ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-298/96-05

License: DPR-46

Licensee: Nebraska Public Power District
1414 15th Street
Columbus, Nebraska

Facility Name: Cooper Nuclear Station

Inspection At: Brownville, Nebraska

Inspection Conducted: February 26 through March 1, 1996

Inspectors: M. Runyan, Reactor Inspector, Engineering Branch
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Approved: C. VanDenburgh, Chief, Engineering Branch, Division of Reactor Safety — Date: 4/10/96

Inspection Summary

Areas Inspected: Routine, announced inspection of the licensee's fire protection program and followup of engineering open items. Inspection Procedures 64704, 92901, and 92903 were used.

Results:

Engineering

- The licensee failed to perform an operability determination after receiving information indicating that 14 safety-related, motor-operated valves were subject to pressure-locking and thermal-binding conditions.

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This was a violation of the licensee's administrative procedures for condition reporting (Section 3.3).

- The inspectors identified an unresolved item concerning the apparent past inoperability of Valve CS-12A and the validity of two assumptions the licensee used for pressure-locking calculations (Section 3.3).
- The licensee had modified Valves CS-12A and CS-12B during Refueling Outage RE-16, thereby, satisfactorily eliminating the susceptibility of these valves to pressure locking (Section 3.3).
- The licensee had initiated appropriate actions to address a large number of control and coordination deficiencies associated with the installation of a major modification on the emergency diesel generators (Section 3.5.2).

Maintenance

- The licensee had initiated appropriate actions to address a large number of motor-operated valve lubrication and insulation discrepancies identified by the licensee during Refueling Outage RE-16 (Section 3.5.1).

Plant Support

- The licensee's fire protection program was technically adequate, and the plant fire protection equipment and features were operable and in good condition (Section 1).

Summary of Inspection Findings:

- Violation 50-298/9605-01 was opened (Section 3.3).
- Unresolved Item 50-298/9605-02 was opened (Section 3.3).
- Unresolved Item 50-298/9328-06 was closed (Section 2.1).
- Unresolved Item 50-298/9413-03 was closed (Section 2.2).
- Violation 50-298/9415-03 was closed (Section 2.3).
- Violation 50-298/93202-22 was closed (Section 3.1).
- Violation 50-298/93202-23 was closed (Section 3.2).
- Unresolved Item 50-298/9513-01 was closed (Section 3.3).
- Inspector Followup Item 50-298/93202-03 was closed (Section 3.4).

Attachments:

- Attachment 1 - Persons Contacted and Exit Meeting
- Attachment 2 - Procedures Reviewed

DETAILS

1 FIRE PROTECTION/PREVENTION PROGRAM (64704)

1.1 Cooper Nuclear Station Fire Protection Requirements

The licensee's fire protection program was incorporated into Operating License Condition 2.C.4, which required the implementation of their fire hazards analysis. The license was licensed prior to January 1, 1979; therefore, the licensee was required by 10 CFR 50.48 to implement 10 CFR Part 50, Appendix R, Sections III.G, J, and O. Compliance with Appendix R was documented in the licensee's Safe and Alternative Shutdown Analysis Report.

1.2 Review of Fire Protection Procedures

The inspectors reviewed the licensee's fire protection program implementing procedures to assure that the fire protection program contained the following items described below.

1.2.1 Combustible Material Control/Fire Hazards Reduction

The inspectors verified that the procedures for combustible controls for transient fire loads in safety-related and adjacent plant areas addressed wood, bulk flammable and combustible liquids and gases storage, anti-contamination clothing and shelving, plastics, and hydrogen lines.

1.2.2 Housekeeping

The inspectors verified that the housekeeping procedures addressed the following items: frequency of licensee-conducted housekeeping inspections, control of combustible waste products, storage of radioactive materials, controls of hazardous chemicals, and control of smoking.

1.2.3 Ignition Source/Fire Risk Reduction Controls

The inspectors verified that procedural controls addressed welding, cutting and grinding operations, and that these operations were authorized only by an appropriate permit. The inspectors also determined that the procedures provided controls for leak testing and other open flame operations.

1.2.4 Fire Control Capabilities

The inspectors verified that the fire protection program provided provisions for fire fighting training and qualifications, fire emergency plans, and fire personnel designations. The inspectors also verified that the fire control capabilities provided for the maintenance and surveillance on fire suppression, detection, and emergency communications equipment.

1.3 Fire Brigade Readiness

The plant fire brigade was composed of five members, three of which were from the operations department and two from other organizations including the security force. The inspectors reviewed the physical examination records of the fire brigade members and determined that all designated fire brigade members had a current physical examination and were qualified to wear self-contained breathing apparatus equipment.

The inspectors also reviewed the training records of fire drills performed during 1995 and determined that the required drills were preplanned, critiqued, and performed for all six fire brigade shifts, including unannounced and backshift drills. The fire brigade drills were conducted at regular intervals not exceeding 3 months for each fire brigade shift during the past year. The inspectors reviewed the classroom training course outlines and verified that the following topics were covered by the initial program and were repeated over a 2-year period:

- Indoctrination of the plant fire fighting plan with specific identification of each individual's responsibilities.

- Identification of the type and location of fire hazards and associated types of fire that could occur in the plant.

- The toxic and corrosive characteristics of expected products of combustion.

- Identification of the location of fire fighting equipment for each fire area and familiarization with the layout of the plant, including access and egress routes to each area.

- The proper use of available fire fighting equipment and the correct method of fighting each type of fire. The types of fires included fires involving energized electrical equipment, cables in cable trays, hydrogen fires, fires involving flammable and combustible liquids or hazardous process chemicals, fires resulting from modifications (welding), and record file fires.

The inspectors reviewed the training records of one fire brigade leader and two brigade members and verified that each member had the following training:

- Initial fire brigade training,
- Classroom training every 3 months,
- Participation in at least two drills per year,
- Attended practice fire fighting sessions, and
- The fire brigade leader had attended fire brigade leadership training.

1.4 Plant Tour

The inspectors performed a walkdown inspection of the outside fire protection system to evaluate the operability and material condition of the fire suppression water supply system. In addition, the inspectors toured various areas of the diesel generator building, the auxiliary building and the control building. The inspectors performed this tour to visually inspect the fire protection equipment and features provided and to evaluate the adequacy of the licensee's fire prevention program from a performance-based perspective. The inspectors observed the following:

- The fire sprinkler systems and deluge systems were operable and well maintained.
- The fire protection equipment, such as hoses, hose reels, detectors, and fire extinguishers were in good material condition.
- The general housekeeping was well maintained.

1.5 Quality Assurance Audit

The inspectors reviewed Quality Assurance Audit Report QAC95220, which was conducted from May 2 through August 2, 1995, to assess the implementation and effectiveness of the fire protection program. The scope of the audit included a review of documentation, plant walkdowns, and performance-based observations to assess and evaluate the effectiveness of the fire protection program. The audit included a fire protection engineer from the River Bend Nuclear Power Station as a technical specialist.

The audit identified that the lack of overall fire protection program ownership contributed to past problems resulting in inadequate program implementation. The report concluded that degree of fire protection program ownership had improved due to the recent engineering reorganization, and that increased management attention was warranted to ensure effective implementation of the fire protection program. The inspectors concluded that this audit provided a critical assessment of the program along with recommendations that should improve implementation of the fire protection program.

2 FOLLOWUP - OPERATIONS (92901)

2.1 (Closed) Unresolved Item 298/9328-06: Concern with the Automatic Start of the Emergency Diesel Generators under Some Conditions

Background

This unresolved item identified two concerns. The first concern involved the ability of the emergency diesel generators to automatically start and load in the event that offsite electrical power was lost during an accident (i.e., loss-of-offsite power subsequent to a loss-of-coolant accident) with miscalibrated diesel generator output breaker closure permissive relays (DG-REL-DG1&2(59). The second concern involved the ability of the emergency diesel generators to automatically start and load during the licensing and design basis events (i.e., loss-of-coolant accident concurrent with loss-of-offsite power) with miscalibrated output breaker closure permissive relays.

The first concern was originally identified as an apparent violation (298/9328-01) in NRC Inspection Report 50-298/93-28, dated January 6, 1994. This inspection report identified a total of five apparent violations involving the emergency diesel generators with the miscalibrated permissive relays. The apparent violations were discussed during a predecisional enforcement conference held on January 31, 1994. The second concern was identified by the licensee during the predecisional enforcement. After the conference, the NRC issued a Notice of Violation, dated March 15, 1994, consisting of two separate violations regarding these issues. The two violations closed Apparent Violations 298/9328-02, -03, -04, and -05. The NRC letter forwarding the Notice of Violation, also closed the first apparent violation and identified a new unresolved item (298/9328-06) to resolve the ability of diesel generator to automatically load under both conditions. The NRC letter also requested that the licensee provide their assessment of these concerns and any corrective actions they planned to implement to address the issue. The licensee provided this response in Letter CNSS940167, dated April 14, 1994.

Inspector Followup

Concern No. 1 - Loss-of-Offsite Power Subsequent to Loss-of-Coolant Accident

Regarding the first concern, the inspectors reviewed the emergency diesel generator's operability requirements to determine if a violation had occurred. The Updated Safety Analysis Report indicated that the emergency diesel generators were required to start on an accident signal (i.e., loss-of-coolant accident) totally independent of the availability of offsite power. However, in the predecisional enforcement conference conducted on January 31, 1994, the licensee maintained that the emergency diesel generators were not designed or licensed to automatically energize the emergency buses if offsite power were lost after the beginning of the design basis loss-of-coolant accident. In addition, the licensee stated that the inability to perform this function was not necessary to consider the emergency diesel generators operable.

In order to resolve this issue, Region IV initiated Technical Interface Agreement 94-TIA-008, dated March 15, 1994, which requested that the Office of Nuclear Reactor Regulation (NRR) address the question of whether the Cooper Nuclear Station had been licensed assuming a capability of the emergency diesel generators to automatically respond to a loss-of-offsite power after the initiation of a design basis loss-of-coolant accident. In a reply dated December 23, 1994, NRR indicated that the facility was not licensed for this condition. Although the staff originally believed that the start of the emergency diesel generators on a loss-of-coolant accident signal could be used as proof that the emergency diesel generators were intended to be capable of automatically handling a loss-of-coolant accident followed by a delayed loss-of-offsite power, NRR could not find any documented generic staff position for this requirement. NRR concluded that the imposition of this requirement for the Cooper Nuclear Station would be considered a backfit in the absence of a clear licensee commitment or a documented NRC generic position on this issue. NRR indicated that this issue is being pursued generically. Based on the response to the technical interface agreement, the inspectors determined that the licensee was not in violation of diesel generator operability requirements identified in Updated Safety Analysis Report 5.3.1.

In addition, the inspectors noted that the licensee's plant-specific probabilistic risk assessment performed for the loss-of-offsite power following a design basis loss-of-coolant accident calculated the mean frequency for core damage to be 8.92E-14/yr, which was well below the cut-off frequency of 1E-08/yr used by the NRC to describe a credible accident. The inspectors determined that this accident for core damage was less severe than the design basis accident with concurrent loss-of-offsite power.

The inspectors reviewed the licensee's corrective actions of this potential concern. The inspectors determined that the licensee provided additional written instructions to notify and train operators on this scenario. The licensee also stated that it was apparent that the operators needed to be trained on the event, since it was not specifically covered by station procedures or the emergency operating procedures. The licensee stated that this postulated event, which was beyond the design basis event, could potentially impact restoration of the emergency diesel generators. The licensee stated that the operators were to be specifically trained on the following sequence of events:

- Allow the start of one residual heat removal pump on each diesel generator.
- Inhibit the start of core spray pumps and the remaining two residual heat removal pumps.
- Allow the sequential loading to complete on the diesel generators.
- Then individually restart the remaining residual heat removal and core spray pumps under full flow conditions as conditions warrant.

The licensee stated that by recognizing the actions taken to protect the diesel generators, this postulated event would be effectively controlled by the control room operators and would mitigate the consequences of the event.

Additionally, the inspectors reviewed specialized training conducted by the licensee on this loss of coolant accident postulated event. The inspector's review determined that all operator crews were trained in April 1994 on the loss-of-coolant accident Scenario SKL051-51-06, which was modified to add a subsequent loss-of-offsite power. In addition, the licensee provided the above guidance on protecting the emergency diesel generators from overloading during the recovery of the postulated event. Based on the very low frequency for the accident, the licensee planned no further corrective actions.

The inspectors' review determined that the training of all reactor operators was conducted by April 13, 1994, and guidance was given to protect the emergency diesel generators from overloading during the recovery. The inspectors determined that the assessment and corrective actions adequately addressed the potential concern. The inspectors determined that no violation of regulatory requirements existed based upon the technical interface agreement response.

Concern No. 2 - Loss-of-Offsite Power Concurrent with Loss-of-Coolant Accident

Regarding the second concern involving the diesel generator's ability to function during a loss-of-coolant accident concurrent with the loss-of-offsite power, the inspectors reviewed the emergency diesel generator's operability requirements to determine if a violation had occurred. As noted above, the inspectors reviewed Updated Safety Analysis Report, Chapter VIII, Section 5.3.1, which discussed events for the loss-of-coolant accident where the emergency diesel generators start and immediately load onto the bus. The inspectors determined that the loss of the startup or normal electrical power to the emergency buses resulted in the automatic starting of the diesel generators and the automatic connection of the emergency buses to the emergency electrical power source. The inspectors noted that the Updated Safety Analysis Report discussions indicated that the emergency diesel generators were required to start independently of the availability of offsite power.

The licensee stated that the miscalibrated relays of both emergency diesel generators would not have prevented the output breakers from closing during a loss of coolant accident sequence when offsite power was not available. The licensee replied to Unresolved Item 298/9328-06 in their April 14, 1994, response to the Notice of Violation (Letter CNSS940167). Their response indicated that the automatic start feature of the emergency diesel generators (concurrent loss-of-coolant accident and loss-of-offsite power) had been satisfactorily demonstrated at the end of their last refueling outage on July 14, 1993. Specifically, the voltage overshoot during the starting sequence had satisfied the permissive logic of the relays and allowed the emergency diesel generator output breakers to automatically close.

The inspectors' review of the licensee response and their surveillance indicated that the emergency diesel generators operated in accordance with their design requirements even with potentially miscalibrated permissive relays. Therefore, the inspectors determined that a violation of regulatory requirements had not occurred.

2.2 <u>(Closed) Unresolved Item 298/9413-03: Core Spray Loop B Subsystem Declared Inoperable</u>

<u>Background</u>

This unresolved item involved the spurious actuation of an essential safety features system during a surveillance test. On April 27, 1994, the licensee declared the core spray system Loop B subsystem inoperable due to the closure of the minimum flow valve during a surveillance test. The licensee was performing Surveillance Procedure 6.3.4.2, "Core Spray Motor-Operated Valve Operability Test," Revision 23, dated April 13, 1994, when minimum flow Valve CS-MOV-MO5B closed and immediately reopened after the operators opened the Loop B test line return Valve CS-MOV-MO26B. By design, the minimum flow valve is a normally open valve; however, it receives a close signal whenever loop flow exceeds 1768 gpm. The surveillance test was normally performed without the core spray pump running; therefore, the opening of the test line return valve should not have produced a flow signal that would actuate the closure of the minimum flow valve. This unresolved item was opened to pursue the licensee's ongoing investigation into the spurious actuation.

<u>Inspector Followup</u>

The licensee generated a Condition Report 94-0106, dated April 27, 1994, to document the corrective actions as a result of the inadvertent actuation of the minimum flow valve. The associated engineering evaluation concluded that the core spray minimum flow problems were a result of spurious close signals to the minimum flow valve. The licensee stated that these signals have been intermittent over the years, with indications that they have existed since original construction. The licensee determined that this condition was created by the following root-cause factors:

- Hydraulic disturbances in the core spray piping.
- The use of a flow nozzle that was sensitive to the effects of trapped air and susceptible to trapping air in the annular space, and
- The use of a sensitive instrument measuring a "zero flow" condition sending a close signal for valve control.

The licensee implemented several corrective actions to address the contributing root causes of the hydraulic disturbances in the core spray system. The most important corrective action was the installation of an 8-second time delay for the core spray minimum flow bypass valve closure. During testing, the licensee recorded spurious differential pressure oscillations and high flow spikes when the operators cycled the test line isolation valve (CS-MOV-MO26B). The licensee determined that the worst-case flow spike recorded during this testing had a peak, which exceeded the high flow setpoint for approximately 2 seconds. Based upon these tests, the licensee selected a time delay relay of 8 seconds for the minimum flow bypass valve closure. An analysis by the nuclear steam system supplier (General Electric) and the licensee's configuration management department concluded that a time delay of up to 10 seconds did not adversely affect the licensee's safety analyses.

The licensee developed and initiated Temporary Design Change 94-224 in April 1994 to prevent spurious flow signals from closing the core spray system minimum flow bypass valves (CS-MOV-MO5A/B). The licensee installed the new 8-second time delay relays in July 25, 1994. On January 15, 1996, the licensee determined that the time delay relays would be installed under a permanent Design Change in accordance with Engineering Project Request 96-012, entitled "Permanent Installation of TDC 94-224."

The inspectors reviewed the corrective actions which addressed the contributing root causes and determined that they appeared to correct the closure actuations of the minimum flow bypass valves. The inspectors also determined that no further bypass valve closure actuations occurred in 1994 or 1995 after installation of the 8-second time delay.

Contrary to the original inspection report, the inspectors concluded that a potential violation of regulatory requirements had not occurred. The core spray system had permanently installed flow orifices (RO-27A/B), which allowed system design flow into the reactor vessel, even if the minimum flow bypass valves (MO5A/B) failed to close. In addition, licensee testing with the valves (MO5A/B) failed open, indicated that the core spray system had adequate system flow into the reactor vessel. The inspector's review indicated that the core spray system Loop B subsystem was operable since unintended actuation of the Loop B minimum flow valve occurred only during testing. The inspectors determined that there was no evidence to suggest that the valve may spuriously operate on core spray system initiation.

In addition, the inspectors determined that subsequent to this event, Surveillance Procedure 6.3.4.1, "Core Spray Test Mode Surveillance Operation," Revision 34, dated July 2, 1994, had successfully tested the operation of the minimum flow valve and its control circuitry by starting the Loop B core spray pump, opening the test line return valve, and verifying that the minimum flow valve closed when the loop flow through the test return path was established. Finally, Surveillance Procedure 6.2.2.4.1, "Core Spray Loop A and B Flow Instrument Calibration and Functional," Revision 30, dated July 28, 1994, had successfully been performed. This surveillance calibrated the core spray system Loop B flow instrumentation. No indication of switch inaccuracy or malfunction was found.

2.3 (Closed) Violation 298/94015-03: Reactor in Operation at Greater Than 2381 Megawatts

Background

This violation involved the failure to correctly calibrate the feedwater flow transmitters. The licensee replaced the General Electric Model 555 feedwater flow transmitters with Rosemount Model 1151 transmitters in 1980. In 1985, the licensee reviewed NRC Information Notice 85-100, "Rosemount Differential Pressure Transmitter Zero Point Shift," for all Model 1153 transmitters. However, the licensee did not include the Model 1151 transmitters in this review because the NRC Information Notice only discussed Model 1153 Rosemount transmitters, even though the two instruments are fundamentally the same. As a result, the licensee did not identify the span shift error due to the static pressure on the feedwater flow transmitters. The underestimation in feedwater flow resulted in core thermal power being approximately 20 megawatts (thermal) greater than what was being calculated in the computer program.

The Cooper Nuclear Station Operating License stated, in part, that the facility was authorized to operate at steady state, reactor core power levels not in excess of 2381 megawatts (thermal). From 1980 until April 1994, at those times when the reactor was operated at full power, the actual reactor power exceeded the steady state limit of 2381 megawatts (thermal) in that actual power was approximately 2400 megawatts (thermal) due to the licensee not compensating for an error in the calibration of the pressure transmitters used for feedwater flowrate calibration.

Inspector Followup

The inspectors reviewed the licensee's response to this violation, which was documented in a letter (NLS940034) to the NRC dated August 29, 1994. The licensee's reasons for the violation were:

- Inadequate guidance in the minor design change,
- Failure to identify the problem during operating experience review, and
- Inadequate training and assignment of responsible reviewers.

The licensee had taken immediate corrective action to reduce reactor power by 20 megawatts (thermal) and had maintained the average power range monitors gain adjustment factor between 0.95 and 1.00. The licensee also had the nuclear steam system supplier (General Electric) perform an evaluation which determined that plant safety had not been compromised. As an interim corrective action, the licensee added a software correction factor to compensate for the error of the static pressure shift on the transmitter span, until the feedwater flow transmitters were correctly calibrated. The licensee recalibrated both feedwater flow transmitters in accordance with the manufacturer's instructions and General Electric's recommendations during June 1994. The licensee determined that this calibration accounted for the static pressure effects on the instruments.

The licensee also stated that they planned the following corrective actions to prevent recurrence:

- Review of the design change process to enhance control of calibration data,

- Review the effectiveness of the operating experience review program and upgrade it, and

- Conduct training to ensure personnel were aware of the violation.

The inspector's review of the design change process indicated that the licensee had made changes to preclude this type of error. These changes included meetings to review the design, checklists to stimulate process effects, and an independent review of the design change.

The inspectors also evaluated the effectiveness of the licensee's operating experience review program and their recommendations for improvement. The inspectors noted that a diagnostic self assessment conducted during July and August 1994 concluded that the licensee had not benefitted sufficiently from the experience of other stations in the industry. The final report of the diagnostic self assessment cited untimely and narrowly focused evaluations as contributing to the station's weak performance in the operating experience review area, as well as a tendency to discount the applicability of many industry events to Cooper Nuclear Station. In addition, the self assessment noted a lack of accountability for meeting the requirements of the operating experience review program and ineffective periodic reviews of the program. The inspectors noted that the licensee had developed improvements to the operating experience review program to address the following attributes:

- Ownership of the operating experience review program. A permanent operating experience staff (with a supervisor reporting to the manager of events analysis) assumed full ownership of the operating experience program.

- Adequacy of operating experience review document reviews. The licensee developed guidance for evaluating historical responses to operating experience documents during the Phase I performance improvement plan. This guidance has become the standard for conducting operating experience review evaluations. In addition, a standard format had been established for documenting operating experience reviews to ensure consistency and thoroughness.

- Suitability of operating experience review procedure. The licensee judged the existing operating experience review procedures to be adequate to meet the programmatic requirements of the program.

- Timeliness of operating experience review responses. The licensee had improved the timeliness of these reviews. Previously, a typical response time for an operating experience document evaluation was on the order of 270 days. From March through June 1995, the average response time was 14 days.

- Effectiveness of operating experience review databases. In addition to the creating a field to track due date extensions, the licensee had enhanced the schedule field to allow better identification of action items that required special plant conditions for completion. Responsible action item owners were now identified down to the actual person performing the action, rather than just the action manager.

The inspectors determined that the licensee's actions appeared to effectively correct the operating experience review program problems. In addition, the inspectors determined that the day-to-day operation of the operating experience review group was meeting station needs for industry events information distribution, evaluation, and followup by assigned personnel.

The inspectors also noted that the licensee had presented training to the reactor operators and shift technical advisors making them aware of the violation with reactor power exceeding the steady state limit with reference to the incorrect calibration of the feedwater flow transmitters. This training was conducted during May 2-31, 1994. The inspectors review determined that the training was extensive and appeared to reinforce the calibration process and lessons learned.

3 FOLLOWUP - ENGINEERING (92903)

3.1 (Closed) Violation 298/93202-22: Inoperable Fire Doors

Background

This violation consisted of 20 examples of fire doors being declared inoperable. Many of the fire doors were found exceeding the door-to-door frame gap limit or the door-to-floor gap limit. The licensee responded to this violation in a letter dated June 20, 1994. The response stated that the reason for the violation was inadequate management oversight of the fire door inspection program. The licensee also erroneously assumed that personnel inspecting the fire doors had the necessary skills. Accordingly, based on the actual skill level of personnel, the procedure used for the fire door inspection was inadequate.

The remedial corrective actions taken by the licensee included reinspection of the fire doors with fire protection personnel present, and the formation of a corrective action review board. The purpose of this board was to evaluate and make recommendations to management to prevent recurrence of this event. The licensee's long-term corrective actions to prevent recurrence included revising fire door control procedures to ensure that operability requirements would be properly assessed; implementation of a quarterly preventative maintenance program for high traffic fire doors; ensuring that sufficient technical detail had been incorporated into related maintenance procedures; and development of a fire door inspection training program.

Inspector Followup

The inspectors reviewed Administrative Procedure 0.16, "Control of Doors," Revision 15, dated December 1, 1995. This procedure defined the various design-basis requirements credited to the installed doors and the station personnel responsibilities for maintaining compliance with the design basis. The inspectors determined that Procedure 0.16 included the necessary provisions to ensure that the operability requirements of the fire doors would be properly assessed. These provisions included fire watch personnel training and responsibilities, fire door examination prior to the door being declared operable, and requirements for when fire doors are left open or obstructed.

The inspectors verified that the licensee had identified, and placed, approximately 68-high traffic fire doors on the quarterly preventative maintenance program. The inspectors randomly selected five of these high traffic fire doors and verified, by reviewing the associated maintenance work orders, that the specified work to ensure that the doors were operable was performed.

The inspectors reviewed Surveillance Procedure 6.4.5.2.12, "Fire Door Annual Examination," Revision 9.1, dated June 13, 1994. This procedure provided instructions for maintenance personnel to examine fire doors with Technical Specification requirements. The inspectors determined that this procedure had incorporated sufficient technical detail to ensure that fire doors were properly inspected to meet door physical integrity, fit-up tolerance and operability.

The inspectors verified that the licensee had developed a lesson plan for the fire door inspection training. The "Fire Door Annual Examination (OJE)," Lesson EQP042-05-71, Revision 00.00, dated May 19, 1994, provided instructions to trainees in examination of fire doors. The inspectors reviewed the Qualification cards of five employees and verified that they had successfully completed Training Lesson EQP042-05-71.

During the plant walkdown of fire protection features, the inspectors did not identify any fire door discrepancies. The inspectors determined that the licensee had taken appropriate corrective actions to prevent recurrence of the fire doors problems identified in this violation, and to ensure fire door operability.

3.2 <u>(Closed) Violation 298/93202-23: Failure to Utilize Design Change Process for Insulation Changes</u>

<u>Background</u>

This violation concerned the licensee practice of modifying insulation on piping and equipment without employing the design change process. These insulation deviations contributed to the problem in restoring insulation that was removed for maintenance to its original design configuration.

In response to these issues, the licensee performed a walkdown inspection to determine the extent of deviation between the installed insulation and the configuration specified by design documents. The licensee also committed in their response of June 29, 1994, to take the following corrective actions:

- Develop a schedule for resolving the discrepancies resulting from the insulation walkdowns. Lessons learned from this event would be incorporated into general orientation and industry events training.

- Develop an insulation reference document to identify the original insulation design requirements. This document would be incorporated into the Design Criteria Document Program and references to the document was to be added to appropriate engineering and maintenance procedures.

<u>Inspector Followup</u>

The inspectors verified that the licensee had initiated immediate actions to address and prevent further insulation deficiencies. Deficiency Report 93-522, dated November 5, 1993, documented these corrective actions. The corrective actions included the development of interim insulation controls to ensure that all insulation work was captured under the maintenance work request process. These immediate corrective actions also included informing system engineers of the insulation problems and of the interim controls to resolve the discrepancies, resulting from the insulation walkdowns. Maintenance and engineering supervisors received copies of Deficiency Report 93-522 to make them aware of the interim controls for insulation work.

The inspectors reviewed the licensee engineering evaluation of the deviations identified during the insulation walkdown inspections documented in Deficiency Report 93-522. The inspectors noted that the engineering evaluation included an assessment as to the impact of the deficiencies on pipe stress analyses, as well as, room heat loads. The licensee engineering evaluation of the insulation discrepancies determined that there were no operability concerns.

The inspectors verified that the licensee had developed an insulation reference document to identify the original insulation design requirements for Cooper Nuclear Station. This information was contained in the "Topical Reference Information Manual for Thermal Insulation," Revision 0, dated June 20, 1994. The inspectors also verified that this document was also added to the appropriate engineering and maintenance procedures.

The inspectors concluded that the licensee had implemented appropriate corrective actions to assure that insulation design and configuration changes were performed in a manner commensurate to those applied to the original insulation design.

3.3 <u>(Closed) Unresolved Item 298/9513-01: Failure to Document Operability Evaluation</u>

<u>Background</u>

The licensee used a contractor (Erin Engineering and Research, Inc.) to analyze the susceptibility of the licensee's motor-operated valves to pressure-locking and thermal-binding conditions. The contractor documented their results in a report entitled, "Cooper Nuclear Station Generic Letter 89-10 MOV Program Pressure Locking and Thermal Binding Update," dated November 14, 1994. This report identified 12 motor-operated valves that were susceptible to pressure-locking conditions and 2 motor-operated valves that were susceptible to thermal-binding conditions, listed as follows:

<u>Motor-Operated Valves Susceptible to Pressure Locking</u>:

CS-MOV12A/B, Core Spray Inboard Injection
HPCI-MO19, High Pressure Coolant Injection
HPCI-MO58, High Pressure Coolant Injection Suppression Pool Suction
RCIC-MO21, Reactor Core Isolation Cooling Injection
RCIC-MO41, Reactor Core Isolation Cooling Injection Suppression Pool Suction
RHR-MO13A/B/C/D, Low Pressure Coolant Injection Suppression Pool Suction
RHR-MO16A/B, Residual Heat Removal Pump Minimum Flow Recirculation

<u>Motor-Operated Valves Susceptible to Thermal Binding</u>:

RHR-MO39A/B, Residual Heat Removal Suppression Pool Cooling

This unresolved item was generated to follow two concerns regarding this issue. The first concern involved the licensee's failure to formally assess the operability of the valves identified as being susceptible to the pressure-locking and thermal-binding conditions until the NRC asked for a documented operability basis in September 1995. The licensee stated that the engineering staff had an informal basis to believe that all of the valves were capable of performing their safety functions under the assumed design conditions, but this informal position had not been documented.

The second concern involved some of the assumptions the licensee used to establish the immediate operability basis for Valves CS-12A/B were not technically justified. Valve CS-12A/B are the Train A and B core spray system inboard injection valves. These valves are normally closed and must open to initiate flow through the core spray system. An open signal is sent to the valves approximately 20 seconds following initiation of a design basis accident. Specifically, the pullout thrust of 5500 pounds appeared very low compared to the measured closing thrust for these valves. The assumed valve factor of 0.35 appeared unreasonably low and the assumed bonnet depressurization rate, which was based strictly on an analytical method, appeared inconsistent with industry test results. At the time of the last inspection, the licensee had planned to test both valves during the upcoming outage. The inspectors anticipated a future review of the test data to evaluate the validity of the assumptions.

Inspector Followup

During the current inspection, the inspectors confirmed that the licensee had not documented an operability evaluation for the valves identified as being susceptible to pressure-locking and thermal-binding conditions in the November 1994 contractor study. The licensee stated that the operability question had been discussed at the time and that all of the valves were informally considered to be operable. However, the licensee stated that they had failed to formally document an operability basis for the subject valves. This failure was attributable to three major causes.

- Distraction from a large number of high-profile issues that needed to be resolved prior to startup from a prolonged forced outage.
- An ongoing transition of engineering functions from the Columbus, Nebraska, office to the plant site.
- A feeling that pressure-locking and thermal-binding condition issues could be temporarily tabled in anticipation of a new NRC generic letter addressing these topics. The NRC subsequently issued Generic Letter 95-07 in August 1995.

Administrative Procedure 0.5, "Condition Reporting," Section 8.3.4.3, stated ". . . an operability assessment [was] required for conditions that could possibly affect the operability of licensing basis SSCs [systems, structures, or components]." The inspectors noted that the licensee had classified some of the valves identified as susceptible to pressure locking or thermal binding as licensing basis components. The inspectors concluded that the licensee's failure to document an operability assessment of the valves identified in the contractor study was a violation of the licensee's administrative requirements (298/9605-01).

The second part of this unresolved item involved questions concerning the past operability of Valves CS-12A and CS-12B. The licensee's operability determination performed, at the inspectors' request, during a previous inspection was considered by the NRC to be acceptable for immediate operability purposes; however, some of the assumptions used in the analyses were questionable. As previously indicated, the licensee tested both of these valves during the recently completed Refueling Outage RE-16. The test results indicated that the static pullout thrust value used in the operability determinations for these two valves was not correct and had been significantly underestimated.

In the previous operability determination, the licensee had used a value of 5500 pounds-force for the static unwedging thrust for both Valves CS-12A and CS-12B. This value was based on a diagnostic test of Valve CS-12A performed during Refueling Outage RE-15. The licensee also used this value in the operability calculation of Valve CS-12B, for which a reliable diagnostic test was not available at that time. Test results from Refueling Outage RE-16 indicated an as-found static pullout thrust of 23,572 pounds-force for Valve CS-12A and 15,743 pounds-force for Valve CS-12B. As a result of these test results, the licensee concluded that Valve CS-12A would not have been capable of opening under the assumed design basis conditions if a pressure-locking condition existed. On the other hand, the licensee determined that Valve CS-12B was capable of operating successfully under these conditions. As corrective action, the licensee modified both of these valves during Refueling Outage RE-16 by drilling a 1/4-inch hole in the upstream valve disc and by resetting the close torque switches to reduce the magnitude of the seating thrust. These modifications eliminated the potential for either valve to become pressure locked.

The licensee stated that they would initiate a licensee event report to report the past inoperable condition of Valve CS-12A. However, the licensee also indicated that its electrical group was planning to analyze the degraded voltage calculation for Valve CS-12A to determine whether a higher degraded voltage condition could be established by removing some conservatisms. It was unclear to the inspectors whether this higher degraded voltage would be sufficient to result in a calculated past operable condition for Valve CS-12A.

The inspectors also identified two assumptions in the licensee's latest pressure-locking calculations for Valves CS-12A/B that were potentially nonconservative. The licensee assumed a 0.35 open valve factor for both valves. This value was based on a hydrostatic test of Valve CS-12A. The licensee computed the valve factor using a very small thrust event occurring just after the valve seat's unwedging, along with the differential pressure across the valve and the disc area. The inspectors considered this calculation to be an imprecise estimation of valve factor because the time history of the small thrust event could not be reliably correlated to the time history of the differential pressure force applied across the valve. The inspectors considered the result to have been highly speculative and may not represent the true frictional performance of the valve under forced flow conditions. Therefore, the inspectors considered the 0.35 valve factor assigned to Valves CS-12A/B to be insupportable. The inspectors noted that the licensee had previously used a valve factor of 0.5 for these valves during the Generic Letter 89-10 program closure. This value represented a more reasonable prediction of the valves' performance.

The second assumption questioned by the inspectors was the bonnet depressurization rate assumed in the pressure-locking calculation. This assumption had been challenged during a previous NRC inspection because the analytical method had not been validated by empirical testing. Since the previous inspection, numerous industry tests have been performed that have quantified the rate at which valve bonnets depressurize following rapid line depressurization. The measured rates have ranged from approximately 1 to 500 pounds per minute. The licensee's calculation assumed a bonnet depressurization of approximately 600 pounds in 12 seconds. This purely analytical assumption has still not been supported by testing and appears to greatly overestimate the rate at which the valve bonnet would depressurize in a design basis accident.

The licensee' efforts to address the apparent past inoperable condition of Valve CS-12A and the re-analysis of the valves degraded voltage design, as well as, the inspector's concerns with the validity of the licensee's assumptions for valve factor and bonnet depressurization will be followed as a new unresolved item (298/9605-02).

3.4 <u>(Closed) Inspector Followup Item 298/93202-03: Fire Drills</u>

<u>Background</u>

This item consisted of four concerns resulting from the licensee's conduct of an unannounced fire drill.

- The lack of communication between the fire brigade leader and the fire brigade members;

- The failure of the health physics technician to don protective clothing and respiratory gear and could not enter the area to assess radiological hazards;

- Two fire brigade members who could not locate air masks and entered the fire area without appropriate protective gear; and.

- A failure to provide sufficient drill observers to effectively evaluate the fire brigade's performance.

The licensee took several corrective actions for these observations. The corrective actions included:

- Placing two dedicated radios inside the control room.
- Providing additional training for security personnel concerning the location of respiratory equipment, and

- Providing additional observers for each fire drill.

Inspector Followup

The inspectors verified that the two dedicated radios were available in the control room for fire brigade use. The inspectors reviewed Fire Brigade Lesson Plan GEN005-01-40, "Fire Brigade Classroom Curriculum," and verified that all fire brigade personnel are trained concerning location and use of personal protection equipment. The inspectors reviewed completed fire drill records for 1995 and verified that the licensee was using three observers for the drills. The inspectors determined that licensee actions were appropriate to address this concern.

3.5 Other Areas Inspected

3.5.1 Motor-operated Valves in Hot Environment

The inspectors reviewed a listing of condition reports to assess the material condition of both the Generic Letter 89-10 and balance-of-plant motor-operated valves. The inspectors were particularly interested in lubrication and insulation degradation affecting motor-operated valves located in the hot main condenser bays because many instances of valve degradation were reported in the condition reports issued during Refueling Outage RE-16. The licensee had detected an adverse trend and had issued Special Condition Report CR3 95-1212 that collated numerous other condition reports for the purpose of developing a generic disposition. The inspectors considered the licensee's actions to be satisfactory; particularly, because these issues involved mainly nonsafety-related valves and no operational failures related to the observed degradations had occurred.

3.5.2 Diesel Generator Modification

The inspectors performed an overview of selected elements of Design Change DC/93-024, "Diesel Generator Upgrades." This modification added several pumps, a new governor, and other components to both emergency diesel generators. The installation of this design change had been problematic largely because some of the work performed by contractors had been faulty and required rework. There had also been a significant turnover among project managers as the project evolved and eventually became the critical path for startup from the outage.

The inspectors were mainly concerned with whether the installation and control deficiencies encountered during implementation of the modification could have resulted in defects that were not identified during post-modification testing. This did not appear likely based on the extensive testing that was performed following installation of the modification. The inspectors also noted that the licensee had adequately captured the administrative and technical problems in condition reports that were currently being pursued for resolution. The inspectors did not identify any additional concerns related to this design change beyond those identified in NRC Inspection Report 50-298/95-17.

4 REVIEW OF UPDATED FINAL SAFETY ANALYSIS REPORT (UFSAR) COMMITMENTS

A recent discovery of a licensee operating their facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR descriptions. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters.