UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

May 6, 2004

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

SUBJECT: COOPER NUCLEAR STATION - NRC INTEGRATED INSPECTION REPORT 05000298/2004002

Dear Mr. Edington:

On March 24, 2004, 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 April 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 2.390 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:
Inspection Report 05000298/2004002
w/attachment: Supplemental Information

cc w/enclosure:
Clay C. Warren, Vice President-Nuclear
Nebraska Public Power District
P.O. Box 98
Brownville, NE 68321

John R. McPhail, General Counsel
Nebraska Public Power District
P.O. Box 499
Columbus, NE 68602-0499

P. V. Fleming, Licensing and
Regulatory Affairs Manager
Nebraska Public Power District
P.O. Box 98
Brownville, NE 68321

Michael J. Linder, Director
Nebraska Department of
Environmental Quality
P.O. Box 98922
Lincoln, NE 68509-8922

Chairman
Nemaha County Board of Commissioners
Nemaha County Courthouse
1824 N Street
Auburn, NE 68305

Sue Semerena, Section Administrator
Nebraska Health and Human Services System
Division of Public Health Assurance
Consumer Services Section
301 Centennial Mall, South
P.O. Box 95007
Lincoln, NE 68509-5007

Ronald A. Kucera, Deputy Director
for Public Policy
Department of Natural Resources
P.O. Box 176
Jefferson City, MO 65101

Jerry Uhlmann, Director
State Emergency Management Agency
P.O. Box 116
Jefferson City, MO 65102-0116

Chief, Radiation and Asbestos
Control Section
Kansas Department of Health
and Environment
Bureau of Air and Radiation
1000 SW Jackson, Suite 310
Topeka, KS 66612-1366

Daniel K. McGhee
Bureau of Radiological Health
Iowa Department of Public Health
401 SW 7th Street, Suite D
Des Moines, IA 50309

William J. Fehrman, President
and Chief Executive Officer
Nebraska Public Power District
1414 15th Street
Columbus, NE 68601

Chief Technological Services Branch
National Preparedness Division
Department of Homeland Security
Emergency Preparedness & Response Directorate
FEMA Region VII
2323 Grand Boulevard, Suite 900
Kansas City, MO 64108-2670

Electronic distribution by RIV:
Regional Administrator **(BSM1)**
DRP Director **(ATH)**
DRS Director **(DDC)**
Senior Resident Inspector **(SCS)**
Branch Chief, DRP/C **(KMK)**
Senior Project Engineer, DRP/C **(WCW)**
Staff Chief, DRP/TSS **(PHH)**
RITS Coordinator **(KEG)**
Dan Merzke, Pilot Plant Program **(DXM2)**
RidsNrrDipmLipb
Rebecca Tadesse, OEDO RIV Coordinator **(RXT)**
CNS Site Secretary **(SLN)**
Dale Thatcher **(DFT)**
W. A. Maier, RSLO **(WAM)**

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket.:	50-298
License:	DPR 46
Report:	05000298/2004002
Licensee:	Nebraska Public Power District
Facility:	Cooper Nuclear Station
Location:	P.O. Box 98 Brownville, Nebraska
Dates:	January 1 through March 24, 2004
Inspectors:	S. Schwind, Senior Resident Inspector S. Cochrum, Resident Inspector P. Elkmann, Emergency Preparedness Inspector R. Mullikin, Senior Reactor Inspector
Approved By:	K. Kennedy, Chief, Branch C, Division of Reactor Projects

Attachment

CONTENTS

SUMMARY OF FINDINGS

IR05000298/2004002; 01/01/04 - 03/24/04; Cooper Nuclear Station; Equip. Alignment, Maint. Rule Implementation, Personnel Performance During Nonroutine Evolutions, Operability Evaluations, Operator Workaround, Temporary Plant Mods, Identification & Resolution of Problems, & Event Followup.

The report covered a 3-month period of inspection by resident inspectors and announced inspections by a regional emergency preparedness inspector and a senior reactor engineer. Three Green noncited violations with multiple examples 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/Mitigating Systems

- Green. The inspectors identified a finding regarding the failure to evaluate an operator workaround created by compensatory measures for the loss of alarm functions on Reactor Feed Pump A. The failure to perform this evaluation had a negative impact on operator performance since not all operating crews were informed of the compensatory measures.

  This finding was more than minor because it affected the initiating events cornerstone and was associated with the configuration control of plant equipment, but it was considered to have very low safety significance since it did not contribute to the likelihood of a primary or secondary system loss of coolant accident, did not contribute to a loss of mitigation equipment, and did not increase the likelihood of a fire or internal/external flood (Section 1R16).

- Green. The inspectors identified a finding regarding the failure to evaluate a temporary modification to the Reactor Feed Pump A control cabinet. Two supervisory alarms were disabled due to nuisance alarms caused by a programming error in the control system. A portable computer and remote camera were staged at the control cabinet to compensate for the loss of these alarms but adequate controls were not established in accordance with the licensee's temporary modification procedure.

  This finding was more than minor because it affected the initiating events cornerstone and was associated with the configuration control of plant equipment, but was considered to have very low safety significance since it did not contribute to the likelihood of a primary or secondary system loss of coolant accident, did not contribute to a loss of mitigation equipment, and did not increase the likelihood of a fire or internal/external flood (Section 1R23).

- Green. Two examples of a noncited violation of Technical Specification 5.4.1 were identified associated with the failure to implement station procedures. The two examples include the following:

  -- A noncited violation of Technical Specification 5.4.1(a) occurred regarding the failure to follow station procedures during recovery from a reactor scram. Operators secured the high pressure coolant injection system using an incorrect method not allowed by the procedure in use at the time. This incorrect method rendered the system inoperable.

  This finding is more than minor since it affected the mitigating systems cornerstone and involved human performance errors during a transient. This finding is of very low safety significance since it did not represent an actual loss of safety function. In addition, it also had crosscutting aspects associated with human performance based on the failure to properly implement station procedures (Section 1R14).

  -- The inspectors identified a noncited violation of Technical Specification 5.4.1(a) regarding the failure to correctly implement the operability determination procedure. The licensee failed to meet timeliness goals and documentation requirements when evaluating the operability of multiple safety-related level transmitters.

  This finding was more than minor because it affected the mitigating systems cornerstone and the failure to follow procedures when assessing operability of safety-related equipment could become a more safety significant safety concern if left uncorrected. The finding was of very low safety significance since the licensee was ultimately able to demonstrate operability of all the affected instruments. This finding had cross-cutting aspects associated with human performance (Section 1R15).

- Green. Three examples of a noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, were identified associated with the failure to promptly identify and correct conditions adverse to quality. The three examples include the following:

  -- The inspectors identified two examples of a noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, regarding the failure to take timely and effective corrective actions to revise high pressure coolant injection procedures following the May 2003 event; and failure to promptly identify and enter high pressure coolant injection procedure violations into the Corrective Action Program following the November 2003 event.

  This finding was more than minor since it was associated with the mitigating system cornerstone attribute of human performance, but it was of very low safety significance 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 actions that were identified were not implemented in a timely manner (Section 4OA2).

-- The inspectors identified a Green noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, for failure to take effective and timely corrective actions associated with the stratification of the reactor vessel. In May 2003, following a reactor scram, stratification occurred which resulted in exceeding Technical Specification heatup and cooldown rates for the reactor vessel. Corrective actions for that event failed to prevent recurrence of the condition in November 2003.

  This finding was more than minor because it affected the initiating events cornerstone attribute of equipment performance of Reactor Coolant System barrier, but it was of very low safety significance since it did not contribute to the likelihood of a primary or secondary system loss of coolant accident, did not contribute to a loss of mitigation equipment, and did not increase the likelihood of a fire or internal/external flood. In addition, it had crosscutting aspects associated with problem identification and resolution since the corrective actions did not prevent recurrence.

- <u>Green</u>. Two examples of a violation of TS 5.4.1(a) were identified for failure to establish adequate procedures for controlling the offsite power circuits. This violation was identified during closure of an unresolved item dealing with multiple historic design and configuration control issues with the main switchyard and secondary offsite power circuit.

  This finding was more than minor since it affected the mitigating systems cornerstone and was associated with configuration control of offsite power, but it was of very low safety significance since no instances were identified where the emergency ac power safety function was unavailable (Section 4OA5).

B. <u>Licensee-Identified Violation</u>

Violations of very low safety significance, which were identified by the licensee, have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. These violations 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 February 1, reactor power was reduced to 70 percent for planned maintenance for approximately 12 hours. On February 14, the reactor recirculation Pump A motor generator tripped due to exciter brush failure, causing reactor power to lower to 68 percent. Following repairs, full power operations resumed on February 16.

1. REACTOR SAFETY

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

1R04 Equipment Alignment

a. Inspection Scope

Partial Equipment Alignment Inspections

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

- Emergency Diesel Generator (EDG) 1 while portions of the starting air system were tagged out for planned maintenance on January 12 (Work Order 4316571). The walkdown included portions of the starting air system in the diesel room to verify that the tagout boundaries did not affect the EDG's ability to start as required.
- Reactor core isolation cooling (RCIC) system while high pressure coolant injection (HPCI) was inoperable for planned maintenance on February 3. The walkdown included portions of the system in the control room and RCIC pump room.
- Residual Heat Removal (RHR) system Loop B while Loop A was out of service for corrective maintenance on February 27. The walkdown included portions of the control room, southwest Quad 859, and RHR Heat Exchanger Room 903.

b. Findings

No findings of significance were identified

1R05 Fire Protection

a. Inspection Scope

The inspectors performed six fire zone walkdowns to determine if the licensee was maintaining those areas in accordance with its Fire Hazards Analysis Report (six inspection samples). The fire zones were chosen based on their risk significance as described in the Individual Plant Examination of External Events. The walkdowns focused on control of combustible materials and ignition sources, operability and material condition of fire detection and suppression systems, and the material condition of passive fire protection features. The following fire zones were inspected:

- Fire pump house on January 5
- Fire Zone 5B, motor generator set area on January 16
- Fire Zone 7A, RHR service water (SW) booster pump and service air compressor area on February 18
- Fire Zone 14A, Diesel Generator Room 1A on February 24
- Fire Zone 8E, Battery Room 1A on February 26
- Fire Zone 3B, Switchgear Room 1G on March 3

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures

a. Inspection Scope

The inspectors performed one internal flood protection inspection of the Division 1 and 2 direct current switchgear rooms located on Elevation 903 of the Control Building (one inspection sample). The inspection included a review of the Updated Final Safety Analysis Report, selected design criteria documents and design calculations including:

- Cooper Nuclear Station Design Criteria Document 38, “Internal Flooding System,” Revision 2
- Calculation NEDC 91-069, “Moderate Energy Line Break Flooding Calcs”
- Calculation NEDC 00-080, “Flood Door Gap Analysis”

In addition, a walkdown of the area was performed on January 5 to determine if the actual configuration of flood protection design features matched the assumptions used in the aforementioned calculations.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance

a. Inspection Scope

The inspectors performed one heat sink performance review by observing the cleaning and inspection activities on reactor equipment cooling Heat Exchanger B performed on February 20, 2004, and reviewed the last set of test data for the heat exchanger recorded on November 24, 2003 (one inspection sample). A review of the heat exchanger performance evaluation was conducted to identify potential deficiencies that could mask degraded performance. The inspectors reviewed the type, location, and calibration of instrumentation used to acquire the data to verify its acceptability for the evaluation. The evaluation review was conducted and documented in accordance with Performance Evaluation Procedure 13.15.1, “Reactor Equipment Cooling Heat Exchanger Performance Analysis,” Revision 20.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

a. Inspection Scope

The inspectors observed one session of licensed operator requalification training in the plant simulator on January 15 (one inspection sample). The training evaluated the operators’ ability to recognize, diagnose, and respond to a security event leading to a major plant transient. Observations were focused on the following key attributes of operator performance:

- Crew performance in terms of clarity and formality of communications
- Ability to take timely, appropriate actions
- Prioritizing, interpreting, and verifying alarms
- Correct implementation of procedures, including the alarm response procedures
- Timely control board operation and manipulation, including high-risk operator actions
- Oversight and direction provided by the shift supervisor, including the ability to identify and implement appropriate TS requirements, reporting, emergency plan actions, and notifications
- Group dynamics involved in crew performance

The inspectors also verified that the simulator response during the training scenario closely modeled expected plant response during an actual event.

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule Implementation

.1 Routine Evaluation Review

a. Inspection Scope

The inspectors reviewed two equipment performance issues to assess the licensee's implementation of their maintenance rule program (two inspection samples). The inspectors verified that components that experienced performance problems were properly included in the scope of the licensee's maintenance rule program and that 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 Service Air Compressor B to start on December 15 (Notification 10285815)
- Failure of Steam Tunnel Fan Cooler Unit A on January 24 (Notification 10292161)

b. Findings

No findings of significance were identified

.2 Periodic Evaluation Reviews

a. Inspection Scope

The inspectors reviewed the Cooper Nuclear Station report documenting the performance of the last maintenance rule periodic effectiveness evaluation to confirm that it was performed in accordance with 10 CFR 50.65(a)(3). The licensee's periodic evaluation covered the period from December 17, 2000, through August 31, 2002.

The inspectors reviewed the handling of risk significant structures, systems and components with degraded performance or degraded condition to assess the effectiveness of the licensee's evaluation and the resulting corrective actions. Inspection Procedure 71111.12, "Maintenance Effectiveness," requires three to five risk significant examples. The inspectors reviewed five examples: EDGs, reactor equipment cooling system, RHR system, SW system, and instrument air system. Additionally, the performance of nonrisk-significant functions were monitored using plant level criteria.

The inspectors evaluated the use of performance history and industry experience to adjust the preventive maintenance requirements, to adjust (a)(1) goals, and to adjust the (a)(2) performance criteria. The inspectors assessed the licensee's adjustment of the scope of the maintenance rule, the licensee's adjustment of the definition of maintenance rule functional failures, the licensee's adjustment of definitions of available/unavailable hours and required hours, and the licensee's review and adjustment of condition-monitoring parameters and action levels.

The inspectors also reviewed the conclusions reached by licensee personnel with regard to the balance of reliability and unavailability for specific maintenance rule functions. This review was conducted by examining the licensee's evaluation of all risk significant functions that had exceeded performance criteria during the evaluation period.

b. Findings

No findings of significance were identified

.3 Identification and Resolution of Problems

a. Inspection Scope

The inspectors evaluated the use of the corrective action system within the maintenance rule program for issues associated with risk significant systems. The review was accomplished by the examination of a sample of corrective action documents, maintenance work items, and other documents listed in the attachment. The purpose of the review was to establish that the corrective action program was entered at the appropriate threshold for the purpose of:

- Implementation of the corrective action process when a performance criterion was exceeded
- Correction of performance-related issues or conditions identified during the periodic evaluation
- Correction of generic issues or conditions identified during programmatic assessments, audits, or surveillances.

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 (four inspection samples). Evaluations for the following maintenance activities were included in the scope of this inspection:

- Corrective maintenance on Service Air Compressor B due to motor breaker not being fully racked in, which rendered Service Air Compressor B inoperable for 35 days beginning November 10, 2003 (Notification 10285815)
- Corrective maintenance on RCIC due to high oil level which rendered RCIC inoperable on December 2 and 14 (Notification 10285814)
- Corrective maintenance on RHR Loop A to replace time delay relay RHR-REL-K93A on February 27 (Work Order 4366202)
- Corrective maintenance on SW Booster Pump C gland water inlet Valve SW-V-643 on March 12 (Work Order 4368552)

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Nonroutine Evolutions

a. Inspection Scope

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

- On November 28, 2003, the inspectors responded to the control room shortly after the reactor automatically scrammed due to low reactor water level in response to Reactor Feed Pump Turbine B switching from automatic to manual mode without operator action, causing reactor water level to drop rapidly. The inspectors observed and evaluated the followup actions by the operators and actions required by procedures and monitored plant conditions during this event. Other aspects of this event are discussed in Sections 4OA2 and 4OA7 of this report.

- On February 14, 2004, the inspectors responded to the control room shortly after the reactor recirculating motor generator tripped due to field undervoltage caused by exciter field brush failure. The inspectors observed and evaluated the followup actions by the operators and actions required by procedures and monitored plant conditions during this event.

b. Findings

Introduction. A Green noncited violation of TS 5.4.1 was identified regarding the failure of personnel to follow procedures for operation of the HPCI system.

Description. On November 28, 2003, a reactor scram occurred due to a reactor feed pump control system malfunction. Following the scram, reactor vessel water level dropped below the Level 2 setpoint, resulting in primary containment isolation system Group 2, 3, and 6 isolations, the start of the HPCI and RCIC systems, and a trip of the reactor recirculation pumps. During the scram recovery, HPCI was secured after the operators determined that the system was not required because reactor vessel water level was rapidly recovering.

During the licensee's postevent review, it was discovered that the control room operators used the wrong procedural step to secure HPCI following the scram recovery. Control room operators noted that reactor vessel level was recovering and determined injection was not required. Emergency Operating Procedure 1A, "RPV Control," Revision 12, and General Operating Procedure 2.1.5, "Reactor Scram," Revision 45, Attachment 2, "Reactor Water Level Control," directed that the HPCI system be operated in accordance with SOP 2.2.33.1, "High Pressure Coolant Injection System Operations," Revision 16. The operators inappropriately secured the HPCI turbine using SOP 2.2.33.1, step 7.3, which directed them to trip the pump and then place the auxiliary oil pump switch in pull-to-lock. Placing the auxiliary oil pump switch in pull-to-lock defeated the HPCI safety function by preventing further automatic system initiations. Instead, operators should have secured the HPCI pump using SOP 2.2.33.1, step 7.2, which would have directed operators to reset the sealed in initiation signal and place HPCI in standby, thus allowing further automatic system initiation if needed. After the plant was shutdown and stabilized, the operators referenced SOP 2.2.33.1 and restored HPCI to standby alignment. A similar event involving the incorrect operation of the HPCI system occurred in May 2003 and was characterized as a licensee identified, Green, noncited violation in NRC Inspection Report 50-298/03-06, Section 1R14.

Analysis. This issue was determined to be a performance deficiency because operators failed to properly implement station procedures for operation of the HPCI system. This finding affected the Mitigating Systems Cornerstone and was considered more than minor since it affected the cornerstone attribute of human performance. Based on the results of a Significance Determination Process (SDP) Phase 1 evaluation, this finding was determined to have a very low safety significance since it did not represent an actual loss of safety function.

This finding had crosscutting aspects associated with human performance. This assessment was based on the operator's failure to properly implement station procedures for operation of the HPCI system. Enforcement aspects of this concern are further discussed in Section 4OA2.

Enforcement. TS 5.4.1(a) requires that licensees establish, implement, and maintain written procedures recommended in Regulatory Guide (RG) 1.33, Revision 2, Appendix A, February 1978. Appendix A recommends procedures for combating emergencies and other significant events such as reactor scrams. Emergency Operating Procedure 1A, "RPV Control," Revision 12, and General Operating Procedure 2.1.5, "Reactor Scram," Revision 45, Attachment 2, "Reactor Water Level Control," directs that the HPCI system be operated in accordance with System Operating Procedure SOP 2.2.33.1, "High Pressure Coolant Injection System Operations," Revision 16. SOP 2.2.33.1, step 7.2, directs operators to reset the sealed in initiation signal and place HPCI in standby. Contrary to the above, on November 28, 2003, following a reactor scram, control room operators failed to secure HPCI and place it in a standby condition in accordance with SOP 2.2.33.1, step 7.2. This violation is being treated as a noncited violation consistent with Section VI.A of the NRC Enforcement Policy (NCV 50-298/0402-01). The licensee entered this issue into their Corrective Action Program as Notification 10302173.

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 (four inspection samples). 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 Updated Final Safety Analysis Report, 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:

- Manufacturing defects reported in time delay Relay RHR-REL-K93B (Notification 10287424)
- High flow through control room emergency filtration system (Notification 10289532)
- Indicated reactor vessel level oscillations on Division 1 instrumentation (Notification 10292528)
- Diesel Generator 2A exciter brush conductor restraints loose (Notification 10301618)

b. Findings

Introduction. The inspectors identified a second example of a Green noncited violation of TS 5.4.1 regarding the failure to follow Procedure 0.5 OPS, “Operations Review of Notification/Operability Determinations,” Revision 20.

Description. On January 26, control room operators inserted six control rods into the core, in an asymmetrical pattern, to facilitate corrective maintenance on the associated control rod drive accumulators. The rod pattern had been verified and approved by reactor engineering, and operators verified that no thermal limits were challenged as a result of the rod pattern. However, the asymmetrical pattern established a resonant pressure wave in the quadrant of the reactor vessel adjacent to the Reference Leg 3A condensing chamber. Reference Leg 3A is common to all the Division 1 wide- and narrow-range level transmitters.

On January 27, at approximately 11 a.m., control room operators noted anomalous indications on narrow-range Level Instruments A and C. Both instruments were oscillating between 32 and 37 inches, approximately five times the oscillation amplitude normally seen on these instruments. Operators verified that the Division 2 level instruments as well as the level indication on the plant computer were all reading normal and were in agreement with each other. Instrument and controls technicians, as well as engineering personnel, were notified to begin troubleshooting the condition.

The instruments affected included narrow-range Level Transmitters (LT) 52 A and C and narrow-range Level Indicating Switches (LIS) 83A, 101 A, and 101 B. Wide-range Instruments LT-59 A and C as well as Fuel Zone LT-91 A and C were also affected, but these instruments provide indication only. The table below summarizes the major function of each instrument and the most limiting TS required action:

Instrument	Safety Related Functions	Applicable TS	Required Action/ Completion Time
LT-52 A and C	Main Turbine/Reactor Feed Pump High Level (L8) Trip	3.3.2.2	Restore trip capability within 2 hours or reduce power < 25 % within 4 hours
LIS-83A	Automatic Depressurization Permissive Signal	3.3.5.1	Place Channel in trip within 96 hours
LIS-101 A and B	Low Level Reactor Scram	3.3.1.1	Place channels in trip within 12 hours

The condition was entered into the CAP as Notification 10292528 at 1:50 p.m. on January 27. However, this notification did not receive the required supervisory review, nor was a reasonable assurance of operability documented in the CAP or in the control room narrative log until 4:53 a.m. on January 28, 18 hours after discovery of the condition. Administrative Procedure 0.5OPS required that these actions be taken as soon as practical and commensurate with the safety importance of the components affected. Furthermore, this procedure directed operators to immediately declare equipment inoperable if a reasonable assurance of operability did not exist. No such assurance was documented, nor was any equipment immediately declared inoperable. During subsequent interviews, the licensee stated that, despite the lack of documentation and indicated oscillations five times greater than expected with no explanation, operators believed that a reasonable assurance of operability existed at the time of discovery since the oscillations were still within the “green band” for the affected instruments. The licensee was later unable to support this conclusion for two of the instruments (LT-52 A and C) and declared the associated features inoperable on January 29. Based on the guidance in Generic Letter 91-18, the inspectors concluded that the 18 hours used to formulate and document a reasonable assurance of operability was not commensurate with safety, given that TS action was required in as little as 2 hours; therefore, the licensee was not in compliance with Administrative Procedure 0.5OPS.

The licensee performed a root cause investigation into the level oscillation phenomena and confirmed that it was due to the asymmetrical rod pattern as described above. In addition, they ultimately concluded that there was sufficient margin in the level setpoint calculations for the affected safety features and operability was unaffected by the condition.

<u>Analysis</u>. The failure to follow station procedures was considered a performance deficiency, which affected the Mitigating Systems Cornerstone since it was associated with the operability of mitigating equipment. This finding was considered more than minor since failure to follow station procedures, specifically those which would require short-term TS actions to be implemented, could become a more significant safety concern if left uncorrected. Based on the results of an SDP Phase 1 evaluation, this finding was determined to have very low safety significance since the licensee was ultimately able to demonstrate operability of the affected equipment.

This finding had crosscutting aspects associated with human performance. This assessment was based on the fact that Procedure 0.5OPS reflected current guidance regarding operability determinations and that a significant amount of training had been conducted regarding operability determinations over the past year, yet personnel still failed to follow the procedure. Furthermore, operators failed to declare the affected components inoperable, despite the fact that an indeterminate state of operability existed on these instruments for approximately 18 hours.

<u>Enforcement</u>. TS 5.4.1 (a) requires written procedures to be implemented as recommended by RG 1.22, Revision 2, Appendix A, February 1978. Appendix A recommends procedures for equipment control. Administrative Procedure 0.5OPS, “Operations Review of Notification/Operability Determinations,” Revision 20, required

operators to document a basis for reasonable assurance of operability commensurate with safety importance of the system affected. Contrary to this requirement, the operators failed to document a reasonable assurance of operability in a time frame commensurate with safety and failed to declare affected equipment inoperable in the absence of a reasonable assurance of operability. This violation is being treated as a second example of Noncited Violation (NCV) 50-298/0402-01, consistent with Section VI.A of the NRC Enforcement Policy. The licensee entered this finding into their CAP as Significant Condition Report (SCR) 2004-0045.

1R16 Operator Workaround

a. Inspection Scope

The inspectors reviewed three operator workaround items (three inspection samples) to evaluate their individual 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. The following operator workarounds were reviewed:

- Diesel Generator 1 day tank fuel oil strainer cleaning
- Reactor Feed Pump (RFP) B supervisory alarm
- Control of Operator Aids program

b. Findings

Introduction. The inspectors identified a Green finding regarding the failure to evaluate an operator workaround created by compensatory measures for the loss of alarm and indication functions on RFP A.

Description. As discussed in Section 1R23, the licensee disabled control room supervisory alarms on RFP A due to a software problem in the digital control system which was causing nuisance alarms. As a compensatory measure, a portable computer was installed on the control cabinet to provide RFP turbine temperature and vibration data. A remote camera was also installed so that the control room could view the computer's display via the local Intranet. This equipment was staged on January 23 and a control room narrative log entry was made instructing operators on the purpose of the equipment and the need to monitor it every 2 hours. This log entry was duplicated in the January 24 logs but omitted thereafter.

The inspectors observed the temporary equipment staged in the turbine building during a plant tour on January 27 and questioned its purpose and the controls placed on it. The operating crew at the time had to consult with engineering in order to answer the inspectors' questions. The inspectors posed the same questions to a different crew on

February 5 and, again, the crew was unable to readily state the purpose and the monitoring requirements. At this point, the log entry made on January 23 was duplicated in the February 5 logs and carried forward until the temporary equipment was removed. The inspectors concluded that this equipment configuration required additional operator actions to compensate for a degraded condition which could have complicated operation of plant equipment. Therefore, it should have been evaluated per the licensee's operator workaround program.

Analysis. The inspectors determined that the licensee's failure to evaluate the operator workaround created by the compensatory measures for the disabled RFP A alarms was a performance deficiency. The finding was more than minor since it affected the Initiating Events Cornerstone attribute of configuration control. Based on the results of an SDP Phase 1 evaluation, the finding was determined to have very low safety significance since it did not contribute to the likelihood of a primary or secondary system loss of coolant accident (LOCA), did not contribute to a loss of mitigation equipment, and did not increase the likelihood of a fire or internal/external flood.

Enforcement. None of the components affected by this operator workaround were considered safety-related; therefore, no violation of NRC requirements was identified. The licensee entered this finding into their CAP as Notification 10295024. This finding is identified as FIN 50-298/0402-02.

1R19 Postmaintenance Testing

a. Inspection Scope

The inspectors reviewed or observed six selected postmaintenance tests (six inspection samples) 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 hydraulic control unit accumulator on January 29 (Work Order 4338644)

- Replacement of prefilter on control room emergency filtration system on February 3 (Work Order 4355883)

- Replacement of Control Rod Drive Valve CRD-V-13 on February 24 (Work Order 4303185)

- Calibration and adjustment of Scram Discharge Instrument Volume Drain Valve CRD-AOV-34 on February 26 (Work Order 4232757)

- Inspection of 4160v Bus 1CS breaker on March 10 (Work Order 4327607)

- Diesel Generator 2A fuel oil strainer replacement on March 17 (Work Order 4347629)

b. Findings

No findings of significance were identified

1R22 Surveillance Testing

a. Inspection Scope

The inspectors observed or reviewed the following five surveillance tests (five inspection samples) 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 Updated Safety Analysis Report, and licensee procedural requirements:

- 6.2RHR.307, “RHR Loop B Heat Exchanger Bypass Time Delay Channel Calibration (Div 2),” Revision 4, performed on January 2

- 6.2SW.101, “Service Water Surveillance Operation (DIV 2)(IST),” Revision 17C1, performed on January 5

- 15.TG.302, “Main Turbine Trip Functional Test,” Revision 5, performed on January12

- 6.1DG.101, “Diesel Generator 31 Day Operability Test (IST)(DIV1),” Revision 29, performed on January 27

- 14.6.10, “HPCI Stop Valve Instrumentation Calibration and Test Setup,” Revision 9, performed on February 3

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed one temporary plant modification (one inspection sample), Work Order 4331617, implemented on January 23, which disconnected a cable in the

RFP A control cabinet. This was done in order to disable the “RFP A Control Trouble Alarm” and “Supervisory Alarm” in the control room due to frequent nuisance alarms.

b. Findings

Introduction. The inspectors identified a Green finding regarding the failure to appropriately evaluate a temporary modification to the RFP A control cabinet.

Description. In January 2004, control room operators experienced numerous spurious trouble and supervisory alarms on RFP A. Troubleshooting on the system indicated that the computer code used by the digital control system’s communications module queried the system for potential faults at too fast an interval. When other portions of the control system were unable to respond to the queries, the communications module interpreted this as a communications failure, which resulted in the supervisory and trouble alarms. The corrective action for this condition was to replace a programmable microchip on the communications module with updated software to slow the query rate; however, it would take approximately 2 weeks to receive the new microchip from the vendor. In the interim, Work Order 4331617, which was written to perform this corrective maintenance, was revised to lift a lead on the communications module to disable the nuisance alarms. The revision to the work order was evaluated by engineering, in accordance with Engineering Procedure 3.4.4, “Temporary Configuration Change,” Revision 3, and was determined to be a temporary alteration in support of maintenance; therefore, a screening per 10 CFR 50.59 was not performed. However, since the lead was lifted 2 weeks prior to receipt of replacement parts in order to eliminate the nuisance alarms, the work order should have been considered a temporary configuration change in accordance with Procedure 3.4.4, and a 10 CFR 50.59 screening should have been performed.

Prior to the lead lift, a portable computer was connected to the control cabinet for RFP A in order to facilitate RFP troubleshooting and data gathering following the November 2003 scram. This computer was appropriately installed in December 2003 under Temporary Configuration Change 4347948. In addition to collecting data, the licensee determined that the computer was capable of providing local indication of RFP turbine vibration levels and temperatures. Since the remote alarm capability of the system for these two parameters was disabled due to the lifted lead under Work Order 4331617, the licensee installed a remote camera to view the computer’s display of RFP turbine vibration levels and temperatures in the control room via the local Intranet as a compensatory measure. This equipment combination (the computer, camera, and local Intranet connection) had not been evaluated as a compensatory measure, was not controlled as a temporary configuration change per Procedure 3.4.4, and had not been evaluated per 10 CFR 50.59. The licensee acknowledged that this should have been controlled per Procedure 3.4.4 and entered this issue into their CAP as Notification 10295024. Corrective maintenance on the RFP A control cabinet was completed and the temporary equipment was removed prior to completing the required evaluations; however, the licensee concluded that this change to the plant configuration would not have required NRC approval prior to implementation.

Analysis. The failure to follow station procedures for maintaining configuration control of plant equipment was a performance deficiency which was more than minor since it affected the Initiating Events Cornerstone attribute of configuration control. Based on the results of an SDP Phase 1 evaluation, the finding was determined to have very low safety significance since it did not contribute to the likelihood of a primary or secondary system LOCA, did not contribute to a loss of mitigation equipment, and did not increase the likelihood of a fire or internal/external flood.

Enforcement. None of the components affected by this configuration change were considered safety-related; therefore, no violation of NRC requirements was identified. The licensee entered this finding into their CAP as Notification 10295024. This finding is identified as FIN 50-298/0402-03.

1EP4 Emergency Action Level (EAL) and Emergency Plan Changes (71114.04)

a. Inspection Scope

The inspector performed an in-office review of Revision 45 to the Cooper Nuclear Station Emergency Plan and Revision 31 to Emergency Plan Implementing Procedure 5.7.1, “Emergency Classification,” submitted December 11, 2004. These revisions:

- Made minor editorial and format changes to 22 EALs
- Added an additional safety parameter display system indication as a basis to classify under EAL 1.1.2
- Removed the requirements for high core plate differential pressure or the inability to insert in-core monitors to classify under EAL 2.3.1
- Clarified the degree of loss of dc power necessary to classify under EALs 4.2.2 and 4.4.3
- Clarified the degree of security threat necessary to classify under EALs 6.2.1 and 6.3.1
- Clarified the basis for classifying a flooded condition under EAL 7.3.3

These revisions were compared to their previous revisions, 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 revisions decreased the effectiveness of the plan. The inspector completed two samples during this inspection.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES (OA)

4OA1 Performance Indicator Verification

a. Inspection Scope

The inspectors sampled three licensee performance indicators (PI) listed below for the period January 1 through December 31, 2003. The definitions and guidance of NEI 99-02, "Regulatory Assessment Indicator Guideline," Revision 2, were used to verify that the licensee accurately reported PI data during the assessment period. Licensee PI data were reviewed against the requirements of Procedure 0-PI-01, "Performance Indicator Program," Revision 13.

Reactor Safety Cornerstone

- Unplanned Scrams
- Scrams with Loss of Normal Heat Removal
- Unplanned Power Changes

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 Failure to Implement Timely and Effective Corrective Actions

a. Inspection Scope

The inspectors performed a review of SCR 2003-1930, which documented the root cause investigation into a reactor scram due to low reactor vessel water level on

November 28, 2003. The inspectors also conducted interviews with selected licensee engineers and the personnel who conducted the investigation. Other aspects of this event are discussed in Sections 1R14 and 4OA7 of this report

b. Findings

Introduction. Two examples of a Green noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Actions, were identified for the failure to take timely and effective corrective actions and failure to identify conditions adverse to quality.

Description. On November 28, 2003, a reactor scram occurred due to an RFP control system malfunction. As discussed in Section 1R14, the control room operators secured HPCI using the incorrect procedural step. A similar event occurred on May 26, 2003, and was documented as a Green, noncited violation in NRC Inspection Report 50-298/03-06, Section 1R14. Following the May 2003 event, the licensee documented this issue in a notification and determined that a procedure change was required to allow operators to secure HPCI in a timely manner. The problem identification report from this event was initially classified as department disposition which was considered to be an enhancement or issue not of the level of a resolve condition report (RCR) and was to be resolved at the responsible manager's discretion. The report was later downgraded and removed from the CAP. However, in accordance with Administrative Procedure 0.5PIR, "Problem Identification, Review, and Classification," Revision 12, the report met the criteria for an RCR, which would require an apparent cause and/or corrective actions to resolve the conditions. After questioning by the inspectors, the licensee re-entered the May 2003 report into the CAP in November 2003 as an RCR for tracking as a procedure change. However, a new corrective action completion date was assigned based on the new entry date, which extended the corrective actions to December 2003, 7 months from original discovery.

Following the event in November 2003, the inspectors noted that the licensee failed to document the HPCI procedure violation in a problem identification report as required in accordance with Administrative Procedure 0.5PIR, "Problem Identification, Review, and Classification," Revision 15, until questioned by the inspectors. After several inquires from the inspectors, the issue was entered into the licensee's CAP as Notification 10302173 in March 2004.

Analysis. These issues were determined to be performance deficiencies because the licensee failed to implement timely corrective actions to revise the HPCI procedure following the May 2003 reactor scram and failed to promptly enter the HPCI procedure violation in the CAP following the November 2003 reactor scram. 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 a very low safety significance since it did not represent an actual loss of safety function.

This finding had crosscutting aspects associated with problem identification and resolution. This assessment was based on the fact that the licensee had identified corrective actions from the May 26, 2003, reactor scram that were not effectively implemented in a timely manner prior to the November 2003 reactor scram. In addition, the procedure violation that occurred in November 2003 was not entered in to the licensee's CAP until the question was raised by the inspectors.

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. Contrary to these requirements, the licensee failed to take timely and effective corrective actions to revise HPCI procedures following the May 2003 reactor scram and failed to promptly identify and enter HPCI procedure violations into CAP following the November 2003 reactor scram. Because the finding was determined to be of very low safety significance and was entered into the licensee's CAP as Notification 10302173, this violation, consisting of two examples, is being treated as a noncited violation, consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 50-298/0402-04).

.2 Reactor Pressure Vessel (RPV) Stratification Resulting in Exceeding Technical Specification Heatup and Cooldown Limits

a. Inspection Scope

The inspectors performed a review of SCR 2003-1959, which documented the root cause investigation into recurring RPV thermal transients caused by a reactor scram on November 28, 2003. The inspectors also conducted interviews with selected licensee engineers and the personnel who conducted the investigation. Other aspects of this event are discussed in Sections 1R14 and 4OA7 of this report.

b. Findings

Introduction. The inspectors identified a third example of a Green noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Actions, for the failure to take timely and effective corrective actions associated with the stratification of coolant in the RPV, resulting in exceeding TS heatup and cooldown rates.

Description. At 10:02 p.m. on November 28, 2003, the RFP B control system malfunctioned, causing a reactor water level transient resulting in a reactor scram. As a result of the scram and RPV level shrink, RPV water level fell below the Level 2 setpoint. This resulted in primary containment isolation system Group 2, 3, and 6 isolations, HPCI and RCIC start, and trip of the reactor recirculation pumps after a 9-second time delay. The combination of no recirculation flow, cold water injection from the control rod drive (CRD) system into the lower head area, and low reactor water cleanup flow resulted in the thermal stratification of coolant in the RPV and a rapid cooldown and heatup of areas in the RPV. Control room operators immediately recognized that forced recirculation flow with the recirculation pumps could not be restored because of the inability to meet TS requirements and procedural restrictions. The operators took actions to recover from stratification as prescribed by plant abnormal procedures. However, due to the limited guidance contained in procedures, operators were unable to prevent TS heatup and cooldown thermal limits from being exceeded during the recovery from the transient.

The licensee's root cause investigation of this event identified several causal factors for the stratification and exceeding heatup and cooldown limits. The root cause team identified that plant procedures were not consistent with industry standards, and two corrective actions from the May 26, 2003, event were not completed that would have prevented or mitigated the stratification transient. The most significant correction action involved a procedure change to allow a rapid restart of the reactor recirculation pumps. This action required additional thermal analysis. The licensee's initial request to the vendor for the analysis was submitted on June 10, 2003, and the vendor's proposal was received back by the licensee on June 16, 2003, but was rejected due to work scope concerns. However no additional actions were taken to resubmit another request until October 27, 2003. The original corrective action due date was September 15, 2003, but was extended to January 15, 2004, due to the extended time taken by the licensee to resubmit another request to the vendor. After receiving and approving the vendor's proposal on November 26, 2003, the vendor was able to provide the final analysis to the licensee for reactor recirculation pump quick restart in less than 40 days. The second corrective action involved a procedure change that had not been implemented to secure CRD pumps to prevent cold water flow into the bottom of the RPV. The root cause team also noted that several opportunities were missed to prevent or mitigate the stratification event based on operating experience, vendor recommendations, and previous events.

A similar event occurred on May 26, 2003, and is described in Sections 1R14, 4OA3, and 4OA7 of NRC Inspection Report 50-298/03-06. The root cause investigation from this event determined the major contributing cause for the stratification event was that plant procedures did not contain reactor recirculation pump quick restart guidance. The root cause team also noted that recommendations contained in the vendor's service information letters had not been effectively utilized, and several opportunities to prevent or mitigate the stratification event based on operating experience were missed.

<u>Analysis</u>. This issue was determined to be a performance deficiency because the licensee had previous opportunities to address and correct the stratification concerns due to a similar occurrence on May 26, 2003, as well as with the information contained in the vendor's service information letters. The inspectors determined that this issue was more than minor because it affected the Initiating Events Cornerstone attribute of equipment performance of the reactor coolant system (RCS) barrier. Based on the results of an SDP Phase 1 evaluation, this finding was determined to have a very low safety significance since the finding did not contribute to the likelihood of a primary or

secondary system LOCA, did not contribute to a loss of mitigation equipment, and did not screen as potentially risk significant due to a seismic, fire, flooding, or severe weather initiating event.

This finding had crosscutting aspects associated with problem identification. This assessment was based on the fact that the licensee had identified corrective actions from the May 26, 2003, reactor scram that were not effectively implemented in a timely manner to prevent recurrence following the November 2003 reactor scram.

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. Contrary to these requirements, the licensee failed to take timely and effective corrective actions following the May 26, 2003, reactor scram to prevent recurrence of reactor pressure vessel stratification that resulted in exceeding TS heatup and cooldown limits. Because the finding was determined to be of very low safety significance and was entered into the licensee's CAP as SCR 2003-1959, this violation is being treated as an third example of NCV 50-298/0402-04, consistent with Section VI.A.1 of the NRC Enforcement Policy.

4OA3 Event Followup

.1 (Closed) LER 50-298/2003-006: Manual Reactor Scram due to Transmission Line Structure Fire

On October 28, 2003, at 1:30 a.m., a fire occurred on a wooden transmission tower supporting the main generator output lines. In anticipation of losing the main generator output lines, operators commenced a rapid plant shutdown but manually scrammed the plant after a portion of the transmission tower failed. Additional details and enforcement aspects associated with this event are discussed further in Sections 1R14, 4OA2, and 4OA7 of NRC Inspection Report 50-298/03-07. This LER is closed

.2 (Closed) LER 50-298/2003-008: Inadequate Evaluation Leads to TS Prohibited Operation

On November 28, 2003, during reactor scram recovery while in Mode 3, it was noted by the operators that TS heatup and cooldown rates for RCS were exceeded. This required operators to determine if the RCS was acceptable for continued operation per TS Action Statement 3.4.9.A.2. However, on December 3, 2003, operators exited this TS limiting condition for operation (LCO) and entered Mode 2 for plant startup based on an inadequate engineering evaluation of the acceptability of the RCS for continued operation. The engineering evaluation failed to address all heatup transients during the scram recovery and required multiple revisions to completely address the required transient analysis. This resulted in operations prohibited by TS 3.0.4, which prohibits entry into other modes of operation when an LCO is not met unless permitted by TS action statements. Subsequently, the plant was returned to Mode 3 for plant shutdown. This finding affected the Initiating Events Cornerstone attribute of equipment performance of the RCS barrier. Based on the results of an SDP Phase 1 evaluation, this finding was determined to have a very low safety significance since the finding did not contribute to the likelihood of a primary or secondary system LOCA, did not contribute to a loss of mitigation equipment, and did not screen as potentially risk significant due to a seismic, fire, flooding, or severe weather initiating event. This licensee-identified finding involved a violation of TS 3.0.4. The enforcement aspects of the violation are discussed in Section 4OA7. This LER is closed.

4OA4 Crosscutting Aspects of Findings

Sections 1R14 and 1R15 describe procedural violations with crosscutting aspects of human performance.

4OA5 Other Activities

a. Inspection Scope

The inspectors completed a review of an unresolved item (URI 050298/0015-01) regarding offsite power sources and their conformance to General Design Criterion (GDC) 17.

b. Findings

Introduction. Two examples of a Green noncited violation were identified regarding the failure to maintain adequate procedures for control of the offsite power sources.

Description.

Cooper Nuclear Station was originally licensed with two qualified offsite ac power sources: (1) the 345 kV source, and (2) an emergency 69 kV source supplied from the Omaha Public Power District (OPPD) power grid. The 345 kV source is routed through the T2 autotransformer and the startup station service transformer (SSST), while the 69 kV source is routed through the emergency station service transformer. This arrangement was reviewed and accepted by the NRC in a safety evaluation report, dated February 14, 1973, which stated, “Our review of the offsite power system revealed that the design satisfies the requirements of General Design Criteria 17 and IEEE-308.”

In 1981, Cooper Nuclear Station modified the offsite ac power supply by building a 161 kV substation just south of the existing 345 kV Cooper Nuclear Station substation and connecting a new 161 kV line from Auburn, Nebraska, to the 161 kV substation. This 161 kV line was intended as a power feed to Auburn, Nebraska. The 345 kV system feeds power to the T2 autotransformer (345 kV - 161 kV -13.8 kV), which feeds

161 kV power to the 161 kV Auburn, Nebraska, line and to the SSST. Power is stepped down to 4160 V for the vital buses (1F and 1G). The T2 autotransformer also powers loads through a 13.8 kV/12.5 kV step-down transformer.

Unresolved Item 050298/0015-01 documented several concerns regarding operational control and modification of the offsite power sources. The concerns were as follows:

1. The 161 kV line was not qualified to GDC 17 standards and, therefore, could not be credited as an offsite power source. During the original inspection of this issue, the inspectors determined that TS Surveillance Procedure 6.EE.610, "Off-Site AC Power Alignment," Revision 1, did not require operators to verify the 345 kV feed to the T2 autotransformer and SSST. The procedure only required verification of voltages at the SSST which, in effect, allowed operators to credit the 161 kV line in order to meet TS operability requirements for offsite power.

   Surveillance Procedure 6.EE.610 was subsequently revised to verify that a 345 kV source of power was available to the SSST in order to verify operability. This was a violation of NRC requirements which has not been previously addressed.

2. If the 345 kV sources were lost during a design basis accident, but the 161 kV line remained energized, the vital buses would remain energized and emergency core cooling systems (ECCS) would begin to sequence onto the buses. Since the 161 kV line was not a qualified offsite source, there was no assurance that it could carry all of the ECCS loads and might have tripped, causing a secondary loss of offsite power. In this case, the vital buses would have transferred to the 69 kV source and ECCS loads would sequentially load onto the vital buses a second time. This would have ultimately delayed the ECCS injection time and increased the probability of system failures. This sequence of events was different from that described in the facility's original design basis and was not adequately evaluated prior to modifying the switchyard.

   Nebraska Public Power District (NPPD) previously held the position that the term "offsite circuit" did not include any equipment between the high-side taps of the SSST and emergency station service transformer and the grid. Therefore, the requirements of 10 CFR Part 50, Appendix A, GDC 17 and 10 CFR 50.59 were not applied to modifications, operations, and configuration control of the 69 kV subsystem and the 345 kV switchyard. In response to a Task Interface Agreement, NRR stated that the term "offsite circuit" applies to the path from the incoming transmission lines, through the switchyard, and into the onsite distribution system. Therefore, the requirements of 10 CFR 50.59 are applicable to these modifications.

   A screen in accordance with 10 CFR 50.59 was performed in 2001 regarding the addition of the 161 kV line. This screening concluded that NRC approval would not have been required prior to the modifications in 1981. In addition, the licensee was able to demonstrate that the existing accident analysis bounded the postulated delay in ECCS injection times. This represented a noncompliance with the requirements of 10 CFR 50.59; however, it was considered minor in accordance with the guidance in Supplement I.E of the NRC Enforcement Policy.

3. SOP 2.2.90, “12.5 kV System,” Revision 19, allowed the 12.5 kV subsystem, which supplies house loads, to be aligned to the 69 kV subsystem. No analysis had been performed to demonstrate that the 69 kV subsystem could support vital loads during an accident as well as the additional house loads.

   The licensee acknowledged this finding at the time of the original inspection and SOP 2.2.90 was revised to prevent loading of 12.5 kV loads on the 69 kV system when that offsite power source was required to be operable. However, this was considered to be a second example of the violation described in Paragraph 1.

4. On two separate occasions (September 4 and 15, 2000), the licensee aligned the vital buses in a manner contrary to TS without declaring them inoperable. This was due, in part, to the failure to translate design requirements into procedures and maintain the TS Bases consistent with the Updated Safety Analysis Report.

   The TS Bases were revised to clarify the required capability of the offsite power sources in order to consider them operable. This issue was treated as a noncited violation of TS 5.5.10(c) in NRC Inspection Report 50-298/01-006.

5. Two additional concerns, not documented with the original unresolved item, were identified regarding the 69 kV transmission line. The addition of the 161 kV line created an additional cross-tie between the NPPD and OPPD transmission systems. As a result, voltage conditions on the 161 kV line influenced the 69 kV line, reducing the level of independence between the GDC 17 offsite power sources. This led to voltages below TS required limits on both offsite power sources on several occasions, including a transient on September 7, 2001. During that transient, a lightening strike on the 161 kV line caused a loss of the T2 autotransformer and a subsequent low voltage condition on the 69 kV line for approximately 48 minutes (Notification 10119487).

   In addition, load growth on the OPPD system led to frequent undervoltage conditions on the 69 kV line, which necessitated the installation of a capacitor bank on that line in order to support operability of that power source. Operational control of the capacitor bank was not clearly defined, which led to numerous occasions where the 69 kV line did not meet TS voltage requirements.

   In response to these concerns, the licensee has improved its interface agreement with the NPPD system dispatcher and implemented on-line grid monitoring software at its transmission control center in Doniphan, Nebraska. This software provides a real-time calculation of postulated voltage available to the Cooper Nuclear Station offsite power sources should Cooper trip off-line and allows for more proactive control over grid conditions to support operability. In addition, the low voltage alarm setpoints on the 161 kV line have been increased to provide a greater time margin to place the 69 kV capacitor bank in service should it be required.

Analysis. While not indicative of current performance, the failure to maintain adequate procedures for configuration control and for the implementation of TS required surveillances represented a performance deficiency at the time of the original inspection. This finding was more than minor since it affected the Mitigating Systems Cornerstone attributes of configuration control. The inspectors did not identify any instances where the emergency ac power safety function was unavailable, nor did the finding represent a loss of an offsite power source for greater than its TS allowed outage time. Therefore, based on the results of an SDP Phase 1 evaluation, this finding was determined to have very low safety significance.

Enforcement. TS 5.4.1(a) requires that the licensee establish and implement written procedures recommended in RG 1.33, Revision 2, Appendix A, February 1978. Appendix A recommends procedures for operation of offsite electrical systems. Contrary to this requirement, Surveillance Procedure 6.EE.610 did not contain adequate acceptance criteria for verifying the operability of offsite power supplies. In addition, SOP 2.2.90 allowed one of the offsite power circuits to be aligned in an unanalyzed configuration. This was an additional example of a violation of TS 5.4.1(a). This finding was of very low safety significance and has been entered into the licensee's CAP as Notification 10110178; therefore, it is being treated as a noncited violation consistent with Section VI.A of the NRC enforcement Policy (NCV 50-298/0402-05).

4OA6 Meetings, Including Exit

On January 13, 2003, the inspector conducted an exit interview by telephone and presented the results of the emergency preparedness inspection to Mr. J. Bednar, Emergency Preparedness Manager, and other members of his staff who acknowledged the findings.

On March 19, 2004, the inspector presented the results of the maintenance effectiveness inspection to Mr. J. Christensen, Plant Manager, and other members of the licensee management who acknowledged the findings.

On April 8, 2004, the 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 discussed or included in the report.

4OA7 Licensee Identified Violations

The following violations of very low safety significance (Green) were identified by the licensee and are violations of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as noncited violations.

- TS 3.4.9(a)2 required the licensee to determine if the RCS was acceptable for continued operation after exceeding the TS heatup rate. Contrary to this requirement, this determination was not completed prior to entering Mode 2 for plant startup. This resulted in operations prohibited by TS 3.0.4, which prohibits entry into other modes of operation when the LCO is not met unless permitted by TS action statements. This finding affected the Barrier Integrity Cornerstone and was of very low safety significance since it did not represent an actual degradation of a fission product barrier. This was identified in the licensee's CAP as SCR 2003-1958.

- TS 5.4.1(a) requires that the licensee establish and implement written procedures recommended in RG 1.33, Revision 2, Appendix A, February 1978. Appendix A recommends procedures for startup, operations, and shutdown of safety-related systems. SOP 2.2.67, "Reactor Core Isolation Cooling System," Revision 55, requires operators to restore RCIC turbine oil level to low in the operating band. Contrary to this requirement, operators failed to restore RCIC turbine oil level to low in the operating band as required by SOP 2.2.67, "Reactor Core Isolation Cooling System," Revision 55, after maintenance on November 17, 2003. This resulted in RCIC being declared inoperable on December 2 and 14, 2003. This finding affected the Mitigating Systems Cornerstone and was of very low safety significance since it did not represent the loss of any safety function. This finding was identified by the licensee and was entered into their CAP as Resolve Condition Report 2003-2003.

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, Plant Manager
Stewart Minahan, Acting Nuclear Site Vice President
T. Chard, Radiological Manager
K. Chambliss, Operations Manager
Kim Dalhberg, Senior Manager of Quality Assurance
J. Edom, Risk Management
R. Estrada, Performance Analysis Department Manager
M. Faulkner, Security Manager
J. Flaherty, Site Regulatory Liaison
P. Fleming, Risk and 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

05000298/2004002-01	NCV	Failure to Follow Procedures for HPCI Operation and Operability Determinations (Sections 1R14 and 1R15)
05000298/2004002-02	FIN	Failure to Evaluate an Operator Workaround (Section 1R16)
05000298/2004002-03	FIN	Failure to Appropriately Evaluate a Temporary Modification (Section 1R23)
05000298/2004002-04	NCV	Failure to Implement Timely and Effective Corrective Actions (Section 4OA2)
05000298/2004002-05	NCV	Failure to Maintain Procedures for Control of Offsite Power Sources (Section 4OA5)

Closed

50-298/2003-006	LER	Manual Reactor Scram due to Transmission Line Structure Fire (Section 4OA3)
50-298/2003-008	LER	Inadequate Evaluation Leads to Technical Specification Prohibited Operation (Section 4OA3)

LIST OF DOCUMENTS REVIEWED

Notiifications

10122256	10122708	10132205	10145238	10165772	10173185
10175970	10185868	10195863	10197960	10198812	10200974
10224323	10228395	10228616	10229608	10231045	10232285
10233065	10233074	10233525	10233631	10235822	10236462
10237762	10237863	10238599	10246515	10246517	10248913
10253124	10253999	10258762	10258763	10261074	10270392
10278032	10278378	10280642	10282634	10292144	10294352
10295241	10296715	10300937	10301090		

Procedures

0.27, Maintenance Rule Program, Revision 15
0.27.1, Periodic Structural Assessment of Structures, Revision 3
0.27.2, Maintenance Rule (a)(1) Evaluation and Goal Setting, Revision 5
0.27.3, Maintenance Rule Program Periodic Assessment, Revision 8

System Health Monitor Program Reports

Diesel Generators, February 27, 2004
Instrument Air, March 4, 2004
Reactor Equipment Cooling, March 4, 2004
Residual Heat Removal System, March 5, 2004
Service Water System, March 5, 2004

Miscellaneous Documents Reviewed

Engineering Evaluation 04-004
Maintenance Rule Expert Panel Meeting Minutes from 2001-2004
Maintenance Rule Periodic Assessment for the Period 12/17/2000 through 8/31/2002

LIST OF ACRONYMS

CAP	corrective action program
CFR	*Code of Federal Regulations*
EAL	emergency action level
ECCS	emergency core cooling system
EDG	emergency diesel generator
FIN	finding
GDC	general design criteria
HPCI	high pressure coolant injection
LIS	level indicating switch
LT	level transmitter
NCV	noncited violation
NPPD	Nebraska Public Power District
OPPD	Omaha Public Power District
PI	performance indicator
RG	regulatory guide
RCIC	reactor core isolation cooling
RHR	residual heat removal
RFP	reactor feed pump
RPV	reactor pressure vessel
SCR	significant condition report
SDP	Significance Determination Process
SOP	system operating procedure
SW	service water
TS	Technical Specification