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

July 26, 2007

Stewart B. Minahan, Vice
President-Nuclear and CNO
Nebraska Public Power District
72676 648A Avenue
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SUBJECT: COOPER NUCLEAR STATION - NRC INTEGRATED INSPECTION REPORT 05000298/2007003

Dear Mr. Minahan:

On June 23, 2007, 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 July 9, 2007, with Mr. M. Colomb, General Manager of Plant Operations, 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 five findings were evaluated under the risk significance determination process as having very low safety significance (Green). Four of these findings were determined to be violations of NRC requirements. However, because these violations were of very low safety significance and the issues were entered into your corrective action program, the NRC is treating these findings as noncited violations, consistent with Section VI.A.1 of the NRC's Enforcement Policy. These noncited violations are described in the subject inspection report. If you contest the violations or significance of the violations, 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 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/

Michael C. Hay, Chief
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Docket: 50-298
License: DPR-46

Enclosure: NRC Inspection Report 05000298/2007003
w/attachment: Supplemental Information

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SUNSI Review Completed: _MCH_____ADAMS: ■ Yes ☐ No Initials: _MCH_____
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R:_REACTORS_CNS\2007\CN2007-03RP-NHT.wpd

RIV:SRI:DRP/C	C:SPE:DRP/C	C:DRS/EB1/STA	C:DRS/PSB	C:DRS/OB
NHTaylor	WCWalker	DAPowers	MPShannon	ATGody
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07/26/07	07/24/07	07/24/07	07/24/07	07/24/07

C:DRS/EB2	C:DRP/C			
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07/23/07	07/26/07			

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U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	50-298
License:	DPR-46
Report:	05000298/2007003
Licensee:	Nebraska Public Power District
Facility:	Cooper Nuclear Station
Location:	P.O. Box 98 Brownville, Nebraska
Dates:	March 25 through June 23, 2007
Inspectors:	N. Taylor, Senior Resident Inspector S. Schwind, Senior Resident Inspector R. Lantz, Senior Emergency Preparedness Inspector L. Ricketson, P.E., Senior Health Physicist G. Pick, Senior Reactor Inspector, Engineering Branch 2
Approved By:	M. Hay, Branch C, Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000298/2007003; 03/25/2007 - 06/23/07; Cooper Nuclear Station: Refueling & Outages, Access Control To Radiologically Significant Areas, Identification and Resolution of Problems, Event Followup.

The report covered a 3-month period of inspection by resident inspectors and region-based inspectors. Four Green noncited violations and one Green finding were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609, "Significance Determination Process." Findings for which the significance determination process does not apply may be Green or be assigned a severity level after NRC management review. 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 self-revealing noncited violation of Technical Specification 5.4.1.a was identified involving an inadequate procedure for transitioning to single recirculation loop operation during power operations. This procedural inadequacy resulted in operators entering the stability exclusion region after securing one reactor recirculation pump for maintenance activities. This issue was entered into the licensee's corrective action program as Condition Report CR-CNS-2007-03555.

  The finding is more than minor because if left uncorrected the finding could become a more significant safety concern. For example, operation in the stability exclusion region could result in core thermal-hydraulic instabilities and rapid power oscillations. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have a very low safety significance because it did not contribute to the likelihood that mitigating systems would be unavailable following a reactor trip. The cause of this finding is related to the human performance cross cutting component of resources because the system operating procedures did not provide guidance for establishing adequate margin to the stability exclusion region prior to securing a reactor recirculation pump (H.2(c)). (Section 4OA2)

- Green. A self-revealing noncited violation of Technical Specification 5.4.1.a was identified for the inadequate isolation instructions contained in System Operating Procedure 2.2.8, "Control Rod Drive Hydraulic System." The use of these inadequate isolation instructions resulted in an unisolable leak from the control rod drive system and insertion of a manual reactor scram. This issue was entered into the licensee's corrective action program as Condition Report CR-CNS-2007-03552.

This finding is more than minor because it is associated with the initiating events cornerstone attribute of procedure adequacy and affects the associated cornerstone objective to limit the likelihood of those events that upset plant stability. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have a very low safety significance because it did not contribute to the likelihood that mitigating systems would be unavailable following a reactor trip. The cause of this finding is related to the human performance cross cutting component of resources because the licensee failed to ensure that the procedure was complete and accurate to assure proper component isolation from the reactor coolant system prior to performing maintenance activities (H.2(c)). (Section 4OA3)

Cornerstone: Mitigating Systems

- Green. A self-revealing noncited violation of Technical Specification 5.4.1.a was identified involving the failure to follow the procedural requirements of System Operating Procedure 2.2.69.3, "RHR Suppression Pool Cooling and Containment Spray." This procedural violation resulted in the inadvertent draining and unavailability of one train of the low pressure coolant injection (LPCI) system. This issue was entered into the licensee's corrective action program as Condition Report CR-CNS-2007-03380.

  This finding is more than minor because it is associated with the mitigating systems cornerstone attribute of human performance and affects the associated cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have a very low safety significance because it did not result in the actual loss of safety function for the LPCI train for greater than its technical specifications allowed outage time. The cause of this finding is related to the human performance cross cutting component of work practices because neither self or peer checking actions prevented the reactor operator from violating the system operating procedure (H.4(a)). (Section 4OA2)

Cornerstone: Barrier Integrity

- Green. The inspectors identified a noncited violation of Technical Specification 5.4.1.a involving the failure to follow the requirements of Procedure 10.13, "Control Rod Sequence and Movement Control" and Procedure 2.0.3, "Conduct of Operations." Specifically, the control room operators failed to follow the prescribed rod movement sequence and mispositioned a control rod during reactor startup. This issue was entered into the licensee's corrective action program as Condition Report CR-CNS-2007-03597.

  This finding is more than minor because it is associated with the barrier integrity cornerstone attribute of configuration control and affects the associated cornerstone objective to provide reasonable assurance that physical design barriers, such as fuel cladding, protect the public from radio-nuclide releases caused by accidents or events. Using the Manual Chapter 0609, "Significance

Determination Process," Phase 1 Worksheet, the finding is determined to have a very low safety significance because it did not have the potential to affect the integrity of the RCS barrier. The cause of this finding is related to the human performance cross cutting component of work practices because neither self or peer checking actions prevented the reactor operator from violating the prescribed rod withdrawal sequence (H.4(a)). (Section 1R20)

Cornerstone: Occupational Radiation Safety

- Green. The inspector reviewed a self-revealing ALARA finding with three examples. The collective dose of three work activities exceeded five person-rem and the planned doses by more than 50 percent. Valve work accrued 34.829 person-rem and exceeded the dose estimate by approximately 86 percent. Refueling floor work accrued 22.271 person-rem and exceeded the dose estimate by approximately 56 percent. Drywell support work accrued 31.638 person-rem and exceeded the dose estimate by 55 percent. The primary reasons were the use of an inexperienced contract work force which used poor ALARA practices and extensive rework caused by human performance errors. The licensee was in the process of developing screening and supplemental training programs for selected contract maintenance workers.

  This finding is greater than minor because it is associated with the occupational radiation safety program attribute of exposure control and affected the cornerstone objective, in that it caused increased collective radiation dose. Using the Occupational Radiation Safety significance determination process, the inspector determined this finding had very low safety significance. Although the finding involved ALARA planning and work controls, the licensee's latest, official three-year rolling average collective dose was less than 240 person-rem. Additionally, this finding had a crossing-cutting aspect in the human performance area associated with resources, in that procedures and other resources were not available and adequate to train personnel before allowing them in radiological working conditions (H.2(c)).

B. Licensee-Identified Findings

Violations of very low safety significance, that 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 correction action tracking numbers are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

The plant began the inspection period at 100 percent power. On May 18, 2007, reactor power was reduced to approximately 50 percent and the reactor recirculation system was placed in single loop operation for planned maintenance on reactor recirculation motor generator A. On May 19, 2007, an unisolable leak developed on a control rod drive hydraulic control unit, forcing operators to insert a manual reactor scram to depressurize the reactor coolant system. Reactor start up commenced on May 21, 2007, and full power operation was achieved on May 25, 2007. The plant maintained 100 percent power for the remainder of the inspection period.

1. REACTOR SAFETY

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

1R01 Adverse Weather Protection (71111.01A)

.1 Readiness for Seasonal Susceptibilities

a. Inspection Scope

The inspectors completed a review of the licensee's readiness for seasonal susceptibilities involving extreme high temperatures. The inspectors: (1) reviewed plant procedures, the Updated Final Safety Analysis Report (UFSAR), and Technical Specifications (TSs) to ensure that operator actions defined in adverse weather procedures maintained the readiness of essential systems; (2) walked down portions of the two systems listed below to ensure that adverse weather protection features were sufficient to support operability, including the ability to perform safe shutdown functions; and (3) reviewed the corrective action program (CAP) to determine if the licensee identified and corrected problems related to adverse weather conditions.

- Main Control Room Ventilation
- Portable Ventilation System Equipment Staging

Documents reviewed by the inspectors included:

- Operating Procedure 2.1.14, “Seasonal Weather Preparations,” Revision 9
- Operating Procedure 2.2.84, “HVAC Main Control Room and Cable Spreading Room,” Revision 44
- Operating Procedure 2.2.38.1, “Portable Ventilation System,” Revision 4
- Work Order (WO) 4526512

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

.2 Readiness For Impending Adverse Weather Conditions

a. Inspection Scope

The inspectors observed the licensee's preparation for impending severe weather. These observations included the implementation of the adverse weather preparation procedures and compensatory measures before the onset of, and during adverse weather conditions. The inspectors also verified that operator actions defined in the licensee's adverse weather procedures maintain readiness of essential systems. Observations were made on May 6, 2007, associated with severe thunderstorms, heavy rains, a tornado watch, and regional flooding.

Documents reviewed by the inspectors included:

- Emergency Procedure 5.1WATCH, "Operations During Weather Watches and Warnings," Revision 18

- Emergency Procedure 5.1FLOOD, "Flood," Revision 4

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04Q)

.1 Partial System Walkdown

a. Inspection Scope

The inspectors: (1) walked down portions of the four risk important systems listed below and reviewed plant procedures and documents to verify that critical portions of the selected systems were correctly aligned; and (2) compared deficiencies identified during the walkdown to the licensee's UFSAR and the licensee's CAP to ensure problems were being identified and corrected.

- April 6, 2007, Division 1, Reactor Equipment Cooling (REC) System
- April 9, 2007, Primary Containment (Torus)
- April 12, 2007, Division 1 Station Batteries
- April 18, 2007, Division 1, Low Pressure Coolant Injection (LPCI)

Documents reviewed by the inspectors included:

- System Operating Procedure (SOP) 2.2A.REC.DIV1, “Reactor Equipment Cooling Water System Component Checklist (Div 1),” Revision 0

- SOP 2.2.38, “HVAC Control Building,” Revision 29

- Condition Report CR-CNS-2007-02561

- Condition Report CR-CNS-2007-02548

- SOP 2.2.69.1, “RHR LPCI Mode,” Revision 21

The inspectors completed four samples.

b. Findings

No findings of significance were identified.

.2 Complete System Walkdown (71111.04S)

a. Inspection Scope

The inspectors: (1) reviewed plant procedures, drawings, the UFSAR, TSs, and vendor manuals to determine the correct alignment of the Control Room Emergency Filtration system; (2) reviewed outstanding design issues, operator workarounds, and UFSAR documents to determine if open issues affected the functionality of the Control Room Emergency Filtration system; and (3) verified that the licensee was identifying and resolving equipment alignment problems.

Documents reviewed by the inspectors included:

- UFSAR Section 10.4.6, “Safety Evaluation”

- RCR 2004-0008

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R05 Fire Protection

.1 Fire Protection Tours (71111.05Q)

a. Inspection Scope

The inspectors walked down the five plant areas listed below to assess the material condition of active and passive fire protection features and their operational lineup and readiness. The inspectors: (1) verified that transient combustibles and hot work activities were controlled in accordance with plant procedures; (2) observed the condition of fire detection devices to verify they remained functional; (3) observed fire suppression systems to verify they remained functional and that access to manual actuators was unobstructed; (4) verified that fire extinguishers and hose stations were provided at their designated locations and that they were in a satisfactory condition; (5) verified that passive fire protection features (electrical raceway barriers, fire doors, fire dampers, steel fire proofing, penetration seals, and oil collection systems) were in a satisfactory material condition; (6) verified that adequate compensatory measures were established for degraded or inoperable fire protection features and that the compensatory measures were commensurate with the significance of the deficiency; and (7) reviewed the UFSAR to determine if the licensee identified and corrected fire protection problems.

- March 27, 2007, Fire Zone 7B, emergency condensate storage tank area
- April 4, 2007, Fire Zone 3C, REC heat exchanger and pump area
- April 5, 2007, Fire Zone 5B, reactor recirculation motor generator (RRMG) area
- April 6, 2007, Fire Zone 9B, cable expansion room
- May 1, 2007, Fire Zone 8D, control building, elevation 903

The inspectors completed five samples.

b. Findings

No findings of significance were identified.

.2 Annual Inspection (71111.05A)

On April 18, 2007, the inspectors observed a fire brigade drill to evaluate the readiness of licensee personnel to prevent and fight fires, including the following aspects: (1) the number of personnel assigned to the fire brigade, (2) use of protective clothing, (3) use of breathing apparatuses, (4) use of fire procedures and declarations of emergency action levels, (5) command of the fire brigade, (6) implementation of pre-fire strategies and briefs, (7) access routes to the fire and the timeliness of the fire brigade response, (8) establishment of communications, (9) effectiveness of radio communications, (10) placement and use of fire hoses, (11) entry into the fire area, (12) use of fire fighting equipment, (13) searches for fire victims and fire propagation, (14) smoke removal, (15) use of pre-fire plans, (16) adherence to the drill scenario, (17) performance of the post-drill critique, and (18) restoration from the fire drill. The licensee simulated a fire in the Auxiliary relay room.

The inspectors completed one sample.

Documents reviewed by the inspectors included:

- Fire Brigade Drill Scenario 5.4 FIRE

- Administrative Procedure 0.23, “CNS Fire Protection Plan,” Revision 49

b. Findings

No findings of significance were identified.

1R06 Flood Protection (71111.06)

Semi-annual Internal Flooding

The inspectors reviewed the flood protection features credited for protecting the control building basement from internal flooding sources. The review included: (1) the UFSAR, the flooding analysis, and plant procedures to assess susceptibilities involving internal flooding; (2) the UFSAR and the corrective action process to determine if the licensee identified and corrected flooding problems; (3) operator actions for coping with flooding to ensure they can reasonably achieve the desired outcomes; and (4) a walk down the control building basement to verify the adequacy of: (a) equipment seals located below the flood line, (b) floor and wall penetration seals, (c) door seals, (d) common drain lines and sumps, (e) sump pumps, level alarms, and control circuits, and (f) temporary or removable flood barriers.

Documents reviewed by the inspectors included:

- Design Criteria Document 38
- NEDC 92-0169, Revision 6
- NEDC 92-066, Revision 1
- Administrative Procedure 0.16, “Control of Doors,” Revision 36
- Surveillance Procedure 6.FLOOD.601, ‘Flood Door Gap Examination,” Revision 1

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11Q)

a. Inspection Scope

The inspectors observed testing and training of senior reactor operators and reactor operators to identify deficiencies and discrepancies in the training, to assess operator performance, and to assess the evaluator's critique. The training scenario involved an overpower event leading to core damage with a loss of secondary containment.

Documents reviewed by the inspectors included:

- Drill Scenario for Team 1 Evaluated Drill, May 16, 2007

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule (711111.12Q)

a. Inspection Scope

The inspectors reviewed the maintenance effectiveness performance issues listed below to: (1) verify the appropriate handling of structure, system, and component (SSC) performance or condition problems; (2) verify the appropriate handling of degraded SSC functional performance; (3) evaluate the role of work practices and common cause problems; and (4) evaluate the handling of SSC issues reviewed under the requirements of the maintenance rule, 10 CFR Part 50, Appendix B, and the TSs.

- Failure of the generator exciter for RRMG B on January 25, 2007

- HPCI Inverter Failure on February 7, 2007

Documents reviewed by the inspectors included:

- Condition Report CR-CNS-2007-00596, Administrative Procedure 0.27, "Maintenance Rule Program," Revision 18

- Condition Report CR-CNS-2007-00905

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation (71111.13)

a. Inspection Scope

The inspectors reviewed the six maintenance activities listed below to verify: (1) performance of risk assessments when required by 10 CFR 50.65 (a)(4) and licensee procedures prior to changes in plant configuration for maintenance activities and plant operations; (2) the accuracy, adequacy, and completeness of the information considered in the risk assessment; (3) that the licensee recognized, and/or entered as applicable, the appropriate licensee-established risk category according to the risk assessment results and licensee procedures; and (4) the licensee identified and corrected problems related to maintenance risk assessments.

- April 2, 2007, Emergency Diesel Generator (EDG) 1 testing concurrent with switchyard relay testing

- April 5, 2007, Reactor building door (Door R101) seal repairs

- April 18, 2007, Residual Heat Removal (RHR) B hydrolazer tap installation

- April 30, 2007, EDG 1 test jack modification concurrent with an overhaul of Service Water Pump A

- May 7, 2007, review of integrated maintenance schedule while the Missouri River was above flood stage

- May 30, 2007, Startup Transformer Outage

Documents reviewed by the inspectors included:

- WO 4503868
- WO 4534477
- WO 4486794
- WO 4554763
- WO 4502174

The inspectors completed six samples.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors: (1) reviewed operator shift logs, emergent work documentation, deferred modifications, and standing orders to determine if an operability evaluation was warranted for degraded components; (2) referred to the UFSAR and other design basis documents to review the technical adequacy of licensee operability evaluations; (3) evaluated compensatory measures associated with operability evaluations; (4) determined degraded component impact on any TSs; (5) used the Significance Determination Process to evaluate the risk significance of degraded or inoperable equipment; and (6) verified that the licensee has identified and implemented appropriate corrective actions associated with degraded components.

The following equipment performance issues were reviewed:

- April 4, 2007, REC Heat Exchanger A fouling factor high

- April 11, 2007, Battery Room 1A thermostat not set in accordance with procedures

- April 20, 2007, RHR Pump D breaker failed to operate in test position

- April 20, 2007, Temporary lead shielding suspended above Division 1 RHR instrument lines with plastic ties

- April 21, 2007, Check valves RHR-CV-18 and RHR-CV-19 exceeded allowable leak rates

Documents reviewed by the inspectors included:

- CR-CNS-2007-02313
- CR-CNS-2007-02548
- CR-CNS-2007-02759
- CR-CNS-2007-02769
- CR-CNS-2007-02783

The inspectors completed five samples.

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors selected six post-maintenance tests associated with the maintenance activities listed below for risk significant systems or components. For each item, the inspectors: (1) reviewed the applicable licensing basis and/or design basis documents to determine the safety functions; (2) evaluated the safety functions that may have been affected by the maintenance activity; and (3) reviewed the test procedure to ensure it adequately tested the safety function that may have been affected. The inspectors either witnessed or reviewed test data to verify that acceptance criteria were met, plant impacts were evaluated, test equipment was calibrated, procedures were followed, jumpers were properly controlled, the test data results were complete and accurate, the

test equipment was removed, the system was properly re-aligned, and deficiencies during testing were documented. The inspectors also reviewed the UFSAR to determine if the licensee identified and corrected problems related to postmaintenance testing.

- April 5, 2007, Reactor Building Door R101 seal repairs
- April 19, 2007, RHR Train B hydrolazer tap installation
- April 30, 2007, EDG 1 test jack modification
- May 3, 2007, Service Water Pump A overhaul
- May 10, 2007, Service Water Pump C impeller lift adjustment
- May 22, 2007, Hydraulic Control Unit (HCU) 26-27 scram time test

The inspectors completed six samples.

b. Findings

No findings of significance were identified.

1R20 Refueling & Outages (71111.20)

a. Inspection Scope

During a four-day forced outage beginning on May 19, 2007, the inspectors reviewed the licensee's outage work scope, the outage risk profile, and verified that key shutdown safety functions, such as power availability and decay heat removal, were not challenged by the outage work scope. The inspectors monitored significant activities including reactor shutdown and startup, forced cooldown, and control rod scram timing testing.

The inspectors completed one sample.

b. Findings

Introduction. The inspectors identified a Green noncited violation of TS 5.4.1.a regarding the licensee's failure to follow the requirements of Nuclear Performance Procedure 10.13, "Control Rod Sequence and Movement Control" and Conduct of Operations Procedure 2.0.3, "Conduct of Operations." Specifically, the control room operators failed to follow the prescribed rod movement sequence and mispositioned a control rod during reactor startup.

Description. On May 21, 2007, control room operators began a reactor startup in recovery from Forced Outage 07-01. During the approach to criticality, the reactor operator mispositioned control rod 50-23, contrary to the requirements of Nuclear Performance Procedure 10.13, "Control Rod Sequence and Movement Control," revision 55. Step 3.2.2 of Procedure 10.13 requires that during the approach to criticality the reactor operator shall "proceed with continuous rod withdrawal using Attachment 5 in the Control Rod Sequence Package..." Attachment 5, Rod Movement Sheet, for rod group 4 showed that control rod 50-23 was to be moved from position 00 to 04. Contrary to these instructions, the reactor operator withdrew the rod in continuous withdrawal with the stated intention of continuing to position 48. Outward rod motion was halted by the rod worth minimizer when control rod 50-23 reached position 10.

The inspectors reviewed operating logs, personal statements and discussed the issue with Operations Department personnel. The inspectors reviewed the governing instructions, including Procedure 10.13 and Conduct of Operations Procedure 2.0.3, "Conduct of Operations," revision 58, which provides the standard protocol for moving control rods and expectations for oversight by the Reactivity Manager and Shift Manager. The inspectors noted that the licensee's investigation team determined that the root cause of the rod mispositioning event was that Procedure 10.13 did not provide a mechanism to alert the operator to a change in the routine of the repetitive task. The inspectors noted that control rod 50-23 was in the third of five rod groups anticipated for startup to criticality. The reactor operator had just finished pulling the rods on the rod group 2 Rod Movement Sheet, all of which were being pulled from position 00 to position 48. Rod 50-23 was the first rod to be pulled on the rod group 4 Rod Movement

Sheet, all of which were intended to be pulled from position 00 to position 04 (for this startup, rod group 4 was being withdrawn prior to rod group 3 due to high rod worths). During post-event interviews, the reactor operator stated that he did not look at the Rod Movement Sheet prior to moving control rod 50-23, but instead erroneously assumed that it was also intended to go to position 48.

In evaluating the adequacy of the licensee's root cause efforts, the inspectors performed a search for previous corrective actions for control rod mispositioning events. The following table summarizes the corrective actions taken or proposed for the last five such events:

Date	Event Description	Corrective Actions Taken
1/4/00	Rod moved beyond intended position	* Revised reactivity control program in its entirety * Added pre-job brief for all rod manipulations * Evaluated modifications to improve user interface with system
3/23/02	Placekeeping error led to mispositioned control rod	* Added concurrent verification when selecting desire control rod * Added check-off block for each rod on the rod movement sheet as a placekeeping aid * Establish standard communication /peer check protocol to ensure right rod & right direction
2/28/06	Rod mispositioned (skipped in rod sequence)	* Added requirement that performer & verifier annotate completion of each step immediately after completion * Added requirement that individual may only manipulate control rods for two hours prior to rotating to another position
2/24/07	Rod positioned in wrong direction	(no programmatic actions taken)
5/21/07	Rod pulled past intended position	* Add a physical action by operator to acknowledge a change in target rod position * Create an assessment activity for reactivity manipulations * Conduct training for all operators (Note - these are the proposed corrective actions as of 6/29/07)

The trend of continuing rod mispositioning events has been addressed largely by procedural changes that have added additional verification steps (verbal protocols, initial blocks, etc). While the inspectors acknowledged the value of these additional verification activities, the inspectors also noted that all of these barriers were in place on May 21, 2007, yet control rod 50-23 was still mispositioned.

The inspectors reviewed watchstander responsibilities and actions during the startup on May 21. The reactor operator properly verbalized his intention to move control rod 50-23 as required by Procedure 2.0.3, but violated Procedure 10.13 by not referring to the Rod Movement Sheet prior to positioning the control rod. The peer checker also verbalized concurrence with the intended rod motion, using the standard protocol of Procedure 2.0.3, but violated the procedure by not checking the Rod Movement Sheet prior to providing concurrence. The Reactivity Manager was present but did not provide the oversight required by Procedure 2.0.3, as he was not place keeping on the Rod Movement Sheets to ensure the control rods were being properly positioned. In addition, the Reactivity Manager was a first-time-performer for this evolution. This challenge was identified during the pre-job brief for the startup, during which the Shift Manager and Control Room Supervisor were assigned to provide oversight of his activities as Reactivity Manager. Contrary to this and to the requirements of Procedure 2.0.3, the Shift Manager did not enforce strict standards for moving control rods during the reactor startup.

The inspectors concluded that while room for procedural improvements exists, the combined failure at all levels of the watchteam to conduct meaningful self or peer checking effectively negated all previous corrective actions to prevent rod mispositioning events.

Analysis. The performance deficiency associated with this finding involved the licensee's failure to comply with the requirements of Nuclear Performance Procedure 10.13, "Control Rod Sequence and Movement Control" and Conduct of Operations Procedure 2.0.3, "Conduct of Operations." The finding is more than minor because it is associated with the barrier integrity cornerstone attribute of configuration control and affects the associated cornerstone objective to provide reasonable assurance that physical design barriers (fuel cladding, reactor coolant system, and containment) protect the public from radio nuclide releases caused by accidents or events. Specifically, the performance deficiency led to the mispositioning of a control rod six steps beyond that directed by the control rod sequence package during reactor startup. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have a very low safety significance because it did not have the potential to affect the integrity of the RCS barrier.

The cause of this finding is related to the human performance cross cutting component of work practices because neither self or peer checking actions prevented the reactor operator from violating the prescribed rod withdrawal sequence (H.4(a)).

Enforcement. Technical Specification 5.4.1.a requires that written procedures be established, implemented, and maintained covering the activities specified in Regulatory Guide 1.33, Revision 2, Appendix A, dated February 1978. Regulatory Guide 1.33, Appendix A, section 2.b, requires that general plant operating procedures for nuclear startup be written and implemented. Contrary to this requirement, control room operators violated the requirements of Nuclear Performance Procedure 10.13, "Control Rod Sequence and Movement Control" in that they did not follow the prescribed rod withdrawal sequence during a reactor startup. Because the finding is of very low safety significance and has been entered into the licensee's CAP as Condition Report CR-CNS-2007-03597, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy: NCV 05000298/2007003-001, "Control Rod Mispositioned During Reactor Startup."

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed the UFSAR, procedure requirements, and TSs to ensure that the seven surveillance activities listed below demonstrated that the SSCs tested were capable of performing their intended safety functions. The inspectors either witnessed or reviewed test data to verify that the following significant surveillance test attributes were adequate: (1) preconditioning; (2) evaluation of testing impact on the plant; (3) acceptance criteria; (4) test equipment; (5) procedures; (6) jumper/lifted lead controls; (7) test data; (8) testing frequency and method demonstrated TS operability; (9) test equipment removal; (10) restoration of plant systems; (11) fulfillment of ASME Code requirements; (12) engineering evaluations, root causes, and bases for returning tested SSCs not meeting the test acceptance criteria were correct; (13) reference setting data; and (14) annunciators and alarms setpoints. The inspectors also verified that the licensee identified and implemented any needed corrective actions associated with the surveillance testing.

- April 5, 2007, Reactor Coolant System Leakage Detection Surveillance
- April 11, 2007, Standby Liquid Control Tank Sampling
- April 11, 2007, Standby Liquid Control Pump Operability Test
- May 10, 2007, Service Water Pump C Inservice Test
- May 19, 2007, Forced Cooldown for Forced Outage 07-01
- June 18, 2007, Division II Undervoltage Relay Testing
- June 20, 2007, HPCI Inservice Test (IST)

The inspectors completed seven samples.

b. Findings

No findings of significance were identified.

1R23 Temporary Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed the UFSAR, plant drawings, procedure requirements, and TSs to ensure that temporary alterations and configuration changes to the plant conformed to these guidance documents and the requirements of 10 CFR 50.59. The inspectors: (1) verified that the modifications did not have an affect on system operability/availability; (2) verified that the installations were consistent with modification documents; (3) ensured that the post-installation test results were satisfactory and that the impacts of the temporary modifications on permanently installed SSCs were supported by the tests; and (4) verified that appropriate safety evaluations were completed. The inspectors reviewed the following temporary modifications:

- April 19, 2007, Temporary power supply for the RHR hydrolazing equipment
- May 8, 2007, "Hot tap" and installation of a temporary pipe plug in the service water backwash line for Turbine Equipment Cooling Heat Exchanger

Documents reviewed by inspectors included:

- WO 4486794
- WO 4547081
- Maintenance Procedure 7.3.61, "Temporary Power," Revision 1
- Temporary Configuration Change 4551771

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness [EP]

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

a. Inspection Scope

The inspector performed an in-office review of Revision 35 to Emergency Plan Implementing Procedure 5.7.1, "Emergency Classification," submitted in March 2007. The revision clarified the definition of an armed intruder, consistent with NRC Bulletin 2005-002, and Regulatory Issue Summary 2006-12, "Endorsement of Nuclear Energy Institute Guidance 'Enhancements to Emergency Preparedness Programs For Hostile Action'."

The revision was compared to the previous revision, 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 standards in 10 CFR 50.47(b), to determine if the revision was adequately conducted following the requirements of 10 CFR 50.54(q). This review was not documented in a Safety Evaluation Report and did not constitute approval of licensee changes, therefore the revision is subject to future inspection.

The inspector completed one sample during the inspection.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

The inspectors observed an emergency preparedness drill conducted on May 16, 2007. The observations were made in the control room simulator and the emergency operations facility and concentrated on the training evolution to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation. In addition, the inspectors compared the identified weaknesses and deficiencies against licensee identified findings to determine whether the licensee is properly identifying deficiencies. Documents reviewed by the inspectors included:

- Emergency Plan for Cooper Nuclear Station, Revision 51
- Emergency Plan Implementing Procedures for Cooper Nuclear Station
- Emergency Preparedness Drill Scenario for May 16, 2007

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety [OS]

2OS1 Access Control To Radiologically Significant Areas (71121.01)

a. Inspection Scope

This area was inspected to assess the licensee's performance in implementing physical and administrative controls for airborne radioactivity areas, radiation areas, high radiation areas, and worker adherence to these controls. The inspector used the requirements in 10 CFR Part 20, the Technical Specifications, and the licensee's procedures required by Technical Specifications as criteria for determining compliance. During the inspection, the inspector interviewed the radiation protection manager, radiation protection supervisors, and radiation workers. The inspector performed independent radiation dose rate measurements and reviewed the following items:

- Performance indicator events and associated documentation packages reported by the licensee in the Occupational Radiation Safety Cornerstone

- Controls (surveys, posting, and barricades) of radiation, high radiation, or airborne radioactivity areas

- Posting and locking of entrances to all accessible high dose rate - high radiation areas and very high radiation areas

The inspector completed 4 of the required 21 samples.

b. Findings

No findings of significance were identified.

2OS2 ALARA Planning and Controls (71121.02)

a. Inspection Scope

The inspector assessed licensee performance with respect to maintaining individual and collective radiation exposures as low as is reasonably achievable (ALARA). The inspector used the requirements in 10 CFR Part 20 and the licensee's procedures required by technical specifications as criteria for determining compliance. The inspector interviewed licensee personnel and reviewed:

- Current 3-year rolling average collective exposure
- Site-specific ALARA procedures
- Four work activities of highest exposure significance completed during the last outage
- ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements
- Intended versus actual work activity doses and the reasons for any inconsistencies
- Person-hour estimates provided by maintenance planning and other groups to the radiation protection group with the actual work activity time requirements
- Dose rate reduction activities in work planning
- Post-job (work activity) reviews
- Method for adjusting exposure estimates, or re-planning work, when unexpected changes in scope or emergent work were encountered
- Self-assessments, audits, and special reports related to the ALARA program since the last inspection
- Resolution through the corrective action process of problems identified through post-job reviews and post-outage ALARA report critiques
- Corrective action documents related to the ALARA program and follow-up activities, such as initial problem identification, characterization, and tracking

- Effectiveness of self-assessment activities with respect to identifying and addressing repetitive deficiencies or significant individual deficiencies

The inspector completed 8 of the required 15 samples and 5 of the optional samples.

b. Findings

Introduction. The inspector reviewed a self-revealing ALARA finding with three examples in which the collective dose of work activities exceeded five person-rem and the planned dose estimate by more than 50 percent. The finding had very low safety significance.

Description. ALARA Package 2006AL-09, "RE23 Valve Activities," accrued 34.829 person-rem and exceeded the dose estimate, 18.702 person-rem, by approximately 86 percent. ALARA Package 2006AL-13, "Refuel Floor," accrued 22.271 person-rem and exceeded the dose estimate, 14.304 person-rem, by approximately 56 percent. ALARA Package 2006AL-29, "Drywell Support," accrued 31.638 person-rem and exceeded the dose estimate, 20.428 person-rem, by 55 percent. In all examples, the reasons for the dose overage were similar. According to licensee representatives, the primary reasons were the use of an inexperienced contract work force which used poor ALARA practices and extensive rework caused by human performance errors. These factors combined to increase significantly the number of person-hours in radiological areas, thereby increasing the collective dose above that estimated/planned.

According to NUREG 0713, "Occupational Radiation Exposure at Commercial Nuclear Power Reactors and Other Facilities," Volume 27, the licensee's three-year rolling average collective dose for 2003 - 2005 is approximately 153 person-rem.

Analysis. The failure to maintain collective dose ALARA is a performance deficiency. This finding is greater than minor because it is associated with the occupational radiation safety program attribute of exposure control and affected the cornerstone objective, in that it caused increased collective radiation dose. Using the Occupational Radiation Safety significance determination process, the inspector determined this finding had very low safety significance. Although the finding involved ALARA planning and work controls, the licensee's latest, official three-year rolling average collective dose was less than 240 person-rem. Additionally, this finding had a crossing-cutting aspect in the human performance area associated with resources, in that procedures and other resources were not available and adequate to train personnel before allowing them in radiological working conditions.

This finding was self-revealing because the higher collective dose totals associated with the three work activities became self-evident and required no active and deliberate observation by the licensee (H.2(c)).

Enforcement. No violation of regulatory requirements occurred. However, the licensee was in the process of developing screening and supplemental training programs for selected contract maintenance workers. This finding is documented in the licensee's corrective action program by Condition Report CR-CNS-2007-02990. FIN 05000298/2007003-02, "ALARA Finding with Three Examples."

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

a. Inspection Scope

Barrier Integrity

The inspectors sampled licensee submittals for the two performance indicators listed below for the period January 2006 through March 2007. The definitions and guidance of Nuclear Energy Institute 99-02, "Regulatory Assessment Indicator Guideline," Revision 4, were used to verify the licensee's basis for reporting each data element in order to verify the accuracy of performance indicator (PI) data reported during the assessment period. The inspectors reviewed licensee event reports, monthly operating reports, and operating logs as part of the assessment.

- Reactor Coolant System Activity
- Reactor Coolant System Leakage

The inspector completed two samples in this cornerstone.

Mitigating Systems

The inspectors sampled licensee submittals for the performance indicator listed below for the period August 2006 through March 2007. The definitions and guidance of Nuclear Energy Institute 99-02, "Regulatory Assessment Indicator Guideline," Revision 4, were used to verify the licensee's basis for reporting each data element in order to verify the accuracy of performance indicator (PI) data reported during the assessment period. The inspectors reviewed licensee event reports, monthly operating reports, and operating logs as part of the assessment.

- Safety System Functional Failures

The inspector completed one sample in this cornerstone.

Occupational Radiation Safety Cornerstone

The inspector reviewed licensee documents from October 1, 2006, through March 31, 2007. The review included corrective action documentation that identified occurrences in locked high radiation areas (as defined in the licensee's Technical Specifications), very high radiation areas (as defined in 10 CFR 20.1003), and unplanned personnel exposures (as defined in Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Indicator Guideline," Revision 4). Additional records reviewed included ALARA records and whole body counts of selected individual exposures. The inspector interviewed licensee personnel that were accountable for collecting and evaluating the performance indicator data. In addition, the inspector toured plant areas to verify that high radiation, locked high radiation, and very high radiation areas were properly controlled. Performance indicator definitions and guidance contained in NEI 99-02, Revision 4, were used to verify the basis in reporting for each data element.

- Occupational Exposure Control Effectiveness

The inspector completed the required sample (1) in this cornerstone.

Public Radiation Safety Cornerstone

The inspector reviewed licensee documents from October 1, 2006, through March 31, 2007. Licensee records reviewed included corrective action documentation that identified occurrences for liquid or gaseous effluent releases that exceeded performance indicator thresholds and those reported to the NRC. The inspector interviewed licensee personnel that were accountable for collecting and evaluating the performance indicator data. Performance indicator definitions and guidance contained in NEI 99-02, Revision 4, were used to verify the basis in reporting for each data element.

- Radiological Effluent Technical Specification/Offsite Dose Calculation Manual Radiological Effluent Occurrences

The inspector completed the required sample (1) in this cornerstone.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Identification and Resolution of Problems

The inspectors performed a daily screening of items entered into the licensee's CAP. This assessment was accomplished by reviewing condition reports and work orders and attending corrective action review and work control meetings. The inspectors: (1) verified that equipment, human performance, and program issues were being identified by the licensee at an appropriate threshold and that the issues were entered into the CAP; (2) verified that corrective actions were commensurate with the significance of the issue; and (3) identified conditions that might warrant additional follow-up through other baseline inspection procedures.

The inspectors also evaluated the effectiveness of the licensee’s problem identification and resolution process with respect to the following inspection areas:

- Access Control to Radiologically Significant Areas (Section 2OS1)
- ALARA Planning and Controls (Section 2OS2)

No findings of significance were identified.

.2 Selected Issue Follow-up Inspection

a. Inspection Scope

In addition to the routine review, the inspectors selected the issues listed below for a more in-depth review. The inspectors considered the following during the review of the licensee's actions: (1) complete and accurate identification of the problem in a timely manner; (2) evaluation and disposition of operability/reportability issues; (3) consideration of extent of condition, generic implications, common cause, and previous occurrences; (4) classification and prioritization of the resolution of the problem; (5) identification of root and contributing causes of the problem; (6) identification of corrective actions; and (7) completion of corrective actions in a timely manner.

- Condition Report CR-CNS-2007-01361, Mis-positioned Control Rod
- Condition Report CR-CNS-2007-02355, Errors in Station Blackout Condensate Inventory Requirement Calculation
- Condition Report CR-CNS-2007-03555, Entry into Stability Exclusion Region of the Power to Flow Map
- Condition Report CR-CNS-2007-03380, RHR Partial Loop Draindown
- Review of cumulative affect of operator workarounds

The inspectors completed five samples during this inspection.

b. Findings

.1 Entry Into the Stability Exclusion Region of the Power to Flow Map

Introduction. A Green self-revealing noncited violation of TS 5.4.1.a was identified regarding the licensee's inadequate procedure for transitioning to single recirculation loop operation during power operations. This procedural inadequacy led to the reactor entering the stability exclusion region when one reactor recirculation pump was secured for maintenance activities.

Description. On May 18, 2007, the licensee lowered power in preparation for securing the A RRMG for preventative maintenance. Using a combination of control rod insertion and lowering RRMG speed, reactor power and total core flow were both reduced to 48 percent. While total core flow was at 48 percent, the two running RRMGs were at very different speeds; the B RRMG was at 64 percent and the A RRMG was at only 22 percent in preparation for being taken off-line.

At 12:31 a.m. on May 19, the A RRMG was tripped as planned. Total core flow immediately dropped to approximately 39 percent without a substantial drop in reactor power. As a result, the reactor entered the stability exclusion region of the power to flow map, contrary to the requirements of Nuclear Performance Procedure 10.13, "Control Rod Sequence and Movement Control," Revision 55. Step 2.5 of this procedure states that "Reactor operation within the Stability Exclusion Region is prohibited." Control room operators immediately recognized the condition and took actions to exit the stability exclusion region as required by Abnormal Procedure 2.4RR, "Reactor Recirculation Abnormal," Revision 27. The reactor was in the stability exclusion region for a total of sixteen minutes, during which time no hydraulic or reactor power instabilities were observed.

Subsequent review of three previous successful transitions to single loop operations revealed that the plant had been stabilized at either much higher flows or lower powers prior to entering single loop operation. The increased margin to the stability exclusion region in these other examples was a result of other operational considerations, not procedural guidance on avoiding the stability exclusion region. In addition, the data revealed that total core flow consistently dropped between 5-10 percent after securing a RRMG to enter single loop operations. The licensee determined that Procedure 2.2.69.3 was inadequate in that it did not provide sufficient guidance to properly position the reactor plant for transition to single loop operations, given the repetitive and predictable nature of this evolution.

Analysis. The performance deficiency associated with this finding involved the licensee's failure to provide adequate instructions for the transition to single recirculation loop operation at power. The finding is more than minor because it could reasonably been viewed as a precursor to a more significant operational event (i.e. core thermal-hydraulic instabilities and rapid power oscillations). Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have a very low safety significance because it did not contribute to the likelihood that mitigating systems would be unavailable following a reactor trip.

The cause of this finding is related to the human performance cross cutting component of resources because the system operating procedures did not provide guidance for establishing adequate margin to the stability exclusion region prior to securing a reactor recirculation pump (H.2(c)).

Enforcement. Technical Specification 5.4.1.a requires that written procedures be established, implemented, and maintained covering the activities specified in Regulatory Guide 1.33, Revision 2, Appendix A, dated February 1978. Regulatory Guide 1.33, Appendix A, section 2.h, requires that instructions for power operation with less than full reactor coolant flow be written and implemented. Contrary to this, System Operating Procedure 2.2.68.1 did not contain adequate instructions for the transition to single recirculation loop operations. Because the finding is of very low safety significance and has been entered into the licensee's CAP as Condition Report CR-CNS-2007-03555, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy: NCV 05000298/2007003-003, "Entry Into the Stability Exclusion Region of the Power to Flow Map."

.2 RHR Partial Loop Draindown

Introduction. A Green self-revealing NCV of TS 5.4.1.a was identified regarding the licensee's failure to follow the procedural requirements of System Operating Procedure 2.2.69.3, "RHR Suppression Pool Cooling and Containment Spray." This procedural violation resulted in the inadvertent draining and unavailability of one train of the LPCI system.

Description. On May 12, 2007, control room operators were completing a torus water transfer utilizing the guidance in System Operating Procedure 2.2.69.3, "RHR Suppression Pool Cooling and Containment Spray," Revision 38. During this evolution, the D RHR pump was running, drawing a suction from and discharging back to the suppression pool. A valve to the radwaste system was opened to remove water from the system and slowly lower suppression pool level. While in this lineup, the "B" Train of LPCI was declared inoperable as required by the unit technical specifications. For the purposes of on-line risk assessment, the LPCI train was still technically available due to its ability to perform its safety function in the event of a loss of coolant accident.

At the completion of the torus water transfer, operators were restoring the system lineup per Procedure 2.2.69.3, Section 7, "Removing RHR Subsystem B Suppression Pool Cooling From Service." Steps 7.2 through 7.4 of the procedure read as follows:

7.2 If RHR Pumps B and D are running, perform the following:
   7.2.1 Throttle closed RHR-MO-34B, SUPPR POOL COOLING INBD THROTTLE, until RHR Subsystem B flow < 8000 gpm.
   7.2.2 Stop RHR B or D
7.3 (Independent Verification) Close RHR-MO-34B, SUPPR POOL COOLING INBD THROTTLE
7.4 When RHR Subsystem B flow is zero, stop RHR Pump B or D

Despite the fact that only the D RHR pump was running, the reactor operator stated his intention to execute step 7.2.2 and secure the D RHR pump (despite the fact that the conditions of step 7.2 were not met). A second operator, serving in a peer checking role, concurred with this action, after which the reactor operator secured the D RHR pump. As a result, the RHR suppression pool cooling loop began gravity draining to the torus (both the pump suction and discharge valves were open).

Several annunciators were received shortly after securing the RHR pump, alerting control room operators that the RHR loop was depressurized and draining. The control room staff promptly recognized the error, declared the B train of LPCI unavailable, and began efforts to refill the piping. The system was recovered and the technical specification action statement was exited later in the same shift.

Had the operators properly executed the procedure, step 7.2 would not have been applicable. Step 7.3 would have been executed and kept the RHR loop from draining when the D RHR pump was secured in step 7.4.

Analysis. The performance deficiency associated with this finding involved the licensee's failure to follow the procedural requirements of System Operating Procedure 2.2.69.3, "RHR Suppression Pool Cooling and Containment Spray." The finding is more than minor because it is associated with the mitigating systems cornerstone attribute of human performance and affects the associated cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have a very low safety significance because it did not result in the actual loss of safety function for the LPCI train for greater than its technical specifications allowed outage time.

The cause of this finding is related to the human performance crosscutting component of work practices because neither self or peer checking actions prevented the reactor operator from violating the system operating procedure (H.4(a)).

Enforcement. Technical Specification 5.4.1.a requires that written procedures be established, implemented, and maintained covering the activities specified in Regulatory Guide 1.33, Revision 2, Appendix A, dated February 1978. Regulatory Guide 1.33,

Appendix A, section 4.h, requires instructions for the operation of emergency core cooling systems. Contrary to this, operators violated the implementation requirements of System Operating Procedure 2.2.69.3 resulting in the partial draining and unavailability of one train of the residual heat removal system during reactor operation. Because the finding is of very low safety significance and has been entered into the licensee's CAP as Condition Report CR-CNS-2007-03380, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy: NCV 05000298/2007003-004, "Operator Error Leads to Draining RHR Loop."

.3 Semiannual Trend Review

a. Inspection Scope

The inspectors completed a semiannual trend review of repetitive or closely related issues that were documented in corrective action documents, corrective maintenance documents, and the control room logs to identify trends that might indicate the existence of more safety significant issues. The inspectors' review covered the 12-month period between April 2006 and April 2007. When warranted, some of the samples expanded beyond those dates to fully assess the issue. The inspectors reviewed the following issues:

- Emergency response organization (ERO) qualifications
- TS Implementation Issues
- Maintenance rule implementation issues
- Problems with Areva local power range monitors
- Reliability issues with the Ronan annunciator system

The inspectors compared their results with the results contained in the licensee's routine trend reports. Corrective actions associated with a sample of the issues identified in the licensee's trend report were reviewed for adequacy. Documents reviewed by the inspectors are listed in the attachment.

b. Assessment and Observations

The inspectors evaluated the licensee's CAP trending methodology, attended departmental trending meetings and observed that the licensee had performed detailed reviews of developing issues. In the past six months, over forty-eight condition reports were written to evaluate emerging trends. In addition to those trends identified by the licensee, the inspectors noted the following:

(1) ERO Qualifications: The inspectors noted a trend in the number of ERO personnel who failed to complete training prior to their qualifications expiring. Between November 2006 and April 2007, there were six instances where members of the ERO allowed their qualifications to lapse. The licensee had previously identified this trend during Quality Assurance Audit 06-03, "Emergency Preparedness Plan." As a result of this audit, Condition Report CR-CNS-2006-02439 was initiated on March 30, 2006 which noted that during 2005, 10 ERO members allowed their qualifications to lapse and during the first quarter of 2006, 4 ERO members allowed their qualification to lapse. This

condition report was assigned as a Category E, the lowest level of condition report. In evaluating this condition, the licensee stated that "The area of requalification training is an area to monitor going forward," and "Actions contained sufficiently by 2006 Business plan. No further actions needed."

In February 2007, the licensee initiated Condition Report CR-CNS-2007-02128 to document an emerging trend in emergency preparedness. This condition report did not explicitly identify a trend in ERO qualification issues, it only documented that there was an increasing number of condition reports related to emergency preparedness. This condition report was also assigned as a Category E.

(2) Annunciator System Failures: During daily plant status, the inspectors noted an increasing trend in the number of entries into Abnormal Procedure 2.4ANN, "Annunciator Failure." The majority of these procedure entries were necessitated by various failures of single multiplexer cards located throughout the plant which represented a degraded condition in the system but not a complete failure.

Based on a review of control room logs and condition reports, the inspectors determined that there were approximately 20 entries into Abnormal Procedure 2.4ANN due to degraded conditions on the annunciator system since September 2006. The licensee had previously identified an adverse trend in Condition Report CR-CNS-2006-05441 which was initiated on July 31, 2006. This condition report documented 14 degraded conditions between January 2006 and July 2006 and was assigned as a Category B (apparent cause) condition. As a result, a number of corrective actions were proposed, including periodic replacement of certain multiplexer cards as well as actions to improve the environmental enclosures containing the multiplexers. Based on the failure history, the inspectors concluded that these were reasonable corrective actions that would improve system reliability; however, as of April 2007, none of these corrective action had been implemented. In addition, no additional condition reports were initiated since July 2006 to document the continued adverse trend in system performance.

4OA3 Event Follow-up (71153)

.1 (Closed) Licensee Event Report 05000298/2006-004: Manual Reactor Scram and Group 2 Isolation due to Plant Air Failure

In August 2005, the licensee began installing new service air compressors (SACs) and related control systems as described in Change Evaluation Document (CED) 6013140. As part of the modification, the existing analog control system was replaced with a digital system that allowed one of the three SAC controllers to control the loading and unloading of the other two compressors with the intention of equalizing run time amongst the three SACs. On May 22, 2006, a total failure of the new SAC control system occurred. B SAC was operating as the lead SAC at the time and failed to load in response to lowering plant air pressure. In addition, the B SAC controller failed to demand either of the other two SACs to start, and a total loss of air pressure ensued. When instrument air pressure dropped below 77 psig, operations personnel manually scrammed the reactor as required by step 4.8 of Emergency Procedure 5.2, "AIR," Revision 13, and restored B SAC in the local control mode. The licensee determined that the root cause of the event was the introduction of a single-point failure vulnerability into the SAC control system. A contributing cause was identified in that the vulnerability was unrecognized in the design process. Subsequent laboratory testing was unable to recreate the condition or determine the nature of the single-point failure mode. No performance deficiencies were identified during the review of this LER. This LER is closed.

.2 (Closed) Licensee Event Report 05000298/2007-001-01: High Pressure Coolant Injection Inverter Circuit Failure Results in Loss of Safety Function

On February 7, 2007, control room operators received a momentary "HPCI Inverter Circuit Failure" annunciator and observed the output values on the HPCI flow controller lowering to approximately 30 percent. As a result, operators declared HPCI inoperable and entered the appropriate action statement per TSs. Subsequent troubleshooting indicated that the failure was due to a broken ground wire internal to the inverter. Although the specific cause of the failure was not determined, the licensee determined the need to establish a periodic maintenance activity which would replace this inverter every 10 years based on a maintenance recommendation contained in the Electric Power Research Institute's EPRI TR-106857-V22, "Preventive Maintenance Basis, Volume 22: Inverters." No performance deficiencies were identified during the review of this LER. This LER is closed.

.3 (Closed) LER 50-298/2007-002: Technical Specification Prohibited Operation Due to Safety Relief Valve Test Failures

On February 28, 2007, the licensee received test data on eight safety relief valve (SRV) pilot valve assemblies which were replaced during Refueling Outage 23. The test data indicated that the pilot valve removed from Relief Valve MS-RV-71ERV exceeded its TS required setpoint (1090 psi) by 3.4 percent. The allowable setpoint range is ± 3 percent. An inspection of the pilot valve assembly confirmed that the test failure was due to corrosion bonding of the pilot valve disc to the seat. The SRV's at Cooper Nuclear Station are two-stage Target Rock safety relief valves. The pilot valve assemblies have Stellite 21 discs and Stellite 6 seats. Several previous test failures at Cooper Nuclear Station were attributed to corrosion bonding in the pilot valve assembly, which is an industry-wide concern with this type of valve. The as-found pressure value for this valve was bounded by the assumptions made in the core reload analyses for Cycles 22; therefore, core performance and RCS integrity were not challenged. Corrective actions for past SRV test failures had not been fully implemented for this particular valve since it was installed during Refueling Outage 22 prior to formulation of the latest corrective action for corrosion bonding therefore, no performance deficiency on the part of the licensee was identified. Based on plant specific operating experience, the licensee has found that the SRV pilot valve will operate reliably for one operating cycle following a replacement of the valve disc and seat. The currently installed SRV pilot valves were overhauled and these components were replaced prior to installation. The enforcement aspects of the violation are discussed in Section 4OA7. This LER is closed.

.4 (Closed) LER 50-298/2007-003: Incorrectly Installed Fuse Block Resulted in a Condition Prohibited by Technical Specifications

During a surveillance test on April 23, 2007, an operator placed his finger on the exterior of a fuse block cover in the 4160V volt bus 1G undervoltage relay circuit, at which time the fuse block cover dropped onto the bottom of the breaker cubicle. The licensee determined that the fuse block cover had been improperly reinstalled following surveillance testing on March 19, 2007, and that during a design basis seismic event the fuse block cover could have become dislodged and caused the inoperability of the startup transformer. This condition violated TS 3.8.1 condition A, which requires that two qualified offsite power circuits be available in Modes 1, 2 and 3. The licensee determined that the cause of the condition was inadequate procedural guidance to ensure that the fuse block cover is properly installed following maintenance activities. The enforcement aspects of the violation are discussed in Section 4OA7. This LER is closed.

.5 Hydraulic Control Unit 26-27 Focused Baseline Inspection

On May 18, 2007, the licensee decreased power to perform required preventive and corrective maintenance, including replacement of directional control valves on three control rod drive (CRD) HCUs. Operations isolated HCU 26-27 for maintenance using Manual Isolation Valves CRD-V-101 and CRD-V-102 among others. During this maintenance, the licensee had placed the unit in a single recirculation loop configuration to perform maintenance on the Train A recirculation motor generator and had the Train B reactor feed pump in service while personnel performed maintenance on the Train A reactor feed pump lube oil system.

At approximately 12:25 a.m., on May 19, 2007, personnel reported that a small water leak had developed from the body to bonnet seal of Directional Control Valve CRD-SOV-SO122 (26-27) when mechanics had loosened three of the four bolts that held the valve in place. Operators took steps to ensure that Valves CRD-V-101 and -102 (26-27) and the scram inlet valves had been properly isolated. However, during these verification activities, because of seat leakage past one or both of the manual isolation valves, the leakage degraded to the point that a visible plume of steam issued from the valve. At 2:12 a.m., operators manually scrammed the reactor because they could not isolate the reactor coolant that leaked from the directional control valve.

a. Inspection Scope

As specified in Attachment B, the inspectors assessed the circumstances related to an unisolable leak from Directional Control Valve CRD-SOV-SO122 (26-27). The inspectors reviewed the scope and conduct of the maintenance on the hydraulic control unit, the actions taken by the licensee to isolate the leak, and the overall risk assessment for this down power. In addition, the inspectors developed a detailed sequence of events for this event, reviewed operator actions related to their emergency plan, reviewed the actions of the radiation protection staff, and assessed the licensee use of relevant industry operating experience.

The team evaluated the licensee considerations related to the use of single valve isolations, precautions and contingencies considered, and any actions implemented to ensure that the hydraulic control lines were depressurized.

b. Observations and Findings

Introduction. A Green self-revealing NCV of TS 5.4.1.a was identified involving inadequate isolation instructions contained in System Operating Procedure 2.2.8, "Control Rod Drive Hydraulic System." Specifically, inadequate isolation instructions contained in the procedure resulted in an unisolable reactor coolant system leak from the control rod drive system during maintenance activities. The unisolable leak required operators to manually scram the reactor.

Description. On May 18, 2007, operators tagged out HCU 26-27 for the purpose of replacing valve CRD-SOV-SO122(26-27) with a more reliable valve design. The tagout was prepared using the instructions of System Operating Procedure 2.2.8, "Control Rod Drive Hydraulic System," Revision 64. Section 25 of Procedure 2.2.8 provided instructions for the total isolation of an HCU for maintenance, based on the guidance contained in vendor manual, GEK-9589, "Control Rod Drive System."

As the body to bonnet bolts were removed during disassembly of CRD-SOV-SO122, water began issuing from the body to bonnet joint in the valve. Maintenance personnel attempted unsuccessfully to reassemble the valve. As the leak continued, and the ambient temperature water from the HCU hydraulic lines issued from the leak site, warmer water from the reactor began to approach the area. Recognizing the degrading situation, operations personnel verified that the tagout isolation had been correctly hung and attempted to open, then reseat the HCU insert and withdraw riser shutoff valves. As operators took these actions, the leak worsened from a two-phase water and steam mixture to a steady plume of steam. Based on the inability to isolate the leak and concerns over high airborne radioactivity levels in the reactor building, control room operators inserted a manual reactor scram in an attempt to depressurize the leaking HCU. Shortly after the reactor scram, the leak ceased.

The licensee subsequently determined that the most likely source of leakage was the insert riser shutoff valve, CRD-V-101. The licensee determined that the leak path from the reactor through CRD-V-101 was shut off by the ball check valve internal to the HCU, which repositioned due to the depressurization of the HCU insert line following the reactor scram.

The licensee's root cause investigation team determined that the isolation boundary provided in Procedure 2.2.8 did not match that provided in the vendor manual. Specifically, GEK-9589, contained instructions to deenergize the solenoids of the scram pilot air valves, which would have resulted in forcing the scram inlet and outlet valves to open. With the scram inlet and outlet valves open, the HCU insert riser would have been vented to an equipment drain through an open drain valve, and any leakage past CRD-V-101 would have been detected by maintenance personnel prior to breaking the body to bonnet joint on CRD-SOV-SO122.

The inspectors reviewed the evolution of Procedure 2.2.8, and noted that on September 8, 2004, the procedure was revised to remove a precaution at the beginning of the section that described HCU isolation for maintenance. The portion of the precaution that was removed read as follows: "This section should only be used when HCU will only be isolated for several hours or reactor is in MODES 4 or 5." This procedure change received a 10 CFR 50.59 screening, as required by Administrative Procedure 0.8, "10CFR50.59 Reviews." The 10 CFR 50.59 screening form documents the rationale for the change and records that the vendor manual, GEK-9589, was reviewed in preparing the procedure change. This presented an opportunity for the personnel performing the change to realize that the isolation being used for on-line HCU maintenance was not in accordance with the vendor manual instructions.

Analysis. The performance deficiency associated with this finding involved the licensee's failure to provide adequate instructions for the isolation of an HCU for maintenance. The finding is more than minor because it is associated with the initiating events cornerstone attribute of procedure adequacy and affects the associated cornerstone objective to limit the likelihood of those events that upset plant stability. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have a very low safety significance because it did not contribute to the likelihood that mitigating systems would be unavailable following a reactor trip.

The cause of this finding is related to the human performance crosscutting component of resources because the licensee failed to ensure that the procedure was complete and accurate to assure proper component isolation from the reactor coolant system prior to performing maintenance activities (H.2(c)).

Enforcement. Technical Specification 5.4.1.a requires that written procedures be established, implemented, and maintained covering the activities specified in Regulatory Guide 1.33, Revision 2, Appendix A, dated February 1978. Regulatory Guide 1.33, Appendix A, section 9.a, requires that maintenance that can affect the performance of safety related equipment be properly preplanned. Contrary to this requirement, System Operating Procedure 2.2.8, "Control Rod Drive Hydraulic System," did not contain adequate instructions to isolate HCU 26-27 for maintenance. Because the finding is of very low safety significance and has been entered into the licensee's CAP as Condition Report CR-CNS-2007-03552, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy: NCV 05000298/2007003-005, "Inadequate Equipment Isolation Instructions Results in Unisolable Leak and Reactor Scram."

4OA6 Management Meetings

On April 16, 2007, the regional inspectors conducted a telephonic exit meeting to present the results of the emergency plan change inspection to Mr. B. Murphy, Supervisor, Emergency Planning. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

On April 27, 2007, the regional inspectors presented the occupational radiation safety inspection results to Mr. M. Colomb, General Manager of Plant Operations, and other members of his staff who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

On July 9, 2007, the NRC resident inspectors presented the results of the inspection activities to Mr. M. Colomb and other members of his staff who acknowledged the findings. The inspectors confirmed that proprietary information was not disclosed in this inspection report.

4OA7 Licensee-Identified Violations

The following violations of very low 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 for being dispositioned as NCVs.

- TS 3.4.3 requires eight SRV's to be operable in Modes 1, 2, and 3. Contrary to this, on February 28, 2007, the licensee determined that one SRV would not have lifted within the required pressure during Cycle 22. This finding affected the Barrier Integrity and Mitigating Systems Cornerstones; however, the finding was not suitable for SDP evaluation, but has been reviewed by NRC management and was determined to be a Green finding of very low safety significance. This was identified in the licensee's CAP as CR-CNS-2007-01609.

- Part 20.1501(a) of Title 10 of the Code of Federal Regulations, requires that each licensee make or cause to be made surveys that may be necessary for the licensee to comply with the regulations in 10 CFR Part 20 and that are reasonable under the circumstances to evaluate the extent of radiation levels, concentrations or quantities of radioactive materials, and the potential radiological hazards that could be present. While reviewing the fourth quarter 2006 dosimetry results on February 8, 2007, the licensee identified a discrepancy between the actual neutron dose and the estimated/planned dose of a worker. The licensee reported the event as an Occupational Radiation Safety cornerstone performance indicator occurrence and performed a root cause analysis. The root cause analysis identified a failure to perform an adequate survey, in accordance with 10 CFR 20.1501(a), to determine the neutron dose rate during valve work in the drywell. The violation occurred on November 22, 2006. The licensee documented the occurrence in CR-CNS-2007-00954. The finding was determined to be of very low safety significance because it was not associated with ALARA planning or work controls issue, there was no overexposure or a substantial potential for an overexposure, and the ability to assess dose was not compromised.

- Technical Specification 5.7.1 requires high radiation areas be barricaded. On December 24, 2006, the licensee identified the high radiation area boundary swing gate around the cavity silver vessel tub tied open. The gate was tied in the open position to facilitate the removal of trash bags and was not returned to its closed position. The condition had existed since December 21, 2006. The licensee documented the occurrence in CR-CNS-2006-10518. The finding was determined to be of very low safety significance because it was not associated with ALARA planning or work controls issue, there was no overexposure or a substantial potential for an overexposure, and the ability to assess dose was not compromised.

- TS 3.8.1 requires two qualified offsite power circuits to be operable in Modes 1, 2, and 3. Contrary to this, on April 23, 2007, the licensee determined during surveillance testing that a pre-existing condition on a fuse block cover had rendered one of the two qualified offsite power circuits inoperable since the previous performance of the test on March 19, 2007. This finding affected the Mitigating Systems Cornerstones and was determined to be of very low safety significance. This was identified in the licensee's CAP as CR-CNS-2007-02818.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

T. Bahensky, System Engineer
J. Bebb, Security Manager
R. Beilke, Chemistry Manager
V. Bhardwaj, Engineering Support Manager
D. Buman, Systems Engineering Manager
T. Carson, Maintenance Manager
K. Chambliss, Nuclear Safety Assurance Director
J. Christensen, Support General Manager
M. Colomb, Plant Operations General Manager
R. Dyer, Heat Exchanger Program Engineer
J. Dykstra, Electrical Engineering Program Supervisor
T. Erickson, System Engineer
R. Estrada, Corrective Actions Manager
J. Flaherty, Senior Licensing Engineer
P. Fleming, Licensing Manager
G. Griffith, Fuels & Reactor Engineering Manager
T. Hough, Maintenance Rule Coordinator
G. Kline, Engineering Director
J. Larson, Quality Assurance Supervisor
M. McCormack, Electrical Systems/I&C System Engineering Supervisor
E. McCutchen, Regulatory Affairs Senior Licensing Engineer
M. Metzger, System Engineer
S. Minahan, Vice President - Nuclear & Chief Nuclear Officer
A. Mitchell, Design Engineering Manager
B. Murphy, Emergency Planning Supervisor
R. Noon, Root Cause Team Leader, Corrective Actions
A. Sarver, Balance of Plant Engineering Supervisor
T. Shudak, Fire Protection Program Engineer
T. Stevens, Mechanical Engineering Supervisor
K. Thomas, Mechanical Programs Supervisor
J. Waid, Training Manager
D. Willis, Operations Manager

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000528/2007003-001	NCV	Control Rod Mispositioned During Reactor Startup
05000528/2007003-002	FIN	ALARA Finding With Three Examples
05000298/2007003-003	NCV	Entry Into the Stability Exclusion Region of the Power to Flow Map
05000298/2007003-004	NCV	Operator Error Leads to Draining RHR Loop
05000298/2007003-005	NCV	Inadequate Equipment Isolation Instructions Results in Unisolable Leak and Reactor Scram

Closed

05000298/2006-004	LER	Manual Reactor Scram and Group 2 Isolation Due to Plant Air Failure
05000298/2007-001	LER	High Pressure Coolant Injection Inverter Circuit Failure Results in Loss of Safety Function
05000298/2007-002	LER	Technical Specification Prohibited Operation Due to Safety Relief Valve Test Failures
05000298/2007-003	LER	Technical Specification Prohibited Operation Due to Inadequate Seated Fuse Block

LIST OF DOCUMENTS REVIEWED

Section 1R19: Postmaintenance Testing (71111.19)

WO 4534477	WO 4502174	WO 4534477
WO 4486794	WO 4534477	
WO 4554763	WO 4504695	

6.1SW.102, “Service Water Surveillance Operation (DIV 1) (IST),” Revision 23
Nuclear Performance Procedure 10.9, “Control Rod Scram Time Evaluation,” Revision 55

Section 1R20: Refueling & Outages (71111.20)

Procedures:

Number	Description	Revision
General Operating Procedure 2.1.5	Reactor Scram	55C1
Abnormal Procedure 2.4RR	Reactor Recirculation Abnormal	27
Event Review Team Report 07-02	Manual Scram from 50% Power Due to Leak on CRD-SOV-SO122 (26-27)	
Conduct of Operations Procedure 2.0.6	Operational Event Response and Review	29
Abnormal Procedure 2.4RXLVL	RPV Water Level Control Trouble	20
General Operating Procedure 2.1.4	Normal Shutdown	104

CNS Air Sample Assay dated 5/19/07

Section 1R22: Surveillance Testing (71111.22)

Number	Description	Revision
6.LOG.601	Daily Surveillance Log – Modes 1 2 and 3	Revision 89 Att 3 Unidentified Leak Rate Checks
6.SLC.601	Standby Liquid Control (SLC) Tank Sampling	Revision 7
6.SLC.101	SLC Pump Operability Test	Revision 13
6.1SW.101	Service Water Surveillance Operation (DIV 1) (IST)	Revision 23
6.RCS.601	Technical Specification Monitoring of FCS Heatup/Cooldown Rate	Revision 14
6.2EE.302	4160V Bus 1G Undervoltage Relay and Relay Timer Functional Test (Div 2)	Revision 14
6.HPCI.103	HPCI IST and 92 Day Test Mode Surveillance Operation	Revision 32

Section 2OS1: Access Controls to Radiologically Significant Areas (71121.01)

Corrective Action Documents

2006-07900, 2006-09816. 2007-01269

Section 2OS2: ALARA Planning and Controls (71121.02)

Corrective Action Documents (Condition Reports)

2006-08153, 2006-08277, 2006-09211, 2006-09839,

Audits and Self-Assessments

Surveillance S07-03 Occupational Radiation Safety (February 5 - 9, 2007)

Radiation Work Package

2006AL-03 Target Rocks
2006AL-09 RE23 Valve Activities
2006AL-13 Refuel Floor Activities
2006AL-20 RE-23 Drywell Support and Limited Maintenance

ALARA Committee Meeting Minutes

February 6, March 6, and April 3, 2007

Section 4OA1: Performance Indicator Verification (71151)

Corrective Action Documents

2007-00954

Procedures

Number	Description	Revision
9.ALARA.4	Radiation Work Permits	7
9.ALARA.5	ALARA Planning and Controls	17

Section 4OA3: Event Followup

Hydraulic Control Unit 26-27 Focused Inspection (71153 OA)

Procedures

Number	Title	Revision
0.10	Operating Experience Program	21
0.26	Surveillance Program	55
0.40	Work Control Program	55
0.40.1	Work Week Process	25
0.49	Schedule Risk Assessment	19
2.2.8	Control Rod drive Hydraulic System	63
7.2.25.1	Bolted or Screwed Bonnet Gate Valve Maintenance	12
7.2.33	Freeze Seals	15
9.RADOP.2	Radiation Safety Standard and Limits	9
9.RADOP.5	Airborne Radioactivity Sampling	17

Clearance Orders

CRD-1-	Replace	Completed
4188800	CRD-SOV-SO118 (38-23)	March 21, 2002
4214543	O-ring CRD-SOV-SPV121 (18-03).	March 21, 2002
4214548	O-ring CRD-SOV-SO121 (10-15)	March 20, 2002
4214549	O-ring CRD-SOV-SO121 (18-35)	March 20, 2002
4215374	Valve CRD-SOV-SO123 (14-47)	March 22, 2002
4215978	Scram Valve CRD-SOV-SO118 (38-27)	March 24, 2002
4224381	Valves CRD-SOV-SO117 & SO118 (06-31)	March 21, 2002
4233103	Valves CRD-SOV-SO117 & SO118 (22-39)	June 13, 2002
4268965	Valves CRD-SOV-SO117 & SO118 (10-07)	December 13, 2002
4350892	Valve CRD-SOV-SO122 (14-23)	December 3, 2002
4399030	Accumulator CRD-ACC-125 (22-51)	September 8,2005
4484597	Accumulator CRD-ACC-125 (18-35)	October 19, 2006

4538390	Accumulator CRD-ACC-125 (02-35)	November 28, 2006
4533382	Valve CRD-V-111 (34-35)	January 27, 2007
4547160	Valve CRD-SOV-SO122 (10-19)	May 19, 2007
4547167	Valve CRD-SOV-SO122 (10-35)	May 20, 2007
4550726	Valve CRD-SOV-SO123 & CRD-ACC-125 (46-39)	May 16, 2007
4547092	Valve CRD-SOV-SO122 (26-27)	May 21, 2007

Miscellaneous

JFP Procedure OP-25, "Control Rod Drive Hydraulic System," Revision 77

Operations Control Center Logs, dated May 18 - 22, 2007

Manual GEK-9582C, selected pages related to isolating a hydraulic control unit

Manual GEK-63100A, selected pages related to isolating a hydraulic control unit

10 years of data related to maintenance on hydraulic control units

Online risk assessment for the planned down power

Lesson Plan COR002-05-02, "Control Rod Drive Mechanism," Revision 10

March 2007, Control Rod Drive System Health Report

Updated Safety Analysis Report, Chapter 5, "Control Rod Drive Mechanical Design"

Final Safety Analysis Report, Chapter 5, "Control Rod Drive Mechanical Design"

NUREG-0654, Appendix 1, "Emergency Action Level Guidelines for Nuclear Power Plants"
Notification 10270111

EPRI TR-016384R1, "Freeze Sealing (Ice Plugging) of Piping," Revision 1

Service Information Letter SIL No. 310, "Stuck CRD Collet"

Service Information Letter SIL No. 292, Supplement 1, "Inadvertent Control Rod Withdrawal"

Service Information Letter SIL No. 292,"Inadvertent Control Rod Withdrawal"

Part Evaluation 4447132, "Replacement of ASCO Directional Control Valve With an AVCO Directional Control Valve," Revision 0

Reactor Building 903' East radiological survey

Smear Count data sheet and Air Sample Assay

Isotopic analysis of Air Sample

Condition Reports CR-CNS-

2006-09932
2007-00027
2007-02127
2007-03559

Work Orders

4547092, Replace CRD-SOV-SO122 (26-27)
4568005, Disassemble and Repair CRD-V-102 (26-27)

LIST OF ACRONYMS

ALARA	as low as reasonably achievable
ASME	American Society of Mechanical Engineers
CAP	corrective action program
CED	change evaluation document
CFR	Code of Federal Regulations
CRD	control rod drive
EDG	emergency diesel generator
ERO	emergency response organization
HCU	hydraulic control unit
HPCI	high pressure coolant injection
IST	inservice test
LER	licensee event report
LPCI	low-pressure coolant injection
NCV	non-cited violation
PI	performance indicator
RCIC	reactor core isolation cooling
RCS	reactor coolant system
REC	reactor equipment cooling
RHR	residual heat removal
RRMG	reactor recirculation motor generator
SAC	service air compressors
SOP	system operating procedure
SRV	safety relief valve
SSC	structure, system, and component
TS	technical specification
UFSAR	updated final safety analysis report
WO	work order