U.S. NUCLEAR REGULATORY COMMISSION

REGION III

REPORT NO. 50-316/95009; 50-316/95009

FACILITY

Donald C. Cook Nuclear Generating Plant

LICENSEE

Indiana Michigan Power Company
Donald C. Cook Nuclear Generating Plant
1 Riverside Plaza
Columbus, OH 43216

DATES

June 20 through August 17, 1995

INSPECTORS

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for 9/8/95

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Date

AREAS INSPECTED

A routine, unannounced inspection of operations, engineering, maintenance, and plant support was performed. Safety assessment and quality verification activities were routinely evaluated. Follow-up inspection was performed for non-routine events and certain previously identified items.

RESULTS

Assessment of Performance

Performance within the area of **OPERATIONS** was poor during this inspection period - see Section 1.0. Concerns with regard to procedural adherence and awareness of plant conditions were evident as described in Section 1.0. Some of these events were either identified by the inspectors, identified by the licensee, or were self-revealing. Each event by itself was not significant, but in the aggregate represented a marked decline in operator performance over the last two months. Recent NRC administered initial operator licensing examinations (Inspection Report 50-315/OL-95-01(DRS)) identified a weakness where a lack of self-checking caused operator candidates to miss steps during procedure performance and others to miss irregularities in system responses. The inspectors were concerned that this weakness was observed in actual plant operations.

A violation for operator failure to follow procedural requirements, including response to a decrease in condenser vacuum that resulted in a reactor trip, was identified. In addition, the inspectors noted weaknesses in operator awareness of plant conditions, including failure to recognize the over-energization of the main transformer in a timely manner during a generator paralleling evolution. The inspectors also identified a violation for failure to comply with 10 CFR Part 72 reportabilty requirements. The examples given for the events that were not reported all pertained to operator errors and represent a programmatic weakness in reportability.

Overall performance in the area of **MAINTENANCE** was considered adequate - see Section 2.0. However, there were three instances where procedures were not followed during maintenance and testing activities. One pertained to the testing of an Emergency Diesel Generator, and one to the exercising of the main steam safety valves (MSSV), both of which were identified by the inspectors. The other pertained to repair of a manual voltage regulator potentiometer that was self-revealing. A concern was also identified regarding failure to perform adequate post-maintenance testing (PMT) resulting in a violation. The three examples in the violation were either identified by the inspectors or self-revealing, with the other example the subject of inadequate PMT during a previous inspection. The inspectors were also concerned that actions taken by the licensee to address a previous event failed to prevent the miswiring of the voltage regulator.

Performance within the area of **ENGINEERING** was adequate - see Section 3.0. The licensee's initiative to attempt to resolve the MSSV bonding issue was considered a strength. However, the licensee did not address the issue regarding the Technical Specification (TS)-required as-left lift setpoint of the MSSVs until prompted by the inspectors. The inspectors were concerned with the non-conservative approach by engineering of not assessing data obtained during the exercising of the valves for TS compliance.

Performance within the area of **PLANT SUPPORT** was good - see Section 4.0. One weakness was identified concerning an investigation by the radiation protection department.

Summary of Open Items
Violations: identified in Sections 1.1, 1.2, 1.3, 2.3, and 2.5
Unresolved Items: not identified in this report
Inspector Follow-up Items: not identified in this report
Non-cited Violations: not identified in this report

INSPECTION DETAILS

1.0 OPERATIONS

NRC Inspection Procedure 71707 was used in the performance of an inspection of ongoing plant operations. Operator performance with regard to procedural adherence and awareness of plant conditions was poor as evident by several events described in the following paragraphs. Some of these events were either identified by the inspectors, identified by the licensee, or were self-revealing. Each event by itself was not significant, but in the aggregate represented a marked decline in operator performance over the last two months. A recent NRC administered initial operator licensing examination (Inspection Report 50-315/OL-95-01(DRS)) identified a weakness where a lack of self-checking caused operator candidates to miss steps during procedure performance and others to miss irregularities in system response. The inspectors were concerned that this weakness was observed in actual plant operations.

1.1 Performance of Operations at Power

1.1.1 Unit 1 Technical Specification (TS) 3.0.3 Entry

On July 4, 1995, while performing 01-OHP 4030.STP.053B, "ECCS Valve Operability Test-Train B," the reactor operator missed step 1.8.1.e., which required that RHR discharge crosstie valves 1-IMO-314 and 1-IMO-324 be opened. This step was required to maintain four loop safety injection capability while the "S" SI pump discharge crosstie valve, 1-IMO-275, was being cycled. Upon identifying the discrepancy, the licensee initially determined that TS 3.0.3 had been entered during the short time that IMO-275 was closed. However, upon further review as part of the investigation into the event, the licensee concluded that TS 3.0.3 was not actually entered and that the event was not reportable. The inspectors' review of the reportability determination is discussed in paragraph 1.3.

1.1.2 Unit 1 Main Condenser Low Vacuum Trip

On July 14, 1995, the Unit 1 reactor tripped due to loss of condenser vacuum. The licensee determined that the cause of the loss of vacuum was the fatigue failure of a 1" main steam dump valve condensate drain line. All safety systems functioned as required.

The operators became aware of decreasing vacuum approximately 10 minutes before the turbine trip when a condenser "A" high hotwell level alarm, closely followed by a low hotwell level alarm, was received in the control room. About three minutes later, the operators received a "main condenser vacuum low" alarm which was common to all three condensers. Since the operators were not immediately able to determine the cause for the decreasing vacuum, an attempt was made to place the start-up air ejectors ("hoggers") in service to try to regain some vacuum. However, the operators encountered a delay in placing the hoggers in service due to the need to locally close a valve which was open to drain condensate build-up in the steam header to the hoggers. The condensate build-up was due to leakby past the steam supply valve, SMO-400.

The unit tripped about 8 minutes after the low condenser vacuum alarm was received, before the operators were able to place the hoggers in service.

The inspectors identified some concerns regarding operator action taken prior to the trip. The inspectors noted that step 3.1 of the annunciator response procedure, 01-OHP 4024.118 (drop 71), stated to "reduce turbine load as rapidly as possible". A note in the procedure stated that step 1 and step 2 (investigate the cause for the decreasing vacuum) could be done concurrently. The operators decided not to reduce load due to the rate at which vacuum was decreasing based on the belief that there would be limited benefit from reducing load and operator resources should be used to investigate the problem. Licensee's management position was that concurrent did not mean at the same time but rather the operator has a choice of what step to perform. Licensee management stated that the operators met management's expectations in the response to the loss of vacuum. However, the inspectors concluded that the operators decision not to reduce power was non-conservative because a reduction would have increased the margin of safety if complications had occurred following the reactor trip. The operators' failure to follow the annunciator procedure to decrease load rapidly is considered an example of a violation of TS 6.8.1.(50-315/95009-01a(DRP)).

In addition, the inspectors also concluded that, with vacuum decreasing at an excessive rate, the operators should have manually tripped the reactor to avoid challenging the automatic trip function. The inspectors noted that an error existed in procedure 01-OHP 4021.050.001 because the procedure required the reactor be manually tripped only if vacuum could not be maintained above 21.6", which was below the automatic trip setpoint of 21.8".

1.2 Performance of Operations While Shut Down

1.2.1 Main Generator Parallel Operation

While the unit was in Mode 3, the licensee repaired the drain line and performed several other corrective maintenance activities, including repair of the main generator manual voltage regulator. On July 16, 1995, while attempting to parallel the main generator during unit restart, the operators inadvertently applied excessive voltage to the Unit 1 main generator and the Unit 1 main output transformer.

The inspectors determined that the operators failed to perform step 4.3.15 of procedure 01-OHP 4021.050.001, "Turbine Generator Normal Startup and Operation," which required that the generator core monitor be placed into service per attachment 1 before closing the exciter breaker (step 4.4.4). Shortly after closing the exciter field control breaker the operators received some unexpected annunciators, including a "generator internals overheated" alarm. Because the operators had not yet completed step 4.3.15 (placing the generator core monitor in service), the operators did not respond to the valid "generator internals overheated" alarm. The operators' failure to follow procedure 01-OHP 4021.050.001 to place the main generator core monitor in service is considered another example of a violation of TS 6.8.1. (50-315/95009-01b(DRP)).

About a minute or two later, the operators received a "main transformer gas relay operated or hydrogen concentration high" alarm, which was symptomatic of overheating/breakdown of the transformer cooling oil. At that point, the operators identified that the generator output voltage was excessively high at approximately 146 volts, well above the expected value of 106 volts with the manual voltage regulator adjusted to the minimum position. After unsuccessfully attempting to lower the voltage with the regulator, the operators opened the exciter breaker. The operators then confirmed the high hydrogen concentration at a local panel. The overvoltage condition for the Unit 1 main generator and the main transformer existed for approximately 5 minutes. The licensee determined that the cause of the over-energization of the transformer was incorrectly landed leads associated with the manual voltage regulator that was worked during the forced outage. This issue is discussed further in paragraph 2.0.

Based on the following, the inspectors concluded that the operator performance during the generator parallel operation was poor because the over-excitation of the main generator was not recognized in a timely manner:

- Paragraph 4.4.5 of 01-OHP 4021.050.001 required that the operators verify that all three phases were energized on the generator voltage meter following closure of the exciter output breaker. Although no acceptance criteria was given for output voltage in the procedural step, the operators had the opportunity at that point to recognize that the value was outside the normal operating range.

- The operators did not ensure that the main generator core monitor was placed in service prior to closing the exciter field breaker.

The inspectors had previously identified concerns regarding operator performance during generator parallel operations in inspection report 50-315/94022; 50-316/94022.

In response to this event, the licensee updated 01-OHP 4021.050.001 to include acceptance criteria for the generator output voltage upon closure of the exciter output breaker. In addition, the licensee clarified the procedure to ensure that the core monitor would be operational prior to closing the breaker.

The licensee performed an internal inspection of the accessible portions of the main transformer and generator and did not discover any damage. However, on July 27, the licensee re-energized the transformer and a high hydrogen concentration developed in the transformer cooling oil due to apparent damage in a portion of the transformer that was not accessible during the inspection. Due to the extended outage required for replacement of the transformer, the licensee elected to enter the refueling outage approximately six weeks prior to the scheduled date. The licensee had the unit in Mode 5 at the end of the inspection period.

1.2.2 Auto Start of Turbine Driven Auxiliary Feedwater (TDAFW) Pump

On July 28, 1995, the licensee removed the reserve feed transformer from service for maintenance to correct a "hot spot" identified during thermography inspections. In order to perform this evolution with Unit 1 shutdown, the licensee revised Procedure **01-OHP 4021.082.001, "4KV Buses Power Source Transfer and De-energizing a Safeguards Bus." This revision described the method to parallel an emergency diesel generator (EDG) to a safety bus, load the EDG, and open the tie-breakers between the related reactor coolant pump (RCP) buses and the safety bus.

During the initial planning of this evolution, the licensee discussed that the turbine-driven auxiliary feedwater (TDAFW) pump would receive an autostart signal when two of the four RCP buses were de-energized, and that the possibility existed for the under-frequency relays to cause the remaining two RCPs to trip. Neither of these issues was incorporated into the procedure, and the pre-job briefing in the control room did not include a discussion regarding the TDAFW pump auto start.

The TDAFW pump autostarted at 3:38 p.m. when breaker T11B1 was opened, de-energizing the second RCP bus. The operators realizing why the pump started, manually tripped the pump and declared it inoperable. The TDAFW pump was reset and declared operable at 11:18 p.m., after the reserve transformer maintenance was completed.

The inspectors had the following concerns with the performance of this evolution:

- The inspectors determined that the autostart of the TDAFW pump was an ESF actuation that was not indicated by a procedural step nor were the control room personnel aware of the specific signal before its occurrence. This concerned the inspectors because the operators did not evaluate the ramifications of deenergizing two of the RCP busses and the subsequent initiation of the ESF signal.

  The inspectors also had some concerns regarding the licensee's justification that the ESF actuation was not reportable. This issue is discussed in paragraph 1.3.

- At approximately 2100, the shift technical advisor identified that conditions 1 and 2 were no longer satisfied for TS 3.0.5 for the West MDAFW pump because its normal power source (reserve feed) was not available and its redundant component (the TDAFW pump) was inoperable. This would have given the licensee 8 hrs. from 3:38 p.m. to have the plant in Mode 4. The shift did not take action to cooldown the plant because the reserve feed was expected to be returned to service prior to the 8 hrs expiring. However, this LCO entry was not logged in the control room log book after being identified. The licensee has initiated condition report No. 1107 to determine why the planning process did not identify this LCO.

- The inspectors were also concerned that since the TDAFW pump autostart and the possibility of the under-frequency relays actuating were not documented in the procedure, the evolution could be performed in the future without these issues being considered.

1.2.3 Erroneous Operation of Containment Ventilation

On July 29, 1995, with Unit 1 in Mode 3, a licensee reactor operator performed the wrong attachment of 01-OHP 4021.028.005, "Operation of the Containment Purge System." The procedure required that the system be operated in the "clean-up" mode when containment integrity was required (Modes 1-4 per TS 3.6.1.1). However, the operator erroneously operated the system in the "ventilation" mode of service for approximately 5 minutes. The significance appeared to be that the vent stack radiation monitor was not source checked and a release permit was not forwarded to Radiation Protection. The licensee initiated a condition report for this event.

1.2.4 Unit 1 Cooldown

On July 30, 1995, while cooling down Unit 1 in Mode 4, a licensee unit supervisor did not follow the required sequence of steps in procedure 01-OHP 4021.001.004, "Plant Cooldown From Hot Standby to Cold Shutdown," for establishing Low Temperature and Operating Pressure (LTOP) protection and prematurely racked out a CCP pump. The consequence was that the licensee made an unidentified entry into TS 3.1.2.4, which required two operable CCPs in Mode 4, for over 1 hour before being discovered by shift management. The licensee initiated a condition report for this event.

1.2.5 Inadvertent Draining of Reactor Coolant System

On August 4, 1995, after isolating a seal injection filter for maintenance and attempting to drain the header, an auxiliary equipment operator (AEO) observed excessive water coming from an open vent valve due to the apparent leakby of a clearance isolation valve. In response, the AEO closed the vent valve and went to the control room to report the problem. However, the AEO left another valve that was also used to drain the system in the open position. Approximately 15 minutes after the drain valve had been left opened, control room operators noticed that pressurizer level had decreased from about 12 percent to 5 percent, or about 1500 gallons. The water had drained to a sump tank. The operators immediately initiated RCS make-up and the drain valve was closed. The licensee initiated a condition report for this event.

1.3 Followup on Previously Identified Items

A review of a previously opened unresolved item was performed per NRC Inspection Procedure 92901. This item was closed based on a violation being identified regarding the failure of the licensee to report events as required by 10 CFR Part 72.

(Closed) Unresolved Item 50-316/94024-01: The inspectors initiated this item in response to a concern regarding the licensee's justification for classifying events as not reportable. During the inspection period, the inspectors identified the following events that should have also been reported to the NRC:

- An example identified as part of the unresolved item involved an unintended entry into TS 3.0.3 on April 2, 1994, due to the inoperabilty of both trains of Unit 2 engineered safety feature exhaust (AES) fans. The function of the AES fans was to provide cooling for ECCS equipment and to ensure that radioactive material leaking from equipment following a LOCA is filtered prior to reaching the environment. The licensee had placed the control switch for the 2-HV-AES-2 fan in the "stop" position after starting the 2-HV-AES-1 fan for post-maintenance testing (PMT), thus making both fans inoperable. The licensee had taken the AES-1 fan out-of-service for replacement of a HEPA filter. The licensee concluded that since the PMT on AES-1 fan was successfully completed, the event was not reportable because the AES-1 fan was capable of performing its intended function at the time AES-2 was stopped. The inspectors concluded that the licensee's justification, which was based on retroactively applying the successful completion of testing, was in error. Therefore, the inspectors concluded that the event was reportable per 10 CFR 50.72, paragraph (b)(1)(ii)(B), as a condition outside the design basis of the plant.

- On October 10, 1994, during performance of STP 205, "ESF Time Response Testing-Train A," the licensee received an unexpected phase "A" isolation of the containment purge system. As part of the preparatory steps of the surveillance testing, the operators had removed the purge system and closed the containment isolation valves to prevent automatic isolation during the testing. However, due to poor communication, an operator placed the purge system back in service before the test was initiated. As a result, the operators experienced the phase "A" isolation signal, which resulted in the isolation of the containment purge isolation valves. The phase "A" containment isolation signal was listed in paragraph 3.a of Table 3.3-3 of TS as part of the ESF actuation system instrumentation, and was not an expected result of the procedure. Therefore, the inspectors concluded that the event was reportable per 10 CFR 50.72 paragraph (b)(2)(ii)(A).

- As discussed in paragraph 1.1 of this report, the licensee initially determined that TS 3.0.3 was entered on July 4, 1995, due to loss of four loop safety injection capability. The licensee determined that a one hour phone call per 10 CFR 50.72 was not required because manual four loop injection was available. In addition, upon further review of the event, as documented in condition report (CR) 95-1107, the licensee performed an analysis that demonstrated that the plant was not in an unanalyzed condition that significantly compromised plant safety. This conclusion was based on the unit being at a reduced power level at the time (57 percent); therefore, UFSAR acceptance criteria for the accidents impacted would continue to be met.

The inspectors reviewed the licensee's justification. The inspectors noted that the licensee could not take credit for operator action for establishing four loop injection. In addition, since the currently docketed design bases and accident analyses approved by the NRC does not recognize two loop injection for both the RHR and SI, an unanalyzed condition did exist and entry into TS 3.0.3 was appropriate. An analysis after the event was not justification for not submitting an LER, but rather an analysis to ascertain the safety significance of the event. Therefore, the inspectors determined that the event was reportable as a condition outside the design basis of the plant as required by 10 CFR 50.72(b)(1)(ii)(B).

- As discussed in paragraph 1.2.2 above, on July 28, 1995, the licensee experienced an automatic start of the Unit 1 TDAFW pump while performing a power source transfer. The pump autostart was due to reactor coolant pump bus undervoltage. This feature was listed in paragraph 7.b of TS Table 3.3-3 " Engineered Safety Feature Actuation System Instrumentation" as part of the ESF actuation system instrumentation. The licensee initially concluded that the event was not reportable as an ESF actuation because some individuals discussed this feature during the initial planning phase of the evolution. However, the inspectors noted that the actuation was not addressed in the procedure and was not expected by the operators. The licensee's procedure that defines the reportability process, PMP 7030.001.001, "Prompt NRC Notification", states that a trip actuation should not be a surprise to the operator to be not reportable. Therefore the inspectors concluded that the event was reportable per 10 CFR 50.72 paragraph (b)(2)(ii)(A) because the TDAFW pump is an ESF as defined in TS and the auto start was not preplanned (documented in a procedure or logged prior to actuation).

The licensee's failure to report the above four events is considered a violation of 10 CFR 50.72.(50-315/95009-02(DRP)).

2.0 MAINTENANCE

NRC Inspection Procedures 62703 and 61726, and 92902 were used to perform an inspection of maintenance and testing activities. Overall performance in this area was considered adequate. However, there were three instances where procedures were not followed during maintenance and testing activities. One pertained to the testing of an Emergency Diesel Generator, one to the exercising of the main steam safety valves, both of which were identified by the inspectors, and the other pertained to repair of a manual voltage regulator potentiometer that was self-revealing. A concern was also identified regarding failure to perform adequate post-maintenance testing (PMT) resulting in a violation. Of the three examples in the violation, one was identified by the inspectors, one was self-revealing, and the other was an example of inadequate PMT during a previous inspection. The inspectors were also concerned that actions taken by the licensee to address a previous event failed to prevent the miswiring of the voltage regulator.

2.1 Maintenance and Surveillance Testing Activities

The inspectors observed routine preventive and corrective maintenance and surveillance activities to ascertain that they were conducted in accordance with approved procedures, regulatory guides, industry codes or standards, and in conformance with Technical Specifications. The following activities were observed and/or reviewed:

- JO# C0030956, "Repair Water Leak on 12-ZRV-404-RV"
- JO# C0031204, "Adjust 12-ZRV-404-RV For 165 Psig"
- JO# C0031146, "2-QT-502-AB, Replace Turbo Rotating Assembly"
- JO# C0025062, "Adjust Limit Switches on Main Generator Voltage Regulator"
- 12 THP 6040 PER.106, "Emergency Diesel Generator Control Panel Tests"
- JO# C24371, Unit 2 CD EDG, "Replace Woodward Governor"
- 01 EHP 4030 STP.217A, "CD EDG Load Shedding & Performance Test"
- 02 OHP 4030 STP.103, "Main Turbine Stop & Control Valve Testing"
- 01 OHP 4030 STP.19F, "Steam Generator Stop Valve Operability Test"
- 12 EHP.6040.PER.141, "Main Steam Safety Valve Exercising Using AVK ULTRASTAR Equipment,"
- 12 EHP4030STP.256, "Main Steam Safety Valve Setpoint Verification,"

2.2 Miswired Voltage Regulator

The licensee established a team to investigate the root causes of the main generator over-excitation event discussed in paragraph 1.2. Although the investigation has not been completed, the licensee has determined that the cause for the event was improperly landed leads on the manual voltage regulator potentiometer that was replaced during the forced outage. The miswiring caused the regulator to be at maximum voltage regardless of the potentiometer setting.

In addition to the wiring error, licensee personnel failed to perform adequate post-maintenance testing (PMT) following the maintenance activity. The original scope of the work on the regulator was to adjust the limit switches for the maximum and minimum voltage light circuits. While performing the activity, the I&C technicians damaged the potentiometer, expanding the scope of the job. Due to poor communication, lack of understanding of system operation, and perceived urgency to complete the work, the original PMT, which consisted of verifying proper operation of the light circuits, was not updated to ensure the regulator would work properly following the potentiometer replacement.

The inspectors' concern regarding the inadequate PMT is discussed in paragraph 2.5 below.

The inspectors had several concerns regarding this event. The licensee had experienced a similar event in March 1993, when an EDG load conservation relay was improperly wired following a calibration activity during a refueling outage, which would have rendered the function inoperable. Fortuitously, the licensee identified the miswiring during blackout testing, which was not specifically performed as a PMT after the work on the EDG load conservation relay, but before the EDG was declared operable.

As action to prevent recurrence of that event, the licensee reinforced the use of self-checking and verification methods appropriate to the consequences of improperly performing the activity. The licensee also committed to compare restored wiring configurations with approved drawings to ensure final configuration agreed with design. This comparison was not performed following the potentiometer replacement. The inspectors also noted that the form used to document the verification of leads lifted and landed for the regulator work activity did not include the potentiometer leads. Therefore, the technicians had to use a hand-drawn sketch, and there were no signoffs for verification of lifting and landing these leads.

2.3 Exercising of Main Steam Safety Valves (MSSVs)

While exercising the MSSVs per procedure 12 EHP.6040.PER.141, "Main Steam Safety Valve Exercising Using AVK ULTRASTAR Equipment," MSSV 1-SV-3-2, which had a setpoint of 1085 psig, the equivalent of 1180 psig was applied without the valve lifting. The test was stopped to confer with the valve vendor to determine if more force could be applied without damaging the valve. Procedure 12 EHP.6040.PER.141, step 5.17 stated that in the event that a valve cannot be exercised, stop testing immediately and notify the shift supervisor (SS). The SS and control room operators were not informed that testing had stopped because 1-SV-3-2 would not lift. The inspectors felt that, although 1-SV-3-2 was already considered inoperable, operations personnel should have been informed of the status of 1-SV-3-2 and the plans to apply more force on the valve. The failure to notify the SS is considered an example of a violation of Technical Specification 6.8.1 (50-315/95009-01c(DRP)). This activity is discussed in further detail in paragraph 3.2 of this report.

2.4 Missed Procedural Steps

On June 22, 1995, during performance of an engineering test, 12 THP 6040 PER.106, "Emergency Diesel Generator Control Panel Tests," the inspectors observed that the operators inadvertently skipped some procedural steps. The objective of the procedure was to provide a record of adjustments made to the voltage and speed potentiometers following replacement of the Unit 2 "CD" emergency diesel generator (EDG) governor. Redundant potentiometers were located in the control room and at the EDG local control panel.

Following adjustment of the control room potentiometers per paragraph 6.2 of procedure 12 THP 6040 PER.106, the operators shut down the EDG to perform the steps required for making the local panel adjustments. However, the control room operators restarted the EDG before the remote-local switch located at the EDG sub-panel was placed in the local position, as required by paragraph 6.3.1 of 12 THP 6040 PER.106. Paragraph 6.3.1 was required to be performed in order to demonstrate the capability of starting the EDG locally, which was an acceptance criterion in the procedure. The cause for the missed step was due to apparent miscommunication between the operators and the test engineer coordinating the evolution.

Upon realizing the step had been missed, the engineer decided to continue with the procedure and evaluate the need to perform the missed step afterwards. However, because of the problems found with the potentiometer at the local EDG control panel, the operators shutdown the Unit 1 "CD" EDG and the engineers were not able to complete the test. After making minor adjustments to the potentiometer, the licensee then satisfactorily performed the "Emergency Diesel Generator Control Panel Tests" during a subsequent EDG maintenance run.

The inspectors discussed the event with the engineer, who initially indicated that the missed step was not a procedural adherence issue. The engineer based this determination on paragraph 3.3 of the procedure, which stated that test steps could be completed out of order if the EDG was already running. However, the inspectors concluded that the statement did not apply to the situation, as the EDG was not running at the time. In response to the inspectors' concerns, the licensee initiated CR No. 95-0965 to document the missed step. The inspectors will review the licensee's investigation into the event and continue to monitor licensee performance in this area.

2.5 Follow-up on Previously Opened Items

A review of a previously opened unresolved item was performed per Inspection Procedure 92902.

(Closed) Unresolved Item 50-315/94014-06(DRP): The inspectors had previously documented an issue regarding PMT for non-routine corrective maintenance. The inspectors were concerned that work planners did not always have an adequate background in system operation to ensure that appropriate PMT would be performed. In response to the inspectors concern and other related events, the licensee issued procedure PMSO.154, "Planning of Post Maintenance Testing Activities," which outlined the circumstances when planners should request engineering review of job orders for PMT. The inspectors initiated the unresolved item to monitor the effectiveness of the PMSO.

The inspectors noted three examples of inadequate PMT during the inspection period.

- The inspectors noted that despite the apparent unfamiliarity of system operation by the planner involved with the voltage regulator maintenance

discussed in paragraph 2.1 above, no engineering review of the job order was requested after the scope of the work was expanded to replace the potentiometer.

- On July 18, 1995, the licensee performed an activity to repair a leak on the controller associated with valve 12-ZRV-404, "West" Diesel Driven Fire Pump back pressure regulating valve. The valve was located on a recirculation line back to the fire water storage tanks and functioned to maintain 165 psi header pressure under load. The PMT specified by the planner in JO C0030956 was to verify no leaks at normal system pressure.

  However, when Operations operated the pump per 12-OHP 4030.STP.121FD, "Diesel Fire Pump Operability Test," during the PMT, it was observed that the pump only developed 120 psi discharge pressure. Although the procedure and the work order did not contain any acceptance criteria for the discharge pressure, the operators questioned the operability of the pump. The operators contacted the system engineer, who initially determined that the condition was not an operability issue. On the following day, the engineer reconsidered his position. The licensee subsequently determined that the regulator was damaged during the work activity and initiated action to replace it.

  The unresolved item had been initiated when the inspectors identified a similar concern regarding PMT of the pressure regulating valve associated with the motor-driven fire pump, 12-ZRV-402. At that time, the inspectors were concerned that, although the setpoint of the valve was adjusted to 165 psi, the PMT did not demonstrate the backpressure regulating function of the valve to maintain header pressure.

- On August 2, 1995, after the licensee completed maintenance on the "AB" emergency diesel generator turbocharger, the resident inspectors raised a concern regarding the adequacy of the PMT performed.

  The licensee performed the maintenance in response to a recent failure of a similarly designed turbocharger at another plant. The failure was attributed to a design change to an insert that provided starting air to the turbocharger during initial roll-up to assist in getting it up to operating speed. The new insert caused the compressor impeller blades to reach resonance frequency at normal turbocharger operating speed, resulting in excessive vibration and fatigue failure of the blades.

  During the maintenance activity, the licensee replaced the insert with the design previously used and inspected the impeller blades for damage. The licensee's PMT consisted of a slow start and full load run. The inspectors determined that the test was inadequate because starting air was not provided to the insert during a slow start; therefore, the licensee did not verify that the turbocharger would perform its intended function under an accident condition. The inspectors noted that during a slow start, the EDGs would not typically roll up to normal speed until 30 seconds after the EDG was started. On an auto start signal, the EDGs would be required to get up to full speed within 10 seconds and begin accepting sequenced loading. In response to the inspectors' concern, the licensee successfully completed a fast start and run.

The above instances are considered examples of a failure to perform adequate PMT and considered a violation of 10 CFR Part 50, Criterion XI (50-315/95009-03(DRP)). This unresolved item is closed based on the issuance of this violation.

3.0 ENGINEERING

NRC Inspection Procedure 37551 was used to perform an onsite inspection of the engineering function. Items closed as a result of this inspection met the criteria established in the Inspection Procedures. Although the initiative to attempt to resolve the MSSV bonding issue described in paragraph 2.4 was considered a strength, the engineering personnel did not address the Technical Specification (TS)-required as-left lift setpoint issue until prompted by the inspectors. The inspectors were concerned with the non-conservative approach by engineering of not assessing data obtained during the exercising of the valves for TS compliance.

3.1 Follow-up on Non-Routine Events

NRC Inspection Procedure 92700 was used to perform a review of the following written report on a non-routine event:

(Closed) LER 50-315/94001 and LER 50-316/94006: The LERs were written concerning MSSVs lifting outside the required tolerances. The LERs are closed and resolution of this issue will be tracked under Inspection followup Item 50-315/94002-05; 50-316/94002-05(DRP) as discussed below.

3.2 Follow-up on Previously Opened Items

A review of the following previously opened unresolved and inspection followup items was performed per Inspection Procedure 92902.

(Open) Inspection Followup Item (50-315/94002-05;50-316/94002-05(DRP))
As discussed in previous NRC Inspection Report Nos. 50-315/94002; 50-316/94002(DRP), 50-315/93019; 50-316/93019(DRP),and 50-315/92009; 50-316/92009(DRP), the licensee has had historical problems with main steam safety valves (MSSVs) lifting at pressures above the setpoint. The licensee believes that bonding between the valve disc and nozzle may be causing the setpoint drift. This theory was supported by the fact that generally the MSSVs which lift above the setpoint on the initial test will lift at lower pressures on subsequent tests without adjustment.

In response to this issue the licensee developed procedure 12 EHP.6040.PER.141, "Main Steam Safety Valve Exercising Using AVK ULTRASTAR Equipment," to exercise the MSSVs during power operation. The purpose of this evolution was to determine if bonding was time dependent (Unit 1 was 12 months into a cycle, and MSSV testing is normally performed at the end of an 18 month cycle) and if so, to determine the proper interval for future exercising to prevent bonding.

The licensee's initiative to attempt to resolve this industry wide issue was considered a strength. However the inspectors had some concerns with the licensee's implementation.

On June 19, 1995, with the unit at approximately 55 percent power, the licensee began exercising the Unit 1 MSSVs. The inspectors identified the following concerns:

- While testing MSSV 1-SV-3-2, which had a setpoint of 1085 psig, the equivalent of 1180 psig was applied without the valve lifting. The test was stopped to confer with the valve vendor to determine if more force could be applied without damaging the valve. Procedure 12 EHP.6040.PER.141, step 5.17 states that in the event that a valve cannot be exercised, stop testing immediately and notify the Shift Supervisor (SS). The SS and control room operators were not informed that testing had stopped because 1-SV-3-2 would not lift. The inspectors felt that, although 1-SV-3-2 was already considered inoperable, operations personnel should have been informed of the status of 1-SV-3-2 and the plans to apply more force on the valve. On the subsequent lift attempt, the valve lifted at approximately 1179 psig, and was returned to service.

- TS 3.7.1.1 requires that a safety valve shall be reset to the nominal value ± 1 percent whenever found outside the ± 1 percent tolerance. After 10 of the 20 MSSVs were exercised, the inspectors questioned why valves found outside the ± 1 percent tolerance were not being reset. Initially the licensee responded that actual lift pressures were not required to be recorded by procedure 12 EHP 6040.PER.141 and therefore TS 3.7.1.1 did not apply. However, although lift pressures were not being recorded, the pressures were displayed and saved by the testing equipment. Also, knowing the pressure at which the valve lifted was essential to the purpose of this evolution. Without knowing the actual lift pressure, the licensee would not be able to determine if bonding forces were present during the initial lift, nor ensure that the bonding forces were relieved during subsequent lifts.

  After further discussion, the licensee determined that TS 3.7.1.1 applied whether or not the data was required to be recorded. The licensee then tested all Unit 1 MSSVs according to procedure 12 EHP4030STP.256, "Main Steam Safety Valve Setpoint Verification," which required all valves to be left within ± 1 percent of the nominal setpoint. This approach to testing MSSVs did not demonstrate a conservative approach to TS surveillance requirements.

This inspection followup item will remain open pending the final determination by the licensee of the cause and actions necessary to prevent the MSSVs from lifting above the setpoint.

(Closed) Unresolved Item (315/316/92003-04(DRS)): The Electrical Distribution System Functional Inspection (EDSFI) team was concerned that the safety-related electrical buses could decrease to 79 percent of rated voltage and set at this value for 2 minutes until initiation of the degraded voltage logic.

In response, the licensee provided the inspectors the "D.C.Cook Voltage Performance Study, 1991-1995 Operating Period" system voltage analysis. The analysis indicated that the low and medium voltage safety-related buses would not decrease below 90 percent of rated voltage during the worst case transmission system contingency. Safety-related motors were designed to start at 80 percent of rated voltage and were capable of operating within a voltage range of $\pm$ 10 percent. The 2 minute time delay was selected to provide sufficient time to start a reactor coolant pump. This time delay was accepted by the NRC in the June 1, 1981, safety evaluation, "Adequacy of Station Electric Distribution System Voltages," that was issued to D.C.Cook. The inspectors concluded the licensee was operating electrical equipment within the design basis. This item is considered closed.

(Closed) Unresolved Item (315/316/92003-06(DRS)): The EDSFI team identified that 250 Vac rated fuses were used in DC applications. The team was concerned that the licensee's evaluation, "Analysis of D.C.Cook 250 Vdc System Compared to UL198L Test Results," did not substantiate that AC rated fuses could be used in DC circuits.

In response, the licensee re-evaluated the analysis and issued calculation No. PS-FUSE-001, "AC Rated Fuses in DC Applications." The calculation showed that the stored energy dissipated in TR-R fuses during DC fault current interruptions were bounded by the fuse manufacturer's stored energy test values. The inspectors concluded that 30A and 100A TR-R current-limiting fuses would interrupt a DC circuit fault and limit the let-thru current to a value that would not damage equipment. This item is considered closed.

(Open) Inspection Followup Item (315/94002-13(DRP)): In late September 1993, Unit 1 operators received a low oil level alarm to the No. 14 reactor coolant pump (RCP) motor lower radial bearing. The low oil condition eventually led to damage to the lower radial bearing. Based on this event, the inspectors had additional questions on the causes for the low oil condition.

On July 21, 1995, Unit 2 operators received a similar low oil level alarm on the No. 23 RCP. The lower radial bearing temperature appeared stable during the remainder of the inspection period. The lower radial bearing temperature indicated about 132 degrees Fahrenheit and was in the observed temperature range for the other three RCPs with normal oil levels.

The operators continued to monitor the No. 23 RCP bearing temperature. Based on the failure observed with the Unit 1 No. 14 RCP, the system engineer estimated that the No. 23 RCP could experience a lower radial bearing failure as early as October or November of 1995. At the end of the inspection, licensee management was reviewing actions required to address the low oil level condition with the No. 23 RCP. Inspectors will monitor conditions of the No. 23 RCP and licensee followup actions.

4.0 PLANT SUPPORT

NRC Inspection Procedures 71750, 83750, and 92904 were used to perform an inspection of plant support activities. Two non-cited violations were identified in the area of radiological controls. Overall performance in the area of plant support was considered good.

4.1 Radiological Controls

The health physics staff has remained stable. Although a corporate health physicist left the company, the radiation protection department remains technically sound. The station also has a large number of employees who are National Registry Radiation Protection Technician qualified.

The inspectors reviewed several quality assurance (QA) audit and surveillance reports covering work activities that occurred over the previous 18 months. Audit activities appeared to be probing and critical of the subject area being reviewed. Results were effectively communicated to the appropriate department and, when appropriate, a condition report was generated for identified deficiencies. The inspectors concluded that the licensee's QA program, specifically with regard to radiation protection, was effective in identifying opportunities for improving overall performance, as well as procedural deviations, and was considered a licensee strength.

4.1.1 Follow-up on Non-Routine Events

NRC Inspection Procedure 92700 was used to perform a review of the following written reports of non-routine events:

(Closed) LER 50-315/94011 and LER 50-315/94012: The LERs were written concerning analysis problems in the liquid and gaseous sampling program. The LERs are closed based on inspector review of the procedural changes that were made to strengthen the program and to prevent recurrence.

4.1.2 Radiological Occurrences (IP 83750)

The inspectors reviewed the licensee's investigation of a radiological event which involved two operators who entered Unit 1 upper containment during in-core detector movement operations. Upper containment was posted as a radiation area instead of an extreme high radiation area (EHRA) as appropriate, because a Radiation Protection Technician (RPT) failed to post and control the area as an EHRA when the moveable detector system (IMDS) clearance was not in effect. Although the dose rates in upper and lower containment ranged from about 26 mR/hr to 6 mR/hr, respectively, during this evolution, containment entry procedures required that both entry areas be posted and controlled as an EHRA during any incore detector movement. When the containment is properly posted and controlled, the operators are allowed entry and provided constant Radiation Protection (RP) coverage. These controls are required to prevent access into the instrument room where extremely high dose rates could exist when moving in core-detectors. The licensee identified this event when another RPT who knew the clearance was not in effect, discovered operators coming out of the upper containment. The operators wore electronic dosimeters (EDs), were exposed to low dose rates and received less than 5 mRem each, and made no attempt to enter lower containment from upper containment. Any attempt to enter lower containment (where the instrument room is located) from upper containment would have required an intentional violation of the hatch entry access controls leading into lower containment.

During the investigation of this matter, the licensee also found that the entrance into Unit 1 lower containment was not posted and controlled as an EHRA. The instrument room is located immediately inside the entry hatch and although none of the detectors from the reactor vessel were sent to the seal table in the instrument room during this specific evolution, the entrance should have been posted and controlled as EHRA. If the operators had entered from the Unit 1 lower containment entrance during in-core detector movement, the controls in place to prevent possible overexposure consisted of personal use of alarming EDs, area radiation monitors (ARMs) located inside the containment near the instrument room which had remote annunciator alarms, a requirement to notify the control room before entry, and the issuance of the lower containment entrance lock key by RP staff. The investigation of this event included discussions with all participants, and radiation verification surveys in both upper and lower containment during flux mapping operations. As a result of the investigation, the licensee concluded that there was not a substantial potential for a whole body overexposure. The root cause assessment indicated there was an RPT personnel error, procedural and key control weaknesses, and no verification to ensure the IMDS clearance was not in effect.

Although the inspector's review of the licensee's investigation indicated that the assessment of the root causes and corrective actions to prevent recurrence was good, the inspectors identified some weaknesses in the lower containment alert/control warning system that were not identified by the licensee during followup of this event. For instance, after the inspectors entered into the Unit 2 lower containment near the seal table during unit operation, the inspectors found that the ED alarm and warning light worked, but the alarm was barely audible because of the noise level from operating equipment. The inspectors also noted that in Unit 2 there was an operable seal table area radiation monitor (ARM) with a local warning light and alarm function with the alarm setpoint at 20 mR/hr. However, the Unit 1 seal table area ARM did not have local alarm and a warning light, but instead had annunciator alarms in the control room and in a designated RP office in the turbine building; the alert alarm set point was 20 mR/hr and the high alarm was set at 100 R/hr. Because these weaknesses in the Unit 1 alarm /control warning system (no local alarm and warning light, a high ARM set point and possible inaudible EDs in noisy areas) were not identified in the condition report for the subject radiological event, no corrective actions would have been taken to strengthen the alert/control warning system. The inspectors discussed this matter with the licensee who indicated that these weaknesses were corrected by installing an interim local ARM with both audible and visible functions and an alarm set point of 20 mR/hr in Unit 1; a permanent system revision will be made in the near future. Although there were weaknesses in the overall control of this evolution and in the alert/control system, it did not appear likely that there was a substantial potential for a whole body exposure in excess of regulatory limits.

5.0 PERSONS CONTACTED AND MANAGEMENT MEETINGS

The inspectors contacted various licensee operations, maintenance, engineering, and plant support personnel throughout the inspection period. Senior personnel are listed below.

At the conclusion of the inspection on August 17, 1995, the inspectors met with licensee representatives (denoted by *) and summarized the scope and findings of the inspection activities. The licensee did not identify any of the documents or processes reviewed by the inspectors as proprietary.

*A. A. Blind, Site Vice President/Plant Manager
*K. R. Baker, Assistant Plant Manager-Operations
*J. R. Sampson, Assistant Plant Manager-Support
*D. L. Noble, Radiation Protection Superintendent
*T. K. Postlewait, Site Engineering Support Manager
*J. S. Wiebe, Superintendent, Plant Performance Assurance
L. H. Vanginhoven, Superintendent, Material Management
*W. M. Hodge, Plant Protection Superintendent
*W. A. Nichols, Acting Operations Superintendent
*G. A. Weber, Superintendent, Plant Engineering
*M. E. Barfelz, Superintendent, Nuclear Safety & Analysis
*A. A. Lotfi, Superintendent, Site Design
*J. D. Allard, Maintenance Superintendent
*D. O. Morey, Chemistry Superintendent
*D. M. Fitzgerald, Superintendent, Environmental, Safety and Health
*T. P. Beilman, Superintendent, Integrated Scheduling
*T. E. Quaka, Superintendent, Project Management and Installation Services
*P. G. Schoepf, Staff Assistant