability of the remaining offsite power source within one hour after the loss of "A" train buses as required by TS. The inspectors noted that the operators had appropriately entered abnormal operating procedures which included steps to restore power to both electrical trains if necessary. Therefore, the inspectors concluded that the safety significance of the missed surveillance was low.

O2 Operational Status of Facilities and Equipment

O2.1 Common Cause Failure of Auxiliary Feedwater Pump Room Coolers (Unit 2)

a. Inspection Scope (71707, 37551)

Between July 1, 2000, and July 8, 2000, the licensee entered into the action statement associated with TS 3.7.1.2.a, "Auxiliary Feedwater System," three times due to operability issues associated with the TDAFWP. Two of these three entries were unplanned. The licensee entered the action statement due to failure of the TDAFWP room coolers, since operability of the TDAFWP depended upon proper operation of the associated room coolers. The inspectors assessed the licensee's root cause determinations and corrective actions for the repeated entries into the TS 3.7.1.2.a action statement.

b. Observations and Findings

During the recently completed Unit 2 outage, the licensee installed two room coolers in the TDAFWP room (2-HV-AFP-T1AC & -T2AC) and one room cooler in each of the motor driven auxiliary feedwater pump (MDAFWP) rooms (2-HV-AFP-EAC & -WAC) in accordance with Design Change Package (DCP)-4261, “Modification of Auxiliary Feedwater Pump Rooms Ventilation.” The room cooler installation permitted the auxiliary feed pump rooms to be sealed for the mitigation of a postulated high energy line break in or near the auxiliary feedwater pumps. The ESW system provided cooling to the ventilation room coolers. Plant Managers Procedure 4030.001.001, “Impact of Safety Related Ventilation on the Operability of Technical Specification Equipment,” Revision 1, required availability ventilation room coolers to ensure operability of the associated pump.

Technical Specification 3.7.1.2.a required three operable auxiliary feedwater pumps with the Unit in Modes 1, 2, and 3. With one auxiliary feedwater pump inoperable, TS action statement 3.7.1.2.a required that the affected pump be restored to service within 72 hours or that the plant be shutdown within the next six hours. During the period of July 1, 2000, through July 8, 2000, the licensee entered the TS 3.7.1.2.a action statement three times, two of these entries were unplanned:

- On July 1, 2000, the licensee entered the action statement to perform planned surveillance testing. On July 4, 2000, while performing the testing, the licensee discovered that the temperature in the TDAFWP room was approximately 100°F. Operations personnel questioned the elevated room temperature and wrote CR 00-9523. During the subsequent investigation, the licensee determined that neither cooler refrigerant compressor was in operation and that ESW flow to the cooler had degraded. As designed, an alarm was not received in the control room to alert operators to the failure of the room coolers. The licensee discovered that normal lake water debris; including sand, silt, and shell pieces; collected in the ESW lines to the room coolers. Engineering Action Plan 00-463 was initiated to develop short and long-term corrective actions, including: monitoring of room temperatures, development of instructions to periodically flush the ESW lines, and installation of flow monitoring instrumentation. The licensee flushed the ESW lines to the coolers and restored adequate ESW flow. The licensee completed the planned testing and exited the TS action statement on July 4, 2000.

- On July 5, 2000, operations personnel questioned if the TDAFWP room coolers were operating properly. The cooler unit compressors appeared to be cycling on and off with the air blower running continuously. The licensee again entered the action statement for TS 3.7.1.2.a and wrote CR 00-9586. The licensee initiated a troubleshooting plan (Job Orders C204931 and C204933) to determine the cause of the unexpected cooler operation. The licensee’s troubleshooting efforts are described in Section E4.1 below. During the course of the troubleshooting effort, the licensee determined that the room coolers were operating as designed, but again discovered degradation in ESW flow.

The licensee determined that, because the ESW return throttle valve was nearly closed, the narrow gap between the valve disk and seat allowed lake water debris to collect at the valve. Because only a single valve was used to control ESW flow, the throttle valve was required to be nearly shut to ensure that maximum flow limits were not exceeded. The debris size was consistent with the mesh size of the ESW pump discharge strainer. The corrective action included using several existing throttle valves in the ESW lines to allow each throttle valve to be opened sufficiently to pass lake water debris. While flushing of the 2-HV-AFP-T1AC was in progress, the operations personnel noted that the ESW flow to the East MDAFWP room cooler decreased below the minimum requirement. The East MDAFWP was declared inoperable, CR 00-9640 was initiated, and TS action statement 3.7.1.2.a for two inoperable AFW pumps was entered. Action statement 3.7.1.2.a required that the unit be placed in Hot Standby within six hours. The licensee flushed the ESW lines to the East MDAFWP room coolers and returned East MDAFWP to an operable status within two hours of identifying the flow degradation. The operability evaluation for CR 00-9586 concluded that the MDAFWP and TDAFWP room coolers were degraded but operable. Compensatory measures for the cooler degradation included frequent monitoring of ESW flow to the coolers and periodic flushing of the ESW lines. On July 7, 2000, the licensee exited the action statement for TS 3.7.1.2.a.

- On July 8, 2000, the TDAFWP was declared inoperable due to room temperature exceeding 85°F. This temperature limit was based upon the Station Blackout Analysis and ensured that the TDAFWP would be available for four hours following a loss of room cooling. The licensee initiated CR 00-9691 and CR 00-9696, entered the TS 3.7.1.2.a action statement, and investigated the cause of the elevated room temperature.

  The licensee determined that the cooler freeze protection temperature switch was set too high and prevented refrigerant compressor operation. The freeze protection switch sensed ESW temperature and prevented refrigerant compressor operation with low lake temperature to prevent icing of the cooler coils. Because the temperature switch was set at 68°F, which was approximately the lake water temperature at that time, the refrigerant compressor did not operate and the cooler heat removal capability without the compressor was insufficient to maintain room temperature below 85°F. The licensee lowered the freeze protection temperature switch setpoint to 62°F, which permitted operation of the refrigerant compressors, and exited the TS action statement on July 9, 2000.

The inspectors concluded that operations personnel exhibited conservative decision making during the loss of TDAFWP room cooling. Operations personnel recognized the dependency of the TDAFWP and MDAFWP on the associated ventilation coolers and appropriately monitored the operation of the cooler units. Operators took proper and prompt actions to restore operability of the auxiliary feedwater pump room coolers and exhibited a questioning attitude concerning operation of the AFW room coolers. Operations personnel effectively communicated with other organizations, including engineering and maintenance personnel.

The inspectors identified one minor procedural violation following the restoration of the TDAFWP to an operable status on July 7, 2000. Plant Managers Procedure 4030.001.001, Attachment 10, Step 3.1.1 required temperature monitoring of TDAFWP room temperature in accordance with Attachment 1, "Temperature Log for Required Monitoring." However, these requirements were not fully met. Although operators were routinely logging AFW pump room temperature, PMP 4030.001.001 contained additional requirements concerning temperature instrument calibration and uncertainty that were not being followed. After the inspectors identified this issue, the licensee took prompt action to comply with the procedural requirements of PMP 4030.001.001 and initiated CR 00-9674. The inspectors concluded that this failure to follow PMP 4030.001.001 requirements was a failure of minor significance and is not subject to formal enforcement action.

c. Conclusions

Between July 4, 2000, and July 8, 2000, repeated failures of the auxiliary feedwater pump room coolers occurred due to inadequate ESW flow. Operators implemented appropriate actions to restore operability of the auxiliary feedwater pump room coolers, closely monitored room cooler performance, and effectively communicated concerns with cooler operation to engineering and maintenance personnel.

O2.2 Failure to Follow High Energy Line Break Barrier Procedures (Unit 2)

a. Inspection Scope (71707)

During a routine plant tour, the inspectors identified discrepancies between actual and required positions for HELB doors. Following this inspection finding, the inspectors performed an assessment of the licensee's procedural controls for HELB barriers.

b. Observations and Findings

In accordance with 10 CFR Part 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants," the licensee implemented design requirements to protect against the postulated affects of a break in a high energy line. A high energy line was defined in the licensee's Updated Final Safety Analysis Report as a piping system with a normal service temperature above 200°F, a normal operating pressure above 275 psig, and a nominal diameter greater than one inch. The proper positioning of HELB doors ensured that mild environment areas containing important plant equipment would not be subject to a harsh environment in the event of a postulated HELB. During the recently completed extended outage, the licensee had identified and corrected a number of HELB issues, including the following Restart Action Matrix Items:

- R.1.14, LER 50-316/98005, "Potential for HELB to Degrade Component Cooling Water system," which was closed in NRC Inspection Reports 50-315/316-2000007.

- R.1.24, LER 50-315/98058, “Postulated HELB Could Result in Condition Outside Design Basis for Auxiliary Feedwater,” which was closed in NRC Inspection Report 50-315/316-2000007.

- R.1.35, LER 50-315/99026-00, “High Energy Line Break Programmatic Inadequacies Result in Unanalyzed Conditions,” which was closed in NRC Inspection Report 50-315/316-2000007.

As a part of the licensee corrective actions for HELB issues, procedural requirements for the control of HELB doors contained in PMP 4030.001.002, “Administrative Requirements for Ventilation Boundary and High Energy Line Break Barriers,” Revision 2, were modified. The plant conditions requiring HELB barriers were Mode 4 and higher.

b.1 Inspector Identification of Improperly Positioned or Labeled HELB Doors

On June 21, 2000, with Unit 2 in Mode 3, the inspectors performed a routine plant tour and identified that turbine building door 12-DR-TUR223 was open. Door 12-DR-TUR223 separated portions of the Unit 2 turbine building from portions of the Unit 1 turbine building that were required to support safe shutdown of Unit 2. Although the door was not labeled as a HELB barrier, the licensee determined that the door was a required HELB barrier. After the inspectors notified the licensees staff of the discrepancies, the door was closed and labeled. Licensee personnel stated that they believed that the failure to label the door as a HELB barrier contributed to the failure to maintain the door closed. Proper HELB door labeling allowed plant personnel who were not familiar with the requirements of PMP 4030.001.002, “Administrative Requirements for Ventilation Boundary and High Energy Line Break Barriers,” Revision 2, to identify and appropriately control HELB doors.

The safety significance of the open HELB door was low because Unit 2 had not yet been restarted, and there were approximately 240 feet between the open door and the protected equipment in Unit 1 that was required to support Unit 2. A licensee walkdown later that day identified 18 other HELB doors that were not properly labeled. The 18 doors were in their required position for HELB protection. The licensee wrote CR 00-9015 to document this issue.

On June 23, 2000, during another routine plant tour, the inspectors again identified that turbine building door 12-DR-TUR223 was open. The door was closed and CR 00-9137 was written by the licensee. The cause for the door being open again was not identified although the door was properly labeled as a HELB barrier. The licensee verified that non-licensed operators were informed of the importance of maintaining HELB doors in their required positions and were trained on the requirements contained within procedure PMP 4030.001.002.

On June 25, 2000, the inspectors identified three auxiliary building doors that were degraded and potentially inoperable. The licensee’s evaluation determined that the doors remained operable because the doors would still easily close and the postulated HELB would tend to push the doors closed. Condition Report 00-9182 was written by the licensee.

b.2 HELB Barrier Control Procedural Weakness

All of the open or degraded HELB doors that were identified by the inspectors were located in well traveled hallways or easily accessible locations. The non-licensed operators and fire protection personnel routinely toured the same areas of the plant but had failed to identify the issues noted above. Licensee management determined that plant staff understanding of the importance of HELB issues needed improvement. The non-licensed operators and the fire protection personnel were briefed on the NRC inspector findings and on the procedural controls over HELB barriers.

The inspectors reviewed Plant Managers Procedure 12-PMP 4030.001.002. The inspectors identified the following procedural weaknesses:

- Procedural requirements for degraded HELB barriers could result in unnecessary TS action statement entries. Plant Managers Procedure 4030.001.002, Step 3.3.1, stated, in part, "If a HELB barrier required to be operable. . . is discovered to be degraded or disabled. . . then. . . Enter the applicable Technical Specification (TS) Limiting Condition for Operation until the condition is evaluated for operability." The inspectors noted that PMP 4030.001.002 requirements did not allow a prompt operability evaluation to be performed prior to declaring the protected equipment inoperable. This procedural requirement could have resulted in declaring protected equipment inoperable when the degraded HELB barrier was capable of performing its intended function.

  Following the identification of three degraded HELB doors on June 25, 2000, the licensee performed a prompt operability evaluation rather than immediately entering the applicable TS action statement. The inspectors concluded that the licensee failed to comply with PMP 4030.001.002 in that the applicable TS action statement was not entered upon the identification of the degraded HELB doors. This was a failure of minor significance and is not subject to formal enforcement action. The inspectors discussed with licensee management that the restrictive requirements in PMP 4030.001.002 regarding degraded HELB doors may have contributed to this occurrence.

- The procedure did not contain specific guidance to indicate which equipment would have been affected by a degraded HELB barrier. In addition there was no guidance in the procedure to assist the SRO in performing a prompt operability evaluation.

- The procedure contained conflicts between required door positions for HELB and the required door positions for room ventilation concerns contained within 12-PMP 4030.001.001. For example, on June 1, 2000, during a routine plant tour, the inspectors identified that the door to the Unit 2 Charging Pump rooms was shut, but the door had a label which stated it needed to be open for ventilation purposes. Additional inspection determined that the door had been closed to comply with HELB requirements. The licensee re-evaluated the door requirements and determined that the Unit 2 Charging Pump room door should remain open for ventilation purposes. The licensee deleted the requirement to close the door for HELB.

- Step 3.2.1 required that, prior to ascending to Mode 4, a HELB door walkdown be performed. The walkdown was to verify that the HELB doors were not damaged, that each door was in its required position, and that the doors were properly labeled. The inspectors determined that the data sheet used for the walkdown did not check for damage or for the installation of labels. A review of the results of the required walkdown determined that the missing labels were not identified. Also, on July 11, 2000, minor damage to foam seals was identified by licensee personnel on two HELB doors. This damage was later assessed and did not affect the HELB function of the doors.

- The procedure did not require any periodic reverification of the HELB door alignment following the initial pre-Mode 4 walkdown.

On July 6, 2000, licensee personnel began periodic re-verification of HELB door positions. As most of the HELB doors were also fire doors, the licensee's fire watch personnel were tasked with checking HELB door positions along with fire doors during the routine fire door tours performed once per 24 hours. In addition, Engineering Action Plan 00-459 was initiated to assist in the systematic identification and resolution of HELB issues.

b.3 Failure to Comply With HELB Procedural Requirements

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 and shall be accomplished in accordance with these procedures. Licensee procedure PMP 4030.001.002, Revision 2, Step 3.1.1, stated that Figure 1 gave the required HELB barrier door position requirements. Figure 1 stated that door 12-DR-TUR223 was required to be closed. Licensee procedure PMP 4030.001.002, Revision 2, Step 3.2.1, stated that the required HELB barrier door position requirements, lack of physical damage to the door, and the proper labeling of the HELB door shall be verified with a walkdown prior to Mode 4.

Contrary to these requirements, door 12-DR-TUR223 was found open instead of closed and the HELB door walkdown did not verify lack of physical damage or proper labeling. This Severity Level IV violation is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as CR 00-9015, 00-9033, and 00-9137 (NCV 50-315/316-2000016-02).

c. Conclusions

An NCV for the failure to follow HELB barrier control procedural requirements was identified. During a routine plant tour, the inspectors twice identified a HELB door that was not in its required position. Subsequent inspector and licensee followup identified three other degraded but operable HELB doors, weak HELB barrier procedural controls, and missing HELB door barrier labels.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62700 and 61726)

The inspectors observed all or portions of the following maintenance activities and reviewed associated documentation:

- Job Order (JO) C0053531 — Install new blow out panel in the Unit 2 East Main Steam Enclosure
- 02-OHP 4030.001.002 — Containment Inspection Tours
- JO C204931 and C204933 — Turbine Driven Auxiliary Feedwater Pump Troubleshooting
- JO C204235 and C205582 — Troubleshoot and Repair Rod Control Logic Cabinet
- JO R81105 — Perform Beginning of Cycle Power Range Nuclear Instrument Calibrations
- JO R79323 and R81061 — Perform Calibration for Intermediate Range Nuclear Instruments
- JO R98426 — Perform Low Power Physics Testing
- JO C204206 and C204051 — Calibrate Loops 3 and 4 RTD Bypass Manifold Low Flow Alarm

b. Observations and Findings

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. Work items were appropriately scheduled in the plan of the day.

c. Conclusions

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 personnel exhibited proper work safety and radiological protection practices. Work items were appropriately scheduled in the plan of the day.

M1.2 Failure to Properly Maintain Scaffolding Configuration Control (Unit 2)

a. Inspection Scope (62707)

During a routine plant walkdown, the inspectors identified scaffolding that interfered with the proper operation of the Unit 2 West Main Steam Enclosure blow out panels. During routine plant walkdowns performed the following day, the inspectors identified additional scaffold interference issues. Following these inspection findings, the inspectors performed an assessment of the licensee's procedural controls for scaffolding.

b. Observations and Findings

Scaffold erection and removal, a maintenance activity, was controlled by Construction Head Instruction (CHI) 5080.CCD.002, Revision 1, "Contractor Scaffold Erection Guidelines," dated January 8, 1998, which was written in accordance with TS 6.8.1. Item 3 of Procedure CHI 5080.CCD.002, required, in part, "Scaffold erected over safety-related equipment or trains shall be "seismically-qualified" scaffold. . . ." Step 4.2.13 of CHI 5080.CCD.002 stated that "Sufficient clearance should be maintained around plant systems and components . . . to allow normal operability and access." During routine plant tours the inspectors identified three scaffolds that were not properly controlled:

- On June 24, 2000, the inspectors identified temporary scaffolding below the blow out panels for the Unit 2 West Main Steam Enclosure. There were four blow out panels and the scaffolding was erected such that vertical poles would have prevented two of the panels from fully opening. At that time, Unit 2 was critical at less than five percent power. In the event of a postulated main steam line break in the Unit 2 West Main Steam Enclosure, the remaining two panels would have functioned to keep the environmental conditions within assumed limits as required by 10 CFR Part 50.49. The portions of the scaffolding that represented the interference were removed and CR 00-9167 was written.

- On June 25, 2000, the inspectors identified non-seismic scaffolding over and outside of the Unit 2 West MDAFWP room cooler. The scaffolding was not seismically qualified. The scaffolding was removed and a past operability determination performed by the licensee concluded that the room cooler and the MDAFWP would have remained operable. The scaffolding was removed and CR 00-9175 was written.

- On June 25, 2000, the inspectors identified non-seismic scaffolding installed in the ceiling of the Unit 2 East Main Steam Enclosure. A walkdown performed by the licensee determined that the scaffolding would require extensive modification (additional bracing) to qualify as seismically qualified. In a seismic event, the scaffold could have damaged the two Main Steam Isolation Valves and/or other safety related equipment in the room. The scaffold was removed and CR 00-9185 was written.

The licensee failed to ensure that scaffolding was controlled to prevent possible operability issues with safety related equipment. Plant walkdowns performed prior to

Mode changes and routine plant tours performed by auxiliary equipment operators failed to identify scaffolding interference.

Technical Specification 6.8.1 required, in part, that written procedures shall be established, implemented and maintained covering the applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978. Regulatory Guide 1.33, “Quality Assurance Program Requirements (Operation),” Revision 2, February 1978, Appendix A, recommended, in part, that procedures be written to cover maintenance activities. Procedure CHI 5080.CCD.002, Revision 1, “Contractor Scaffold Erection Guidelines,” Revision 1, was written in accordance with Regulatory Guide 1.33 to provide guidelines for controlling a maintenance activity, installing scaffolding in the plant. The inspectors identified the following failures to implement the requirements of CHI 5080.CCD.002:

- Item 3 of Procedure CHI 5080.CCD.002, required, in part, “Scaffold erected over safety-related equipment or trains shall be “seismically-qualified” scaffold. . . .” Contrary to the above, on June 25, 2000, the inspectors identified non-seismically qualified scaffold over safety-related equipment in the Unit 2 East Main Steam Enclosure and the Unit 2 West Motor Driven Auxiliary Feedwater Pump room. These two instances of a failure to install seismically qualified scaffolding over safety-related equipment constituted a violation of TS 6.8.1 in that procedure CHI 5080.CCD.002 required seismically qualified scaffold over safety-related equipment.

- Step 4.2.13 of CHI 5080.CCD.002 stated that “Sufficient clearance should be maintained around plant systems and components . . . to allow normal operability and access.” Contrary to the above, on June 24, 2000, the inspectors identified scaffolding which interfered with the operability of the Unit 2 West Main Steam Enclosure blow out panels which serve a safety-related function to open. This failure to maintain sufficient clearance between scaffolding and plant systems constituted a violation of TS 6.8.1 in that procedure CHI 5080.CCD.002 required sufficient clearance to be maintained around plant systems and components to allow normal operability.

These two examples of a Severity Level IV violation of TS 6.8.1 are being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy. This violation is in the licensee’s corrective action program as CR 00-9167, 00-9175, and -9185 (NCV 50-315/316-2000016-03).

c. Conclusions

An NCV for the failure to follow scaffolding installation procedure requirements was identified. During a routine plant tour, the inspectors identified three non-seismically qualified scaffolds in the main steam enclosures and an auxiliary feedwater pump room that could have interfered with the proper operation of equipment. The scaffolding was in well traveled areas yet was not identified during plant tours by licensee personnel.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Performance of Containment Closeout Inspection and Review of Inspection Procedure (Unit 2)

a. Inspection Scope (61726)

The inspectors performed a containment closeout inspection following the licensee's performance of their containment closeout inspection tour. The inspectors observations are discussed below and in Section E8.1, below.

b. Observations and Findings

The inspectors performed a detailed walkdown inspection of Unit 2 containment after the licensee determined that containment was ready for restart. During the walkdown, the inspectors verified that selected valve positions were appropriate for the current operating mode, any leaks identified were documented in the corrective action system, debris was not laying about containment, and that fibrous material was properly controlled.

The inspectors identified small amounts of loose debris such as duct tape, nails, screws, nuts, plastic tie wrap, and maslin cloth. The debris identified would not have challenged the operability of the recirculation sump. The inspectors also identified minor ice build up on the intermediate deck doors located in the upper ice condenser. The licensee removed the ice and made operational changes to eliminate the ice build up. The ice build up did not result in an inoperable ice condenser and licensee inspection tours of the ice condenser were increased to once per day to ensure the ice build up had been appropriately addressed.

Subsequently, the licensee continued to find ice buildup and increased the tours to once per shift (12 hours). Additional operational changes were made to the ice condenser air handling units to minimize the ice buildup. The inspectors' findings for the assessments of upper and lower containment were documented in CRs 00-8043 and 00-8106.

The inspectors reviewed the recently revised May 18, 2000, containment inspection tour procedure and noted that a portion of the procedure provided direction for boric acid program observation activities. The inspectors found that boric acid identification terms were not defined and it appeared that Figure 3 of the tour procedure, which contained a list of boric acid susceptible components, was not complete. For example, Section 3.2 for the pressurizer area of containment was missing the pressurizer heater penetrations. The inspectors observed that the procedure had not received the appropriate cross discipline review by the Boric Acid Program staff. As a result, the containment tour staff were unaware of boric acid program changes or that the procedure had been placed on administrative hold, and therefore there would not have been an official copy available for use during containment walk-down tours. The licensee issued CRs 00-7815 and 00-7673 to address these issues and corrected the procedural deficiencies prior to the performance of containment walkdowns.

c. Conclusions

The inspectors determined that the material condition of the Unit 2 containment was good and ready for restart of the Unit. The containment closeout surveillance performed by the licensee was of good quality and was effectively performed.

III. Engineering

E1 Conduct of Engineering

E1.1 Safeguards Test Cabinet Failure Mechanism (Both Units)

a. Inspection Scope (37550)

The inspectors reviewed the design of the Safeguards Test Cabinet (STC) and related engineered safeguard features (ESF) equipment to determine if a failure of components housed in the STC cabinet could inhibit an ESF Actuation Signal (ESFAS). Various drawings, FSAR sections, Technical Specifications, and NSSS vendor documents were reviewed. Personnel in Engineering and Instrument Maintenance were interviewed. A walkdown of the Unit 1 Train "B" STC was conducted.

b. Observations and Findings

b.1 Solid State Protection System (SSPS) and STC Design

The SSPS used multiple relays to initiate ESF actions for accident mitigation; there was a separate Train "A" and Train "B" subsystem to meet the single failure criteria of the August 1968 draft of IEEE 279 "Proposed Criteria for Nuclear Power Plant Protection Systems." The first level output of the SSPS logic channels was the K500 series "Master Relay" which energizes in response to accident conditions. The K500 series relays in turn would energize K600 series "Slave Relays." When the K600 Slave Relays coils energize, K600 contacts would change state resulting in ESF end device actuation. Some K600 Slave Relays were combined together to drive an auxiliary K600 series relay which in turn was used to actuate the ESF components.

There were two basic tests which could be conducted with the STC; "Go Tests" result in actuating ESF devices to their accident response conditions. "Block Tests" use special circuitry to test the ESF circuits without actuating end devices where equipment operation could be disruptive while the plant is at power. The Block Tests were associated with ESF functions such as main turbine and generator trips, closure of main steam and feedwater isolation valves, and isolation of critical RCP support systems such as seal water injection and lube oil cooling. The Block Test circuit designs were further subdivided into designs which have normally closed K600 contacts open for ESF actuation, and those which have normally open K600 contacts closed for ESF actuation.

The time of licensing (TOL) FSAR included Question and Answer (Q&A) 7.11. In their response to 7.11, the licensee stated that STC was designed and installed to permit testing of SSPS actuated components at both shutdown and power conditions. The licensee described the capability of the STC during power operation as well as procedures which would use it, but informed the inspectors that they had not committed to use the STC while at power. These tests were initiated by switches in the STC which energize the K800 series relays; by design each K600 Slave Relay should have one or more K800 relay's associated with it. This provided the capability to start some ESF components such as Emergency Core Cooling System (ECCS) pumps without opening related emergency flow path valves.

The answer to question 7.11 also contained the following description of the block circuit function: "For those devices which cannot be actuated, the procedure provides for checking from the process signal to the logic rack and from there, low voltage application to output cables to circuit breakers and valve starters. The actuation testing is therefore a continuation of the testing described in Topical Report WCAP-7672 and is totally in conformance with the requirements of IEEE-279." The inspectors noted that although the SSPS used low voltages to verify circuit continuity of the Slave Relay coils, the STC did not use low voltage signals to verify circuit continuity to the end device.

The inspectors noted minor technical errors in Q&A 7.11 including an incorrect list of circuits which would use Block Tests at power to verify ESF system operability. The licensee initiated CR 00-8474 to address the technical errors in Q&A 7.11.

b.2 STC Use

Earlier vintage NSSS vendor, Westinghouse, relay systems did not permit online testing of ESF circuits down to the actuated components and the initially proposed SSPS did not permit testing beyond the Slave Relay coils. The STC was designed by the NSSS vendor to fill the testing gap between the Slave Relay coils and the end device actuation circuit.

Subsequent to the FSAR response the Technical Specifications were approved which required end device testing of ESF signals once every refueling cycle (currently every 18 months.) Therefore the licensee's TSs did not require ESF end device testing at a periodicity which would make online testing desirable. As a result, the licensee chose to not use the STC for routine ESF component testing.

In the response to TOL FSAR question 7.11, the licensee stated the SSPS would have the "capability for testing completely from the process signal to the logic cabinet and from there to the individual pump circuit breakers, valve starters or solenoid valves, including all cabling used in the circuitry called upon to operate for an accident condition." This entire Q&A was incorporated in the FSAR in the 1982 time period. Additionally, the update included the statement in Section 7.52 "All pumps and valves associated with the Engineering Safeguards System are being tested in the manner described with the following exceptions: ..." The FSAR statements clearly indicate the licensee was using the STC for ESF testing, but a 1985 internal document acknowledged the STC was not being nor was it ever used for complete ESF circuit testing on or offline.

In 1987, the description of the ESF testing was removed from the FSAR, and in 1995 a statement was added explicitly stating online testing with the STC would not be done.

The licensee was not able to locate a written safety evaluation for the 1987 or 1995 changes to the FSAR.

b.3 STC Failure Analysis

The SSPS and ESF actuation circuits were made more complex to support the online testing features provided by the STC. The inspectors noted during the review of the Slave Relay test circuitry that there were two nondesirable effects of test relay circuitry failure. If the test relay inadvertently energized or if the relay contacts in the ESF component failed to the energized relay condition for the Go Test circuits when no ESF actuation condition existed, the ESF device would go to its accident condition. This failure would be self disclosing if the component was in its non-accident condition. For example, if a Safety Injection (SI) pump started without operator action and no valid autostart signal existed, the pump starting would be easily detected by operating crews. A licensee I&C design engineer stated an inadvertent ESF is addressed in the accident analysis.

For a Block Test, if the test relay was inadvertently energized or the test relay contact failed to the energized relay position, and a concurrent or a subsequent valid ESF actuation signal existed, the ESF component would not receive a signal to go to the accident condition. The failure of the relay or contact would not be detected unless personnel noted the associated white indicator inside the normally locked closed STC was not illuminated. Licensee operations and maintenance personnel stated STC was only used during shutdown periods by Performance Engineering personnel who use only a small subset of the STC as a convenient means for outage related testing. Therefore, the inspectors concluded the failure would probably remain undetected until the next refueling outage. The licensee stated the latent failure of the relay or its contacts would fall under the category of the single failure assumed in accident analysis. The inspectors were unable to determine if this is an appropriate single failure assumption and forwarded the question of whether a relay failure should be treated as a single failure to the Office of NRR. Pending the response of the Office of NRR and the inspectors' review, the issue of whether the latent failure of a test relay would fall under the category of a single failure will remain an Unresolved Item (URI 50-315/316-2000016-05(DRS)).

b.4 STC Configuration Control

The inspectors compared various licensee schematic drawings with those issued and approved by the NSSS vendor, and compared the panel switch arrangement with the installed Unit 1 Train "B" STC. Discrepancies between the in-house and vendor drawings were identified including the test circuit for fan HV-CEQ-1 and 2, and feedwater regulating and isolation valves FMO-201 and -204, and FRV-210, -220, -230, and -240. The licensee initiated CR 00-8537 to address these discrepancies. The inspectors concluded that the design drawing discrepancies were of minor significance and were not subject to formal enforcement action.

c. Conclusions

The inspectors identified an Unresolved Item regarding single failure vulnerability of failures of relays in the Safeguards Test Cabinet. The Safeguards Test Cabinet was installed to permit online testing of Engineered Safety features actuating circuits beyond the slave relay coils. Failures of relays may go undetected during plant operation.

E2 Engineering Support of Facilities and Equipment

E2.1 Failure to Establish Appropriate Trip Setpoints for Intermediate Range and Power Range Nuclear Instrumentation (Unit 2)

a. Inspection Scope (37751)

Following Unit 2 restart, the licensee conducted power ascension physics testing in accordance with Unit 2 Engineering Head Procedure (EHP) 6040 PER.359, “Zero Power and Power Ascension Tests for Post-Refueling Startups,” Revision 5. Technical Specification 3.10.3, “Special Test Exceptions - Physics Tests,” allowed suspension of rod insertion limits during low power physics testing provided certain conditions were met. The inspectors reviewed the licensee’s compliance with the required actions of TS 3.10.3.

b. Observations and Findings

During low power physics testing, the licensee completed rod worth verification testing per 12-EHP 6040 PER.352, “Rod Worth Verification Test Utilizing RCC [Rod Control Cluster] Bank Interchange.” Control rod worth measurement using the bank interchange method required control rod insertion in excess of TS 3.1.3.5, “Shutdown Rod Insertion Limit,” and TS 3.1.3.6, “Control Rod Insertion Limit.” Technical Specification 3.10.3 allowed suspension of rod insertion limits provided that: (1) reactor power was less than five percent of rated thermal power (RTP), and (2) reactor trip setpoints for the intermediate range (IR) neutron flux and the power range (PR) neutron flux, low setpoint were set less than or equal to 25 percent of RTP.

Procedure 12-EHP 6040.PER.357, “Initial Criticality, All Rods Out Boron Concentration and Nuclear Heating Level,” Revision 7b, established reactor power limitations to ensure that reactor thermal power was maintained less than five percent rated thermal power during low power physics testing. Calibration and setpoint data for the IR and PR nuclear instrumentation was determined by the methodology of procedure 12-EHP 6040 PER.364, “Excore Nuclear Instrumentation Calculations and Thermocouple Selection,” Revision 7. Calibration and setpoint data was calculated by adjusting the calibration settings from the last operating cycle to reflect changes in relative fuel bundle power between the last cycle to the predicted relative power for the upcoming fuel cycle. The licensee’s methodology did not adjust calibration data to account for analytical and instrument uncertainties.

Reactor engineering forwarded IR and PR calibration data to Instrumentation and Control (I&C) personnel via design information transmittal (DIT) 00-00484. The inspectors reviewed DIT 00-00484 and the results of nuclear instrumentation calibrations documented in 2-IHP 4030.SMP.230, “Intermediate Range Nuclear Instrumentation Functional Test and Calibration,” and 2-IHP 4030.SMP.231,”Power Range Nuclear Instrumentation Functional Test and Calibration.” The I&C personnel calibrated the IR and PR instruments in accordance with the data provided by reactor engineering.

During power ascension, the licensee determined that the trip setpoints for both IR instruments, N35 and N36, exceeded 25 percent of rated thermal power. Furthermore, the setpoint for IR N36 exceeded the 30 percent allowable limit specified by TS 2.2.1, “Limiting Safety System Settings.” The licensee later determined that N35 and N36 would have tripped at the approximate rated thermal power levels shown in the table below:

<u>Approximate Rated Thermal Power Setpoints</u>
<u>for Intermediate Range Nuclear Instrumentation</u>

Intermediate Range Instrument	Actual Neutron Flux, Low Power, Trip Setpoint	TS 3.10.3.b Required Reactor Trip Setpoint	TS 2.2.1 Allowable Reactor Trip Setpoint
N35	29% RTP	Less than or equal to 25% RTP	Less than or equal to 30% RTP
N35	36% RTP		

The licensee declared N36 inoperable in accordance with TS 3.3.1.1 and initiated CR 00-9180. Technical Specification 3.3.1.1 Table 3.3-1, required that both IR nuclear instruments be operable in Modes 1 and 2. At the time N36 was declared inoperable, reactor power exceeded five percent RTP and the action associated with one inoperable IR instrument allowed continued power operation. However, because the licensee failed to recognize the condition until reactor power was raised to approximately 20 percent RTP, the actions specified by TS 3.3.1.1, Table 3.3-1 were not met during the startup and power ascension.

The power ascension procedure required several power holds in order to perform in-core flux mapping and reactor thermal power determinations. Following the initial thermal power determinations, the licensee determined that several PR instruments were reading non-conservatively and required an adjustment to increase the instrument gain. Because a change in instrument gain impacted the nuclear instrument indicated power and the actual core thermal power corresponding to the high neutron flux trip setpoint, the inspectors questioned if the low initial gain settings could have resulted in inoperability of the associated PR instrument during startup and power ascension. Based on the inspectors’ questions, the licensee evaluated the PR trip points and determined that the PR nuclear instruments would have tripped at the approximate thermal power levels shown below:

Approximate Rated Thermal Power Setpoints for Power Range Nuclear Instrumentation

Power Range Instrument	Actual Neutron Flux, Low Power, Trip Setpoint	TS 3.10.3.b Required Reactor Trip Setpoint	TS 2.2.1 Allowable Reactor Trip Setpoint
N41	25% RTP	Less than or equal to 25% RTP	Less than or equal to 26% RTP
N42	26% RTP		
N43	28% RTP		
N44	28% RTP		

As shown above, the neutron flux, low setpoint, value for N42, N43, and N44 exceeded the TS 3.10.3.b limit of less than or equal to 25 percent RTP. Additionally, the setpoint for N43 and N44 exceeded the TS 2.2.1 allowable limit of less than or equal to 26 percent. The licensee wrote CR 00-9197 to address this condition. The inspectors concluded that the failure to comply with the actions of TS 3.10.3 and TS 3.3.1.1 was due to failure of engineering personnel to provide sufficient margin in the IR and PR instrumentation setpoints to account for the effects of instrument or analysis uncertainty.

Technical Specification 3.3.1.1 required, in part, a minimum of three operable PR neutron flux channels and two operable IR neutron flux channels for operation in Modes 1 or 2. Technical Specification 2.2.1 required, in part, that an IR channel be declared inoperable if the trip setpoint for the IR, neuron flux reactor trip was greater than 30 percent RTP. Additionally, TS 2.2.1 required, in part, that a PR channel be declared inoperable if the trip setpoint for the PR, neutron flux, low setpoint was greater than 26 percent RTP. Contrary to the above, the licensee entered Mode 2 on June 22, 2000, and continued operation in Mode 1 through June 26, 2000 with one IR channel and two PR instruments exceeding the allowable reactor trip setpoint of TS 2.2.1. This condition resulted in the failure to meet the minimum operable channel requirements of TS 3.3.1.1 in that operation in Modes 1 and 2 continued with one inoperable IR channel and two inoperable PR channels during the period of June 22, 2000, through June 26, 2000. The inspectors determined that the failure to comply with TS 3.3.1.1 was a Violation of NRC requirements. This Severity Level IV violation is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as CR 00-9180 and CR 00-9197 (NCV 50-316/2000016-05).

Technical Specification 3.10.3.b required that the trip setpoints for the operable IR, neutron flux, and the PR, neutron flux, low setpoint, be set at less than or equal to 25 percent of rated thermal power in order to suspend the requirements of TS 3.1.3.5 and TS 3.1.3.6. Contrary to the above, during the period June 23, 2000 through June 24, 2000, the licensee conducted control rod worth verification testing per 12-EHP 6040.PER.352. During performance of 12-EHP 6040.PER.352, the licensee inserted control rod shutdown and control banks in excess of the insertion limits specified by TS 3.1.3.5 and TS 3.1.3.6. The licensee failed to comply with the requirements of TS 3.10.3.b in that the setpoint for both IR neutron flux channels exceeded 25 percent RTP and the setpoint for three of the four PR, neutron flux, low setpoint, reactor trip channels exceeded 25 percent RTP. The inspectors determined that the failure to comply with TS 3.10.3 was a Violation of NRC requirements. This Severity Level IV violation is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as CR 00-9180 and CR 00-9197 (NCV 50-316/2000016-06).

Updated Final Safety Analysis Report Table 14.1.0-6, "Plant Systems and Equipment Available for Fault Conditions," credited the actuation of the PR, neutron flux, low setpoint, reactor trip during the following accidents: (1) uncontrolled Rod Control Cluster Assembly Withdrawal form a subcritical condition, and; (2) feedwater system malfunctions that result in an increase in feedwater flow. The accident analyses assumed an analytical trip value of 35 percent RTP for the PR, neutron flux, low setpoint. The difference between the nominal setpoint and the safety analysis value represented an allowance for instrumentation channel error and setpoint error. The bases for TS 2.2.1 did not credit actuation of the IR neutron flux reactor trip in the accident analysis. Based upon the actual trip setpoints established for PR nuclear instruments, the inspectors concluded that the safety significance of this event was minimal.

c. Conclusions

The inspectors identified an NCV of TS 3.3.1.1 when the Unit 2 reactor entered Mode 2 on June 22, 2000, and continued operation in Mode 1 through June 26, 2000, with one intermediate range channel and two power range channels exceeding the allowable reactor trip setpoint of TS 2.2.1. This condition resulted in the failure to meet the minimum operable channel requirements of TS 3.3.1.1. Because the safety analysis bound the actual trip setpoints, the safety significance was minimal.

The inspectors identified an NCV of TS 3.10.3.b when the licensee conducted control rod worth verification testing during the period June 23, 2000 through June 24, 2000. TS 3.10.3.b required that the trip setpoints for the operable intermediate range, neutron flux, and the power range, neutron flux, low setpoint, be set at less than or equal to 25 percent of rated thermal power. Because the safety analysis bound the actual trip setpoints, the safety significance was minimal.

E4 Engineering Staff Knowledge and Performance

E4.1 Engineering Staff Performance During Common Cause Failure of Auxiliary Feedwater Pump Room Coolers (Unit 2)

a. Inspection Scope

As discussed in Section O2.1 above, the licensee experienced repeated failures of the auxiliary feedwater pump room coolers. Engineering personnel provided support in the development of troubleshooting plans, evaluation of cooler performance, and implementation of corrective action. The inspectors assessed engineering support to operations during the repeated entries into TS action statements for TDAFWP inoperability. The inspectors also assessed the implementation of DCP-4261, "Modification of Auxiliary Feedwater Pump Rooms Ventilation," design requirements.

b. Observations and Findings

The inspectors reviewed Engineering Action Plan 00-463 and troubleshooting plans for the AFW room coolers (Job Orders C204931 and C204933) and determined that the corrective actions for restoration of the room coolers to service were thorough. The inspectors attended several meetings related to the troubleshooting and corrective actions for the room coolers and noted that there was good communications among participating organizations, including operations, engineering, and maintenance personnel. The licensee responded to the cooler failure within the time constraints of TS 3.7.1.2.a. The troubleshooting efforts identified the root causes of degraded cooler performance and established appropriate compensatory actions to ensure continued cooler functionality.

Although the troubleshooting effort successfully returned the AFW room coolers to service within the TS allowed outage time, the inspectors identified a number of issues concerning the room cooler failures. These issues included the following:

- The lack of understanding of chiller operation by engineering personnel resulted in additional unnecessary out of service time for the TDAFWP. During the cooler troubleshooting efforts on July 6, 2000, the inspectors noted that there was some confusion among licensee personnel regarding the proper operation of the room cooler units. The licensee initially believed that the chiller control system was not operating correctly and that the freeze protection temperature switch was incorrectly set.

  The design of the room cooler modification was performed during the recently completed outage. The design included the freeze protection function. Nevertheless engineering required approximately 20 hours to determine that the cooler was operating as designed and that the freeze protection setpoint was in accordance with the design change package.

  On July 8, 2000, the TDAFWP room temperature exceeded the operability limit of 85°F. This condition resulted in an additional entry into the TS 3.7.1.2.a action statement due to TDAFWP inoperability. Additional evaluation and investigation was required in order to identify that the freeze protection setpoint was set too high. On July 9, 2000, following a reduction in the freeze protection setpoint and increased cooling to the pump room, the licensee exited the TS action statement.

- Station blackout analysis limitations were not reflected in operations procedures. On July 4, 2000, the licensee discovered that the TDAFWP room temperature had risen to approximately 100°F. In accordance with 10 CFR 50.63, "Loss of all alternating current power," the unit must be able to withstand and recover from a station blackout. Calculation MD-12-HV-033-N, "Turbine Driven Auxiliary Feedwater (TDAFW) Pump Room Temperature Under Station Blackout Conditions," assumed an initial TDAFWP room temperature of 85°F. As designed no control room alarms were actuated as a result of either the cooler unit failure or elevated room temperature.

  The inspectors questioned the basis for the 85°F initial temperature assumption based upon the following: (1) no control alarms were available to alert operators of cooler failure with the coolers in automatic mode (the normal operating condition), (2) the room high temperature alarm would not be actuated until the room temperature reached approximately 110°F, and (3) routine operator rounds of the TDAFWP room, conducted in accordance with 02-OHP 5030.001.001, "Operations Plant Tours," required a general area check but did not specify maximum temperature requirements. The operability determination for CR 00-9586 determined that the TDAFWP and MDAFWPs were degraded but operable. Compensatory measures for the degraded condition included periodic monitoring of ESW flowrates to the cooler and flushing of the ESW lines as required. Additionally, PMP 4030.001.001 required periodic monitoring of TDAFWP room temperature in the event that one room cooler fails. The corrective actions for CR 00-9586 included actions to evaluate the TDAFWP room alarms and temperature monitoring during routine operator rounds. Although the inspectors concluded that the licensee adequately factored SBO temperature limitations into the TDAFWP operability after the cooler failures, engineering and operations failed to ensure that analysis assumptions were reflected in plant procedures following installation of DCP-4261.

- Common cause failure mechanisms for AFW Room Coolers was not adequately considered during the development of DCP-4261. Because the licensee determined that installation of AFW ventilation room coolers represented an unreviewed safety question, the licensee requested a licensee amendment to allow installation of the coolers on February 18, 2000. In their amendment request, the licensee stated that the room cooler installation introduced a new dependency of AFW room cooling on the ESW system, but that the loss of ESW initiating event frequency was conservatively estimated as 2.79×10^{-5} per reactor year. Following NRC review of the license amendment request, Unit 2 license amendment 225 was issued on April 25, 2000. In the Safety Evaluation Report (SER) for license amendment No. 225, the NRC concluded that the small potential risk increase due to the AFW dependency on ESW would be substantially compensated by the risk decrease due to elimination of the HELB vulnerability. The licensee's safety evaluation (SE) for DCP-4261 (SE 1999-1602) stated that "a common cause failure related to either maintenance or design is not considered credible." Additionally, the SE stated that "there is no credible common mode failure of the ESW cooling supply that could cause a failure of all AFW room coolers."

The inspectors questioned the validity of the information presented in the license amendment request and the SE because of the repeated failures of the AFW room coolers between July 4, 2000, and July 9, 2000. The inspectors concluded that engineering personnel did not adequately consider a potential common cause failure mechanism for the AFW room coolers. The licensee informed the inspectors that they believed that the common cause failure of the TDAFWP and MDAFWP room coolers due to degradation in ESW flow would be reportable per 10 CFR 50.73, "Licensee event report system." The licensee's reportability conclusion was based upon 10 CFR 50.73(a)(2)(vii), which required "any event where a single cause or condition caused at least . . . two independent trains . . . to become inoperable in a single system" to be reported.

c. Conclusions

The inspectors concluded that engineering personnel did not adequately consider a potential common cause failure mechanism for the auxiliary feedwater (AFW) room coolers. Consequently, degradation of flow in the Essential Service Water (ESW) cooling lines, a common cause failure mechanism, resulted in repeated failures of the AFW room coolers. Additionally, plant procedures did not adequately reflect the station blackout analysis initial condition for TDAFWP room temperature. The lack of understanding of TDAFWP room cooler control circuit operation by engineering personnel resulted in unnecessary additional time with an out-of-service TDAFWP.

E4.2 Engineering Errors in Flow Switch Setpoint Calculation (Unit 2)

a. Inspection Scope (37551)

Prior to Unit 2 restart, the licensee lowered the setpoints for the reactor coolant loops 3 and 4 RTD bypass manifold low flow alarm in order to reduce intermittent low flow alarms. The revised setpoint and basis were documented in DIT B-1355. The inspectors reviewed the DIT methodology and the basis for the revised low RTD bypass flow setpoint alarm setpoint.

b. Observations and Findings

On June 18, 2000, the licensee increased the alarm setpoint of flow switch 2-NFA-230, "Reactor Coolant Loop 3 Hot & Cold RTD Bypass Manifold Intermediate Leg Low Flow Alarm Switch," to a nominal value of 316 gpm. The normal operating flow in the RTD bypass manifold was approximately 325 gpm. Fluctuations in measured flow caused repeated actuations of the low bypass flow alarm for the loop 3 RTD bypass manifold. The licensee documented these intermittent flow alarms in CR 00-8918. In order to reduce the occurrence of intermittent low flow alarms, the licensee lowered the nominal flow switch setpoint for the loops 3 and 4 low flow alarm to 280 gpm on June 19, 2000.

The inspectors reviewed the engineering analysis associated with the lower alarm setpoint to determine if the revised setpoint adequately reflected safety analysis assumptions. The low RTD bypass flow alarm was designed to alert control room operators of degraded flow conditions or blockage in the RTD bypass manifold. Flow reduction in the manifold would have resulted in a longer time response for safety-related loop cold and hot leg RTDs and potential inoperability of the loop temperature instrumentation. Low manifold flow conditions could potentially impact the time response and operability of several reactor trip functions, such as the overpower delta temperature (OPΔT) and over temperature delta temperature (OTΔT) trips. Annunciator Response Procedure 02-OHP 4024.207, "Annunciator #207 Response: Reactor Coolant," required the bistables associated with the affected RTD bypass manifold temperature detectors to be placed in a tripped state in accordance with TS 3.3.1.1. The licensee's methodology for setting the low flow alarm setpoint required that the setpoint be set high enough to ensure that the transport time between the reactor loop and the RTDs was less than one second. This one second transport time was consistent with accident analysis assumptions discussed in UFSAR Chapter 14, Table 14.1.0-4, "RPS [Reactor Protection System] Trip Points and Time Delays."

The bypass manifold was arranged with a cold leg tap located downstream of the reactor coolant pump and a hot leg tap located upstream of the steam generator. After the bypass flow from each leg passed through the associated RTDs, the hot and cold leg bypass combined into a single return line to the suction of the reactor coolant pump. Due to this piping arrangement, the flow path associated with the cold leg RTDs experienced a higher differential pressure than the hot leg RTD flow path. Because the bypass manifold flow switch was located on the combined return line, a reduction in manifold flow would indicate flow degradation in either one or both of the manifold flow legs.

The inspectors identified three errors with the licensee's analysis and modeling assumptions supporting the reduction of the low bypass flow setpoint to 280 gpm:

- The analysis did not consider bypass manifold blockage as a potential cause of reduced bypass manifold flow. The licensee calculated the low flow alarm setpoint based on a postulated reduction in differential pressure across the entire manifold. Decreased differential pressure across the manifold would have resulted in a reduction in flow in both the hot and cold legs. Previous analyses considered the more bounding case that the postulated bypass manifold flow reduction was caused by a blockage in either the hot or cold manifold leg. Blockage of either a hot or cold bypass leg would have resulted in an increase in flow in the unblocked leg. The licensee's failure to consider the effect of blockage in the manifold legs contributed to the calculation of a non-conservative low alarm setpoint.

- The failure to accurately model the differential pressures in the bypass manifold would have resulted in an incorrect estimate of hydraulic resistance and inability to correctly predict flow response to changes in differential pressure. The model assumed that the differential pressure across the bypass manifold hot and cold legs was equal. The differential pressure across the manifold cold leg was roughly equivalent to the reactor coolant pump developed head, while the differential pressure across the bypass manifold hot leg was roughly equivalent to the differential pressure across the steam generator. Consequently, the actual differential pressure across the cold leg side of the manifold was between two and three times the differential pressure across the hot leg portion of the bypass manifold.

- The hydraulic resistance of the manifold piping was assumed to be directly proportional to the flowrate rather than the square of the flowrate. Use of a linear function for hydraulic resistance would have predicted a smaller change in pressure drop for a given change in flowrate.

In response to the inspectors' questions, the licensee re-evaluated their analysis and determined that the alarm setpoints for the loop 3 and 4 low bypass flow alarm were set non-conservatively. The inspectors reviewed the revised analysis, documented in calculation MD-02-RCS-006-N, "RTD Bypass Flow Rates," and identified no additional errors. On June 20, 2000, the setpoints for the loop 3 and 4 flow alarms were reset to a nominal value of 305 gpm and 296 gpm, respectively.

The inspectors concluded that the licensee performed an inadequate analysis supporting the reduction of the RTD bypass manifold low flow setpoint to 280 gpm. Because Unit 2 was in Mode 3 during the period, and reactor trips impacted by the RTDs were not required, the safety impact of this occurrence was minimal. The licensee recalibrated the loop RTD bypass manifold setpoints prior to mode ascension to Mode 2.

c. Conclusions

The inspectors determined that the licensee performed an inadequate engineering analysis supporting the reduction in the resistance temperature detector (RTDs) bypass manifold low flow alarm setpoint. A low flow condition in the bypass manifold could have resulted in longer time response for the loop hot and cold leg RTDs or inoperability of reactor trip and engineered safeguards functions associated with loop temperature. The licensee performed additional analysis and revised the affected alarm setpoints prior to the RTDs being required by the TSs.

E8 Miscellaneous Engineering Issues

E8.1 (Closed) Case Specific Checklist Item 13, "Systems and Containment Readiness Assessments"

a. Inspection Scope (37551)

By NRC letter dated September 17, 1999, the NRC transmitted the updated Case Specific Checklist for the D.C. Cook Nuclear Plant, which identified specific issues requiring resolution prior to restart. The inspectors focused on the licensee's corrective actions for resolution of Case Specific Checklist Item 13, "Systems and Containment Readiness Assessments."

The standard applied to evaluate the acceptability for resolution of these items was that described in paragraphs C.1.1 “Root Cause Determination,” C.1.2 “Corrective Action Development,” and C.1.3 “Corrective Action Plan Implementation and Effectiveness,” of Enclosure (2) of the NRC letter transmitting the CSC.

b. Observations and Findings

Systems and containment readiness assessments were performed in two parts. Portion 13A, addressed systems and containment problem discovery, and portion 13B, addressed systems and containment final readiness review. Problem discovery (13A) was assessed as part of the Expanded System Readiness Reviews (ESRR) and documented in NRC Inspection Reports 50-315/316-99002, 99003, 99006, and 99007. Problem discovery was determined to be adequately performed and CSC 13A was closed.

Systems and containment final readiness review (13B) was assessed as part of the Restart Readiness Assessment Team Inspection (RRATI) which was documented in NRC Inspection Report 50-315/316-2000003, and in resident inspector activities documented in this inspection report. In addition to the eight systems that were assessed by the RRATI, the resident inspectors assessed three additional systems. The systems assessed were the radiation monitoring system, nuclear instrumentation, and the engineered safety features ventilation system. Based upon the sampling performed, the inspectors concluded that system open items were appropriately closed, exceptions were properly documented and tracked, systems were properly lined-up, and corrective maintenance items appropriately prioritized and scheduled. The inspectors determined that the systems were ready for restart.

Containment final readiness for restart was assessed in NRC Inspection Report 50-315/316-99026 as part of the closeout of CSC Item 6 on ice condenser readiness, 50-315/316-2000003 and 07 on CSC Item 11, hydrogen mitigation system resolution, and 50-315/316-99029 on CSC Item 8, hydrogen recombiner operability issues. Additional inspections were performed as part of the RRATI and resident inspection activities documented in this inspection report.

In addition to the RRATI assessment of containment readiness, the resident inspectors performed a detailed walkdown of containment following the licensee’s declaration that containment was ready for restart. The inspectors’ walkdown included upper and lower ice condenser, refueling cavity, reactor head cavity, under vessel area, containment spray headers, polar crane, annulus, accumulator rooms, in-core instrument room, and regenerative heat exchanger room. The results of the resident inspectors’ containment walkdown is discussed in Section M2.1.

Based upon the information noted, the inspectors determined that CSC Item 13B, “Systems and Containment Final Readiness Review,” was closed.

c. Conclusions

The inspectors determined that licensee corrective actions related to Case Specific Checklist Item 13, "Systems and Containment Readiness Assessments," were adequate and CSC Items 13 and 13B are closed.

E8.2 Inspectors Review of Restart Action Matrix Items

a. Inspection Scope (37551)

In a letter dated July 30, 1998, the NRC informed the licensee that an oversight panel had been established in accordance with NRC Manual Chapter (MC) 0350, and a checklist was enclosed which specified activities which the NRC considered necessary to be addressed prior to restart. In accordance with MC 0350, an inspection plan was developed to evaluate the effectiveness of the licensee's actions to correct the items listed on the Case Specific Checklist.

In addition to the Case Specific Checklist, on November 22, 1999, the NRC MC 0350 oversight panel developed a Restart Action Matrix (RAM) to track the completion of NRC and licensee activities which were determined necessary for plant restart. The NRC MC 0350 oversight panel assessed the RAM items on the basis of importance, from "risk significant" to "little or no risk significance" and established criteria for inspection of the RAM items based on the relative risk. For low-risk significant items, the panel criteria required that: (1) the licensee had written a condition report to track the issue addressed by the RAM item, and (2) the licensee appropriately tracked the item as required for restart.

b. Observations and Findings

The inspectors reviewed the following low-risk items and concluded that the licensee's actions met the requirements of the MC 0350 oversight panel restart criteria; therefore, the following items are discussed:

- (Closed) RAM Item R.1.32, LER 50-315/99022-01: Electrical bus degraded voltage set points too low for safety-related loads.

  On June 9, 1999, the licensee identified that the degraded voltage lower allowable limit was too low to ensure adequate voltage for some of the 600 VAC and 120 VAC safety-related loads during a design basis accident. The licensee documented this finding in Licensee Event Report (LER) 50-315/99022-00 and Condition Report 99-15072. Subsequently, the licensee's engineering staff determined that the safety-related 4160 VAC buses must remain at or above 3902 VAC to ensure that the safety-related loads will function properly during a design basis accident. On March 23, 2000, the licensee issued a supplement to LER 50-315/99022 to document the corrective actions which would be taken to ensure that the analytical limit of 3902 VAC is maintained. These actions included physical changes to the electrical distribution system to obtain higher voltages and minimize voltage drops, and changes to operations department procedures for voltage monitoring and response to low voltage conditions.

As indicated in the May 4, 2000 letter, prior to Unit 2 restart, the licensee planned to implement several modifications to improve terminal voltage. These include installing a breaker to split electrical load between two 34.5 kV transformers, changing transformer tap settings, installing voltage regulating transformers, and replacing undersized motor cables on some equipment. The licensee also planned to establish administrative controls with the American Electric Power System Operations group to monitor grid voltages. The licensee accomplished these planned actions. In addition, the licensee initiated an evaluation to install automatic load tap changing transformers for the long term and planned to re-review their responses to applicable Generic Letters within one year of restart of Unit 1 and initiate any required licensing actions.

The inspectors reviewed the licensee's voltage calculations and corrective actions. The inspectors verified that the physical changes to the electrical distribution system were completed as described in the LER. The inspectors reviewed the changes to the operating procedures and concluded that the licensee had implemented adequate corrective actions to ensure that the 4160 VAC buses were maintained above the analytical limit. Restart Action Matrix Item R.1.32 and LER 50-315/99022-01 are closed.

- (Closed) RAM Item R.1.38: Licensee biennial review of operations' procedures.

  On May 16, 2000, the NRC identified that the licensee was behind schedule in performing biennial reviews of the plant operating procedures. In response to the inspectors' finding, the licensee identified 64 operations procedures which were overdue for review. The licensee wrote Condition Report 00-07066 to document the issue and developed an action plan to ensure all of the procedures receive the required review. The inspectors reviewed the licensee's action plan and determined that the licensee had appropriately prioritized the 64 overdue procedure reviews to ensure that the operating procedures necessary to support Unit 2 restart had all been reviewed prior to restart. The licensee placed the remaining unreviewed procedures on administrative hold pending review. The inspectors concluded that the licensee had appropriately entered this issue into the corrective action program and that the licensee actions were adequate to support Unit 2 restart. RAM Item R.1.38 is closed.

- (Closed) RAM Item R.2.3.55, RAM Item 3.7, LER 50-315/98047-00: Potential for increased leakage from reactor coolant pump seal identified.

  Section 9.2.3 of the Updated Final Safety Analysis Report stated that, "On a loss of seal injection water to the reactor coolant pump seals, seal water flow may be reestablished by manually rerouting the flow or starting a standby charging pump. Even if seal water injection flow is not reestablished, the plant can be operated indefinitely since the thermal barrier cooler has sufficient capacity to cool the reactor coolant flow which would pass through the thermal barrier cooler and seal leakoff from the pump volute." However, on November 17, 1998, the licensee identified that the thermal barrier heat exchanger may not be able to maintain reactor coolant pump (RCP) seal leak-off temperatures below 235^{o}F during a loss of seal injection. The licensee wrote Condition Report 98-07002 and LER 50-315/98047-00 to document the issue. The licensee decided not to restore the plant to the original design basis as stated in the UFSAR and determined that this issue constituted an unreviewed safety question.

The licensee's corrective actions involved revising the reactor coolant pump operating procedures, the component cooling water operating procedures, and the emergency operating procedures. The Office of Nuclear Reactor Regulation (NRR) staff reviewed the licensee's procedure revisions and concluded that the compensatory measures established by the procedure revisions were adequate to prevent two phase flow in the seal leakoff line. In addition, the NRR staff concluded that the compensatory measures maintained the licensing basis of the plant as described in the UFSAR. The licensee planned to submit a change to the UFSAR which would require tripping an RCP on a loss of seal injection and remove the statement about indefinite plant operation without seal injection flow. RAM Item R.2.3.55, RAM Item R.3.7, and LER 50-315/98047-00 are closed.

- (Closed) RAM Item R.3.4: Unreviewed Safety Question on Hydrogen Sub-compartment Issue.

Following the shutdown of both units at D. C. Cook the licensee performed Expanded System Readiness Reviews. During the reviews, the licensee discovered discrepancies in the licensing basis, as described in the Updated Final Safety Analysis Report (UFSAR), for the containment hydrogen analysis. Specifically the licensee found that in 1991, the fuel vendor notified the licensee that the clad oxidation value used in the design basis loss of coolant accident should be changed from 0.3 to 1.0 percent. The licensee failed to recognize the impact on the containment hydrogen analysis pursuant to 10 CFR 50.44 (Standards for Combustible Gas Control System in Light-water Cooled Power Reactors).

Following this discovery, the licensee recognized the need to perform a new containment hydrogen analysis prior to restart of Unit 2. In July 1998, the licensee identified that changes to the UFSAR reflecting the new hydrogen analysis potentially could result in an unreviewed safety question, requiring NRC review and approval prior to restart. The licensee later determined; however, that resolution of the hydrogen subcompartment issue would not result in an unreviewed safety question. The licensee presented this information during a public meeting with the NRC in February 2000.

As part of its corrective actions, the licensee completed a new bulk hydrogen generation analysis. The analysis was performed in accordance with Regulatory Guide 1.7, "Control of Combustible Gas Concentrations in Containment Following a Loss of Coolant Accident." The results of the analysis confirmed that, following a loss of coolant accident, the long-term hydrogen concentration would not exceed four percent in the sub-compartments in containment. The results of the analysis confirmed that the licensee was in compliance with 10 CFR 50.44. The licensee changed the UFSAR to reflect the new hydrogen generation analysis.

As documented in NRC Inspection Report 50-316/2000003, the NRC Restart Readiness Assessment Team reviewed FAI/99-27 "Hydrogen Subcompartment Analyses for the D.C. Cook Unit 1 and 2 Containments Following DBA LOCAs [Loss of Coolant Accidents]." This analysis established the containment subcompartment hydrogen levels following a design basis loss of coolant accident. The team verified that input assumptions and conclusions were consistent with 10 CFR 50.44 requirements and Regulatory Guide 1.7. The team determined that the licensee adequately demonstrated that post-accident containment hydrogen levels remained below four percent for both subcompartment and global containment hydrogen levels.

- (Closed) RAM Item R.3.5: Containment Sump/Spray pH Issue.

  During performance of the expanded system readiness reviews, the licensee identified a number of potential issues involving pH calculations on the containment sump and spray systems. During a public meeting with the NRC in March 1999, the licensee indicated that a license amendment may be needed to resolve the issues prior to restart. The licensee later determined; however, that the issues do not constitute an unreviewed safety question and a license amendment was not necessary prior to restart. The licensee presented this information during a public meeting with the NRC in February 2000.

  The license resolved the issues by performing a new set of calculations for the minimum and maximum pH values for design basis accidents; namely, a large break loss of coolant accident, a small break loss of coolant accident, and a main steamline break accident. The results of the calculations demonstrated that the pH values remain within the existing TS range and therefore a change to the TSs was not necessary. In addition, the licensee determined that although Procedure 02-OHP 4023 ES-1.3 "Transfer to Cold Leg Recirculation," needed to be revised, the revision did not constitute an unreviewed safety question.

E8.3 Inspectors Review of NRC Manual Chapter 0350 "Staff Guidelines for Restart Approval"

a. Inspection Scope

In letters to the licensee dated July 30, 1998, and October 13, 1998, the NRC documented the implementation of the NRC Manual Chapter (MC) 0350 "Staff Guidelines for Restart Approval". Included with these letters were checklists which specified activities which the NRC considered necessary to be addressed prior to restart. Enclosure 2 to these letters listed specific criteria which would be evaluated prior to plant restart. In accordance with MC 0350, an inspection plan was developed to evaluate the effectiveness of the licensee's actions to address the selected items. During this inspection period the MC 0350 panel reviewed licensee actions and inspector assessments related to the issues discussed below:

b.1 Staff Guidelines for Restart Approval Item C.3.2, Assessment of Corporate Support

- (Closed) SGRA Item C.3.2.g: Effectiveness of licensing support.

  During the time that Units 1 and 2 have been shutdown the licensee has maintained an adequate licensing staff, who in most cases developed submittals that were sound and complete. On occasion, Requests for Additional Information were required. The licensee's responses to the Requests for Additional Information have been prompt and accurate.

b.2 Staff Guidelines for Restart Approval Item C.4, Assessment of Physical Readiness of the Plant

- (Closed) SGRA Item C.4.a: Operability of Technical Specification systems, specifically those with identified operational, design, and maintenance issues.

  The NRC assessed the operability of TS systems by performing inspections of the specific systems that were identified as inoperable at the start of the extended shutdown (reference NRC Inspection Reports 50-315/316-99023, 024, 026, 029, 032, 033, 2000001, and 2000007). Additional systems and components were inspected as documented in the Restart Readiness Assessment Team Inspection (NRC Inspection Report 50-315/316-2000003), and NRC Inspection Reports 50-315/316-99021, and 2000016. All systems and components inspected were determined to either be operable or the process for restoring operability was acceptable.

- (Closed) SGRA Item C.4.c: Results of pre-startup testing.

  The inspectors reviewed the results of pre-startup testing to verify that significant equipment problems have been resolved and that all required safety systems have been restored to an operable status. NRC inspections during the extended shutdown have concentrated on the operability of systems, structures, and components important to safety, including the ice condenser, motor operated valves, electrical distribution, and engineered safeguards systems. The inspectors have concluded that the licensee has implemented effective corrective actions for equipment problems. NRC inspection efforts have included reviews and observations of post modification testing and the inspectors determined that testing adequately ensured that equipment problems were resolved. Additionally, during the review and closeout of Case Specific Checklist Item 1, "Programmatic Breakdown in Surveillance Testing," the NRC concluded that corrective actions for surveillance test program deficiencies have been effective and that observed testing activities were well conducted. The above findings and conclusions have been documented in NRC Inspection Reports 50-315/316-99020, 99021, 99026, 99033, 2000001, 2000002, and 2000003.

  Routine NRC inspection activities have determined that the licensee's post modification and surveillance testing programs are functioning properly. Furthermore, Plant Managers Procedure-7200.RST.004, "Expanded System

Readiness Review Program," required the development of test plans for safety significant plant systems. Plant Managers Procedure-7200.RST.005, "Restart and Power Ascension Testing Program," required that system test plans be reviewed by the Plant Operations Review Committee and approved by the Plant Manager. The inspectors reviewed a sample of system test plans and did not identify any significant issues. Overall, NRC inspection results determined that there is reasonable assurance that the licensee adequately executed the pre-startup test program and resolved significant equipment problems.

- <u>(Closed) SGRA Item C.4.d</u>: Adequacy of system lineups.

  Selected TS systems were walked down in order to determined their operability status and their readiness to support plant restart. The walk downs were performed as part of the Restart Readiness Assessment Team Inspection (NRC Inspection Report 50-315/316-2000003), and resident inspection assessments documented in NRC Inspection Reports 50-315/316-99022, and 2000016. During the performance of the containment close out inspection documented above, selected components were verified to be properly aligned. Examples included, both CEQ fans, and the safety injection throttle valves. The inspectors determined that the selected systems were adequately lined up to support operability and readiness for plant restart.

- <u>(Closed) SGRA Item C.4.g</u>: Adequacy of the Power Ascension Testing Program.

  The review of the Power Ascension Testing Program was assigned to the Restart Readiness Assessment Team Inspection (RRATI) and documented in NRC Inspection Report 50-315/316-2000003. The RRATI concluded that the startup and power ascension testing plan contained comprehensive test requirements, reviews and verifications to ensure plant readiness for restart. In addition, the RRATI concluded that appropriate controls were established to ensure lessons learned from the Unit 2 restart would be documented and tracked for management review and integration into the Unit 1 restart plan. However, at the time of the RRATI the power ascension testing schedule was not sufficiently developed to support plant restart. In order to complete the assessment of the power ascension testing program, the testing schedule was reviewed after the licensee had sufficiently developed and documented the schedule.

  The inspectors reviewed the licensee's power ascension testing schedule and determined that the schedule was sufficient to support plant restart. The schedule included appropriate holds at various power levels (including 20 percent and 50 percent) to assess plant conditions and to ensure continued power ascension was appropriate. Several power ascension tests were also reviewed by the inspectors and determined to be adequate to support plant restart. Combined with the program review documented in Inspection Report 50-315/316-2000003 and the schedule review performed in this Inspection Report, this item is closed.

- (Closed) SGRA Item C.4.h: Effectiveness of the plant maintenance program.

  The licensee initiated a new Maintenance Proficiency Evaluation (MPE) training program in order to assess and improve maintenance performance. The inspectors interviewed training and maintenance management personnel and toured the training facilities to assess the licensee's changes in the training program. The MPE training program was thorough and focused on improving the performance of both the maintenance workers and supervisors. This inspection was documented in NRC Inspection Report 50-315/316-99001.

  The inspectors reviewed the Maintenance Department Functional Area Assessment Plan and the preliminary findings documented in RST-1999-001-MT, the Maintenance Area Functional Assessment Report. The inspectors also interviewed members of the maintenance department and licensee management regarding the maintenance functional area assessment. The inspectors concluded that the maintenance area functional assessment was performed in accordance with licensee procedures and programs and was considered adequate. This inspection was documented in NRC Inspection Report 50-315/316-99013.

  During routine resident inspector assessments the performance of plant maintenance was observed. 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. Work items were appropriately scheduled in the plan of the day. These inspections were documented in NRC Inspection Reports 50-315/316-99010, 015, 017, 019, 020, 021, 022, 2000001, and 2000013.

  The inspectors assessment of the effectiveness of the plant maintenance program was determined to be adequate to support plant restart.

- (Closed) SGRA Item C.4.j: Adequacy of Plant Housekeeping and Equipment Storage.

  Routine inspections have been performed by the resident inspectors for housekeeping and equipment storage. Special inspections were performed by the Restart Readiness Assessment Team Inspection (RRATI). Housekeeping was determined to be adequate for licensee entry to Mode 6, Refueling and documented in NRC Inspection Report 50-315/316-2000001. The RRATI determined that housekeeping was adequate for the existing plant conditions (Mode 5) but that additional NRC assessments were necessary prior to restart. The RRATI conclusions were documented in NRC Inspection Report 50-315/316-2000003.

  During this inspection period, the resident inspectors assessed licensee facilities to determine the adequacy of housekeeping and equipment storage. Areas assessed included Unit 2 upper and lower containment, the auxiliary building, radioactive waste storage facilities, turbine building, emergency diesel generator rooms, auxiliary feedwater pump rooms, essential service water pump rooms, and safety-related switchgear rooms. Additional areas assessed included equipment storage rooms within the turbine building and the auxiliary building. The inspectors determined that plant housekeeping and equipment storage were adequate for licensee restart.

b.3 Staff Guidelines for Restart Approval Item C.5, Assessment of Compliance with Regulatory Requirements

- (Closed) SGRA Item C.5.a: Applicable licensee amendments have been issued.

  The licensee submitted six license amendments that required NRC review and approval prior to Unit 2 restart. The NRR staff completed the review and approval of all six of the license amendments. The last amendment was issued on April 25, 2000.

- (Closed) SGRA Item C.5.b: Applicable exemptions have been granted.

  The licensee did not submit any exemptions that required NRC review and approval prior to Unit 2 restart and none were required. Because no exemptions were necessary, this item is closed.

- (Closed) SGRA Item 5.c: Applicable reliefs have been granted.

  The licensee did not submit any reliefs that required NRC review and approval prior to Unit 2 restart and none were required. Because no reliefs were necessary, this item is closed.

- (Closed) SGRA Item C.5.d: Imposed orders have been modified or rescinded.

  There have been no orders imposed upon the licensee related to the current extended shutdown. The licensee requested modification to the requirements pertaining to containment hydrogen monitors contained in the Confirmatory Order issued on March 14, 1983, addressing implementation of actions following the accident at Three Mile Island. Specifically, by letter dated December 22, 1999, the licensee requested relief from the requirement to have monitoring of containment hydrogen concentration available from 30 minutes following initiation of safety injection, using risk insights as the basis for their request. The licensee requested that containment hydrogen concentration be available at 90 minutes following initiation of safety injection. NRR reviewed, approved, and issued the requested modification to the Order on February 4, 2000.

- (Closed) SGRA Item C.5.g: Allegations have been appropriately addressed.

  The Inspection Manual Chapter 0350 Restart Panel reviewed all open allegations on June 2, 2000, and determined none to be startup issues. In addition, on April 24, 2000, the Panel discussed allegations within the context of the health of the safety conscious work environment at the site. The Panel determined that the work environment at the site was conducive to raising and resolving safety concerns and is adequate for restart of the plant.

- <u>(Closed) SGRA Item C.5.h</u>: 10 CFR 2.206 Petitions have been appropriately addressed.

  On October 9, 1997, the Union of Concerned Scientists submitted a Petition pursuant to 10 CFR 2.206 requesting that the operating license for the Donald C. Cook Nuclear Plant, Units 1 and 2, be modified, revoked, or suspended until there is reasonable assurance that plant systems are in conformance with design and licensing bases requirements. The Petition was amended on January 12, 1998. The Director of NRR issued a final decision concerning the Petition on February 11, 1999. To date, no additional petitions have been filed.

IV. Plant Support

R1 Radiation Protection and Chemistry Controls (71750)

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

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 July 17, 2000. 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.

X2 Summary of MC 0350 Restart Action Matrix Items

The inspectors reviewed selected items from the NRC Inspection Manual Chapter 0350 Staff Guidelines for Restart Approval (SGRA) Items and the Restart Action Matrix (RAM). The following list indicates NRC and RAM Items which are discussed in the report:

a. Case Specific Checklist Item 13, Systems and Containment Readiness Assessments

b. Case Specific Checklist Item 13B, Systems and Containment Final Readiness Review

- RAM Item R.1.32, Electrical bus degraded voltage set points too low for safety-related loads was closed in Section E8.2.

- RAM Item R.1.38, Licensee biennial review of operations' procedures was closed in Section E8.2.

- RAM Item R.2.3.55, and RAM Item 3.7, Potential for increased leakage from reactor coolant pump seal identified was closed in Section E8.2.

- RAM Item R.3.4, Unreviewed Safety Question on Hydrogen Sub-compartment Issue was closed in Section E8.2.

- RAM Item R.3.5, Containment Sump/Spray pH Issue was closed in Section E8.2.

- RAM Item R.3.7, Unreviewed Safety Questions on Reactor Coolant Pump Seal Leakoff

- SGRA Item C.3.2.g, Effectiveness of licensing support was closed in Section E8.3.

- SGRA Item C.4.a, Operability of Technical Specification systems, specifically those with identified operational, design, and maintenance issues was closed in Section E8.3.

- SGRA Item C.4.c, Results of pre-startup testing was closed in Section E8.3.

- SGRA Item C.4.d, Adequacy of system lineups was closed in Section E8.3.

- SGRA Item C.4.g, Adequacy of the Power Ascension Testing Program was closed in Section E8.3.

- SGRA Item C.4.h, Effectiveness of the plant maintenance program was closed in Section E8.3.

- SGRA Item C.4.j, Adequacy of Plant Housekeeping and Equipment Storage was closed in Section E8.3.

- SGRA Item C.5.a, Applicable licensee amendments have been issued was closed in Section E8.3.

- SGRA Item C.5.b, Applicable exemptions have been granted was closed in Section E8.3.

- SGRA Item 5.c, Applicable reliefs have been granted was closed in Section E8.3.

- SGRA Item C.5.d, Imposed orders have been modified or rescinded was closed in Section E8.3.

- SGRA Item C.5.g, Allegations have been appropriately addressed was closed in Section E8.3.

- SGRA Item C.5.h, 10 CFR 2.206 Petitions have been appropriately addressed was closed in Section E8.3.

PARTIAL LIST OF PERSONS CONTACTED

<u>Licensee</u>

#A. Bakken, Site Vice President
#M. Depuydt, Regulatory Compliance and Licensing
#M. Finissi, Director, Plant Engineering
#R. Gaston, Compliance Manager
#J. Gebbie, Engineering Programs
#S. Greenlee, Director, Design Engineering
#R. Godley, Director, Regulatory Affairs
#J. Kingseed, Assistant Director, Nuclear Fuel, Safety, and Analysis
#W. Kropp, Director, Performance Assurance
#W. Lacey, Engineering
#M. Marano, Business Services
#R. Meister, Regulatory Affairs
#J. Molden, Director, Operations
#T. Noonan, Director, Restart
#R. Powers, Senior Vice President
#R. Womack, Supervisor, Engineering Programs

# Denotes those present at the July 17, 2000, 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 Follow-up of Written Reports of Nonroutine Events at Power Reactor Facilities

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-316/2000016-01	NCV	Failure to follow Technical Specification 3.8.1.1 following partial loss of off-site power
50-315/2000016-02 50-316/2000016-02	NCV	Failure to follow procedural requirements for control of high energy line break doors
50-315/2000016-03 50-316/2000016-03	NCV	Failure to follow procedural requirements for the control of scaffolding near safety related equipment
50-315/2000016-04 50-316/2000016-04	URI	Response to TIA on the issue of whether the latent failure of a test relay would fall under the category of a single failure.
50-316/2000016-05	NCV	Failure to meet Technical Specification 3.3.1.1 requirements for operable intermediate and power range nuclear instrumentation
50-316/2000016-06	NCV	Failure to meet Technical Specification 3.10.3 requirements for intermediate and power range nuclear instrumentation

Closed

50-316/2000016-01	NCV	Failure to follow Technical Specification 3.8.1.1 following partial loss of off-site power
50-315/2000016-02 50-316/2000016-02	NCV	Failure to follow procedural requirements for control of high energy line break doors
50-315/2000016-03 50-316/2000016-03	NCV	Failure to follow procedural requirements for the control of scaffolding near safety related equipment

50-316/2000016-05	NCV	Failure to meet Technical Specification 3.3.1.1 requirements for operable intermediate and power range nuclear instrumentation
50-316/2000016-06	NCV	Failure to meet Technical Specification 3.10.3 requirements for intermediate and power range nuclear instrumentation
50-315/98047-00	LER	Potential for increased leakage from reactor coolant pump seal identified
50-315/99022-01	LER	Electrical bus degraded voltage set points too low for safety-related loads
50-315/2000004-00	LER	Partial loss of offsite power results in start of both emergency diesel generators

Discussed

LIST OF ACRONYMS

AFW	Auxiliary Feedwater System
AFX	Spent Fuel Pit Exhaust Ventilation System
AHU	Air Handling Unit
CCW	Component Cooling Water
CFR	Code of Federal Regulations
CR	Condition Report
D/G	Diesel Generator
DIT	Design Information Transmittal
DRP	Division of Reactor Projects
EHP	Engineering Head Procedure
ESF	Engineered Safety Features
ESRR	Expanded System Readiness Review
ESW	Essential Service Water
IST	In-Service Test
JO	Job Order
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
LOOP	Loss of Off-Site Power
MC	Manual Chapter
MHP	Maintenance Head Procedure
MOV	Motor Operated Valve
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
NSSS	Nuclear Steam Supply System
OHI	Operations Head Instruction
OHP	Operations Head Procedure
OSO	Operations Standing Order
PDR	Public Document Room
PMI	Plant Manager's Instruction
PMP	Plant Manager's Procedure
PMSO	Plant Manager's Standing Order
PMT	Post Maintenance Testing
RAM	Restart Action Matrix
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RRATI	Restart Readiness Assessment Team Inspection
RWST	Refueling Water Storage Tank
SRO	Senior Reactor Operator
SSPS	Solid State Protection System
STC	Safeguards Test Cabinet
STP	Surveillance Test Procedure
TDB	Technical Data Book
TOL	Time of Licensing
TS	Technical Specification
VIO	Violation