APPENDIX

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-298/94-12

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 17-23, 1994

Inspector: R. A. Kopriva, Senior Resident Inspector
W. C. Walker, Resident Inspector
C. J. Paulk, Regional Inspector

Approved: P. H. Harrell, Chief, Project Branch C — Date 5/24/94

Inspection Summary

Areas Inspected: Special, announced inspection concerning the licensee's activities associated with the inadvertent isolation of the residual heat removal inboard and outboard isolation valves (RHR-MOV-M017 and -M018), which resulted in the loss of the shutdown cooling.

Results:

- Initial response by the control room operators to the loss of shutdown cooling was good. (Section 1.1)
- Initial investigation efforts by the Problem Resolution Team appeared to be adequate. (Section 1.2)
- The overall effectiveness of the Problem Resolution Team was marginally adequate because it: (1) failed to perform timely personnel interviews, (2) failed to recognize the weakness in Abnormal Procedure 2.4.2.4.1, (3) failed to make use of all available data, (4) did not establish a detailed sequence of events time line, and (5) did not consider bounding the pressure transient to verify that maximum pressures had not been exceeded. (Sections 1.2 and 1.6)

Summary of Inspection Findings:

- None

Attachment:

- Persons Contacted and Exit Meeting

DETAILS

1 ONSITE RESPONSE TO EVENTS (93702)

1.1 Event Description

On March 16, 1994, at 7:45 p.m. (CST), the inspectors observed the licensee perform a manual reactor shutdown in preparation for working on residual heat removal (RHR) outboard isolation Valve RHR-MOV-MO27A and the main turbine digital electrohydraulic control system. The licensee had taken several precautions to address a potential loss of shutdown cooling (SDC) because one loop of SDC was being removed from service to work on Valve RHR-MOV-MO27A. To preclude the potential loss of the only available SDC loop, the Plant Manager provided all plant personnel with a list of systems and/or equipment in which work on, or near, for any reason, was strictly forbidden. The list included systems and/or equipment that could potentially cause a loss of SDC or would be needed in the event that SDC was lost. Also, the licensee verified that all surveillance and preventive maintenance activities were up to date prior to commencing work on Valve RHR-MOV-MO27A.

On March 17, at approximately 7 a.m., the inspector observed the control room operators initiate SDC, with reactor water temperature at approximately 280°F and reactor pressure at 25 psig. At 8:42 a.m., with reactor water temperature less than 212°F and reactor pressure of 0 psig, the operators opened the reactor head vents to meet the conditions for cold shutdown.

At 9:24 a.m., the reactor operator noted reactor water level decreasing and, at the same time, alarms were received for RHR flow off normal, source range monitor, and RHR Pump D trip. At 9:26 a.m., the inboard and outboard SDC isolation valves (RHR-MOV-MO17 and -MO18) shut. At 9:28 a.m., the operators entered Abnormal Procedure 2.4.2.4.1, "RHR Loss of Shutdown Cooling." The operators investigated plant equipment that may have caused the loss of SDC and found no abnormal indications. As a result of the operators not having identified any potential causes, an operator attempted to open Valve RHR-MOV-MO18 per Procedure 2.2.69.2, "RHR System Shutdown Operations," to reestablish SDC flow, but the valve would not open. The operator then reset the Group 2 primary containment isolation system (PCIS), an action that was not addressed in Procedure 2.2.69.2. Again, the operator attempted to open Valve RHR-MOV-MO18 and it opened. At 9:39 a.m., Valve RHR-MOV-MO17 was reopened and RHR Pump D was started to reinitiate SDC flow. At this time, the operator noted that the reactor recirculation system temperature was approximately 181°F on Reactor Recirculation (RR) Loop A, which was in operation at the time.

1.2 Event Followup

The licensee created a Problem Resolution Team (PRT) to investigate the loss of SDC event. The PRT's charter included: (1) identification of the root cause of the event, (2) presentation of the results of the investigation to licensee management, and (3) presentation of recommendations to licensee management to preclude any future events.

The PRT's initial efforts were focused on the gathering of data, including alarm and other computer printouts, interviews with the operating crew, and a review of the control room recorders. During the PRT's ongoing review of data, efforts were initiated to identify all possible root causes for the loss of SDC.

After the PRT had initiated their review of the available data, they concluded that the closure of Valves RHR-MOV-MO17 and -MO18 was caused by the overpressure protection instrumentation. The possible causes were categorized into two groups: (1) an electrical input signal malfunction of the pressure switches or (2) the pressure sensed at the instrumentation exceeded the valid pressure setpoint.

With a concern that an electrical signal malfunction may have existed, Relays K-28 and K-50, used to control the overpressure protection closure of the valves, were inspected. The inspectors accompanied licensee personnel during the performance of thermographic inspection of Relays K-28 and K-50 and no problems were identified. The licensee was to perform a more detailed evaluation of the data. Subsequent to this inspection, the licensee determined that the K-28 and K-50 relays functioned as designed.

Several hours after the loss of SDC, information was received by the PRT that mechanical maintenance personnel, preparing for planned maintenance on Valve RHR-MOV-MO27A. heard what was described as a bang and then felt the valve shake. Immediately following valve movement, the mechanics heard actuation of a motor-operated valve. When SDC was lost, the licensee stopped all activities in the plant to assess the problem. Upon being recalled to the shop, the mechanics were informed that SDC had been lost. The motor-operated valve that the mechanics heard operate was Valve RHR-MOV-MO17, which is located near Valve RHR-MOV-MO27A. Later, a senior manager provided the PRT members with this information. The PRT's investigation process was considered to be weak in that personnel that had been in the plant at the time of the loss of SDC had not been interviewed by the PRT and, therefore, the PRT had not acquired all potential information or data related to the event in a timely manner.

Other data being assembled by the PRT appeared to confirm that a pressure transient had occurred. There had been an increase in flow in RR Loop A at approximately the same time as the RHR Pump D tripped. Vibration monitors for the RR Pump A motor recorded a vibration spike on all channels at the time SDC was lost. An instrument and control technician, working near RHR Pump B at the time of the pump trip, reported a normal trip and coast down, with no evidence of cavitation at the pump or check valve noise. This information indicated that Loop B of RR and RHR had not experienced or exhibited any abnormal indications, supporting the identified facts that the pressure transient had occurred in Loop A.

Due to the possibility that a valid high pressure had been sensed at the instrumentation, the PRT identified a need to perform a walkdown of the piping systems that may have been affected by a potential waterhammer. An inspector accompanied licensee personnel on an inspection of piping, hangers, supports, and instrument tubing associated with the SDC and RR systems outside of the drywell. The licensee inspected for visible signs of damage and none were identified.

The inspectors continued their efforts in investigating the loss of SDC and attended the majority of the status meetings held by the PRT. As the inspectors compiled information, several issues were identified that were not fully understood by the licensee. These issues included: (1) the slowly decreasing reactor water level prior to isolation of the SDC system, (2) a step-change decrease in reactor water level, and (3) a source range monitor annunciator that had alarmed. The licensee noted that an alarm of the source range monitor, during shutdown conditions, was not uncommon.

During the inspectors' review of data and activities, it was questioned why the operators had to reset the Group 2 PCIS before Valves RHR-MOV-MO17 and -MO18 would reopen, when there had been no indication that the Group 2 PCIS had actuated. Further review revealed that there had not been any PCIS actuations and that resetting of the Group 2 PCIS had caused the 75 psig high pressure isolation interlock to reset. The 75 psig interlock was installed to isolate the RHR system on a high pressure transient to prevent overpressurization of the system piping. This supported the hypothesis that a pressure perturbation had taken place.

The inspectors reviewed Abnormal Operating Procedure 2.4.2.4.1, "RHR Loss of Shutdown Cooling," Revision 12, and Station Operating Procedure 2.2.69.2, "RHR System Shutdown Operations," Revision 12. The inspectors found that Procedure 2.2.69.2, Step 8.1.3, required the operator to reset the reactor high pressure isolation when pressure drops to less than 75 psig in the RHR system. To reset this interlock when a pressure transient takes pressure above 75 psig, the operator must reset the Group 2 PCIS logic. A note prior to Step 8.1.3 stated that the high pressure automatic isolation of Valves RHR-MOV-MO17 and -MO18 is not developed or actuated by Group 2 PCIS logic, but the reset feature is fed through the Group 2 PCIS reset switches. The inspectors noted that Abnormal Operating Procedure 2.4.2.4.1 did not address the possible loss of SDC as a result of a pressure transient. The procedure provided guidance on resetting the Group 2 PCIS logic if a Group 2 isolation signal was present, but did not address what actions to take if a Group 2 PCIS signal was not present. The inspectors noted that the operators had taken the appropriate action to reset the high pressure isolation. The operator's actions were based on their knowledge that a Group 2 PCIS signal would cause the RHR isolation valves to go shut.

The inspectors reviewed a computer printout provided by the licensee and noted a decreasing reactor vessel level prior to the event. The licensee initially informed the inspectors that the level increase observed on the level graph was due to a pressure wave in the system, which was sensed by the level transmitters. This position was taken prior to licensee discussions with GE. After the licensee talked with GE, the inspectors were informed that there had actually been a decrease in reactor vessel level, as depicted by the reactor water level graph. The inspectors asked the licensee to explain the ramped level decrease indicated on the graph. The licensee explained that the ramp was the result of data acquisition and that data was taken at two points and a straight line was drawn between the points. The inspectors then requested the licensee to address the operator's statement regarding a decreasing level with respect to the graph. At this point, the licensee stated that the graph probably indicated an actual level decrease prior to the total collapse of the bubble.

The inspectors then requested the licensee to explain why the Channel A and C level instruments did not sense the change in level, but the Channel B instrument did. The licensee stated that the Channel A and C instruments were on one side of the reactor vessel and the Channel B instrument was on the other side. The inspectors asked if this could indicate the location of the bubble formation and the licensee stated that this information would be evaluated.

During the investigation and review of the event, the PRT identified supporting evidence that a pressure transient had taken place within the RR or RHR system. There was indication that the pressure had reached 75 psig, which would account for the closure of Valves RHR-MOV-MO17 and -MO18. The inspectors asked the licensee if they had considered what maximum pressure had been experienced in the RHR system. Until that time, the licensee had not considered establishing a maximum pressure that had occurred during the transient. There were some indications that the pressure had not exceeded 100 psig. The inspectors questioned the licensee about pressure relief valves in the system and whether a relief valve had lifted. This item had not been considered and was added to the PRT's list of items to be resolved.

The licensee was prompt in gathering data; however, the data from the computer had been archived for later evaluation. The inspectors were informed that the computer was capable of providing the previous 2 hours of data in real time; however, the licensee failed to gather any real time data. The archived data was compressed, resulting in a different sampling frequency. This made some data reviews very difficult.

The licensee failed to develop a sequence of events time line until asked for by the inspectors. The first time line provided by the licensee was composed of reproduced sections of the computer printout. The inspectors questioned the licensee about time lines and were informed that the licensee had little opportunity to evaluate nonscram events and had not received formal training in the area of event analysis.

The inspectors questioned the licensee as to the potential location of the steam bubble. The licensee's initial response did not address the location of the steam bubble. The PRT's final resolutions did include a logical, detailed assessment of the potential location of the steam bubble.

1.3 Potential Cause Evaluations

The PRT identified the potential causes of the loss of SDC as: (1) the RHR pressure switches were out of calibration, (2) agitation of RR pressure switches, (3) power supply interruption to overpressure protection relays, (4) possible vortex in RHR pump suction, (5) steam bubble collapse in the sensing lines for the RR pressure switches, and (6) a steam bubble collapse in the RR or RHR suction lines to the RHR pump. The licensee assessed each of the potential causes listed above by field observation and/or testing and review of data. Items 1-4 were appropriately dispositioned by the licensee and determined not to be a contributor to this event.

The PRT's conclusion, based on information that was obtained during their investigation, indicated that the most likely cause was the formation and subsequent collapse of a steam void in Loop A of the RR or in the RHR shutdown cooling suction lines, which resulted in a mild waterhammer. The collapse of a steam bubble in the piping and the resultant pressure wave could explain the system flow disturbances identified by the plant equipment.

The licensee indicated that General Electric (GE), the reactor vendor, had been contacted to provide an independent, third-party review of the event. GE's evaluation supported the conclusion that the most probable cause of the event was a mild waterhammer.

1.4 Plant and Industry Experience

During discussions with GE, the licensee was informed that, although efforts can be taken to minimize the potential for a waterhammer event, the possibility of a similar event cannot be completely eliminated.

The licensee searched the Nuclear Plant Reliability Data System for similar occurrences and none were found. GE's research identified similar occurrences at several other boiling water reactors. GE indicated that Fitzpatrick had looked into the phenomena in some detail and recommended that the licensee contact Fitzpatrick personnel. The licensee informed the inspectors that this recommendation was placed on the action and commitment tracking system, was assigned to engineering, and would be completed by May 20, 1994.

The inspectors asked the licensee if they had any previous experiences with this type of event. The licensee indicated that one previous occurrence at Cooper Nuclear Station was documented in Nonconformance Report 92-040 and Licensee Event Report 92-007. The inspectors reviewed the licensee event report, which indicated that steam voiding was postulated to have occurred in the sensing lines for the RR pressure switches. The event included two separate occurrences of SDC isolation during RHR system flushing with reactor pressure less than 10 psig. The licensee's corrective actions had included revising two procedures to require initiation of SDC above 25 psig. The inspectors verified that the licensee had implemented the stated actions.

The inspectors reviewed GE Service Information Letter (SIL) 175, dated June 15, 1976, which discussed waterhammer events associated with the loss of SDC. The inspectors also reviewed the licensee's response to the SIL, which indicated that recommendations of the SIL had been addressed in the appropriate licensee procedures. The inspectors verified that the procedures had been revised.

1.5 Licensee's Conclusions

The PRT completed their investigation and review of the available information and provided management with results, conclusions, and recommendations to be pursued. There were some outstanding items contracted to GE that had not been completed, which pertained to the bounding of the pressure transient.

The inspectors attended the PRT's presentation of inspection findings to licensee management. The PRT concluded that the gradual reactor vessel level decrease was from the condensation of the steam in the void prior to collapse. Level decrease had been noted for several seconds, both by the shift crew and the level trend recorder. The step drop in vessel level, approximately 7 inches, corresponded to the size of the steam void. The indicated level drop was a response to the change in vessel level upon collapse of the void. GE had concluded that the 7-inch decrease was equivalent to a fluid volume change of about 75 cubic feet. Vessel level was subsequently restored by condensate system flow in response to level control demand. The spike in RR flow, as indicated by the Loop A RR instrument, was caused by the pressure wave (resulting from the void collapse) passing the pressure transmitters.

The PRT provided preliminary results of their efforts to bound the pressure perturbation. The results of the walkdown of the RR Loop A and connected RHR piping indicated no visible damage to, or movement of, the piping supports. The inspectors agreed with this observation. Pressure Switch RHR-PS-118, which is located in the SDC suction to the RHR pumps and set at 100 psig, did not actuate the control room annunciator. The PRT concluded that these factors provided qualitative evidence that the pressure perturbation was of relatively small magnitude and short duration. The licensee contracted GE to perform a more quantitative evaluation. The analysis results had not been completed at the end of this inspection period.

The licensee determined that the most probable cause for the formation of the steam void was that the plant cooldown was performed quickly and the temperature of the metal in the piping systems was relatively high. Because of stagnant flow in portions of the system, relatively high metal temperatures, and the system being vented to atmosphere, a steam void was formed in the system piping. An evaluation was performed to determine the most likely locations for steam void formation. The evaluation concluded that the steam void formation was in the idle RHR Loop A injection line near the tap from the RR Pump A discharge line. The conclusion was based upon review of piping isometric drawings and the physical evidence surrounding the event.

1.6 Inspector's Conclusions

The inspectors concluded that the licensee would not have identified the decrease in vessel level on the graph as an effect of the event, even though an operator had specifically identified the condition.

The licensee had not considered bounding the severity of the pressure perturbation. The inspectors recognized that the licensee was cognizant of several different pressure indications that had or had not alarmed, which should have provided information as to possible maximum pressure of the transient. The licensee did not attempt to establish the maximum pressure experienced during this event and did not verify whether pressure relief valve actuation had occurred.

Data gathering efforts were slow, resulting in loss of real time data. The licensee indicated that they are in the process of reviewing their computer capabilities and are investigating the acquisition of more updated equipment.

Additionally, the inspectors concluded that the licensee failed to review and analyze all data prior to determining the most probable cause of the event. Without the aid of an accurate time line derived from a detailed sequence of events, the inspectors found it difficult to understand whether the licensee had fully captured and reviewed all activities pertinent to the event.

The inspectors concluded that the PRT's results and recommendations appeared adequate in the identification of the root cause of the event and potential corrective actions to mitigate and or reduce the potential for recurrence. A lack of formalized training for PRT members in the area of event analysis was noted by the inspectors.

ATTACHMENT

1 PERSONS CONTACTED

Licensee Personnel

M. F. Armstrong, Administrative Secretary I
L. E. Bray, Regulatory Compliance Specialist
D. W. Bremer, Operations Support Group Supervisor
M. A. Dean, Nuclear Licensing and Safety Supervisor
J. W. Dutton, Nuclear Training Manager
R. W. Foust, Assistant Engineering Manager
R. L. Gardner, Plant Manager
G. R. Horn, Vice President, Nuclear
T. E. Hottovy, Quality Assurance Audit Supervisor
R. A. Jansky, Outage and Modifications Manager
J. E. Lynch, Plant Engineering Manager
E. M. Mace, Senior Manager Site Support
J. M. Meacham, Senior Nuclear Division Manager of Safety Assessment
D. R. Robinson, Quality Assurance Assessment Manager
B. D. Seidl, Electrical I&C Engineer I
V. L. Wolstenholm, Division Manager of Quality Assurance
R. J. Zona, Senior Electrical I&C Engineer

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

2 EXIT MEETING

An exit meeting was conducted on March 31, 1994. During this meeting, the inspector reviewed the scope and findings of this report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspector.