UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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ARLINGTON, TEXAS 76011-4005

January 27, 2004

Randall K. Edington, Vice
President-Nuclear and CNO
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P.O. Box 98
Brownville, Nebraska 68321

SUBJECT: COOPER NUCLEAR STATION - NRC INTEGRATED INSPECTION REPORT 50-298/03-07

Dear Mr. Edington:

On December 31, 2003, the U. S. Nuclear Regulatory Commission (NRC) completed an inspection at your Cooper Nuclear Station. The enclosed integrated inspection report documents the inspection findings which were discussed on January 8, 2004, with Mr. S. Minahan, Acting Site Vice President, and other members of your staff.

This inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

Based on the results of this inspection, the NRC identified five findings that were evaluated under the risk significance determination process as having very low safety significance (Green). The NRC also determined that there were three violations associated with these findings. These violations are being treated as noncited violations (NCVs), consistent with Section VI.A of the Enforcement Policy. These NCVs are described in the subject inspection report. If you contest the violation or significance 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 U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011-4005; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Cooper Nuclear Station facility.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Should you have any questions concerning this inspection, we will be pleased to discuss them with you.

Sincerely,

/RA/

Kriss M. Kennedy, Chief
Project Branch C
Division of Reactor Projects

Docket: 50-298
License: DPR-46

Enclosure:
NRC Inspection Report 05000298/2003007
w/attachment: Supplemental Information

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket.:	50-298
License:	DPR 46
Report No.:	05000298/2003007
Licensee:	Nebraska Public Power District
Facility:	Cooper Nuclear Station
Location:	P.O. Box 98 Brownville, Nebraska
Dates:	September 28 through December 31, 2003
Inspectors:	S. Schwind, Senior Resident Inspector S. Cochrum, Resident Inspector P. Elkmann, Emergency Preparedness Inspector P. Gage, Senior Operations Engineer
Approved By:	K. Kennedy, Chief, Project Branch C, Division of Reactor Projects

SUMMARY OF FINDINGS

IR05000298/2003007; 09/28/03 - 12/31/03; Cooper Nuclear Station: Personnel Performance During Nonroutine Evolutions, Operability Evaluations, Postmaintenance Testing, Refueling and Outage Activities, Identification and Resolution of Problems.

The report covered a 3-month period of inspection by resident inspectors and announced inspections by a Region IV emergency preparedness inspector and a senior operations engineer. Three Green noncited violations and two Green findings were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, "Significance Determination Process." The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. A noncited violation of Technical Specification 5.4.1(a) was identified for a failure to establish an adequate system operating procedure for the turbine oil purification and transfer system during main turbine lube oil reservoir vapor extractor maintenance. This caused an oil leak resulting in a fire.

  This finding was greater than minor since inadequate system operating procedures could be reasonably viewed a precursor to a significant event and, if left uncorrected, could become a more significant safety concern. The finding was determined have a very low safety significance (Green), since it did not affect the fire mitigation defense in depth elements in Figure 4-1 of Inspection Manual 0609, "Significance Determination Process," Appendix F. In addition, it had crosscutting aspects associated with problem identification and resolution, since a number of opportunities were missed to identify the procedure error and prevent the subsequent fire (Section 1R14).

- Green. The failure to correctly rack in a breaker and to establish an adequate postmaintenance test following corrective maintenance on Station Air Compressor B was determined to be a self-revealing finding. The air compressor was rendered inoperable following maintenance as a result of its breaker not being fully racked in, and this condition was not discovered for 35 days.

  This finding was more than minor since it was associated with the increased likelihood of a loss of instrument air, which is an initiating event, but was determined to have very low safety significance (Green), since it did not increase the likelihood of a LOCA, did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available, and did not increase the likelihood of a fire or internal flooding. In addition, this finding had crosscutting aspects associated with human performance because personnel failed to specify a postmaintenance test per station procedures and incorrectly racked in the breaker (Section 1R19).

- Green. A self-revealing finding was identified associated with the failure to evaluate and take corrective actions for a fire on the Booneville 345 kV transmission line in 1997. This led to a similar fire on a transmission tower between the main transformers and the main generator disconnect switches which induced a plant transient in October 2003.

  This finding was more than minor since it induced a plant transient. Given the configuration of the switchyard, the fire did not pose a challenge to offsite power. It was determined to have a very low safety significance (Green) since it did not affect the fire mitigation defense in depth elements in Figure 4-1 of Inspection Manual 0609, "Significance Determination Process," Appendix F. In addition, it had crosscutting aspects associated with problem identification and resolution since the October 2003 fire and transient could have been avoided had the 1997 fire been more thoroughly evaluated (Section 4AO2).

Cornerstone: Mitigating Systems

- Green. A noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, was identified regarding the failure to take adequate corrective actions for degraded conditions on the diesel fuel oil transfer system. In February 2003, corrosion products from the fuel oil storage tank clogged the fuel oil strainer supplying Emergency Diesel Generator 1. Corrective actions for that event failed to preclude recurrence of the condition in November 2003.

  This finding was more than minor since it was associated with the operability, availability, and reliability of a mitigating system but was of very low safety significance (Green), since it did not represent the actual loss of a safety function. In addition, it had crosscutting aspects associated with problem identification and resolution since the corrective action only addressed symptoms of the problem and not the root cause, which was corrosion of the fuel oil storage tank (Section 1R15).

Cornerstone: Barrier Integrity

- Green. A noncited violation of Technical Specification 5.4.1(a) was identified regarding the failure to establish an adequate procedure for operation of the residual heat removal system. Within the guidance of the existing procedure, operators inadvertently established a flow path between the reactor vessel and the condensate storage tank which resulted in draining 300 gallons of reactor coolant to the condensate storage tank.

  This finding was more than minor, since it was associated with the cornerstone attribute of procedure quality, but was determined to have very low safety significance (Green), since the draindown was small and decay heat removal capabilities were not challenged (Section 1R20).

B. Licensee-Identified Violation

A violation of very low safety significance, which was identified by the licensee, was reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. This violation and corrective action tracking numbers are listed in Section 4OA7 of this report.

REPORT DETAILS

The plant was operating at full power at the beginning of this inspection period. On September 28, reactor power was reduced to approximately 25 percent as required by Technical Specifications (TS) due to failure of a turbine trip device during testing. Full power operations were resumed on October 1. On October 16, reactor power was reduced to approximately 65 percent in response to a fire reported underneath a main turbine bearing. Full power operations were resumed on October 17 following completion of firefighting activities and a damage assessment. On October 28 the reactor was manually scrammed due to a fire reported on a tower adjacent to the 345 kV switchyard. Full power operations resumed on November 3 following completion of repairs. One November 28 the reactor automatically scrammed on low reactor pressure vessel (RPV) level due to an unexpected decrease in reactor feed pump speed. Full power operation resumed on December 13 following troubleshooting on the reactor feed pump.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness

1R01 Adverse Weather Protection

a. Inspection Scope

The inspectors selected four samples representing the review of preparations/protection for cold weather conditions on two risk significant systems. The four samples included:

- A review of maintenance work orders completed in order to prepare the systems for possible freezing temperatures
- A review of deficiency tags and condition reports associated with heat tracing and other cold weather protection measures to determine their impact on the systems
- A walkdown of the 250 vdc station batteries to determine if room temperatures were being maintained above 70°F
- A walkdown of the environmental controls in the intake structure to verify that the licensee had completed the required actions identified in the work orders

The two systems chosen for this inspection included:

- Portions of the 250 vdc system including the 250 vdc station batteries.
- The intake structure, including the sluice gates on the ice control tunnel, the ice deflector, and environmental controls in the service water pump room

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

a. Inspection Scope

Partial Equipment Alignment Inspections

The inspectors performed one partial equipment alignment inspection. The walkdown verified that the critical portions of the selected systems were correctly aligned per the system operating procedures (SOP's). The following system was included in the scope of this inspection:

- Emergency Diesel Generator (EDG) 1 while EDG 2 was inoperable for planned maintenance on October 27. The walkdown included portions of the system in the diesel building, the Division I critical switchgear room, and the control room.

Complete Equipment Alignment Inspections

On October 24, the inspectors performed one complete system alignment inspection of the standby liquid control (SLC) system. The inspectors verified that the system was in the appropriate configuration per the SOP and that it was installed and capable of performing its design functions as described in the Updated Final Safety Analysis Report (USAR). A review of maintenance work orders and corrective actions documents for the past 12 months was also performed. A walkdown of the system was performed to assess material condition such as system leaks and housekeeping issues that could adversely affect system operability.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

a. Inspection Scope

The inspector conducted an in-office review of the annual operating examination test results for 2002. Since this was the first half of the biennial requalification testing cycle, the licensee had not yet administered the written examination. These results were assessed to determine if they were consistent with NUREG 1021 guidance and Manual Chapter 0609, Appendix I, "Operator Requalification Human Performance Significance Determination Process," requirements. This review included examination test results for 7 crews, which included 42 licensed individuals.

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule Implementation

a. Inspection Scope

The inspectors reviewed two equipment performance issues to assess the licensee's implementation of their maintenance rule program. The inspectors verified that components that experienced performance problems were properly included in the scope of the licensee's maintenance rule program, and the appropriate performance criteria were established. Maintenance rule implementation was determined to be adequate if it met the requirements outlined in 10 CFR 50.65 and Administrative Procedure 0.27, "Maintenance Rule Program," Revision 15. The inspectors reviewed the following equipment performance problems:

- Failure of Steam Tunnel Fan Cooling Unit CNS-9-HV-FCU-FC-R-1KA on October 17 (Notification 10276549)

- Failure of Supply Fan HV-DG-1D to automatically start during testing of EDG 2 on October 29 (Notification 10278560)

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

a. Inspection Scope

The inspectors reviewed four risk assessments for planned or emergent maintenance activities to determine if the licensee met the requirements of 10 CFR 50.65(a)(4) for assessing and managing any increase in risk from these activities. Evaluations for the following maintenance activities were included in the scope of this inspection:

- Emergency Station Service Transformer outage due to maintenance on the 69 kV transmission line by Omaha Public Power District on October 15

- EDG 2 outage for planned maintenance on October 29 (Work Order 4248388)

- EDG 2 fuel oil strainer planned maintenance on November 24 (Work Order 4346703)

- Station Service Air Compressor (SAC) B 480 V breaker found not fully racked in, which rendered the compressor inoperable from November 10 through December 15 (Notification 10285815)

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Nonroutine Evolutions

a. Inspection Scope

For the nonroutine events described below, the inspectors reviewed operator logs, plant computer data, and strip charts to determine what occurred, how the operators responded, and if the response was in accordance with plant procedures:

- On October 16, the inspectors responded to the control room shortly after a fire was reported in the turbine building. The inspectors observed and evaluated the actions by the control room, actions required by procedures, and monitoring of plant conditions during this event.

- On October 28, the inspectors responded to the control room shortly after operators manually scrammed the reactor in response to a fire on a transmission tower between the main transformers and the main generator disconnect switches. The inspectors observed and evaluated the followup actions by the operators, action required by procedures, and monitoring of plant conditions during this event. This event is discussed in Sections 4OA2 and 4OA7 of this report.

b. Findings

Fire in Turbine Building

Introduction. A Green noncited violation (NCV) of TS 5.4.1(a) was identified for a failure to establish an adequate SOP for the turbine oil purification and transfer system during main turbine lube oil reservoir vapor extractor maintenance, which caused an oil leak resulting in a fire.

Description. On October 16 at 12:19 p.m., a station operator discovered a small fire located beneath Main Turbine Bearing 1. The operator had been sent inside the main turbine shield wall to evaluate earlier reports of smoke observed by a remote camera in the turbine building. Control room operators immediately entered Emergency Procedure 5.4FIRE, "General Fire Procedure," Revision 5. The fire brigade responded, but their initial attempts to extinguish the fire with portable CO_2 and dry chemical extinguishers were unsuccessful. At 12:30 p.m., a Notice of Unusual Event was declared, since the duration of the fire had exceeded 10 minutes. The fire was extinguished using water and foam at 1:36 p.m. No offsite assistance was requested. Due to elevated dose rates in the fire affected area and the extended time required to fight the fire, reactor power was reduced to 65 percent to maintain the fire brigade's dose as low as is reasonably achievable. Damage was limited to discoloration of piping underneath the affected area. There were no injuries and the Notice of Unusual Event was terminated at 3:41 p.m. after the licensee determined that the fire was completely extinguished and there was no risk of re-ignition.

The licensee determined that the fire was caused by an oil leak from the seals of the Main Turbine 1 bearing, which came into contact with hot piping in the area. Securing both turbine lube oil vapor extractors allowed oil to leak out of the journal bearing seals. The vapor extractors are designed to maintain a slightly negative pressure on the turbine bearing oil return system, which prevents oil from leaking out of the bearing seals. Both vapor extractors were secured for planned maintenance per SOP 2.2.81, "Turbine Oil Purification and Transfer System," Revision 29, and were out of service for approximately 6 hours. They had been restored to service 45 minutes prior to the fire. Multiple reports were made to the control room of an oil mist on the turbine deck prior to restoring the vapor extractors to service.

In 1986, a design modification added a redundant vapor extractor as recommended by Westinghouse Bulletin 8504. This bulletin also recommended that the main turbine be shutdown if both vapor extractors were out of service. The Westinghouse vendor manual recommended limiting the time both vapor extractors are out of service to the time necessary to transfer operation from one to the other. The recommendations of the bulletin were translated into Design Change 86-84, "Installation of Redundant Vapor Extractor," which stated that a failure of the vapor extractors would require shutdown of the turbine generator;, however, SOP 2.2.81 was changed in July 2002 to allow operation of the main turbine with both vapor extractors secured. This condition was allowed for an unspecified period of time.

Analysis. This finding had crosscutting aspects associated with problem identification and resolution. This assessment was based on industry operating experience that was provided to the work planner and discussed at the plan-of-the-day meeting on October 15, indicating that fire events had occurred at other nuclear power stations when both lube oil vapor extractors were secured during turbine operation. Also, there were several opportunities to address the oil leak prior to the fire based on multiple reports made to the control room of an oil mist on the turbine deck. This assessment was also based on the licensee's root cause investigation, which determined that a number of opportunities were missed to identify the error in SOP 2.2.81 during the procedure change review.

This finding was more than minor, since it affected the Initiating Events Cornerstone, the inadequate SOPs could be reasonably viewed as a precursor to a significant event and, if left uncorrected, it could become a more significant safety concern. Inspection Manual Chapter 0609, "Significance Determination Process," Appendix F, was used to assess the safety significance of this finding. Phase 1 of the significance determination process (SDP) concluded that the finding was of very low safety significance (Green), since it did not affect the fire mitigation defense in depth elements in Figure 4-1.

Enforcement. TS 5.4.1(a) requires that licensees establish, implement, and maintain written procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Appendix A recommends operating procedures for the turbine-generator system. Contrary to the above, adequate operating procedures were not established for the turbine-generator system, since the licensee's procedures for the operation of the lube oil vapor extractors did not minimize the time that both vapor extractors could be secured and allowed turbine-generator operation with both vapor extractors secured for an unspecified period of time. This finding is being treated as an NCV (50-298/0307-01) consistent with Section VI.A of the NRC Enforcement Policy. The licensee entered this issue into their corrective action program (CAP) as significant condition report (SCR) 2003-1808. Procedure 2.2.81 was revised to correct the procedural inadequacy.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed four operability determinations regarding mitigating system capabilities to ensure that the licensee properly justified operability and that the component or system remained available so that no unrecognized increase in risk occurred. These reviews considered the technical adequacy of the licensee's evaluation and verified that the licensee considered other degraded conditions and their impact on compensatory measures for the condition being evaluated. The inspectors referenced the USAR, TS, and the associated system design criteria documents to determine if operability was justified. The inspectors reviewed the following equipment conditions and associated operability evaluations:

- Inservice Test (IST) failure of Diesel Fuel Oil Transfer Pump A due to debris buildup on the inlet strainer for Fuel Oil Day Tank 2 (Notification 10279881)
- Missed surveillance test on SLC pump discharge relief valves (Notification 10277107)
- Inadvertent removal of riprap during dredging operations adjacent to the intake structure (Notification 10280113)
- Failure of the main turbine mechanical trip device on high reactor vessel level during testing (Notification 10272894)

b. Findings

Introduction: A Green NCV was identified regarding the failure to take adequate corrective actions for degraded conditions on the diesel fuel oil transfer system.

Description: On November 5, Fuel Oil Transfer Pump A failed to develop the required flowrate during Surveillance Procedure 6.1DG.401, “Diesel Generator Fuel Oil Transfer Pump IST Flow Test (Div 1),” Revision 13. Troubleshooting indicated that the fuel oil strainer on the inlet float valve for Fuel Oil Day Tank 1 had accumulated sufficient corrosion product debris from the fuel stream as to restrict flow. The licensee cleaned the strainer, and the transfer pump subsequently passed the surveillance test. In addition, an operability determination was performed which concluded that the corrosion products were being transported from the fuel oil storage tank, which was a slow process that could be managed through the preventive maintenance (PM) program. The operability determination also stated that, if the strainer became clogged during diesel operation, there would be a sufficient volume of fuel in the day tank to allow for cleaning or replacement of the strainer without interruption of engine operation.

The diesel fuel oil system at Cooper Nuclear Station consists of two underground storage tanks, two transfer pumps, and a day tank for each EDG. Each transfer pump takes a suction approximately 3 inches from the bottom of its respective storage tank, and the pump discharge headers are normally cross-connected. Although either transfer pump can supply fuel to either day tank, a single transfer pump does not have sufficient capacity to supply fuel to two fully loaded EDG’s. Therefore, each transfer pump is required to support operability of its respective EDG.

A similar event occurred in February 2003, when Fuel Oil Transfer Pump A failed a surveillance test due to corrosion products in the strainer. The licensee’s response to that event was similar; the strainer was cleaned and an operability determination was performed which concluded that the debris buildup could be managed by the PM program. The PM to clean and inspect the strainer was increased from a 72-week frequency to a 24-week frequency and the contents of both fuel oil storage tanks were filtered in May 2003 in an attempt to reduce the amount of sediment in the tanks. Based on trend data from past engine runs and the current condition of the fuel oil storage tanks, the licensee concluded that the fuel strainer would become blocked by debris after approximately 30 to 35 hours of run time. The 24-week PM frequency was considered adequate to prevent this. At the time of the failure in November, EDG 1 had approximately 40 hours of run time and the strainer clogged prior to the end of the 24-week maintenance interval.

Analysis: This finding had crosscutting aspects associated with problem identification and resolution. This assessment was based on the fact that the licensee had performed an analysis that indicated the failure would repeat itself at approximately 30 to 35 hours of engine run time, yet the corrective action for the February 2003 failure was to change the PM frequency based on calendar time rather than engine run time. In addition, the corrective actions primarily dealt with the symptoms caused by increased fuel storage tank corrosion, not the root causes. This approach also created an operator workaround, since manual action would be required to maintain an EDG operable during its 7-day mission time.

This finding affected the Mitigating Systems Cornerstone and was considered more than minor, since it was associated with the operability, availability, and reliability of a mitigating system. Based on the results of an SDP Phase 1 evaluation, this finding was determined to have very low safety significance, since it did not represent the actual loss of a safety function.

Enforcement: Appendix B, Criterion XVI, of 10 CFR Part 50 states that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective actions taken to preclude repetition. Failure of Fuel Oil Transfer Pump A was considered a significant condition adverse to quality, since it adversely impacted the ability of a risk significant safety system to perform as designed. Corrective actions for the transfer pump failure in February 2003 failed to preclude an additional failure in November 2003. This violation of 10 CFR Part 50, Appendix B, Criterion XVI, is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy (50-298/0307-02). The licensee entered this issue into their CAP as SCR 2003-1876.

1R16 Operator Workarounds

a. Inspection Scope

The inspectors reviewed eight operator workaround items to evaluate their cumulative affect on mitigating systems and the operators’ ability to implement abnormal or emergency procedures. In addition, open operability determinations and selected condition reports were reviewed and operators were interviewed to determine if there were additional degraded or nonconforming conditions that could complicate the operation of plant equipment.

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing

a. Inspection Scope

The inspectors reviewed or observed seven selected postmaintenance tests to verify that the procedures adequately tested the safety function(s) that were affected by maintenance activities on the associated systems. The inspectors also verified that the acceptance criteria were consistent with information in the applicable licensing basis and design basis documents and that the procedures were properly reviewed and approved. Postmaintenance tests for the following maintenance activities were included in the scope of this inspection:

- Replacement of scram solenoid pilot valves from September 12 to October 28 (Work Order 432210)

- EDG 2 piston replacement on October 29 (Work Order 4248388)

- Leak repair on moisture separator for Station Air Compressor (SAC) B on November 10 (Work Order 4338511)

- Cleaning and inspection of Diesel Fuel Oil Strainer DGDO-STRN-FLTV11 on November 24 (Work Order 4343940)

- Control panel switch replacement for Reactor Coolant Sample Valve RR-AOV-741AV on December 11 (Work Order 4172876)

- Cleaning and inspection of Service Water Strainer A on December 16 (Work Order 4323349)

- Control board replacement in 250 vDC Battery Charger A on December 17 (Work Order 4314331)

b. Findings

Introduction: A Green finding was identified regarding the failure to correctly rack in a breaker and to specify an adequate postmaintenance test following corrective maintenance on SAC B.

Details: On November 10, SAC B was removed from service to repair a leak on the moisture separator. The tagging order specified that the breaker for the compressor (EE-CB-480G) be racked to the test position and specified the restoration configuration as racked in. The corrective maintenance on the moisture separator was completed, the tags were cleared, and the system was restored to a standby configuration. Work Order 4338511 did not specify any postmaintenance test following this job.

SAC B remained in standby until December 15 when operators attempted to start it as part of their normal equipment rotation routine. The compressor failed to start and, upon further investigation, it was determined that Breaker EE-CB-480G was not fully racked in. Once the breaker had been fully racked in, operators were successful in starting SAC B.

Analysis: This finding had crosscutting aspects associated with human performance. This assessment was based on the fact that personnel failed to follow station procedures regarding work planning and control. Administrative Procedure 0.40, "Work Control Program," Revision 39, Section 6.7.1, requires that postmaintenance testing be specified to demonstrate satisfactory completion of work and verify that no new deficiencies have been created. This was not done. In addition, station personnel failed to correctly restore the breaker for SAC B following maintenance.

This finding affected the Initiating Events Cornerstone and was considered more than minor, since it was associated with the increased likelihood of a loss of instrument air, which is an initiating event. Based on the results of an SDP Phase 1 evaluation, this finding was determined to have very low safety significance, since it did not increase the likelihood of a LOCA, a fire, or internal flooding and did not contribute to either the likelihood of a reactor trip or that mitigation equipment or functions would not be available.

Enforcement: Although SAC B is a risk significant component, it is not considered safety related. Therefore, no violation of NRC requirements was identified. The licensee entered this issue into their CAP as Notification 10285815.

1R20 Refueling and Outage Activities

a. Inspection Scope

The inspectors observed outage-related activities during Forced Outage 03-05. Activities included the scram recovery actions following a manual reactor scram on October 28, plant cooldown, placing the residual heat removal (RHR) system in the shutdown cooling mode of operation, and startup activities.

b. Findings

Introduction: An inadequate procedure, which led to an RPV draindown event while placing RHR in shutdown cooling, was considered to be a self-revealing, Green NCV.

Description: On October 29, operators were in the process of flushing Division 1 of the RHR system in preparation for placing it in shutdown cooling. During the flushing and venting process, SOP 2.2.69.2, “RHR System Shutdown Operations,” Revision 42, directed operators to open the RHR shutdown cooling condensate supply valves, RHR-96 and RHR-97, and then to open the inboard and outboard shutdown cooling isolation valves, RHR-MO-17 and RHR-MO-18. This established a drain path from the RPV to the condensate system and, subsequently, to the condensate storage tank (CST). Control room operators noted that RPV level decreased by 1.5 inches during this evolution and that RHR-96 and RHR-97 were hot, which indicated they were passing reactor coolant. At this point, the drain path was isolated. It was estimated that 300 gallons were inadvertently transferred from the reactor coolant system to the CST at a flow rate of approximately 60 gallons per minute.

Analysis: This finding affected the Barrier Integrity Cornerstone since it represented the unintentional bypass of two fission product barriers (reactor coolant system and containment system) and was more than minor, since it was associated with the cornerstone attribute of procedure quality. This finding degraded the safety of a shutdown reactor; therefore, MC 0609, Appendix G, "Shutdown Operations Significance Determination Process," was used to assess its signficance. A quantitative assessment was not performed since an RPV level change of 1.5 inches does not represent a loss of control. Pages T-14 through T-16 of Appendix G were used to assess the significance since the reactor was in hot shutdown, time to boil was less than 2 hours, and initial conditions for RHR operations had been met. The guidelines for core heat removal, inventory control, and power availability were met. In addition, the containment guidelines were met, since the automatic containment isolation function for RHR on low RPV level (7.81 inches on the wide-range instrument) was operable. Although this finding did increase the likelihood of a loss of reactor coolant inventory, a Phase 2 analysis was unnecessary because level instrumentation was unaffected and this was not considered rapid loss of inventory. Based on these results, this finding was determined to have very low safety significance.

Enforcement: TS 5.4.1(a) requires written procedures to be established, implemented, and maintained as recommended by Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Appendix A recommends operating procedures for the shutdown cooling system. SOP 2.2.69.2, "RHR System Shutdown Operations," Revision 42, did not meet this requirement in that it directed operators to align the system in a manner which established a drain path from the RPV to the CST. This violation is being treated as an NCV (50-298/0307-03) consistent with Section VI.A of the NRC Enforcement Policy. The licensee entered these issues into their CAP as Notifications 10249930 and 10249920.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors observed or reviewed the following three surveillance tests to ensure that the systems were capable of performing their safety function and to assess their operational readiness. Specifically, the inspectors verified that the following surveillance tests met TS requirements, the USAR, and licensee procedural requirements:

- 15.TG.302, "Main Turbine Trip Functional Test," Revision 5, performed on September 29
- 6.2ADS.303, "ADS [alternate depressurization system] Logic System Functional Test (Div 2)," Revision 7, performed on October 17
- SLC pump discharge relief valve testing under Work Orders 4285654 and 4338440.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed Temporary Configuration Change 4347948, dated December 2, 2003, which installed temporary diagnostic equipment in the controller cabinet for Reactor Feed Pump B and installed an additional supervisory alarm for the feed pump turbine in the control room. The inspectors verified that the change did not require NRC approval prior to implementation and that adequate controls on the installation existed.

b. Findings

No findings of significance were identified.

1EP4 Emergency Action Level and Emergency Plan Changes

a. Inspection Scope

The inspector performed an in-office review of Revision 44 to the Cooper Nuclear Station Emergency Plan, submitted September 17, 2003. This revision:

- Clarified responsibility for on-shift dose assessment
- Revised documentation requirements for Letters of Agreement
- Updated the description of tone alert radios
- Revised the description of the conduct of emergency response organization training
- Updated titles

The revision was compared to its previous version, to the criteria of NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," Revision 1, and to the requirements of 10 CFR 50.47(b) and 50.54(q) to determine if the revision decreased the effectiveness of the plan. The inspector completed the required one sample during this inspection.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation

a. Inspection Scope

The inspectors observed the licensee perform an emergency preparedness drill on December 17. Observations were conducted in the control room, technical support center, and emergency operations facility. During the drill, the inspectors assessed the licensee's performance related to classification, notification, and protective action recommendations. Following the drill, the inspectors reviewed the licensee's critique to determine if issues were appropriately identified and documented. The following documents were reviewed during this inspection:

- Emergency Plan for Cooper Nuclear Station
- Emergency Plan Implementing Procedures for Cooper Nuclear Station
- Cooper Nuclear Station Emergency Preparedness Drill Scenario for December 17.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES (OA)

4OA1 Performance Indicator (PI) Verification

a. Inspection Scope

The inspectors sampled licensee PIs listed below for the period October 01, 2002, through September 30, 2003. The definitions and guidance of NEI 99-02, "Regulatory Assessment Indicator Guideline," Revision 2, were used to verify the licensee's basis for reporting each data element in order to verify the accuracy of PI data reported during the assessment period. Licensee PI data were reviewed against the requirements of Procedures 0-PI-01, "Performance Indicator Program," Revision 13.

Reactor Safety Cornerstone

- Reactor Coolant System (RCS) Leakage

The inspectors reviewed a selection of licensee event reports (LERs), portions of operator log entries, monthly reports, and PI data sheets to determine whether the licensee adequately collected, evaluated, and distributed PI data for the period reviewed.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

.1 Reactor Scram Due to a Fire on a 345 kV Transmission Tower

a. Inspection Scope

The inspectors performed a review of SCR 2003-1844, which documented the root cause investigation into a fire on a wooden transmission tower between the main transformers and the main generator disconnect switches. The inspectors also conducted interviews with selected licensee engineers and the personnel who conducted the investigation. Other aspects of this event are discussed in Section 4OA7 of this report.

b. Findings

Introduction: A Green, self-revealing finding was identified associated with the failure to evaluate and take corrective actions for a fire on the Booneville 345 kV transmission line. This led to a similar fire on a transmission tower between the main transformers and the main generator disconnect switches, which induced a plant transient.

Description: On October 28 at 1:30 a.m., control room operators were notified by security of a fire on the crossarm of a wooden 345 kV transmission tower adjacent to the 345 kV switchyard. The tower supported the main generator output lines and was located between the main transformers and the main generator disconnect switches. At 1:45 a.m. operators began a rapid shutdown of the plant in anticipation of losing the main generator output line. In addition, the Emergency Response Organization was activated as a precautionary measure, even though no emergency declaration was required or had been made. At 1:59 a.m., operators manually scrammed the reactor when the crossarm of the tower failed, allowing one phase of the main generator output lines to fall. This phase remained suspended above the ground and no generator grounds or phase-to-ground arcing occurred. The inspectors arrived in the control room at approximately 2:20 a.m. to observe operator response to the reactor scram. The fire was extinguished and the plant was stable in Mode 3 by 6:47 a.m.

The licensee’s root cause investigation concluded that the fire on the crossarm was caused by the lack of grounding straps on the crossarm insulators. In addition, the crossarm showed signs of age-related deterioration due to the loss of wood preservative. This was evidenced by moss growth on the crossarm and cracks in the wood. These factors, combined with light rain several hours prior to the event, established a high resistance current path across one of the insulators, through the wooden crossarm, and across the tower poles to ground. This high resistance current path eventually heated the wood sufficiently to ignite the crossarm.

The licensee evaluated the extent of this condition and determined that the Booneville 345 kV transmission line had a similar configuration as the main generator output line. The insulators on the wooden tower supporting this line were not properly grounded; however, the wooden crossarm was in better material condition since it had been replaced in 1997 following a similar fire. The licensee entered that event into their CAP as Department Disposition 2-18586; however, no root cause investigation or extent of condition evaluation was performed and the only corrective action implemented was to repair the damaged crossarm.

Following the more recent fire event, the licensee implemented a number of corrective actions, including a modification to the main generator output line which removed the wooden transmission tower and the installation of grounding straps on the wooden tower supporting the Booneville 345 kV transmission line.

Analysis: This finding had crosscutting aspects associated with problem identification and resolution. This assessment was based on the licensee's failure to question the causes and extent of condition regarding a similar fire event in 1997. A thorough evaluation of that fire could have prevented the fire in 2003 and the associated plant transient.

This finding was more than minor, since it affected an Initiating Events Cornerstone attribute by increasing the likelihood of a transient. Although this fire induced a transient, it did not pose a challenge to offsite power due to the configuration of the switchyard and did not challenge mitigating equipment. Inspection Manual Chapter 0609, "Significance Determination Process," Appendix F, was used to assess the safety significance of this finding. Phase 1 of the SDP concluded that the finding was of very low safety significance (Green), since it did not affect the fire mitigation defense in depth elements in Figure 4-1.

Enforcement: The portion of the electrical distribution system affected by this fire was nonsafety-related; therefore, no violation of NRC requirements was identified. This finding was entered into the licensee's CAP as SCR 2003-1844.

.2 Cross-References to Problem Identification and Resolution Findings Documented Elsewhere

Section 1R14 describes that the licensee missed a number of opportunities to identify procedure errors, which resulted in a turbine lube oil leak.

Section 1R15 describes that the licensee's corrective actions dealt primarily with the symptoms rather than the root causes for a clogged diesel fuel oil strainer. This condition repeated itself 9 months later.

Section 4OA2 describes that the licensee failed to thoroughly evaluate a fire on a 345 kV transmission line in 1997. This contributed to a similar fire in 2003, which induced a plant transient.

4OA3 Event Followup

.1 (Closed) LER 50-298/03-001-00 Inadequate Communication Results if Both Diesel Generators Inoperable Simultaneously

On February 28, 2003, the licensee declared EDG 2 inoperable due to a question regarding the qualified life of an Agastat time delay relay in the diesel room ventilation system. This ventilation system was required to support operability of EDG 2. EDG 1 had previously been declared inoperable on February 24 due to a clogged strainer in the fuel oil system. The reactor was in cold shutdown (Mode 4) at the time both EDG's were inoperable. During this period of time, only one EDG was required to be operable per TS and at no time were both EDG simultaneously unable to perform their safety function. The time delay relay was replaced on February 28 and EDG 2 was declared operable. On March 2, maintenance on the fuel oil system was complete and EDG 1 was declared operable. The enforcement aspects associated with this event are discussed in Section 1R15 of this report and Section 4OA2 (Example 2) of NRC Inspection Report 05000298/2003002. This LER is closed.

.2 (Closed) LER 50-298/03-005-00 Turbine Trip Failure During Testing Due to Ester Contamination of Turbine Lube Oil

On September 28, during turbine trip testing, the turbine trip block failed to actuate as designed while testing the solenoid and low vacuum trip portions of the device. Troubleshooting indicated binding in the auto stop oil dump valve which is mechanically linked to the trip block. This rendered the high reactor water level (Level 8) turbine trip feature inoperable, which required reactor power to be reduced below 25 percent per TS. After the valve was exercised, the trip block operated properly and full power operation was resumed. The probable cause of the auto stop oil dump valve binding was the presence of trace amounts of hydrolyzed ester contaminants in the turbine lube oil. The source of the ester could not be determined; however, compensatory measures, such as regularly exercising the auto stop oil dump valve, were implemented to ensure the condition did not recur. In addition, the turbine lube oil purification system has been effective in removing the hydrolyzed ester contaminants. Since the source of lube oil contamination could not be determined, the inspectors were unable to identify any licensee performance deficiency and no findings of significance were identified. This LER is closed.

4OA6 Meetings, Including Exit

On November 12, 2003, the inspector presented the results of the emergency plan inspection to Mr. J. Bednar, Emergency Preparedness Manager, and other members of his staff who acknowledged the findings.

On January 8, 2004, inspectors presented the results of the resident inspector activities to Mr. S. Minahan, General Manager, Site Operations, and other members of his staff who acknowledged the findings.

In all cases, the inspectors confirmed that proprietary information was not provided or examined during the inspection.

4OA7 Licensee Identified Violations

The following violation of very low safety significance (Green) was identified by the licensee and is a violation of NRC requirements which met the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as an NCV.

- TS 5.4.1(a) requires that the licensee establish and implement written procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Appendix A recommends procedures for combating emergencies and other significant events, such as reactor scrams. Contrary to this requirement, operators failed to take manual control of reactor feed pumps as required by General Operating Procedure 2.1.5, “Reactor Scrams,” Revision 44, during scram recovery actions performed on October 28, 2003. This contributed to level control problems following the scram. This finding was identified by the licensee during their postscram review and was entered into their CAP as Resolve Condition Report 2003-1846. This finding was of very low safety significance, since it did not represent the loss of any safety function.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

J. Bednar, Emergency Preparedness Manager
C. Blair, Engineer, Licensing
M. Boyce, Corrective Action Program Senior Manager
D. Cook, Senior Manager of Emergency Preparedness
J. Christensen, Acting Nuclear Site Vice President
T. Chard, Radiological Manager
K. Chambliss, Operations Manager
J. Edom, Risk Management
R. Estrada, Performance Analysis Department Manager
M. Faulkner, Security Manager
J. Flaherty, Site Regulatory Liaison
P. Fleming, Risk & Regulatory Affairs Manager
C. Kirkland, Nuclear Information Technology Manager
W. Macecevic, Work Control Manager
L. Schilling, Administrative Services Department Manager
R. Shaw, Shift Manager
J. Sumpter, Senior Staff Engineer, Licensing
K. Tanner, Shift Supervisor, Radiation Protection
D. Knox, Maintenance Manager
A. Williams, Manager, Engineering Support Division

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000298/2003007-001	NCV	Inadequate Procedure Results in Oil Fire Underneath Main Turbine (Section 1R14)
05000298/2003007-002	NCV	Inadequate Corrective Actions Result in Repetitive Degraded Condition on EDG (Section 1R15)
05000298/2003007-003	NCV	Inadequate Procedure Results in Inadvertent RPV Draindown (Section 1R20)
Finding	FIN	Inadequate Postmaintenance Test of SAC (Section 1R19)
Finding	FIN	Inadequate Corrective Actions Result in Fire and Plant Transient (Section 4OA2)

Closed

05000298/2003-001-00	LER	Inadequate Communication Results in Both Diesel Generators Inoperable Simultaneously (Section 4OA3.1)
05000298/2003-005-00	LER	Turbine Trip Failure During Testing Due to Ester Contamination of Turbine Lube Oil (Section 4OA3.2)

LIST OF DOCUMENTS REVIEWED

Miscellaneous Documents Reviewed

Cooper Nuclear Station 2002 Operating Examination Results

LIST OF ACRONYMS

ADS	alternate depressurization system
CAP	Corrective Action Program
CFR	*Code of Federal Regulations*
CST	condensate storage tank
EDG	emergency diesel generator
IST	inservice test
LER	licensee event report
NCV	noncited violation
NEI	Nuclear Energy Institute
PI	performance indicator
PM	preventive maintenance
RHR	residual heat removal
RPV	reactor pressure vessel
SAC	station air compressor
SCR	significant condition report
SDP	Significance Determination Process
SLC	standby liquid control system
SOP	system operating procedure
TS	Technical Specification
USAR	Updated Final Safety Analysis Report