APPENDIX

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-298/94-13

License: DPR-46

Licensee: Nebraska Public Power District
P.O. Box 499
Columbus, Nebraska

Facility Name: Cooper Nuclear Station

Inspection At: Brownville, Nebraska

Inspection Conducted: March 27 through May 7, 1994

Inspectors: R. A. Kopriva, Senior Resident Inspector
W. C. Walker, Resident Inspector

Approved: for D Powers 6/9/94
P. H. Harrell, Chief, Project Branch C Date

Inspection Summary

Areas Inspected: Routine, announced inspection of onsite response to events, operational safety verification, maintenance and surveillance observations, and followup.

Results:

- Plant Operations

General plant housekeeping has improved; however, less traveled areas have not received the attention that the high traffic areas have received. A number of areas that have needed additional housekeeping attention for at least 2 years showed no indication of efforts by the licensee to correct the problem(s) (Section 3.2).

- Maintenance

Maintenance activities associated with the cracked, high pressure core injection stop valve stem were good. The licensee's decision to have General Electric (GE) assist in correcting the problems identified with the balance chamber steam pressure appeared to be prudent. The procedure used for maintenance activities on the stop valve may not have

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been appropriate for the circumstances. This issue is being tracked as an unresolved item.

A timing error by an operator, during the performance of a surveillance test, indicated a lack of attention to details during testing (Section 4.1).

- Engineering

The licensee's pursuit of a potential feedwater flow error indicated good followup by the corrective action program. Several past errors were identified and resolution of the recommended corrective actions were not completed (Section 6.1).

A repetitive engineering safety feature actuation of the core spray (CS) minimum flow valve identified a weak root cause evaluation of a previous event (Section 6.3).

- Plant Support

Decontamination efforts within the reactor building continued to show good progress (Section 3.3).

- Management Overview

The Problem Resolution Team (PRT) and Condition Resolution Teams (CRT) formed by management to review minor plant events appeared to function well (Sections 4.1, 6.1, and 6.3).

Summary of Inspection Findings:

- Unresolved Item 298/9413-01 was opened (Section 5.1).
- Unresolved Item 298/9413-02 was opened (Section 6.1).
- Unresolved Item 298/9413-03 was opened (Section 6.3).

Attachment:

- Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

At the beginning of this inspection period, the plant was at 90 percent power and returning to full power operation. On April 11, 1994, the licensee discovered a potential concern pertaining to the calibration of the feedwater flow indicators. The licensee reduced power by 20 megawatts thermal, approximately 0.8 percent power, and continued to operate the plant at this reduced power level until calibration of the flow indicators can be performed, which is currently scheduled for the Fall 1994 mini-outage.

At the end of this inspection period, the plant was at a steady state power of 99 percent.

2 ONSITE RESPONSE TO EVENTS (93702)

2.1 Control Room Envelope Pressurization Test

On April 11, 1994, the inspectors were informed that Surveillance Procedure (SP) 6.3.17.18, "Control Room Envelope Pressurization Test," Revision 2, was performed and the results obtained did not meet the acceptance criteria. This placed the licensee in a 7-day shutdown condition per the Technical Specifications (TS). The pressurization test is performed once per operating cycle to ensure that the control room envelope can be maintained at a pressure greater than atmospheric pressure during accident conditions.

Due to required maintenance on Door H-300, part of the control room pressure boundary, SP 6.3.17.18 was performed to verify operability of the control room envelope. This test failed and the licensee began to troubleshoot the cause of the failure.

On April 18, the licensee was unable to satisfy the TS requirements for ensuring positive pressure in the control room envelope and requested enforcement discretion from the NRC. This request was granted and extended the limiting condition for operation action statement to a total of 14 days.

The licensee was able to successfully complete the surveillance test to verify that the control room envelope would maintain a positive pressure. A special inspection will be performed to review the licensee's actions related to testing of the control room envelope. The results of this inspection will be documented in NRC Inspection Report 50-295/94-16.

3 OPERATIONAL SAFETY VERIFICATION (71707)

3.1 Control Room Observations

The inspectors observed control room activities on a sampling basis. The operators demonstrated good control of the activities relating to safe operation of the facility. Communications and repeat-backs in the control room continued to improve. The operators' knowledge of annunciated alarms was good as they were cognizant of conditions causing the alarm condition and were aware of ongoing activities to clear the alarms. Plant management oversight of operations included daily control room tours.

3.2 Plant Tours

The inspectors conducted tours of accessible areas of the plant on a routine basis and noted areas of improvement pertaining to housekeeping activities. The regularly used areas continue to be well maintained, but the lesser visited (less visible) areas did not appear to receive comparable housekeeping efforts. Some of the areas (e.g., catch basins used to collect fluid from leaking valves in the control rod drive pump room, the reactor water cleanup valve room, and above the standby liquid control tank and debris above the reactor building elevator motor rooms and in reactor building cable trays) needing additional management attention have existed for up to 2 years. Management has been aware of these housekeeping concerns and little action has been taken to address the deficiencies. The inspectors discussed this issue with licensee management, who stated that the areas needing additional attention would be addressed.

3.3 Radiation Protection Observations

During plant tours, the inspectors observed the decontamination efforts for the control rod drive hydraulic control units, the high pressure coolant injection (HPCI) room, and the reactor core isolation cooling (RCIC) room. The licensee has been able to reclaim these areas as clean areas, thus eliminating the contaminated area barriers. Besides the obvious benefits of reducing contaminated areas within the plant; the operators, engineers, and maintenance personnel are able to perform tours, inspections, and maintenance in a more proficient manner without the constraints imposed by the barriers.

4 SURVEILLANCE OBSERVATION (61726)

4.1 HPCI Stop Valve Problems

On March 25, 1994, the inspector observed the performance of SP 6.3.3.1.1, "HPCI IST and Quarterly Test Mode Surveillance Operation." During the surveillance, it was noted that the opening time of the HPCI stop valve (HPCI-HOV-HOV10) was 51 seconds, which exceeded the specified inservice testing requirement of 38 seconds. Being unable to satisfactorily complete the surveillance as a result of excessive stroke time, the licensee declared the HPCI system inoperable and entered a TS 7-day shutdown limiting condition for operation.

The licensee disassembled the stop valve and identified a cracked valve stem. The valve stem was replaced and the valve reassembled. In addition to the valve stem cracking, problems were also identified with the valve steam balance chamber pressure. A GE consultant was on site to assist the licensee in adjusting the stop valve steam balance chamber pressure. The inspector was informed that some problems, discussed in Section 5.1 of this report, were identified when the balance chamber pressure was adjusted. The balance chamber problems were corrected and the balance chamber pressure was adjusted within the specified values.

On March 30, SP 6.3.3.1.1 was performed with acceptable results. The GE consultant stated that the cracked valve stem had no bearing on the valve stroke timing. The steam balance chamber pressure will affect the stability of the valve opening, but will have immeasurable affect on the opening stroke time of the stop valve.

A PRT was assigned by licensee management to investigate this event. The PRT concluded that there was no indication of a condition, mechanical or hydraulic, that could have caused the HPCI stop valve to stroke open in 51 seconds, as recorded by the control room operator during the performance of the procedure. The PRT stated that, if the stop valve had required 51 seconds to open, a normal turbine startup would not have occurred. The turbine startup was noted to be normal during the testing. The PRT reviewed the operator's activities and concluded that the stop watch used to record the stop valve stroke time of was incorrectly read and that the actual time to open was 21 seconds.

The inspector reviewed past surveillance records, and the 21-second time frame coincided with previous test data that dated back to May 1990. The previous data ranged from 20-28 seconds. The stop watch used by the operator was an analog-type stop watch with each revolution of the watch equal to 30 seconds. Thus, the indication of 21 and 51 seconds are at the same location on the stop watch.

The licensee's corrective actions included removal of all analog-type stop watches used for timing the inservice testing of components and replaced them with digital-type stop watches.

This issue indicated a lack of attention to details and a questioning attitude by operations personnel in that no verification of the valve stroke time was performed. The lack of verification caused the licensee to disassemble the valve; however, as a result of disassembly, problems with the valve were identified.

5 MAINTENANCE OBSERVATION (62703)

5.1 HPCI System Declared Inoperable

On March 25, 1994, the HPCI system was declared inoperable due the stop valve opening time exceeding the limit specified in SP 6.3.3.1.1, "HPCI IST and Quarterly Test Mode Surveillance Operation."

The inspector observed the licensee's efforts during stop valve disassembly, as specified in Maintenance Work Requests 94-1333 and 94-1335. When disassembled, the valve stem was found to be out-of-round by 0.010 inches and cracks were observed in the area where the stem threads into the split coupling. The inspector's review of the maintenance history of the valve indicated that the stem had been in service approximately 12 years. As a result of the cracks and out-of-round reading, the licensee replaced the stem.

After the stop valve reassembly was completed, Maintenance Procedure (MP) 7.2.54, "HPCI Turbine Stop Valve Steam Balance Chamber Pressure Adjustment," was performed to adjust the stop valve steam balance chamber pressure. The balance chamber pressure was measured at 650 psig; whereas, the procedure required a pressure of 100-180 psig.

On March 28, the inspector observed the stop valve disassembly a second time. Inspection revealed that the tolerance between the cover cylinder and valve disc was slightly excessive. The licensee contacted GE to assist with the adjustment of the balance chamber steam pressure. On March 30, with the valve reassembled, MP 7.2.54 was again performed. A discrepancy was identified in a measurement critical for properly blocking open the pilot valve. The licensee adjusted the pilot valve and reperformed MP 7.2.54. The results were satisfactory, with a stroke open time of 22 seconds. Balance chamber steam pressure was verified to be 125 psig.

No anomalies were identified during the subsequent HPCI surveillance run; however, the procedure used to perform the maintenance activities discussed above may not have been appropriate to the circumstances. This issue is unresolved pending review of the procedure by the inspectors (298/9413-01).

6 FOLLOWUP (92701)

6.1 Feedwater Flow Errors

On April 11, 1994, with the plant operating at full power, the licensee identified a potential problem in the calibration of the Rosemont Model 1151 differential pressure transmitters, which are used to measure feedwater flow. The licensee had previously reviewed GE Service Information Letter 452 and Supplement 1 to the information letter, which addressed concerns with feedwater flow elements. In 1987, 1988, and 1991, the licensee reviewed the feedwater flow element concerns identified in the service letter and, at that time, had no indication that any problem existed at Cooper Nuclear Station.

Engineering department personnel had written an engineering work request, in October 1993, to review the calibration of the flow elements. In January 1994, the Corrective Action Program Review Group recommended another review of the GE information letter to document current plant information and to provide additional justification for the engineering work request.

The problem, identified on April 11, was that a static pressure correction factor, needed to correct a systematic span shift, had not been incorporated into the feedwater flow transmitter calibration procedure. The lack of this correction factor in the calculation could result in a nonconservative error in the total feedwater flow signal. The under estimation of feedwater flow resulted in core thermal power being 19.897 megawatts thermal greater than what was being calculated by the plant computer. The licensee's immediate action was to instruct the plant operators to reduce plant power by 20 megawatts thermal (0.8 percent power).

In 1985, Information Notice 85-100, issued by the NRC, alerted all licensees of a potential problem with differential pressure transmitter zero point shift in Rosemont Model 1153 instruments. The inspector was informed that, at the time the information notice was issued, the licensee did not investigate the possibility that Rosemont Model 1151 may also have been affected, since the notice specifically addressed only Model 1153 transmitters. Rosemont Model 1153 instruments are used in essential (safety-related) applications and the Model 1151 instruments in nonessential (nonsafety-related) applications at the Cooper Nuclear Station.

The licensee formed a CRT to investigate and identify all problems or concerns pertaining to feedwater flow measurements. The CRT identified seven different activities the licensee had failed to perform and corrective actions were recommended to resolve any current concerns and to prevent recurrence of the problem. The inspector questioned the licensee about any portion of their license or TS that may have been exceeded due to thermal power having been approximately 20 megawatts thermal greater than calculated. The licensee's response was that the impact of the flow signal errors did not appear to have exceeded any TS limits. GE was tasked by the licensee with performing a safety evaluation to determine the impact in regard to transients, accidents, and the TS. The licensee indicated that the final determination on reportability would be made upon completion of the review by GE.

The inspector inquired as to when calibration of the Rosemont 1151 instruments would take place. The licensee indicated that they did not want to calibrate the instruments during operation and had scheduled calibration for October 1994, during a planned mini-outage, unless an earlier opportunity became available. The licensee was reviewing the use of instruments for all Rosemont Models 1151 and 1153 throughout the plant. This issue will be tracked as an unresolved item pending an NRC review of the licensee's efforts to resolve this issue (298/9413-02).

6.2 HPCI Air Controller Failure

On April 13, 1994, the inspectors were informed that, during performance of SP 6.3.3.1.1, "HPCI IST and Quarterly Test Mode Surveillance Operation," Valve AO-PCV-50 failed to open, as required by the surveillance procedure. The function of the valve is to control pressure in the cooling water supply line for the HPCI turbine lube oil cooler heat exchanger.

The inspectors questioned the licensee as to why the valve remained closed since its fail-safe position was to open on loss of air. The licensee investigated the failure and determined that a hose had become disconnected inside the air regulator controller and Valve AO-PCV-50 did not actually sense a loss of air pressure. The instrument and control technician locally released the air from the valve and the valve then opened.

The inspectors discussed with the licensee, the past history concerning three air controllers and were informed that a history search had been conducted. The past history identified no similar failures. The licensee initiated Condition Reports 94-1617 and 94-1618 to perform visual inspections of similar air controllers in the RCIC and service water systems. Two of the three controllers inspected had discrepancies. The RCIC controller (AO-PCV-23) had two clamps installed that appeared not to be in proper position. On the service water controller (PIC-3614), a hose was found disconnected. The system engineer initiated two additional condition reports to repair the discrepancies.

The inspector's review noted that none of the deficiencies identified affected operability of the systems. The licensee stated that a preventive maintenance item would be generated to periodically inspect the air controllers.

6.3 CS Loop B Subsystem Declared Inoperable

On April 27, 1994, the CS Loop B subsystem was declared inoperable due to an unanticipated actuation of an engineered safety feature (ESF) system. During performance of SP 6.3.4.2, "Core Spray Motor Operated Valve Operability Test," the minimum flow valve (CS-MOV-MO5B) closed and immediately reopened when Loop B test line return valve (CS-MOV-MO26B) was opened. The minimum flow valve is normally open and receives a closed signal when loop flow exceeds 1768 gpm. The surveillance is performed without the CS pump running, and the opening of the test line return valve should not produce a flow signal that would actuate the closure of the minimum flow valve.

The licensee informed the inspectors of the ESF actuation. This event was identical to the ESF actuation, which occurred on February 1, 1994, and was discussed in NRC Inspection Report 50-298/94-03. Nonconformance Report 94-0106, which documented the February occurrence, concluded that the minimum flow valve actuation was due to a pressure transient introduced in the CS pump discharge line by opening the test line return valve. The licensee was unable to reproduce the actuation in February, thus attributing the occurrence as a spurious actuation. During the performance of SP 6.3.4.2 in March 1994, no anomalies were noted.

The licensee noted that the start of the pressure maintenance (keep fill) booster pump produced a slight transient on the CS Loop B flow instrument, thus resulting in a momentary flow indication. The pressure transient induced on the system was minimal, with no indication of an overpressurization problem of the CS piping.

The inspectors asked why only CS Loop B experienced the ESF actuation. The system engineers responded that the CS Loop A piping configuration was different and that the flow transmitter was located at a further distance from the test line return tap and beyond a 90-degree elbow in the injection line from that in CS Loop B.

The inspectors reviewed the CS surveillances results for system operability concerns and found no occurrences where the minimum flow valve failed to perform its intended function. The momentary closure of the CS Loop B minimum flow valve appeared to take place only during surveillance testing of the valve.

When the ESF actuation occurred on April 27, the licensee was again unable to reproduce the occurrence. A CRT was formed to investigate the event. The licensee was in the process of generating a special test procedure to identify the specific cause, timing, and duration of the pressure transient induced on the system when the test line return valve was opened.

Due to the ongoing investigation by the licensee into the spurious actuation, the inspectors will continue to pursue this issue as an unresolved item (298/9413-03).

ATTACHMENT

1 PERSONS CONTACTED

1.1 Licensee Personnel

F. R. Alderman, Fire Protection and Industrial Safety Supervisor
M. F. Armstrong, Administrative Secretary I
L. E. Bray, Regulatory Compliance Specialist
R. Brungardt, Operations Manager
M. A. Dean, Nuclear Licensing and Safety Supervisor
S. S. Freborg, Plant Engineering Supervisor
G. R. Horn, Vice President - Nuclear
R. A. Jansky, Outage and Modifications Manager
J. E. Lynch, Engineering Manager
E. M. Mace, Senior Manager of Site Support
J. M. Meacham, Senior Nuclear Division Manager of Safety Assessment
D. R. Robinson, Quality Assurance Assessment Manager
J. V. Sayer, Technical Assistant to Plant Manager
M. E. Unruh, Maintenance Manager
R. L. Wenzl, Nuclear Engineering Division Site Manager
V. L. Wolstenholm, Division Manager of Quality Assurance

The personnel listed above attended the exit meeting. In addition to the personnel listed above, the inspectors contacted other licensee personnel during this inspection period.

2 EXIT MEETING

An exit meeting was conducted on May 10, 1994. During this meeting, the inspectors reviewed the scope and findings of this report. The licensee acknowledged the findings discussed in this report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.