ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-298/95-18

License: DPR-46

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

Facility Name: Cooper Nuclear Station (CNS)

Inspection At: Brownville, Nebraska

Inspection Conducted: December 24, 1995, through February 3, 1996

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Inspection Summary

Areas Inspected: Routine, unannounced inspection of onsite review of events, operational safety verification, plant support activities, surveillance and maintenance observations, followup of corrective actions for violations, and followup of licensee event reports (LERs).

Results:

Operations

- An unresolved item was identified due to licensed operators committing a rod insertion error, taking corrective actions on their own, and not promptly disclosing their error to supervision (Section 2.2).

- Plant startup after the refueling outage was well controlled, and communications were complete and clear (Section 3.1).

- The inspector identified a miscommunication between Operations staff and reactor engineering in that the control room personnel did not clearly understand the status of four control rods (Section 3.2).

- A noncited violation was identified when a control room ventilation fan was found after plant startup, in a lineup different than that required by procedures (Section 3.3).

- An inspector walkdown of the drywell after operations closeout identified numerous small paper and plastic materials, many of which were later removed by the licensee (Section 3.4).

- The Safety Review and Assessment Board (SRAB) evidenced a self-critical safety perspective during its January 26, 1996, meeting (Section 3.5).

- Before a surveillance was run, a shift supervisor (SS) identified that running the scheduled surveillance under current operational conditions could have caused an unplanned augmented off-gas (AOG) isolation (Section 5.1).

Maintenance/Surveillance

- An unresolved item was identified when maintenance personnel performed work on Core Spray Valve CS-MOV-M026A, although their work procedures stated Residual Heat Removal (RHR) Valve RHR-MOV-M026A. The technicians subsequently withheld pertinent information from supervision regarding the error (Section 4.1).

- A noncited violation was documented when the licensee identified that control circuitry for service water flow control valves for the RHR heat exchangers was not environmentally qualified. The licensee later determined that the circuitry was qualifiable, with no past operability concerns (Section 4.2).

- Planning and scheduling groups failed to recognize that a scheduled surveillance could have caused an unplanned AOG isolation (Section 5.1).

- An operating crew inappropriately assumed a root cause of water accumulation in the high pressure core injection (HPCI) turbine exhaust line and agreed, contrary to procedural guidance, to delay pump shutoff for 30 seconds after receipt of an anticipated alarm. Due to inspector intervention, no procedural violations occurred (Section 5.2).

Engineering

- After drywell closeout, several small items remained in the drywell, but were not included in an analysis of the emergency core cooling system (ECCS) suction strainers. Conservatisms in the analysis adequately bounded the concern posed by these small items (Section 3.4).

- Engineering oversight and acceptance of contractor work pertaining to development of Code boundary documents failed to identify numerous administrative errors in the documents that were identified by the inspector (Section 8.2).

Plant Support

- Radiation Protection (RP) technicians conducted thorough, appropriate, in-depth job briefings prior to the 500 and 1000 psig reactor coolant system (RCS) inspections of the drywell (Section 7.1).

- Security officers appeared to be identifying and compensating for lighting deficiencies within the protected area (Section 7.2).

Summary of Inspection Findings:

Open Items

- Unresolved Item 298/9518-01 (Section 2.2)
- Noncited Violation 298/9518-02 (Section 3.3)
- Unresolved Item 298/9518-03 (Section 4.1)
- Noncited Violation 298/9518-04 (Section 4.2)
- Unresolved Item 298/9518-05 (Section 6.1)

Closed Items

- Violation 298/9317-02 (Section 8.1)
- Violation 298/9317-08 (Section 8.2)
- Inspector Followup Item 298/93202-02 (Section 9.1)
- Inspector Followup Item 298/93202-04 (Section 9.2)
- Inspector Followup Item 298/93202-05 (Section 9.3)
- LER 298/94-026, Revision 0 (Section 10)
- LER 298/94-026, Revision 1 (Section 10)

Attachment:

- Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

At the beginning of the inspection period the plant was making preparations to start up. The 16th refueling outage ended on December 30, 1995, when the turbine output breaker was closed. The licensee completed the outage in 77 days, 22 days past their scheduled outage time. The outage was extended primarily due to the difficulties with implementation of a major modification to the emergency diesel generators.

On January 7, 1996, the plant reached 99 percent power, when Reactor Recirculation Pump A tripped and power was reduced to 49 percent. On January 10, the plant was further reduced to 21 percent power to perform maintenance on the turbine lube oil system.

On January 19, the plant achieved 100 percent power.

On January 27, power was reduced to 70 percent for turbine valve testing. That same day, the plant was returned to 100 percent power where it remained through the end of this inspection period.

2 ONSITE RESPONSE TO EVENTS (93702)

2.1 Control Rods Manipulated Out Of Sequence

2.1.1 Event Summary

On January 7, 1996, at about 6:41 p.m., with the plant at full power, Reactor Recirculation Pump A tripped. The cause of the motor-generator trip was a loose connection in the tachometer on the generator. Reactor power stabilized at approximately 65 percent. Control room personnel implemented Abnormal Procedure 2.4.2.2.1, "Trip of Recirculation Pump," and Operating Procedure 2.2.68.1, "Single Loop Reactor Recirculation Pump Operation," which required that the rod line be lowered to below 80 percent.

To lower the rod line to below 80 percent, the control room supervisor (CRS) directed that the reactor operators insert control rods in the reverse sequence per Procedure 10.13, "Control Rod Sequence and Movement Control," Revision 26. At 7:14 p.m., two reactor operators began the control rod insertion. The operators found the sequence book open to page 37 and began the rod insertion at that point. Neither operator verified that this was the last page (end) of the sequence. They inserted Rod Groups 17 and 18 from position 36 to 30. This rod movement was completed at 7:25 p.m.

When the operators turned to page 36, they realized that they had not begun the rod insertions at the end of the sequence. They turned to page 51 (the end of the sequence) and inserted Rod Group 19 from position 08 to 00. This rod movement was completed at 7:31 p.m.

The operators then inserted Rod Group 20, which was the group designated on the emergency control rod movement sheet. During the insertion of this group, the reactor engineer entered the control room. Also, the CRS noticed that they were inserting the rods on the emergency control rod movement sheet, but did not question the action. This rod movement was completed at 7:39 p.m.

At this time, one operator briefed the reactor engineer that they had started inserting control rods on the wrong page and he summarized to the reactor engineer the subsequent rod movements. The reactor engineer verified the control rod positions and checked the thermal limits.

The operators then inserted Rod Group 16 from position 08 to 00. This rod movement was completed at 7:43 p.m. At this time, even though the rods were not yet in sequence, the rod insertions were suspended while a reactor feedwater pump was removed from service. The operators had not yet informed the CRS of the rod insertion mistake or of the need to use the rods on the emergency control rod movement sheet.

One reactor operator asked the reactor engineer if the rod sequence insertion error could be considered a reactivity mismanagement event. The reactor engineer responded in the affirmative and, after some discussion, the reactor operator reported the mistake to the CRS and the SS. The SS briefed site management personnel on the event and directed a period of quiet time for the operators so that they would not be preoccupied with the mistake and cause another mistake. Licensee management responded to the control room to ensure the mispositioning incident was properly handled. Rod motion was resumed at about 9 p.m., and the rods were returned to sequence at about 9:14 p.m.

2.1.2 NRC Initial Review

Region IV dispatched a senior inspector to obtain a comprehensive understanding of the events that took place and ensure that the licensee's followup actions were appropriate. Inspectors interviewed the reactor engineer, SS, CRS, operations manager, plant manager, site manager, and the licensee's review team leader to collect the facts surrounding the event. Additionally, inspectors reviewed shift personnel written statements, control room logs, and computer printouts for the period associated with the control rod mispositioning.

Inspectors found that the sequence of alarm printout of January 7, 1996, for the times 7:12 p.m. to 7:48 p.m. showed that the times of the control rod movements recorded on the rod sequence sheets were consistent with the times of the alarm printout. Additionally, inspectors found that the nuclear steam supply core performance logs of January 7, 1996, for the times 6:56 p.m., 7:10 p.m., 7:44 p.m., 9:15 p.m., 9:55 p.m., and 11:01 p.m. showed that the linear heat generation rate, critical power ratio, and average planar linear heat generation rate were calculated to be within limits.

2.1.3 Use of Procedures

Inspectors reviewed Procedure 10.13. Step 8.1.5 stated in part "Do not deviate from the sequence unless approved by a Reactor Engineer (or Shift Supervisor in an emergency) or per a SORC approved procedure." Step 2.6 defined a mispositioned control rod as "a control rod found in a position other than the intended position and not identified/corrected before or during the completion of the 'checked by' step of the sequence sheet. Section 8.4 specified for a mispositioned control rod to implement a recovery plan with the concurrence of the SS and the reactor engineer.

In this event, operators did not refer to Procedure 10.13. This procedure was classified by the licensee as "information only," so was not required to be "in hand" as the operators performed the rod movement.

2.2 Response By Plant Management to Reactivity Mismanagement Event

As stated in paragraph 2.1.1, licensee management responded to the control room to ensure the mispositioning incident was properly handled. Upon their departure from the site on the evening of January 7, 1996, licensee management was apparently not aware that the operators involved did not promptly disclose their error and that they took corrective actions without input from the SS or reactor engineer. It was not until the morning of January 8, 1996, when management read written personnel statements of the events that transpired, that management realized there were concerns with personnel not disclosing their error and taking unauthorized corrective actions.

Senior licensee management removed the involved crew from shift and formed an independent assessment team, led by the Quality Assurance Division Manager and including two senior industry officials who were members of the licensee's Safety Review and Assessment Board. In the team's review, it was determined that the requirements for reactivity management and the need to inform CRS upon improper control rod manipulation were clear. Additionally, the need to obtain supervisory approval before inserting emergency control rods was also determined to be clearly stated in the reactivity management procedure as well as reiterated in training which had been performed within the last month.

The command and control aspect of this event was also evaluated since it was determined that the CRS was distracted from oversight of control rod manipulation in order to manage balance-of-plant concerns. The team further determined that some ambiguities existed in instructions for control rod motion and the required supervisory approval, but these ambiguities should not have prevented or precluded operators from fully understanding the need to report the reactivity activity mismanagement promptly to control room supervisors. These requirements were stated during recent operator training, during review of industry events over the past year, and multiple discussions were held with personnel by plant management concerning the need to promptly come forward and identify mistakes.

On January 13, 1996, the licensee informed the NRC that two licensed operators (a senior reactor operator and a reactor operator) were suspended without pay pending termination on January 19. The action was taken for gross misconduct on the part of the operators. The specific reasons for the terminations were: (1) failure to correctly implement instructions from the SS, (2) knowingly withholding information from the CRS and SS, and (3) taking corrective actions on their own, contrary to procedure, which had the potential to put the reactor core at risk.

The failure of the operators to report mismanagement of control rod position immediately upon discovery, but instead to continue to move control rods based upon their own judgement, is considered a failure on the part of the Cooper Nuclear Station to properly control licensed activities.

The actions of the operators in positioning control rods out of sequence, taking corrective actions regarding reactivity management on their own, and failing to promptly disclose their error is an unresolved item (298/9518-01).

3 OPERATIONAL SAFETY VERIFICATION (71707)

3.1 Plant Startup

On December 27, 1995, the licensee turned the mode switch from Refuel to Startup/Hot Standby position and commenced control rod withdrawal. The inspector observed the startup process and found it to be well controlled by the control room crew.

Two licensed reactor operators performed the control rod movements; one actuated rod controls, the other one verified that the correct control rod was selected and moved to the correct position in accordance with the control rod withdrawal sequence. The inspector also verified that, once a control rod was fully withdrawn, the reactor operator checked for overtravel. Communications were complete and clear between the crew members.

The control room crew was expanded to include two senior licensed operators and two licensed reactor operators to help limit distractions for the normal control room crew during plant startup. Also, a reactor engineer was present during power ascension to confirm that the core was responding as expected. There were many observers during this evolution, i.e., the Site Manager, Plant Manager, Operations Manager, and others. The observers did not interfere with the plant startup.

3.2 Miscommunication Between Operations and Engineering

On December 22, 1995, the inspector identified that communications regarding the operability of control rods between operations crew and engineering were not clear.

The inspector questioned an SS and an operator, from different crews, as to whether four control rods which engineering had evaluated were operable. The

operators concluded the control rods were operable based on an ambiguous log entry. Through discussions with reactor engineering, the inspector learned that engineering considered the control rods inoperable based on degraded scram response times identified during testing the previous day.

This miscommunication has low safety significance because the plant was in a shutdown condition that did not require operable control rods. Plus, the corrective action for the control rods was planned and scheduled for completion in the immediate future.

The licensee agreed that inadequate communication had taken place, documented the problem with a condition report, and planned to issue a "lesson learned" document for operations crew.

The inspector concluded that, due to the incomplete log and inadequate shift turnover, the control room did not understand if the control rods were operable.

No violations or deviations were identified. The inspector will continue to monitor interorganizational communications during routine inspections.

3.3 Control Room Ventilation Fan

Before reactor startup, operations crews must place plant systems in lineups according to procedural requirements. On December 27, 1996, the licensee identified that the two control room filter supply fans were not in the correct lineup, in that Fan SF-C-1B was running and SF-C-1A was not. The opposite lineup was required by Procedure 2.2.84, "HVAC Main Control Room and Cable Spreading Room," Revision 18.

The licensee was unable to determine the root cause of the incorrect lineup, but considered it likely that the fans had not been returned to the correct lineup after maintenance conducted on December 22.

The licensee's corrective action included initiating a condition report, documenting this occurrence in a lessons learned file, and informing operating crews of management's expectations for configuration control and the need to ensure procedures return equipment to the required configuration after maintenance or testing.

The safety significance is low, in that the fans were in a lineup which had recently been tested and met the operability criteria for the control room ventilation system. Failure to implement Procedure 2.2.84 as written is a violation of 10 CFR Part 50, Appendix B, Criterion V, in that activities were not accomplished in accordance with procedures. This licensee-identified and corrected violation is being treated as a noncited violation, consistent with Section VII of the NRC Enforcement Policy (298/9518-02, closed).

3.4 Drywell Closeout Walkdown

On December 23, 1995, the inspector performed a final closure walkdown of the drywell after the licensee had cleaned and inspected it. The inspector identified tape, radiation protection stickers, plant identification stickers, paper tags attached with string, two small plastic bags for contaminated material, and plant identification tags attached with an adhesive.

The inspector questioned whether the material would affect the operability of the ECCS strainers during a design basis event. Prior to reactor startup, the licensee removed a significant amount of the identified items. On December 28, the inspector performed a walkdown of the RCS, and a drywell inspection. The inspector again observed some of the previously described items in these areas. The licensee performed an evaluation of the remaining material and determined that the material would not impact ECCS strainer performance and that existing calculation assumptions in other areas bounded the effects of the additional material in containment. The inspector reviewed this evaluation and concluded it adequately addressed the identified concerns.

3.5 SRAB Meeting

On January 26, 1996, the inspector observed the SRAB meeting, which included several agenda items associated with the plant safety processes. The members, consisting of both the plant and offsite members, discussed recent events and clearly focused on safety significance of past problems, as well as potential weaknesses.

Two SRAB members had been tasked to lead or participate in investigations associated with recent events. The SRAB examined the methods to assure independence of the SRAB members associated with the evaluations of these events. The members determined that the results of the evaluations would be presented to the SRAB and evaluated as separate issues on the agenda at an interim meeting and during the next scheduled meeting.

SRAB member reports in various areas of plant activities addressed concerns at the management level and also addressed potential methods to more intrusively evaluate plant safety performance. The SRAB questioned effectiveness of licensee performance in a self-critical manner and identified future areas to evaluate licensee effectiveness and performance.

The inspector concluded that the SRAB focused on appropriate areas of plant safety and met requirements of it's charter to evaluate plant safety performance.

4 MAINTENANCE OBSERVATIONS (62703)

4.1 Maintenance Performed on Wrong Valve

On December 20, 1995, the licensee identified that technicians performed work on Core Spray Valve CS-MOV-M026A without a clearance or proper authorization. The work was to be performed on RHR Valve RHR-MOV-M026A, which was authorized and was tagged out of service.

The technicians went to Valve CS-MOV-M026A, determinated the motor leads, removed the motor, and identified that the pinion key was out of the valve shaft. The technicians informed the Outage Control Center personnel of the condition of the pinion key. The Outage Control Center personnel informed the technicians that they were working on the wrong valve. The technicians then reterminated the valve motor and rebolted the motor to the valve actuator.

On January 12, 1996, maintenance technicians informed the maintenance supervisor that the valve motor was actually determinated. Management had not been made aware that the valve motor was actually determinated until the information was brought forward. There was a significant time delay in reporting what actually occurred due to the technicians' reluctance to bring this information forward.

Licensee management determined that electricians involved in core spray valve work had determinated the motor without having had the motor electrically isolated. After determination of the motor, mechanical maintenance technicians determined that a pinion key was not installed as required in the valve. When informed by outage management that they were working on the incorrect valve, electrical maintenance technicians recognized they had worked on energized equipment without appropriate safety precautions and, at that time, reterminated the motor and agreed to not inform licensee management that the motor had been determinated. This would result in the appearance that only the mechanical maintenance technicians had performed work on the incorrect valve.

Potential safety significance of determinating and reterminating the motor without electrical isolation and proper postmaintenance testing could have resulted in personnel injury and potential valve inoperability. The actual safety significance of the lack of a postmaintenance test was low since the valve has since been successfully tested.

The safety significance of the technicians' failure to come forward immediately to the licensee concerning potentially inoperable equipment is of much greater concern since, under other circumstances, this could provide safety significant risk to the plant. In addition to its normal corrective action process, the licensee instituted an independent Performance Problem Identification Team to: (1) determine if there is an atmosphere that fosters the withholding of information concerning performance-related errors, and (2) if it exists, identify the factors contributing to that atmosphere. Interviews of approximately 20 percent of the plant staff began on January 22,

1996. On January 24, 1996, the licensee called an all day maintenance standdown to discuss issues surrounding the maintenance error.

The concern associated with the maintenance personnel performing work on a component not released for work and their failure to disclose their error is an unresolved item (298/9518-03).

4.2 Service Water (SW) Motor-Operated Valve Controller Design Error

On December 26, 1995, the licensee discovered that control circuitry components for safety-related SW Valves SW-MOV-M089A and -B were not controlled as essential parts. Specifically, the components were not environmentally qualified for operation in the harsh environment that would occur in the event of a high energy line break in the reactor building. Accordingly, both valves were declared inoperable. The valves in question function to throttle SW flow through the RHR heat exchangers. Their inoperability would preclude the ability to assure adequate RHR in some postaccident scenarios.

On December 26, 1995, a positioning gear failure on Valve SW-MOV-M089B caused a false valve position signal, resulting in the valve failing open. By an earlier engineering analysis, the licensee incorrectly concluded that the positioning gear and associated potentiometer provided an indication function only and that they were not integral to valve control and, therefore, could be considered nonessential components.

As corrective actions, new control switches which enabled operators to throttle the valves were installed. The nonqualified circuitry that provided feedback for automatic valve positioning was removed from the circuit. Accordingly, the automatic control ability of the valve was defeated.

On January 22, 1996, the licensee determined that the potentiometer and positioning gear assembly were qualifiable based on an analysis performed at the Hatch Nuclear Station using IE Bulletin 79-10B prescribed methodology for environmental qualification. Therefore, the licensee concluded that no past operability concerns existed. The inspectors' review of the licensee's analysis did not identify any deficiencies.

The licensee determined that operations and instrumentation and control had understood the control circuit of the valve and knew that failure of the assembly would cause valve inoperability. Engineering analysis had incorrectly assumed that the mechanism provided an indication function only. The past failure to properly identify and control the potentiometer gear consistent with its regulatory requirements for equipment qualification is a violation of 10 CFR 50.49, which requires appropriate dedication and qualification to the environment expected under design basis conditions. This licensee identified and corrected violation meets the criteria for the exercise of discretion under the NRC's Enforcement Policy and is, therefore, being documented as a noncited violation, consistent with Section VII of the Policy (298/9518-04, closed).

5 SURVEILLANCE OBSERVATIONS (61726)

The inspectors observed the performance of portions of the surveillances listed below. The observations included a review of the procedures for technical adequacy, conformance to Technical Specifications, and limiting conditions for operation, and verification of test instrument calibration; observation of all or part of the actual surveillance, removal and return to service of the system or component, and review of the data for acceptability based upon the acceptance criteria.

Procedure Number	Title
6.2.2.6.14	Reactor Core Isolation Cooling (RCIC) Control System Calibration Test
6.RCIC.309	RCIC Beginning of Cycle Test
6.3.1.13	Division I H2/O2 Analyzer Calibration and Functional
6.3.3.1A	HPCI Test Mode Surveillance Operation From Alternate Shutdown - HPCI Panel
6.HPCI.101	HPCI Monthly Test Mode Surveillance Operation

The inspectors found no significant strengths or weaknesses during the observations, except as noted below:

5.1 Procedure 6.3.3.1A, HPCI Test Mode Surveillance Operation From Alternate Shutdown - HPCI Panel

On January 17, 1996, the SS identified that performing Procedure 6.3.3.1A, "HPCI Test Mode Surveillance From ASD-HPCI Panel," Revision 10.1, under current plant conditions, would have caused an unexpected AOG isolation.

A prejob briefing was conducted that was informative and addressed expectations for all participants. The briefing also stressed good communications techniques, procedural adherence, and using STAR (stop think, act, and review) when manipulating controls. During the discussions of expectations, the SS recognized that the procedure required valve manipulations that would result in an automatic isolation of the AOG system.

The unexpected AOG isolation would have resulted in a gaseous release with higher then normal activity levels, but within limits. If no operator action was taken within 30 minutes, a turbine trip and subsequent reactor trip would have resulted.

The licensee agreed that the surveillance planner or scheduler should have recognized the consequences of performing the surveillance. The licensee further stated that the AOG isolation would have caused alarms to actuate in

the control room and an operator would have been dispatched to take actions that would prevent the turbine/reactor trip within 30 minutes.

The inspector concluded that the surveillance planner and the scheduler did not understand the consequences of the procedure being performed during power operations. In the past, the procedure had been implemented during shutdown conditions. The SS demonstrated a questioning attitude recognizing this planning/scheduling error.

A condition report was written and the surveillance was postponed until adequate planning and scheduling was in place that would allow securing AOG. The inspector will continue to monitor planning and scheduling activities to ensure adequate corrective actions are implemented.

5.2 Procedure 6.HPCI.101 HPCI Monthly Test Mode Surveillance Operation

On January 17, 1996, the inspector witnessed the performance of Procedure 6.HPCI.101, "HPCI Monthly Test Mode Surveillance Operation," Revision 0.

The briefing for this surveillance was not as detailed as the previous briefing discussed in Section 5.1 for the HPCI surveillance subsequently cancelled. The same representatives were present at both, and the inspector concluded that the briefing was adequate, although not as thorough.

When the turbine was started the control room received two unexpected alarms, HPCI turbine exhaust drip leg high level and HPCI turbine exhaust drip leg high-high level. The operator reviewed Alarm Response Procedure 2.3.2.22, "Panel 9-3 - Annunciator 9-3-2," and performed the operator actions, as stated, to trip the HPCI turbine if not required to ensure adequate core cooling. The HPCI turbine was immediately tripped. The SS, SS in training, CRS, station technical engineer, and system engineer agreed that Valve HPCI-MO-14, a steam supply valve, was repaired during the outage; therefore, the valve was not leaking as in the past, resulting in a lower turbine casing temperature. The operators concluded that the high level in the drip leg was caused by condensation when the steam entered the colder turbine casing.

A briefing was held to inform the control room of the apparent cause of the alarms and the course of action. In the brief, the SS in training stated that the HPCI surveillance was going to be reperformed but, this time, the operator would delay tripping the turbine for 30 seconds if the alarm was received. If the alarm did not reset after 30 seconds, the HPCI turbine would be tripped. If the alarm did reset, the operator was to continue with the surveillance procedure. The inspector questioned the SS as to whether they would be following their procedure if they waited 30 seconds prior to tripping the HPCI turbine. The SS reviewed the alarm response procedure and agreed that the HPCI turbine would have to be tripped immediately. The SS then directed the crew to immediately trip the HPCI turbine if the alarm was received. During the second surveillance, the control room did not receive the HPCI turbine exhaust drip leg high-high level.

The licensee management considered that the crew had not implemented management expectations regarding compliance with procedures when considering actions to delay the HPCI trip.

The inspector concluded that, during this surveillance observation, the control room crew was directed to take actions that were contrary to their procedures, resulting in the inspector questioning the SS on whether these planned actions were consistent with their procedure.

If the SS would not have been questioned, the operator performing the surveillance would have violated the alarm response procedure by waiting 30 seconds for the alarm to clear and not tripping the HPCI turbine as directed by the alarm response procedure. No violations were identified, although the expectations of licensee management were not followed by the crew.

6 ONSITE ENGINEERING (37551)

6.1 Automatic Depressurization System (ADS) Accumulator Test

The inspectors reviewed the surveillance procedures associated with the accumulators which provide motive force to the safety relief valve and main steam line isolation valves. These accumulators provide backup air pressure in the event of a loss of instrument air. The inspectors reviewed Procedure 6.2.2.2.6, "ADS Accumulator Test," Revision 14. The inspectors noted that the two low low set accumulators (which act preferentially after an ADS actuation) required a minimum pressure of 90 psig after 1 hour, while the remaining ADS valves required a minimum accumulator pressure of 88 psig.

The inspectors reviewed Calculation NEDC 88-306, which had revised the minimum pressure from 65 and 63 psig to the current surveillance specification. The calculation addressed expected ECCS conditions of drywell pressure and Emergency Operating Procedure actuation requirements. The inspector determined that the increases in pressure in the surveillance specifications were prompted by industry guidance and NRC Generic Letter 88-14, both of which addressed the performance of pneumatically actuated components in accident environments. The inspector concluded the licensee had taken appropriate actions based on the guidance provided. No concerns were identified regarding the adequacy of the calculation.

The licensee's evaluation did not specifically address the past operability of the lower accumulator pressure specifications. The inspector reviewed a small sample of archived test records and found instances in which individual components were substantially lower than the current 88 or 90 psig specification, but did not find cases in which multiple valves were below the revised specification simultaneously or in which the as-left accumulator pressures were less than the revised specifications. A larger sample of test data will be required to be reviewed to determine if a past operability concern existed. The past operability of the ADS valves is an unresolved item (298/9518-05).

The inspectors noted that the check valves were noncode ASME class. The licensee stated that the valves were procured as safety-related, however, not in accordance with a code and provided a basis document which concluded these valves were not controlled under ASME Class 3 requirements. The inspector determined the basis document was appropriate. However, an augmented testing program was in place since the valves performed a safety-related function.

The inspectors also noted that training documents associated with the operation of the safety relief valves listed 65 and 63 psig as the alarm point for the low accumulator pressure and informed the licensee of the incorrect information. The licensee noted that the document will be changed.

The inspector reviewed Surveillance Procedure 6.2.2.2.6, "ADS Accumulator Functional Test," performed at the end of the cycle just prior to the outage. The inspector noted that Accumulator 2566 did not satisfy the acceptance criteria and Condition Report 1-15606 was generated as a result. The particular accumulator involved was Accumulator 256H, corresponding to Safety Relief Valve H. Instead of maintaining a pressure greater than or equal to 88 pounds, the accumulator was observed to have 84 pounds after a 1-hour pressure drop test. Analysis performed by the licensee determined the accumulator was operable. The inspector considered the licensee's conclusions were justifiable.

7 PLANT SUPPORT ACTIVITIES (71750)

7.1 RP Coverage During Drywell Entry

On December 28, 1995, the inspector attended the job briefing by RP technicians for the 500 psig RCS pressure walkdown of the drywell. The RP technicians were very knowledgeable and informative about the expected conditions in the drywell. Old survey data from every entry from 1982 was compiled on area survey maps and discussed with the group. The RP technicians covered the radiation work permit, hazardous work permit, tasks that were to be performed, and safety rules that were in effect. The group was broken into two teams to expedite the time spent in the drywell, one covering the top two elevations and the other one covering the bottom two elevations.

The inspector accompanied the second team that performed inspections on the lower two elevations. The RP technician monitored the teams' exposure, while documenting the data for a survey map. The inspector concluded that the RP technician appeared to provide strong coverage during the evolution.

Another drywell entry was performed at 1000 psig RCS pressure and the RP technician, a different person then stated above, providing RP coverage was also assigned to remove tape and equipment stickers while in the drywell. As a result, the RP technician appeared to be distracted from his primary responsibility of monitoring worker exposure and allowed the inspector to be out of sight on some occasions. During discussions, the RP technician stated that this was the second entry and a detailed survey map had been completed; therefore, he performed enough monitoring and surveillance to provide

assurance that conditions had not changed appreciably. The inspector concluded that the additional duty to remove stickers distracted the RP technician from his primary responsibility of monitoring radiological conditions; however, this was characterized only as a concern, since monitoring requirements appeared to have been met.

7.2 Security Observations

On December 17, 1995, the inspector toured the protected area boundary and noted three deficiencies: two piles of dirt in the isolation zone, a trench covered with a tarp in the isolation zone, and the inner security fence missing a 6 foot section. The inspector brought these deficiencies to the attention of the security SS. The security SS informed the inspector that the items were being compensated for by performing hourly security patrols in the areas of these deficiencies.

The inspector also identified areas where the skirting around two trailers was loose and informed security. Security patrol routes provided hourly coverage of these areas, although these items were not listed. The two items were added to the list of deficiencies that were checked during the hourly patrol.

The inspector concluded that the security officers were identifying areas that did not meet the requirements stated in the security plan and were taking compensated actions for them. This appeared to be an improvement from the observations made in NRC Inspection Report 50-298/95-14.

8 FOLLOWUP ON CORRECTIVE ACTIONS FOR VIOLATIONS (92702)

8.1 (Closed) Violation 298/9317-02: The Licensee Did Not Comply with the Technical Specification Requirements for an Inoperable Primary Containment Hydrogen Concentration Analyzers During Plant Operation

The licensee had experienced unreliable and erratic operation of hydrogen and oxygen analyzers. As corrective action a design modification installed particulate filters. However, the unreliable and erratic operation continued. The interim corrective action was to frequently replace the particulate filters. The licensee did not evaluate the operability of the analyzers while the analyzers were unreliable and erratic, nor did it accurately determine the root cause of the problem.

The NRC cited the failure to declare the analyzers inoperable because the root cause was water condensate in the system, and the corrective actions of adding a filter were therefore inadequate. The licensee actions corrected the symptoms, rather than the problem. This sequence of events appeared to be the result of inadequate postmodification testing. This was also an example of the licensee not being proactive in resolution of nonconformances.

The licensee corrected the problem by changing the sample line slope, which precluded entrapment of condensate. A design change, DC 90-320, installed in January 1995, removed the filters and resloped the lines. Postmodification

testing confirmed the effectiveness of the design change. Other configurations were reviewed and a field walkdown performed to ensure no similar situations existed.

The inspectors reviewed the current configuration of the analyzer system and verified that the erratic operation had gone away. The system engineer stated that the problem of unreliable and erratic responses was resolved. The inspectors reviewed the documentation on the review of other configurations and the field walkdown. The specific concerns for analyzers appeared to have been adequately addressed.

The licensee has already committed to address generic issues of evaluation of postmodification testing effectiveness and operability determinations in the "Configuration Management Phase 3 Plan." The NRC will address these areas in future inspections.

8.2 (Closed) Violation 298/9317-08: The Licensee Did Not Comply With the Requirements of 10 CFR Section 50.55a(g)(1) for Inclusion of the Service Water and Reactor Equipment Cooling Systems in the Inservice Inspection Program

The licensee did not include the SW and reactor equipment cooling systems in the inservice inspection program due to inadequate evaluation when the NRC regulation 10 CFR 50.55a was put into effect in 1976. Licensee failure to critically evaluate the classification of systems was determined to have caused the inadequate evaluation.

The licensee issued LERs 93-026, Revision 0, and 93-026, Revision 1, as a result of this violation. The licensee, with the help of an outside consultant, analyzed ASME boundaries and classifications which addressed all components and systems. The inservice inspection program was revised (Revision 4) to add the SW and reactor equipment systems as well as a few support welds and hangers. At the same time, an analysis was performed by the same consultant to establish an inservice testing design basis document. The inservice testing program was also revised (Revision 7) because some valve tests were also found to have been omitted.

The inspectors reviewed the additions to the programs, the boundary analysis, the valve testing design basis, and the revised inservice inspection and testing programs. The inspectors verified a sample of piping and valves to be included in the programs.

In review of the boundary classification and inservice testing design basis documents, the inspectors found minor discrepancies. These discrepancies were mostly misidentification of valve numbers. Also, the NRC identified that the code boundaries were not correct on a flow diagram, Reactor Building Main Steam System 2041, Revision 61. The required code boundary flags associated with Valves RHR-MO-166A and -B and RHR-MO-167A and -B were not on the drawing.

The code boundary document was also inconsistent in the identification of the RCIC and HPCI turbines. The code boundary document identified the turbine stop valve on the high pressure coolant injection turbine as the code boundary, but did not identify the comparable valve on the reactor core isolation turbine, the turbine throttle valve. Instead, the RCIC governing valve, which was down stream on the steam supply line, was identified as the code boundary.

After the inspectors identified these discrepancies in the code boundary document, the licensee issued Condition Report 96-0060, which will require the review of the boundary classification document for additional discrepancies. Also, a drawing change notice will be issued to correct Flow Diagram 2048 and any additional boundary errors on flow diagrams. In summary, the licensee review and control of the contractors work product was not effective in this case.

In this case, the absence of code boundaries constituted a failed barrier in safety-related equipment classification. The absence of the code boundaries was compensated for in that, in the safety related component data base, components affected by the absence of code boundaries were found to have been appropriately classified.

9 FOLLOWUP (92701)

9.1 (Closed) Inspector Followup Item 298/93202-02: Remote Shutdown Panel Training

This followup item was concerned with the availability of keys for remote shutdown panel operators, adequacy of simulator or plant walkdowns on the remote shutdown procedures, and the absence of procedural guidance to avoid travel through the cable spreading room during a control room evacuation.

The inspectors found that the availability of keys has been addressed in the remote shutdown procedure. The inspectors also found the procedure is addressed in an operator training lesson plan, which addresses remote operator activities. In regard to the control room evacuation through the cable spreading room, the licensee revised procedures to add a caution note to avoid the cable spreading room in response to the issues raised in this inspection.

9.2 (Closed) Inspector Followup Item 298/93202-04: Complete Modification Packages

The team had observed that one modification had not been completely closed out after 2.5 years and documented concern that untimely closeouts could result in vulnerabilities such as having out of date drawings during an accident, lack of tags or labels on equipment, and improper surveillance or maintenance.

The inspectors performing followup found that 168 design modifications were open at the time of this inspection. Of these open design modifications, 118 were installed but not closed. The distribution over time was: 35 were from

1995, 40 from 1994, 39 from 1993, 2 from 1992, and 2 from 1991. The inspectors reviewed a sample of the 1993 open design modifications that were installed and not closed. The review established that the design modifications were installed and necessary document changes (procedures, drawings, etc.) had been made. The formal close out was pending a final verification of all document changes. Engineering management reported that the majority of these design changes were planned to be closed by the end of February 1996. The balance is planned to be closed by March 1996.

9.3 (Closed) Inspector Followup Item 298/93202-05: Engineering Work Load

This inspector followup item was documented during the Operational Safety Team Inspection due to concern with a backlog of engineering action items. Engineering action items were defined as items other than design changes which needed engineering disposition such as condition reports, NRC Information Notices, Bulletins, INPO SOERs, and vendor Part 21 reports. During this inspection, the inspector reviewed the backlog and determined that significant progress had been made in reducing the backlog and it was currently not excessive.

10 IN OFFICE REVIEW OF LERs (90712)

The inspectors performed a review of the following LERs associated with operating events. Based on the information provided in the report, review of associated documents, and interviews with cognizant licensee personnel, the inspectors concluded that the licensee had met the reporting requirements, addressed root causes, and taken appropriate corrective actions. The following LERs are closed:

- 298/94-026, Revision 0: ASME Section XI Inspection and Test Requirements Associated with Safety-Related Portions of the Service Water and Reactor Equipment Cooling System

- 298/94-026, Revision 1: ASME Section XI Inspection and Test Requirements Associated with Safety-Related Portions of the Service Water and Reactor Equipment Cooling System

ATTACHMENT

1 PERSONS CONTACTED

1.1 Licensee Personnel

D. Buman, Design Engineer Manager
J. Dillich, Maintenance Manager
J. Dorn, Plant Engineering
C. Gaines, Event Analysis Manager
J. Gausman, Plant Engineering Manager
R. Godley, Nuclear Licensing and Safety Manager
P. Graham, Senior Engineering Manager
J. Hale, Radiological Protection Manager
J. Herron, Plant Manager
R. Jones, Senior Manager Safety Assessment
J. Mueller, Site Manager
D. VanDeKamp, Operations
B. Victor, Nuclear Licensing and Safety
R. Wenzl, Engineering Support

1.2 NRC Personnel

M. H. Miller, Senior Resident Inspector
W. H. McNeill, Reactor Inspector, RIV/DRS

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 February 7, 1996. During this meeting, the inspectors reviewed the scope and findings of this report. The licensee did not express a position on the inspection findings documented in this report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.