ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-298/95-10

License: DPR-46

Licensee: Nebraska Public Power District
1415 15th Street
Columbus, Nebraska

Facility Name: Cooper Nuclear Station

Inspection At: Brownville, Nebraska

Inspection Conducted: July 9 through August 19, 1995

Inspectors: M. Miller, Senior Resident Inspector
C. Skinner, Resident Inspector
J. Melfi, Resident Inspector, Arkansas Nuclear One
R. Mullikin, Senior Resident Inspector, Fort Calhoun Station

Approved: Terrance Reis 8-31-95
P. H. Harrell, Chief, Project Branch C Date

Inspection Summary

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

Results:

Operations

- Control room staff decorum and knowledge appeared good (Section 3.1).
- Control room key control was effective (Section 3.3).
- Timely and well-focused operations response to an improperly performed surveillance minimized potential effects on the reactor plant (Section 5.6).

Maintenance

- Maintenance activities observed by the inspector were well implemented, with good coordination with operations staff during postmaintenance testing (Section 4).

Surveillance

- Operations' performance of high pressure core injection (HPCI) testing appeared well controlled (Section 5.1).

- An inadequate procedure and lack of attention to detail by a technician caused a reactor vessel level indicator instrument to give momentary erroneous readings and control signals. The technician's and operations' recovery from the error was very strong (Section 5.6).

- The inspector identified that required emergency diesel generator surveillance tests may be able to be performed concurrently, resulting in a reduced out-of-service time (Section 5.2).

- A minor procedural error regarding calculations required as part of a service water pump surveillance test procedure was self-identified. The error did not affect the outcome of the test and was promptly identified and corrected (Section 5.4).

Engineering

- The identification and analysis of the significance of removal of a hatch to allow control rod drive pump replacement was good (Section 4.3).

Plant Support

- Health physics briefings and coordination with other plant organizations were good (Sections 5.5 and 7.1).

Management Oversight

- Plant management provided continuing, close involvement with activities associated with the 7-day HPCI action statement (Section 2).

- Management expectations were clearly transmitted to operators for testing of HPCI (Section 5.1).

Summary of Inspection Findings:

New items

A noncited violation is identifed in Section 5.6.

Closed Items

- Violation 298/9306-01 (Section 8.1)
- Violation 298/9326-02 (Section 8.2)
- Violation 298/9328-02 (Section 8.3)
- Violation 298/9328-04 (Section 8.4)
- Unresolved Item 298/9317-09 (Section 9.1)
- Unresolved Item 298/9329-02 (Section 9.2)
- Unresolved Item 298/9413-01 (Section 9.3)
- LER 298/93-001 (Section 10.1)
- LER 298/93-013 (Section 10.2)
- LER 298/93-035 (Section 10.3)
- LER 298/94-006 (Section 10.4)

Attachment:

- Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

The plant operated at full power during this inspection period with the exception of a brief reduction to 95 percent power on July 26, 1995, for control rod pattern adjustment and reductions on August 13 and 15 to 60 and 70 percent, respectively, to support turbine valve testing.

2 ONSITE RESPONSE TO EVENTS (93702)

On August 3, 1995, the licensee determined that the HPCI system was inoperable due to the potential for allowable stresses on the HPCI exhaust line snubbers and supports to be exceeded. The licensee identified that water could accumulate in a low point in the exhaust line and be accelerated down the piping. The acceleration of water in the exhaust line could be expected to occur upon restart of the HPCI turbine. If the water was accelerated, the stresses could potentially exceed the allowable stresses for the HPCI turbine exhaust line, which connects to the torus. As a result of this condition, the licensee declared the HPCI system inoperable and disabled the turbine in order to ensure containment integrity would not be challenged upon the start of the turbine.

On August 10, after modifications to the HPCI governor and exhaust line pipe supports, the licensee declared the HPCI system operable, although the system was still vulnerable to collection of water in the exhaust line.

The inspectors observed continuing, close involvement of plant management in the activities associated with the modification and testing of the HPCI system. The system modifications are discussed in Section 4.2 of this report. A special NRC inspection was conducted to review the operability issues associated with the collection of liquid in the HPCI turbine exhaust line. Discussion of the review is provided in NRC Inspection Report 50-298/95-11.

3 OPERATIONAL SAFETY VERIFICATION (71707)

3.1 Control Room Observations

During several observations of the conduct of operations in the control room, the inspectors noted that plant status was well understood and effectively conveyed to the control room staff during morning meetings, during communications associated with routine surveillance testing evolutions, and during various discussions among the operators. Shift supervisor turnovers were thorough and included detailed discussion of equipment status. Access to the control room was controlled effectively in that routine interfaces with maintenance, health physics, and other personnel were conducted outside the control room.

3.2 Plant Tours

On several occasions during this inspection period, the inspectors toured the HPCI room, the area around the torus, and the diesel generator rooms. The inspectors observed details of the installations, valve positions, seismic supports, and other indicators of material condition. The overall conditions of these rooms and systems was appropriate to support the operability of the systems.

3.3 Control of Keys

The inspector reviewed the key control program to verify that operations personnel could access all the required areas during response to an emergency. Operators possessed keys to rapidly open doors to access areas in emergencies, even though some doors may be locked for security, radiological, or other reasons. This issue became an industry concern as noted in Generic Letter 85-13, "Transmittal of NUREG-1154 Regarding the Davis-Besse Loss of Main and Auxiliary Feedwater Event."

The inspector verified that auxiliary operators obtained a key ring from the security alarm station prior to shift turnover and the off-going operators returned their key ring. The security organization logged the issuance and return of each key ring. Each key ring contained security master keys and radiation area keys to allow operators to go into locked areas during an emergency. Access to radiation areas in an emergency was controlled by Procedure 9.1.2.4, "Access Control - Radiological."

The control room operators did not normally carry keys to access remote shutdown areas, but would need keys in case of a control room evacuation to shut down the plant outside the control room. Since the security alarm station was part of the control room envelope and would be evacuated along with the control room, the inspector reviewed the actions the licensee would take on a control room evacuation. The inspector found that emergency procedures required the shift supervisor take the keys from the security alarm station.

The inspector verified that shift supervisors were aware that they needed to obtain the keys in this emergency situation. The inspector concluded that the key control program was effective in ensuring that operations personnel could gain access to locked areas in a prompt manner.

4 MAINTENANCE OBSERVATIONS (62703)

The inspectors observed and evaluated portions of the following maintenance activities to verify compliance with regulatory requirements, licensee procedures, use of hold cards, use of calibrated equipment, and postmaintenance testing.

4.1 Service Water Pump A Adjustment

On July 10, 1995, the inspectors observed and evaluated portions of the performance of Maintenance Work Request 95-1937, which provided instructions for adjustment of the lift on Service Water Pump A.

The inspector did not observe any problems and confirmed that maintenance personnel performed the work activity in accordance with the instructions.

4.2 Modifications to HPCI

To address the issue regarding the operability of the HPCI system (see Section 2), the licensee installed three modifications to the HPCI system. One was a modification to implement a gradual ramp for opening the governor valve on the HPCI turbine during initial start. This modification had been installed on several other plants to reduce the potential of a HPCI turbine trip upon initial start due to an abrupt opening of the valve and later overshoot of valve position, causing an overspeed trip of the turbine. The licensee had not installed this modification because previous operation of the turbine had not resulted in overspeed trips.

This modification resulted in a much slower rate of pressure increase in the turbine exhaust line and, therefore, less acceleration of any liquid in the exhaust line. The resulting slower clearing of the liquid in the line would result in reduced forces applied to the piping supports and snubbers and the containment penetration associated with the exhaust line.

The second modification to the HPCI system involved replacing the first snubber downstream of the dual check valves with a larger snubber since, even with the governor modification installed, the forces on that particular snubber were near the limit for allowed stressed. The third modification installed reinforcements on a support to compensate for potentially higher dynamic loads.

The inspector observed testing performed by the licensee after installation of the modifications. The first test involved a "cold start" of the HPCI turbine. Operations personnel continuously monitored system operation during the 8-10 minute run of the turbine.

The pretest briefing in the control room was performed by the operations manager and addressed various concerns, which included the expected performance of the turbine and the need to be observant and trip the turbine at the first sign of a lack of control or failure to perform in an expected manner. The operations manager emphasized the need for clear, concise communications during the test and observance of the requirement to make the turbine inoperable by placing the oil pump control switch in the pull-to-lock position in the event the turbine tripped. This action would prevent an inadvertent restart of the turbine and, therefore, avoid the concern of the acceleration of any accumulation of water in the exhaust line.

The test was performed in a well-controlled manner. Operators followed the procedure in a step-by-step fashion and maintained clear communications with the operators at remote locations. The operators closely monitored plant and system parameters during the testing and the turbine performed as expected.

4.3 Control Rod Drive Pump Replacement

On July 28, Control Rod Drive Pump A vibration and noise levels increased significantly. The licensee determined that the pump required replacement. Removal of the pump involved rigging the pump through a floor hatch in the 903 foot level of the reactor building. The licensee identified that this particular floor hatch was assumed closed during the flooding analysis associated with the feedwater line break. Subsequently, the licensee reviewed the feedwater line break flooding analysis and determined that this hatch cover was not required, although it was desirable. Removal of the hatch cover was controlled as a plant temporary modification, and a 10 CFR 50.59 analysis was performed. The review concluded that safe shutdown capability of the plant in the event of a feedwater line break would be maintained in that removal of the hatch cover would only potentially affect Train B of the core spray system. Train A of the core spray as well as the HPCI and RCIC systems would remain unaffected. Therefore, removal of the hatch did not constitute an unreviewed safety question. The inspection concluded that the licensee's analysis was technically sound.

5 SURVEILLANCE OBSERVATIONS (61726)

5.1 HPCI Surveillance Test

On July 5, 1995, after a routine HPCI surveillance test, engineering determined that a significant quantity of water had accumulated in the HPCI turbine exhaust line. Indication of liquid in the exhaust line is monitored by an alarm on a low point drain pipe. For this particular surveillance, the alarm was not received as it had been during the performance of the previous month's surveillance. Since there was documented concern with water accumulation in the line, engineering further investigated and found that the level switch which actuates the alarm had stuck. The level switch was freed and the alarm was received, as expected. A condition report was initiated to repair the level switch. When the alarm is observed, operators cycle drain valves. The liquid flows to the HPCI gland exhaust condenser which is then pumped to radwaste after 2.5 gallons of water accumulate in the condenser. Operator experience has shown that in some cases the gland exhaust condenser vacuum pump must be actuated to create adequate differential pressure to allow the exhaust line to drain and, thus, clear the drain alarm. For the case of routine surveillances, this alarm actuates intermittently for about an hour as liquid collects in the low point drain. The licensee speculated that liquid accumulation is caused by moderate leakage by HPCI steam admission Valve HPCI-MO14. The licensee identified that in this case the gland exhaust condenser pump cycled several times, and engineering estimated that approximately 120 gallons had accumulated in the HPCI exhaust line.

The licensee initiated a condition report and an operability determination was made. The operability determination concluded that the HPCI was operable provided that operators drained the exhaust line every 6 hours to ensure removal of water accumulation until the level switch was repaired. The operations staff also required that an evaluation be performed by engineering to determine the past operability of the HPCI with 120 gallons in the exhaust line and to determine the root cause of the accumulation of 120 gallons. NRC assessment of licensee actions taken with respect to this degraded condition are documented in NRC Inspection Report 50-298/95-11.

5.2 Diesel Generator (DG) Outage Time During Surveillance

The inspector observed portions of the following safety-related surveillance tests to determine if the test met Technical Specification and procedural requirements.

- Procedure 6.1DG.101, "Diesel Generator Monthly Operability Test," on July 10, 1995

- Procedure 6.1DG.401, "Diesel Fuel Oil Transfer Pump IST Flow Test," on July 10, 1995

The inspector reviewed the data from these tests and had the following observation. The licensee ran these tests in series, as opposed to running them concurrently.

The licensee initially ran the DG with the diesel fuel oil pump off, resulting in the level in the day tank decreasing during the 4-hour diesel run. The licensee ran the diesel fuel oil pump inservice testing surveillance test, which took about 15 minutes to obtain the required data. Following the inservice testing, the diesel fuel oil pump ran about 3 hours until the day tank was restored to its normal level.

The inspector observed that total out of service time due to the surveillance testing may be able to be reduced if the tests can be run concurrently. The observation was communicated to plant management.

5.3 Main Steam Line High Flow Instrumentation Surveillance

On July 24, 1995, the inspectors observed Procedure 6.2.1.4.2, "PCIS Main Steam Line High Flow Calibration and Functional Test." This procedure provided instructions to calibrate and perform a functional test of the instrumentation. This instrumentation is provided to measure steam flow and initiate a closure signal to the main steam isolation valves on high steam flow.

The inspector witnessed a portion of the performance of the procedure in the field and in the control room. The three maintenance technicians observed by the inspector were knowledgeable of the procedure, used good self-checking techniques, and demonstrated good radiological control practices. They performed the procedure in a step-by-step and controlled manner. The communication techniques used by the maintenance technicians were considered adequate by the inspector, although repeat backs were seldom utilized outside the control room. Licensee policies only require that repeat-back techniques be employed as is considered necessary by maintenance technicians in this situation. Repeat-back techniques are expected to be utilized for control room evolutions.

5.4 Service Water (SW) Pump D Postmaintenance Test

On July 5, 1995, the SW system engineer calculated the differential pressure for SW Pump D to be 58.28 psid. The minimum operability limit was 56.2 psid. Therefore, the system engineer scheduled a pump lift adjustment to address the small operability margin. The lift adjustment was performed on July 24.

The inspector observed the pump postmaintenance test, Procedure 6.3.18.3, "Service Water Surveillance Operation." The operator controlling the surveillance gave a briefing outlining where he wanted the operators stationed and what steps they were to perform. The briefing resolved confusion or questions on what was expected from the operators during the surveillance.

During the surveillance, the inspector observed good self-checking before manipulating valves and adequate communications. Overall, the operators demonstrated good procedure adherence, except during the calculations performed to verify proper pump differential pressure when the operator incorrectly read a step and did not perform the calculation as written. The procedure required that the calculations be checked by another person and this person failed to identify the error. During the engineering review of the acceptance criteria, the error was identified and corrected. The error did not affect the results of the procedure, because both calculated values were within the acceptance criteria.

On July 28, 1995, the Operations Manager discussed this issue at the plan-of-the-day meeting where he addressed the importance of performing proper reviews regardless of the number of people reviewing the material. The Operations Manager asked the other managers to inform their departments of this occurrence and of the lessons learned. This corrective action appeared appropriate.

5.5 Scram Discharge Volume (SDV) Surveillance

On July 26, 1995, the inspector witnessed maintenance technicians performing a surveillance on the SDV in accordance with Procedure 6.1.20, "South SDV High Water Level Switches and Transmitters Examination, Calibration, and Functional Test." The maintenance technicians adhered to the procedure and demonstrated good verification techniques when manipulating valves and performing independent verification.

The maintenance technicians and health physics support technician displayed very good radiological work practices while working in a contaminated area. The maintenance technicians waited for the health physics support technician to arrive before disconnecting a hose, because there was a chance that the water in the hose would spill onto the floor. If enough water was spilled, it could have flowed from the contaminated area to a noncontaminated area. Once the health physics support technician was present, the connection was broken and the small volume of water that was spilled was contained in the contaminated area. The health physics support technician cleaned up the water and surveyed the maintenance tools and hose that were used in the contaminated area. In this instance, the radiation protection practices by the health physics and maintenance technicians were strong.

5.6 Alternate Rod Insertion Surveillance

On August 7, 1995, during a surveillance functional test of the alternate rod insertion system, an instrument and control (I&C) technician failed to properly isolate a reactor vessel pressure instrument line before installing test equipment in the alternate rod insertion system. This caused brief depressurization of Reactor Vessel Reference Leg B, which was immediately observed by control room operators. Control room operators were aware of the ongoing surveillance and ordered all surveillance activities stopped. Channel B was controlling reactor vessel feedwater flow, which promptly limited feedwater flow on a reactor vessel level high signal. The I&C technician promptly secured his work, recognizing that the vessel level instrument had not been properly isolated, and quickly isolated the instruments and informed the control room. Plant management stopped all I&C work and determined the cause of the perturbation to be a poorly written procedure step which required three actions in one step, one of which was to isolate the reactor vessel instrument.

The licensee determined that maintenance work could continue provided that concurrent verification be performed for completion of all steps to ensure that this type of error was not repeated.

The licensee was already in the process of revising maintenance and surveillance procedures to clarify and separate actions into individual steps, as well as list valve numbers specifically as they are required to be operated. This process had not yet been performed on the procedure that was being used. The licensee issued a condition report to control work while procedures of this type were revised. Technicians were reminded in various meetings to be aware of the need to carefully implement procedures and to perform concurrent verification to ensure steps are implemented properly while the procedure revision process is ongoing. This action appeared appropriate. This procedural inadequacy constitutes a violation of minor significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy.

During the transient, actual reactor vessel level dropped approximately 1 inch and then recovered due to the operator's quick response. The expected alarms occurred and no additional perturbations were observed.

6 ONSITE ENGINEERING (37551)

Lack of Qualification of Agastat Relays with Auxiliary Contacts

On August 3, 1995, the licensee identified that Agastat Relays which had add-on contacts (L-Option) or delayed timer add-ons (T-Option) were not qualified for safety-related service with those options attached. The equipment was not acceptable under seismic or equipment qualification considerations. The licensee documented this concern in a condition report and later found that the same concern had been previously resolved and documented in an engineering judgement, Document Number 94-058. Since these relays were used in a mild environment, the equipment qualification concern was not an issue, and the engineering judgement document noted that the potential contact chatter and existing seismic testing bounded the Cooper design basis conditions. During discussions on August 3, the licensee identified that some further configuration control issues may warrant more precise documentation of the relay qualifications. At the conclusion of one of the discussions, the inspector noted that, although the licensee had identified that the relays were qualified so long as circuits were not attached to the auxiliary contacts, it appeared that no configuration control was in place to prevent addition of circuits to these auxiliary contacts at a later date. The licensee pointed out that adequate documentation was in place to identify that these auxiliary contacts should not have circuits attached and that this aspect of configuration control may have been addressed without the inspector's comment during subsequent review.

However, the licensee agreed that specific configuration controls to prevent attachment of circuitry to the auxiliary contacts would be an enhancement. The licensee planned to address this concern as part of the routine scheduled reviews of the qualification of these relays. This appeared reasonable to the inspector.

7 PLANT SUPPORT ACTIVITIES (71750)

7.1 Radiation Protection

The inspectors observed four health physics briefings of maintenance, operations, and engineering personnel for various tests, surveillances, and maintenance work. A special work permit was written to support the tests of the HPCI pump, which appeared appropriate, since the HPCI room became a high radiation area during the run. The briefings by radiation protection personnel were thorough, detailed, and focused on maintaining exposure as-low-as-reasonably-achievable (ALARA).

7.2 Security Observations

On July 24, 1995, an inspector was unable to gain access to the SW pump room because of a malfunction with the card reader. The inspector contacted a security officer, who also was unable to gain access to the room. An MWR was written to have the card reader repaired.

Later that day, the inspector returned to observe maintenance being performed in the room and verified that a security officer was present and controlling access to the room. Every entry and exit from the room was logged by the security officer. On July 26, the inspector verified that the card reader was repaired and working properly.

8 FOLLOWUP ON CORRECTIVE ACTIONS FOR VIOLATIONS (92702)

8.1 (Closed) Violation 298/9306-01: Failure to Comply with 10 CFR 50.9 Requirements

In response to a Notice of Violation, a letter dated December 1, 1992, the licensee provided written information to the Commission that was inaccurate. This information was inaccurate because the licensee's response stated that the reactor core isolation cooling system preoperational test contained a step which was signed-off, indicating that a temporary strainer had been removed. There was no document that existed indicating that the strainer had been removed and on January 29, 1993, the temporary strainer was found installed in the system.

The inspector verified that the licensee had implemented the following corrective actions:

- Lesson Plan INT035-02-01, "Position Specific Industry Events," provided training to reinforce management's philosophy for achieving accuracy and completeness at all times.

- The Nuclear Power Group Manager issued a memorandum to his direct reports stating his expectations on accuracy and completeness for all Commission correspondence and on individual accountability.

- Two overview committees were formed, one at the general office and one at Cooper Nuclear Station, to review all Commission correspondence for accuracy and completeness. Eventually, the licensing organization started to perform this function and the overview committees were dissolved.

- Standardized guidelines were established through Administrative Procedure .42, "NRC Correspondence Control Procedure," which outlined the requirements for controlling correspondence to ensure accurate, complete, and timely disposition of regulatory issues.

- Lesson Plan ADM004-01-03, "Make the Call Reportability/Operability," provided training on 10 CFR Part 50.9 to management and technical staff.

The inspector concluded that the licensee actions were sufficiently comprehensive to close the issue.

8.2 <u>(Closed) Violation 298/9326-02: Failure to Maintain Positive Pressure in Control Room Test</u>

On November 19, 1993, positive pressure in the control room envelope could not be maintained in the cable spreading room, which is part of the control room envelope, due to leakage past Fire Door H-305. On November 18, personnel removed Fire Door H-305 as part of an effort to ensure fire door operability for all fire doors. After replacing the door, engineering personnel noticed a gap at the top of the door and recommended that a pressurization test be done to ensure that the control room envelope had not degraded. Since the control room did not pressurize, the licensee repaired the door and satisfactorily tested the control room pressure envelope on November 20, 1993.

This event revealed problems with the maintenance planning process since applicable Maintenance Work Request, MWR 4068, did not address the potential effects of door maintenance on the control room envelope and also did not specify a postmaintenance test of the control room envelope. Further, the shift supervisor who approved Maintenance Work Request 4068 did not recognize that it affected the control room envelope.

The licensee modified Procedure 0.16, "Control of Doors," to note that the doors were essential and labeled plant doors to show the functions each door performs. Further, training was given to maintenance planners and licensed operators on the importance of these doors. The inspector verified that the labels were on control room envelope doors.

The licensee's corrective actions appeared to address this issue adequately.

8.3 <u>(Closed) Violation 298/9328-02: Inadequate Procedure for Relay Maintenance</u>

This violation involved inadequacies discovered in Maintenance Procedure 7.3.1, "Protective Relays Setting and Testing," for the emergency diesel generators. The procedure inadequacies were that the tested relays were not clearly identified and that the manufacturer's maintenance recommendation for frequency and measurement of contact swipe were not included.

The licensee's immediate corrective action was to issue new Maintenance Procedure 7.3.1.3, "DG-REL-DG1(59) and DG-REL-DG2(59) Relays Testing and Setting." The inspector verified that the new procedure identified the correct contacts to be tested and that the manufacturer's recommendation for contact swipe was incorporated. In addition, the licensee had an outside contractor perform an evaluation of the protective relay maintenance program. This evaluation resulted in 26 recommendations for improving the program. The licensee has incorporated some of these items prior to the last plant startup. The other recommendations were considered program enhancements by the licensee and will be evaluated separately.

8.4 (Closed) Violation 298/9328-04: Inadequate Corrective Action to Correct DG Relays Out of Tolerance

This violation resulted from the discovery that common relays on both emergency DGs were found out of tolerance, resulting ir both generators being declared inoperable. In addition, the licensee failed to make a timely declaration of an Unusual Event after both emergency DGs were declared inoperable. The licensee had failed to take adequate corrective action after similar occurrences.

The licensee determined that the reason for the violation was an inadequate root cause analysis for the previous relay problem and personnel error on the part of the shift supervisor in not following procedural guidance.

The licensee's corrective action included the formation of the corrective action program which provided enhanced training on the root cause analysis process. Also, for the failure to make a timely notification, shift supervisors were informed of the event. A contributing cause of the untimely event declaration was that Emergency Plan Implementing Procedure 5.7.1, "Emergency Classification," stated for Emergency Action Level 4.1.2 that an Unusual Event should be declared for the loss of both emergency DGs. The licensee subsequently clarified this statement by substituting the word "inoperable" for "loss." This statement had been misinterpreted by the shift supervisor during the event.

The inspector reviewed Procedure 5.7.1 to verify that Emergency Action Level 4.1.2 was revised. However, this requirement to declare an Unusual Event for the inoperability of both emergency DGs, without the loss of offsite power, was not in Procedure 5.7.1. The inspector brought this to the licensee's attention. The licensee responded that this requirement was removed from Revision 30 of the Emergency Plan based upon guidance provided by the Commission staff. The licensee determined, based upon this guidance, that the inoperability of both emergency DGs would not be an emergency since all normal electrical buses would be powered by the normal offsite power sources. The inspector concluded that the licensee had properly removed this corrective action commitment based upon NRC guidance and review.

9 FOLLOWUP - MAINTENANCE (92902)

9.1 (Closed) Unresolved Item 298/9317-09: Review of Testing Requirements for Manual Valves

This item resulted from the inspectors' discovery that three manual valves that were required to be operated by Emergency Operating Procedure 5.8.7, "Primary Containment Flooding Systems (PC/L-2)," were not being routinely cycled. The inspectors' concern was that without cycling there would be no assurance that these valves could be operated during an accident. The licensee performed an inventory of the manual valves that would be required to be operated by actions specified in all of the emergency operating procedures. The licensee determined that there were 89 such manual valves and that 28 of these were already being cycled by a procedure or a preventive maintenance activity. Thus, the licensee included the other 61 valves in the preventive maintenance program to have them cycled and visually inspected once per operating cycle. These actions resolved this inspector concern.

9.2 (Closed) Unresolved Item 298/9329-02: Review of Inadvertent Lifting of Safety Relief Valve During Surveillance Testing

This item resulted from the inadvertent lifting of safety relief Valve MS-71 during the performance of a surveillance test. The licensee formed a problem resolution team to review the incident. The licensee determined that the safety valve lift was due to personnel error by the control room operators. Several recommendations resulted from this review. The inspectors discussed these recommendations with licensee management and the licensee decided to review other recent personnel error events to determine if similarities existed.

The licensee formed a team to review similarities between the personnel error events. The team concluded that there was no overall common cause of the events, although there were common factors in one or two of the events. These action resolved the inspector concerns.

9.3 (Closed) Unresolved Item 298/9413-01: Review of HPCI Maintenance Procedure

This item resulted from the performance of Maintenance Procedure 7.2.54, "HPCI Turbine Stop Valve Steam Balance Chamber Pressure Adjustment." A discrepancy was discovered in the measurement critical for blocking open the pilot valve. The licensee's investigation revealed the discrepancy was due to the way individuals took a measurement from the bottom of the split coupling to the top of the valve yoke flange. It was discovered that two different individuals had taken these measurements. One had taken it from the center of the split coupling and the other had taken it from the outside. This resulted in different measurements and, subsequently, different settings. The licensee's corrective action was to revise Procedure 7.2.54 to require that the coupling and valve yoke flange be match marked. The inspector reviewed Procedure 7.2.54 and verified that this instruction was in the procedure, thus providing consistent measurements. These actions resolved this inspector concern.

10 ONSITE REVIEW OF LERs (92700, 90712)

10.1 (Closed) LER 298/93-001: Potential for Insufficient Cooling Due to SW System Design

This LER described inadequate train separation for the SW filter system and heat exchangers. During a design basis reconstitution effort, the licensee found that the Division I SW pumps supplied the Division II reactor equipment cooling heat exchangers, and vice versa. The reactor equipment cooling heat exchanger is used to remove heat from safety-related components. Therefore, with a failure of a division power supply, the operable service water would go into the inoperable heat exchanger. The licensee implemented Design Change 93-057 to correct this problem.

This design change was previously reviewed by the NRC in Inspection Report 50-298/94-04 and found to be thorough. The inspector verified that the design change was implemented and that selected components were powered by the correct divisional power supply. Based on the licensee's actions to correct this problem and their continuing design basis reconstitution, this LER is closed.

10.2 (Closed) LER 298/93-013: Safety/Relief and Safety Valve Setpoint Variance Not Within Technical Specification Limits

This report discussed a situation where the setpoint for seven valves was not within the TS required limits.

This issue was reviewed, as discussed in NRC Inspection Report 50-298/95-03, and it was determined that the licensee had taken appropriate corrective actions.

10.3 (Closed) LER 298/93-035: Incorrect Relay Settings on the Emergency DGs

This issue involved the identification of incorrect relay setpoints on the emergency DGs, caused by inadequate procedures.

The issue was reviewed, as discussed in NRC Inspection Report 50-298/93-28, and the actions taken by the licensee to address this issue were found to be satisfactory.

10.4 (Closed) LER 298/94-006: Inoperable Control Room Emergency Filter System

This LER described circumstances that led to the control room emergency filter system being declared inoperable. This filter system provides clean filtered air to the control room envelope to maintain a positive air pressure with respect to adjoining areas. The licensee found that this filter system could not maintain a positive pressure for the control room envelope since the filter system had a marginal capacity. The surveillance procedures were not adequate to detect degradation, and the acceptance criteria for the control room envelope was not well defined. The licensee also noted that previous problems with this filter system were not investigated or analyzed properly. Due to these problems, the inoperability of the control room envelope was discussed in NRC Inspection Report 50-298/94-19.

The licensee fixed door seals and penetrations in the control room envelope, established operability limits, and approximately tripled the capacity of the emergency filter system fan. These actions significantly increased the attainable pressure in the control room. The licensee continued a design basis reconstitution effort and also implemented training for personnel for root cause determination. Based on the licensee's corrective actions and continuing actions, this LER is closed.

ATTACHMENT

1 PERSONS CONTACTED

Licensee Personnel

T. Carson, Maintenance Supervisor
R. DiRito, Operations Manager
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 Manager
J. Herron, Plant Manager
M. Peckham, Senior Manager Site Support
R. Sessoms, Quality Assurance Division Manager

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 August 11, 1995. During this meeting, the inspector 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.