UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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ARLINGTON, TEXAS 76011-8064

April 26, 2001

J. H. Swailes, Vice President of
Nuclear Energy
Nebraska Public Power District
P.O. Box 98
Brownville, Nebraska 68321

SUBJECT: COOPER NUCLEAR STATION - NRC INSPECTION REPORT 50-298/00-15

Dear Mr. Swailes:

On March 31, 2001, the NRC completed an inspection at your Cooper Nuclear Station. The enclosed report documents the inspection findings which were discussed on April 3, 2001, with Mr. William Macecevic and other members of your staff.

This inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. Within these areas, the inspection covered selected examination of procedures and representative records, observations of activities, and interviews with personnel.

Based on the results of this inspection, the NRC has identified four findings of very low safety significance (Green). Two of these findings were determined to involve a violation of NRC requirements. Because the violations were of very low safety significance, and because they were entered into your corrective action program, the NRC is treating the findings as noncited violations, in accordance with Section VI.A of the NRC's Enforcement Policy. If you contest these violations, you should provide a response with the basis for your denial within 30 days of the date of this inspection report, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Cooper facility.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/NRC/ADAMS/index.html (the Public Electronic Reading Room).

Should you have any questions concerning this inspection, we will be pleased to discuss them with you.

Sincerely,

/RA/

Charles S. Marschall, Chief
Project Branch C
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Docket: 50-298
License: DPR-46

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NRC Inspection Report
50-298/00-15

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RIV:SRI:DRP/C	RI:DRP/C	PE:DRP/C	SOE:DRS/OB	C:DRS/OB
JAClark	MCHay	WCSifre	TOMcKernon	ATGody
E - DPLoveless	***E - DPLoveless***	***/RA/***	***JLShackelford for***	
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DRS/EMB	C:DRS/EMB	PSI:DRS/PSB	C:DRS/PSB	C:DRP/C
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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket:	50-298
License:	DPR 46
Report No.:	50-298/00-15
Licensee:	Nebraska Public Power District
Facility:	Cooper Nuclear Station
Location:	P.O. Box 98 Brownville, Nebraska
Dates:	December 31, 2000, to March 31, 2001
Inspectors:	J. Clark, Senior Resident Inspector W. Sifre, Acting Senior Resident Inspector M. Hay, Resident Inspector T. McKernon, Senior Operations Examiner M. Runyan, Senior Reactor Inspector D. Schaefer, Physical Security Inspector
Approved by:	C. Marschall, Chief, Project Branch C Division of Reactor Projects

SUMMARY OF FINDINGS

Cooper Nuclear Station
NRC Inspection Report 50-298/00-15

IR 05000298-00-15; 12/31/2000-03/31/2001; Nebraska Public Power District; Cooper Nuclear Station. Integrated Resident/Regional Report; Safety Eval. Prog., Heat Sink Perf., Personnel Perf. During Nonroutine Plant Evolutions, Postmaintenance Testing, and Physical Security Plan

The inspection was conducted by resident inspectors and regional specialists. The inspection identified four Green findings, two of which was a noncited violation. The significance of issues is indicated by their color (Green, White, Yellow, Red) and was determined by the Significance Determination Process in Inspection Manual Chapter 0609.

Cornerstone: Initiating Events

- Green. Plant operators failed to properly control plant transients during a normal reactor shutdown. Improper operator actions, to control reactor vessel level, could have produced a loss of feed initiating event (Section 1R14).

  The inspectors determined the event was of very low safety significance using the guidance of Inspection Manual Chapter 0609. The inspectors noted that Reactor Feed Pump A remained available, other emergency core cooling system equipment was capable of injecting, and that the length of the transient was only slightly more than an hour.

Cornerstone: Mitigating Systems

- Green. Three elements for the testing of the residual heat removal heat exchangers may have resulted in an inaccurate estimation of their performance under design-basis conditions. The testing was often conducted under dynamic rather than stabilized thermal conditions, the testing was not conducted during the worst season for biological growth (and the design basis temperatures), and the testing was conducted after a flush of the heat exchanger that may have had the effect of improving the thermal performance (Section 1R07).

  The risk associated with the three anomalies in the testing of the residual heat removal heat exchangers was determined to be of very low safety significance because the cumulative effect was likely to be less than the available thermal performance margin. Additional factors that mitigated this concern were a recent change-out of valves in the service water system that reduced the standby leakage flow through the residual heat removal heat exchangers and a recently-initiated practice of running normal flow through the heat exchangers weekly for 30 minutes, both of which should have the effect of reducing the buildup of slime and scale.

- Green. The inspectors identified a noncited violation for the failure to document and maintain a design standard, for surge suppression varistors in the Division 2 emergency diesel control circuit. The use of incorrect values for these components caused the generator to frequently trip during the shutdown process and thereby be unavailable for immediate restart (Section 1R19).

The noncited violation was of very low safety significance because this condition only affected one diesel, and the condition only affected its ability to do a hot restart immediately after a previous run. The time that a diesel is in this condition, compared to the standby condition, is very small. Therefore the probability of an actual demand for the diesel during these conditions was very low.

Cornerstone: Physical Protection

- Green. Section 9.2.B of the licensee's physical security plan and paragraph 6.5 of the licensee's security Procedure 2.14 require that, upon degradation of a portion of the perimeter detection system, an observer or armed guard with a view of the degraded coverage area, will be positioned within 10 minutes. On November 6, 2000, the licensee identified that an observer or armed guard was not posted at a degraded segment of the perimeter detection system until 48 minutes following degradation, as described in the licensee's corrective action program, reference Problem Identification Report 4-12402 (Section 4OA3).

  This noncited violation was determined to be greater than minor in nature because the condition, if left uncorrected, would become a more significant safety concern. The issue was further determined to be of very low safety significance (Green) by the significance determination process because there were not greater than two similar findings in the last four quarters.

Report Details

Operators conducted a plant shutdown on March 3, 2001, for a midcycle outage. Operators returned the plant to full power on March 21, 2001. During all other times, the plant operated at 100 percent power, except for minor power reductions for control valve testing and control rod pattern adjustments.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R02 Changes to License Conditions and Safety Analysis Report (71111.02)

a. Inspection Scope

The inspectors reviewed eight safety evaluations to verify that the licensee had appropriately considered the conditions under which the licensee may make changes to the facility or procedures or conduct tests or experiments without prior NRC approval.

The inspectors reviewed 12 safety evaluation screenings, in which the licensee determined that safety evaluations were not required, to ensure that a full evaluation was consistent with the requirements of 10 CFR 50.59.

The inspectors also reviewed problem identification reports, design changes, and other related documents initiated by the licensee that addressed problems or deficiencies associated with 10 CFR 50.59 to ensure that appropriate corrective actions were being taken.

b. Findings

Background:

Cooper Nuclear Station was originally licensed with two qualified offsite ac power sources: (1) the 345 kV source, and (2) an emergency 69 kV source supplied from the Omaha Public Power District power grid. This arrangement was reviewed and accepted by the NRC in a safety evaluation report, dated February 14, 1973, which stated, “Our review of the offsite power system revealed that the design satisfies the requirements of General Design Criteria 17 and IEEE-308.”

General Design Criteria 17 contained in Appendix A to 10 CFR Part 50 requires:

- [offsite power] shall be supplied by two physically independent circuits (not necessarily on separate rights of way) designed and located so as to minimize, to the extent practical, the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both circuits is acceptable.

- Each of these circuits shall be designed to be available in sufficient time following a loss of all onsite alternating current power supplies and the other offsite electric power circuit, to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded.

- One of these circuits shall be designed to be available within a few seconds following a loss-of-coolant accident to assure that core cooling, containment integrity, and other vital safety functions are maintained.

- Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electric power supplies.

Changes to the facility's design basis that continue to satisfy these requirements are allowed in accordance with 10 CFR 50.59 provided that a Technical Specification change is not required and that an unreviewed safety question is not created.

In 1981, Cooper Nuclear Station modified the offsite ac power supply by building a 161 kV substation just south of the existing 345 kV Cooper Nuclear Station substation and connecting a new 161 kV line from Auburn, Nebraska, to the 161 kV substation. This 161 kV line was intended as a power feed to Auburn, Nebraska (see attached diagram). The 345 kV system feeds power to the T2 autotransformer (345 kV - 161 kV - 13.8 kV), which feeds 161 kV power to the 161 kV Auburn, Nebraska, line and to the startup station service transformer. Power is stepped down to 4160 V for the vital buses (1F and 1G). The T2 autotransformer also powers loads through a 13.8 kV/12.5 kV stepdown transformer.

<u>161 kV Offsite Power Source</u>

The inspectors identified that the 161 kV Auburn, Nebraska, line has never been analyzed and accepted as a General Design Criteria 17 qualified offsite ac power source. The original design basis had the power source transferred from the 345 kV/161 kV startup station service transformer to the 69 kV emergency transformer upon a loss of the 345 kV source. Under the original design basis for a design basis accident (e.g., large break loss of coolant accident) the emergency core cooling system equipment would start, sequentially load, and be powered from the startup station service transformer. Should a loss of power from the startup transformer occur during the design basis accident, the loads on the vital buses would strip on signals from the undervoltage relays, the power would be transferred to the 69 kV emergency station service transformer, and the vital loads would sequence onto the vital buses.

In the facility's present design, during a design basis accident with a subsequent loss of the 345 kV power source, the startup station service transformer would remain powered by backfeeding power from an unqualified power source (the 161 kV Auburn, Nebraska, line). Cooper Nuclear Station has stated in correspondence to the NRC (proposed Technical Specification change withdrawal letter, November 1990) that the 161 kV line could not be credited as a 10 CFR Part 50, Appendix A, General Design Criteria 17, qualified source because of seasonal variations in capacity, principally caused by air conditioning and irrigation loads in the summertime. This backfeed capability to the site and the startup station service transformer has not been verified and substantiated through analysis. The facility stated that the line was a plant enhancement so that maintenance on the T2 transformer could be performed.

Additionally, the site would lose a 13.8kV step down to a 12.5 kV power feed from the autotransformer (the 345 kV source) when breaker ACB 110 would trip open upon undervoltage on the T2 autotransformer. This power source feeds other downstream equipment (site auxiliaries), which may be needed for the facility's ability to combat an emergency. Some of these loads include the emergency operations facility, technical support center, fire protection pump stations, and others which can only be returned to power by manually transferring to the 69kV emergency power source.

It was noted that changes were made to the Technical Specification Bases for B3.8.1, which implies that the licensee considers the 161kV Auburn, Nebraska, line as a qualified source. It states that "The offsite power sources are a startup station transformer, which connects to the 161 kV switchyard and a separate emergency station service transformer energized by a 69 kV line. The 161 kV switchyard is connected to one 161 kV line, which terminates in a switchyard near Auburn, Nebraska, and the 345/161 kV, 300 kVA autotransformer, which connects to the 345 kV/161 kV switchyard." Discussions with facility engineers indicated that they do not consider the 161 kV Auburn, Nebraska, line as a qualified source. The licensed operators in the control room have procedures which have them verify only the power feed from the startup station service transformer and do not require them to enter Technical Specification 3.8.1 on a loss of either the 69 kV or the 345 kV, as long as they have ac power supplied through the startup station service transformer. Changes were also made to the Updated Safety Analysis Report, Section VIII, 2, which states that "The five 345kV lines and one 161kV line are individually or jointly capable of supplying power to the startup station service transformer." There was no mention that the 161 kV line from Auburn, Nebraska, was an unqualified offsite line and no analysis thereof was included. On the contrary, the Updated Safety Analysis Report states, on page VIII-2-5, "The startup ac power source is in conformance with 10 CFR Part 50, Appendix A, General Design Criteria 17." However, because the 161 kV line was unqualified and cannot be credited, the emergency core cooling system loads could shed and a second cycling (sequential loading) onto the vital buses, now powered from the 69 kV emergency transformer, would occur. This sequence was different from that described in the facility's original design basis. The licensee had previously performed a 10 CFR 50.59 evaluation on the 161 kV line in Unreviewed Safety Question Evaluation 1998-0073, dated July 26, 1999, but only addressed the independence requirements between the 69 kV emergency line and the 161 kV line. This evaluation was inadequate because it did not address the above discussed change in plant response. The potential of second cycling prolongs the plant's response to a design basis accident and increases the likelihood of safety equipment failures, which could complicate postloss-of-coolant accident operator recovery actions.

This issue is considered to be an unresolved item awaiting additional technical evaluation by the licensee and the NRC (50-298/0015-01).

1R04 Equipment Alignments

.1 Partial walkdown

a. Inspection Scope

The inspectors did a partial walkdown of the reactor core isolation cooling system, the reactor equipment cooling system, the Division I 125 Vdc distribution system, and the Division II emergency diesel. The inspectors used the facility Updated Safety Analysis Report, system operating procedures, design documents, and drawings to verify that these systems could perform their design function(s). The inspectors also verified the operability of these systems while redundant or associated equipment was out of service for maintenance and testing.

b. Findings

The inspectors identified no findings of significance.

.2 Complete walkdown

a. Inspection Scope

The inspectors did a complete system walkdown of the offsite ac power system. The inspectors used the facility Updated Safety Analysis Report, system operating procedures, design documents, and drawings to verify that the offsite power system could perform its design function. The inspectors reviewed all problem identification reports issued for the system for the last 6 months. The inspectors also conducted interviews with operators and engineers to determine if workarounds existed or if unauthorized modifications had been installed on the system.

b. Findings

During review of the 69 kV offsite power circuit operating procedures, the inspectors noted that operators could align the 69 kV offsite power source to supply the 12.5 kV subsystem. This subsystem feeds other downstream equipment or site auxiliaries. Examples of these auxiliaries include the emergency operations facility and pump stations for fire protection. The inspectors noted design documents neither described nor analyzed the 69 kV line for supporting the 12.5 kV loads, along with the essential plant loads needed for a safe shutdown. The licensee agreed that the 12.5 kV subsystem should not be powered from the 69 kV line during power operations and made procedural changes to control this activity. This issue is unresolved awaiting additional technical evaluation by the licensee and the NRC. This issue will be tracked as an additional example of the unresolved item (50-298/0015-01) described in Section 1R02, “Changes to License Conditions and Safety Analysis Report.”

On March 3, 2001, the inspectors conducted a walkdown of accessible portions of the off-site ac power circuits. The inspectors specifically observed the status and apparent physical condition of the breakers and equipment associated with the circuits. While conducting the review, the inspectors noted a discrepancy between the design alignment requirements specified in the Updated Safety Analysis Report, and Technical Specification 3.8.1 Bases.

Section VIII of the Updated Safety Analysis Report states, “If the normal station service transformer (powered by the main generator) is lost, the startup station service transformer, which is normally energized, will automatically energize the 4160 V Buses 1A and 1B as well as their connected loads, including the critical buses. If the startup station service transformer fails to energize the critical buses, the emergency station service transformer, which is normally energized, will automatically energize both critical buses.” However, the Technical Specification 3.8.1 Bases document states that, for the limiting condition for operation, “one offsite circuit must be capable of providing power to one 4.16 kV critical bus and the other offsite circuit must be capable of providing power to the other 4.16 kV critical bus.”

The inspectors questioned station operators about the requirements for offsite circuits. Operators stated that Technical Specification 3.8.1(a) required two qualified circuits between the offsite transmission network and the onsite Class 1E ac electrical power distribution system. The operators considered the Technical Specification Bases as the actual requirements for offsite power circuit functionality. Upon subsequent review, the inspectors determined that the operators had used the Bases' less conservative interpretation, for offsite circuit operability, on at least two previous occasions. On both September 4 and 15, 2000, the licensee failed to declare an offsite circuit inoperable when it was only capable of supplying one critical bus.

Single offsite circuits only capable of supplying a single critical bus may be in violation of NRC requirements. However, the NRC will further evaluate the role of these offsite circuits. This issue will be tracked as a third example of the unresolved item (50-298/0015-01) described in Section 1R02, “Changes to License Conditions and Safety Analysis Report.”

1R05 Fire Protection

.1 Routine Inspection

a. Inspection Scope

The inspectors did routine plant tours to assess the material condition of fire protection equipment and proper control of transient combustibles. The specific risk-significant areas inspected included:

- Division 2 diesel generator room
- Control room
- Division I battery room
- Division II battery room
- Reactor building northeast quad

b. Findings

The inspectors identified no findings of significance.

.2 Drills

a. Inspection Scope

The inspectors observed the fire brigade exercise for the first quarter of 2001. The inspectors observed the use and condition of firefighting equipment. They also observed the command and control of the fire brigade and monitored communications. The inspectors interviewed fire brigade members about firefighting methods and strategies.

b. Findings

No findings of significance were identified.

1R06 Flood Protection

.1 Seasonal

a. Inspection Scope

In preparation for the spring thaw and the watershed collection of recent heavy rainfall, the inspectors reviewed the flood protection measures at the facility. The inspectors reviewed external flood protection barriers for those susceptible areas containing risk significant structures, systems, and components as analyzed by plant engineering personnel. Specifically, the inspectors reviewed the flood barriers for the diesel generator building, reactor building, and control building. The inspectors performed a review of the licensee's Emergency Procedure 5.1FLOOD, "Flood," Revision 0. This procedure describes the operator actions required to mitigate the consequences of a flood and the materials needed to combat an external flooding event. The inspectors toured the applicable areas to verify the appropriate inventory of materials.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

The inspectors reviewed selected documents related to the inspection, maintenance, cleaning, and testing of safety-related heat exchangers and heat sinks with a potential to increase risk at the Cooper Nuclear Station. The three heat sinks and heat exchangers chosen were ranked high in the plant risk assessment and are listed as follows:

a. Reactor equipment cooling heat exchangers
b. Residual heat removal heat exchangers
c. Service water intake

.1 Performance of Testing, Maintenance, and Inspection Activities (Biennial)

a. Inspection Scope

The inspectors reviewed the licensee's test methodology for the selected heat sinks/exchangers and also reviewed the results from the most recent tests. Specifically, the inspectors verified proper extrapolation of test conditions to design conditions, that tests used appropriate instrumentation, and that tests appropriately accounted for instrument inaccuracies. Additionally, the inspectors verified that these test results were being adequately trended, the causes of the trends were being assessed, and necessary actions were being taken for any step changes in these trends.

b. Findings

The inspectors observed that three elements of the testing of the residual heat removal heat exchangers may cause the results to be somewhat unrepresentative of performance under design-basis conditions. Specifically, the following three points were identified:

(1) The test is often conducted under conditions of rapidly changing temperatures. An example is the test of the Residual Heat Removal System B heat exchanger on October 14, 2000. During this test, flow and temperature measurements of service water and residual heat removal flow were taken over an 8-minute period. During that time, the inlet residual heat removal temperature decreased by 16°F and the outlet residual heat removal temperature decreased by 10°F. Concurrently, the service water outlet temperature increased by 4°F. Because the licensee did not establish equilibrium conditions during the test, a random error was introduced into the calculation of the fouling factor, which was then used to predict performance under design basis conditions. The inspectors noted that the licensee had not provided a margin to account for the dynamic thermal conditions.

(2) Testing of the residual heat removal system heat exchangers is conducted in the spring and fall months during shutdowns for refueling outages. However, the peak time for biofouling of the heat exchangers is during the summer months, when higher river water temperatures allow for increased biological growth and plating on the inner surfaces of the heat exchanger tubes. Therefore, the fouling

factor measured in the spring or the fall may be quantitatively less than the fouling factor that exists in the summer. Furthermore, the measurement of the fouling factor in the spring and fall may be made additionally unrepresentative of summer conditions because of the scouring effect of the pumps pushing water and suspended sand through the tubes. This sand acts as a scouring agent to remove silt and scale, resulting in a lower fouling factor in a very short period of time after the pumps are started. With less sand available in the summer, the silt and scaling in the tubes may persist for a greater length of time; therefore, the licensee's test process may cause an error in the prediction of design basis performance (the design basis condition is 90°F river water which exists only in the summer).

(3) The licensee's test procedure includes a 30-minute (minimum) period of time in which the service water booster pumps are running through the residual heat removal heat exchangers before any test measurements are taken. The movement of this fluid with suspended sand particles results in a scouring and cleaning effect on the inner surfaces of the heat exchanger tubes. As a consequence, the fouling factor measured after this cleaning effect has occurred may not be representative of the fouling factor that would exist at the outset of a design basis accident.

The inspector observed several mitigating facts to the three concerns noted above. The licensee was running service water through the system on a weekly basis for approximately one half hour on each heat exchanger. This would have the effect of reducing the buildup of slime and scale over time. Additionally, valves in the service water system were recently replaced and much less leakage flow was passing through the heat exchanger than occurred previously, which may have the effect of reducing the accumulation of slime and biological scale. These additional factors should reduce the buildup of slime and scale.

The inspector noted that the residual heat removal heat exchangers were generally demonstrating thermal margins in the range of 10 to 15 percent. Heat Exchanger B was somewhat more marginal and was projected, using a very conservative degradation rate, to be close to its thermal performance limit by the end of the current operating cycle (November 2001). However, the licensee intended to retest this heat exchanger during a planned outage in March 2001. The licensee engineers stated that they expected to see no significant degradation from the last test.

The inspectors determined that the cumulative effect of the three issues discussed above was likely to be less than the available thermal performance margin. The identification of this issue is considered to be a finding (50-298/0015-02). The inspectors considered this finding to have a credible impact on safety because it could eventually affect (given future aging and plugging of tubes) the operability, availability, reliability, or function of the residual heat removal heat exchangers. However, because of the noted mitigating factors, the current significance of this finding was considered very low.

.2 Verification of Conditions and Operations Consistent with Design Bases (Biennial)

a. Inspection Scope

The inspectors verified that the heat sink and heat exchanger test criteria were consistent with the design bases. Specifically, the inspectors reviewed the applicable design basis calculations to ensure that the thermal performance test acceptance criteria were being applied consistently throughout the calculations. The inspectors also verified that the appropriate values for fouling and tube plugging were within the values used in the design basis calculations.

b. Findings

No findings of significance were identified.

.3 Reactor Equipment Cooling Heat Exchangers (Annual)

a. Inspection Scope

The inspectors reviewed selected documents related to the inspection, maintenance, cleaning, and testing of safety-related heat exchangers and heat sinks with a potential to increase risk at the Cooper Nuclear Station. The inspectors specifically reviewed these factors for the reactor equipment cooling heat exchangers. Additionally, the inspectors verified that test results were being adequately trended and that the causes of the trends were being assessed. The inspectors also reviewed problem identification reports, submitted during the previous 6 months, for these heat exchangers.

b. Findings

No findings of significance were identified.

.4 Identification and Resolution of Problems

a. Inspection Scope

The inspectors examined the licensee's corrective action program for significant problems affecting the selected components over the past 2 years. The inspectors assessed the adequacy of the licensee’s actions to correct the identified deficiencies.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

.1 Quarterly Simulator Training Reviews

a. Inspection Scope

On March 14, 2001, the inspectors attended a simulator exercise for licensed operator requalification. The inspectors reviewed the scenario, observed event initiation, and monitored the operators' response to various plant problems. The inspectors observed the exercise for proper emergency plan usage, proper emergency declarations, and fidelity of the simulator to the actual control room.

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule Implementation

.1 Maintenance Effectiveness Reviews

a. Inspection Scope

The inspectors reviewed the licensee's maintenance rule implementation for the following structures, systems, or components that displayed performance problems:

- Division 2 diesel generator
- High pressure coolant injection system
- Control room emergency filtration system
- Zulu sump pumps
- Reactor recirculation flow controllers
- Division I 125 Vdc battery

The inspectors verified that engineering personnel adequately tracked and trended failures and performance data for these components. The inspectors reviewed selected problem identification reports, associated with these systems, to decide if licensee staff had properly captured potential maintenance rule issues.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors reviewed risk assessments done for selected planned maintenance activities and emergent work. Inspectors also reviewed risk assessments to verify that the licensee effectively controlled risk-significant equipment alignments. The inspectors verified that work control and operations personnel were aware of risk categories and applicable contingency actions. The inspectors also verified that the licensee properly controlled troubleshooting and repairs associated with emergent work activities. Specifically, the inspectors reviewed the following activities:

- Risk profile and activities developed for Midcycle Outage 01-01
- Effects of intake structure dredging on the service water system
- Potential inoperability of safety relief valves because of environmental qualification concerns
- Emergent issue of degraded or inadequate fire seals discovered during audit

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Nonroutine Plant Evolutions and Events

a. Inspection Scope

On March 3, 2001, the plant was shut down to conduct a midcycle outage. Several unexpected equipment responses and abnormal transients occurred during this evolution. The inspectors observed portions of the evolution and reviewed parameter logs and printouts. They also conducted interviews with operators and plant staff to learn the potential cause(s) and significance of the evolution.

b. Findings

On March 3, 2001, licensed operators manually scrammed the Cooper reactor from 18 percent power as part of a planned shutdown for a midcycle outage. The transients that occurred following the scram were the result of equipment deficiencies and operating crew performance problems. Although this event indicated a need for improvement in licensed operator human performance, the resulting plant perturbations were of very low safety significance.

Following the reactor scram, vessel water level initially dropped, as expected, then increased until a high reactor level signal tripped the operating reactor feedwater pump. In response to the high level condition, operators used the reactor water cleanup system to drain the vessel.

The high reactor water cleanup flowrate during the drain caused high temperatures in the system as well as in the reactor equipment cooling system, the system that cools reactor water drains from the reactor water cleanup system. Water in the reactor equipment cooling system expanded rapidly as it was heated. This resulted in a reactor equipment cooling system surge tank high level and the associated main control room alarm. Shortly after this alarm, the reactor water cleanup system isolated on high temperature caused by a high flowrate through the system heat exchangers. The operators also received reactor equipment cooling system high pressure and surge tank low level alarms. Plant operators found water on the floor surrounding the system surge tank, and water in the system was below the tank's sight glass level.

As the system drained and reactor water continued to boil off, licensed operators attempted to restart Reactor Feedwater Pump B; however, it could not be reset following the original high level trip. After starting Reactor Feedwater Pump A, licensed operators elected to secure it because pump vibration was abnormally high. Without a ready source of main feedwater, reactor vessel water level dropped to near the low level scram setpoint. Operators started the reactor core isolation cooling system to restore water level, approximately 45 minutes after the loss of feedwater on high level.

Immediately after initiating injection, the shrink from the cold water caused a reactor low water level scram, resulting in Groups 2, 3, and 6 containment isolations. The reactor water cleanup system and secondary containment automatically isolated. Reactor water level was recovered using the reactor core isolation cooling system. Operators significantly reduced the system flow once reactor vessel level increased to clear the low level alarm point.

With reduced flow from the reactor core isolation cooling system, reactor vessel water level again decreased rapidly. Licensed operators inserted a manual reactor scram signal in lieu of an automatic scram on low reactor vessel level. Level was restored and reactor core isolation cooling was secured.

An additional complication occurred during recovery of the secondary containment following the automatic isolations. Licensed operators could not maintain the required differential pressure and declared secondary containment inoperable. Approximately 10 minutes later, secondary containment was restored.

After the event, inspectors interviewed members of the operating crew and plant management. These individuals described several problems to the inspectors. Operations management stated that the operating crew had previous performance problems and was one of two crews that had failed simulator exercises in September of 2000. Plant management also stated that proper command and control of the event was not demonstrated by the crew. Finally, the inspectors learned that several potential equipment malfunctions contributed to the problems. Plant operators initiated a problem identification report (4-14539) to enter the event into the corrective action program.

The inspectors determined that the event had an actual impact on plant safety. Improper operator actions, to control reactor vessel level, could have produced a loss of feed initiating event. The inspectors determined that the event was of very low safety significance using the guidance of Inspection Manual Chapter 0609. Reactor Feed Pump A remained available, emergency core cooling system equipment was capable of injecting, and the length of the transient was only slightly more than one hour. Both NRC regional senior reactor analysts, and the licensee's analysts, stated that the delta for core damage frequency was approximately 1.0e-6, which did not indicate significantly elevated risk.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the technical adequacy of three operability evaluations to determine if continued operability was justified. The reviewed assessments included:

- Updated assessment of drywell spray interaction with primary containment (Radiological Condition Report 2000-0378)

- Operability assessments for 161 kV and 69 kV offsite ac circuits

- Operability evaluation for Weidmuller terminal blocks in the drywell (Problem Identification Report 4-12831)

b. Findings

No findings of significance were identified.

1R16 Operator workarounds

a. Inspection Scope

The inspectors reviewed the current list of operator workarounds. The inspectors also reviewed the licensee's lower-tier list of operator concerns to find whether any of these issues should be considered as workarounds. The inspectors reviewed the cumulative effects of workarounds and discussed this with operation's management.

b. Findings

During this inspection period, the inspectors identified a number of workarounds that were not included on the licensee's list, nor were they included in the corrective action program.

The inspectors noted, during the review of the problems associated with the plant shutdown for the midcycle outage (see Section 1R14), that several operator workarounds were included in the feedwater system operating procedure. Examples of these included:

- A note that startup feedwater flow control valves leaked so excessively that shutting the discharge valves may be required to control vessel level.

- A note to run only Reactor Feedwater Pump B, during single pump operation, because Pump B has a longer suction pressure trip delay to enhance system stability.

The inspectors noted that the excessive feeding of the vessel, through the leaking valves, presented a challenge to the operators to maintain proper level. The inspectors also noted that, partially because of the reliance on Pump B for single pump operation, the operators became confused about the proper alignment and conditions required to start Pump A during the event.

Several licensed operators stated that, once incorporated into a plant procedure, they no longer considered these issues to be operator workarounds. The operators gave the inspectors additional examples of workarounds that were included in plant procedures. These included essential functions such as securing the control room emergency filtration system and repositioning dampers in that system.

The inspectors noted that the institutionalizing of workarounds could mask the overall effect, or significance, of these workarounds. The operations manager stated that he was assigning an individual to identify such workarounds that were placed in procedures. This individual would also canvas the operators to determine where additional workarounds may be located. The operations manager stated that, once all of these issues were identified, the collective significance would be determined and corrective actions taken as necessary. Subsequently, a senior manager was assigned as management oversight of this issue.

The inspectors determined that each of the specific equipment deficiencies identified had been documented in the licensee's corrective action program and/or work documents. However, the inspectors placed this issue in the inspection report to document an item that may have cross-cutting human performance issues when combined with other inspection findings.

1R19 Postmaintenance Testing

a. Inspection Scope

The inspectors observed or evaluated postmaintenance testing done on the following equipment to decide whether the tests adequately confirmed equipment operability:

- Postmaintenance testing after modification to the 161 kV disconnect
- Postmaintenance testing of reactor recirculation flow controllers
- Postmaintenance testing for Weidmuller terminal block replacements in the drywell
- Postmaintenance testing after repairs to the Zulu sump pumps
- Postmaintenance testing of the Division II emergency diesel generator controller

b. Findings

In December 2000, the Division 2 emergency diesel generator tripped several times while being shut down. Technicians localized the problem to the controller and did maintenance to replace the controller. On January 18, 2001, the Division 2 emergency diesel generator again tripped while shutting down. Maintenance and engineering personnel observed relay spiking in the controller almost every time the diesel was secured. Engineers subsequently determined that the surge suppression varistors in the control circuit were oversized. Engineers stated that the design control documents for the diesel control circuits included no specific varistor requirements.

On January 23, 2001, maintenance personnel replaced the varistors via engineering Change CED-2001-0018. Maintenance and operations personnel subsequently did postmaintenance testing of the diesel. The inspectors noted that plant engineers verified that the Division 1 emergency diesel generator had properly sized varistors for this application.

The inspectors determined that trips caused by incorrect varistors, in the Division 2 emergency diesel generator, could affect the ability to do a hot restart of the diesel, immediately after a previous run. However, this did not affect the ability to start and load the diesel from normal standby conditions.

Criterion III of 10 CFR Part 50, Appendix B, requires that measures shall be provided to assure that appropriate quality standards are specified and included in design documents and that deviations from such standards are controlled. The failure to document and maintain a design standard, for surge suppression varistors in the diesel control circuit, is a violation of Criterion III of 10 CFR Part 50, Appendix B. The inspectors are treating this as a noncited violation (50-298/0014-02) consistent with Section VI.A of the NRC Enforcement Policy. The licensee documented this issue in their corrective action process as Problem Identification Report 4-13798.

The inspectors determined that this issue had an actual impact on plant safety. The use of improperly sized surge suppression varistors caused diesel trips, which could prevent immediate restarts, thereby affecting diesel availability. The noncited violation was of very low safety significance because this condition only affected one diesel, and the condition only affected its ability to do a hot restart immediately after a previous run. The time period that a diesel is in this condition, compared to the standby condition, is very small. Therefore the probability of an actual demand for the diesel during these conditions was very low.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors observed or reviewed the following tests:

- Surveillance Procedure 6.SUMP.101, “Z Sump and Air Ejector Holdup Line Drain Operability Test”
- Surveillance Procedure 6.DWLD.301, “Drywell Floor Drain Sump Flow Measuring System Functional Test”
- Surveillance Procedure 6.EE.610, “Off-Site AC Power Alignment”

- Surveillance Procedure 6.1CS.100, “Core Spray Test Mode Surveillance Operation”
- Surveillance Procedure 6.1DG.101, “Diesel Generator 31 Day Operability Test”
- Surveillance Procedure 6.RCIC.102, “RCIC IST and 92 Day Test”
- Surveillance Procedure 6.REFUEL.304, “Refueling Interlocks Functional Test”

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed temporary modifications to important safety equipment at the facility. The inspectors evaluated the modifications to ensure that equipment could provide its intended safety function with the installed modification or was appropriately considered inoperable. Records and postmaintenance tests were also reviewed, as applicable, to ensure that temporary modifications were properly removed and equipment was properly restored. The inspectors reviewed the following temporary modifications:

- High pressure coolant injection system temporary instrumentation
- 161 kV switchyard disconnect temporary jumper
- Sump Z modification to essential/nonessential limit switches

b. Findings

No findings of significance were identified.

3. SAFEGUARDS

Cornerstone: Physical Protection

3PP1 Access Authorization (71130.01)

a. Inspection Scope

The inspector performed the following inspection activities:

- Reviewed licensee event reports and safeguards event logs to identify problems in the access authorization program

- Reviewed procedures, audits, and self-assessments of the following programs/areas: behavior observation, access authorization, fitness-for-duty, supervisor and escort training, and requalification training

- Interviewed six supervisors/managers and six individuals who had escorted visitors into the protected and/or vital areas to determine their knowledge and understanding of their responsibilities in the behavior observation program

- Reviewed condition reports, licensee event reports, safeguards event logs, audits, selected security event reports, and self-assessments for the licensee's access authorization program to determine the licensee's ability to identify and resolve problems

b. Findings

No findings of significance were identified.

3PP2 Access Control (71130.02)

a. Inspection Scope

The inspector performed the following inspection activities:

- Reviewed licensee event reports and safeguards event logs to identify problems with access control equipment

- Reviewed procedures and audits for testing and maintenance of access control equipment and for granting and revoking unescorted access to protected and vital areas

- Interviewed security personnel concerning the proper operation of the explosive and metal detectors, X-ray devices, and key card readers

- Observed licensee testing of access control equipment and the ability of security personnel to control personnel, packages, and vehicles entering the protected area

- Reviewed procedures to verify that a program was in place for controlling and accounting for hard keys to vital areas

- Reviewed the licensee’s process for granting access to vital equipment and vital areas to authorized personnel having an identified need for that access

- Reviewed condition reports, licensee event reports, safeguards event logs, audits, selected security event reports, and self-assessments for the licensee's access control program in order to assess the licensee's ability to identify and resolve problems with the access control program

- Interviewed key security department and plant support personnel to determine their knowledge and use of the corrective action reports and resolution of problems regarding repair of security equipment

b. Findings

No findings of significance were identified.

3PP4 Security Plan Changes (71130.04)

a. Inspection Scope

The inspectors completed the following actions:

- Reviewed the Physical Security Plan, Revision 38, dated January 24, 2001, to determine if requirements of 10 CFR 50.54 (p) had been met

- Reviewed the previous year’s safeguards event logs and interviewed security personnel to determine their knowledge and use of the corrective action program and resolution of problems as it relates to making changes to the licensing documents

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification

Inspection Scope

The inspectors reviewed logs and plant reports to verify the accuracy of reported data for the following indicators:

- Unplanned power changes
- Residual heat removal system unavailability
- Safety system functional failures

The inspectors also did routine checks, while on tours throughout the plant, to ensure that locked high radiation areas were properly secured.

b. Findings

No findings of significance were identified.

4OA3 Event Followup (71153)

(Closed) Licensee Event Report 50-298/2000-S01-00: Failure to provide adequate compensatory measures following degradation of a segment of the perimeter detection system

Section 9.2.B of the licensee's physical security plan and paragraph 6.5 of licensee's Security Procedure 2.14, "Compensatory Measures," require that, upon degradation of a portion of the perimeter detection system, an observer or armed guard with a view of the degraded area will be positioned within 10 minutes.

On November 29, 2000, the licensee submitted Licensee Event Report 50-298/2000-S01-00, which stated that on November 6, 2000, microwave Zone 22 of the perimeter detection system exceeded the nuisance alarm rate during inclement weather and was required to be posted by a compensatory security officer within 10 minutes. The compensatory security officer was not posted until 48 minutes following degradation of the perimeter detection system because of a miscommunication between operators in the central and secondary alarm stations.

The licensee's investigation determined that security officers in each alarm station had a conversation over the intercom concerning the posting of the compensatory measure. However, upon completion of the conversation, security officers in each alarm station thought that the other alarm station would post a compensatory officer inside the station to monitor the affected perimeter alarm zone via closed circuit television. The licensee identified that the root cause of this event was personnel error, i.e., miscommunication between security officers in the alarm stations. While communicating with each other via intercom, both stations were transmitting at the same time and neither station clearly heard and understood the actions that needed to be taken and who would take those actions. Compensatory measures were implemented upon discovery that microwave Zone 22 of the perimeter detection system had not been adequately compensated.

The inspector verified the licensee's corrective actions which included the following:

- Revision of Security Procedure 2.1, "General Security Duties and Responsibilities," Revision 6.4, requiring use of 2-part repeat-back communication for the security operational crew

- Revision of Security Procedure 2.14, "Compensatory Measures," Revision 6, requiring supervisory verification of all compensatory measures

The licensee's failure to post an observer or armed guard at the degraded portion of the perimeter detection system within 10 minutes was a violation of Section 9.2.B of the physical security plan and paragraph 6.5 of Security Procedure 2.14. This is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy. This violation was entered into the licensee's corrective action program as Problem Identification Report 4-12402 (50-298/00-15-03).

This issue was determined to be greater than minor in nature because the condition, if left uncorrected, would become a more significant safety concern. The issue was further determined to be of very low safety significance (Green) by the significance determination process because there were not greater than two similar findings in the last four quarters.

4OA6 Meetings

.1 Exit Meeting Summary

The inspectors presented the heat exchanger performance inspection results to Mr. J. McDonald, Plant Manager, and other members of licensee management at the conclusion of the inspection on February 15, 2001.

The inspectors presented the safety evaluation program inspection results to Mr. D. Gardner, Manager Quality Assurance, and other members of licensee management at the conclusion of the inspection on January 25, 2001.

The inspectors presented the access authorization and control inspection results to Mr. Mike Hale, Senior Manager of Site Support, and other members of licensee management at the conclusion of the inspection on March 29, 2001.

The inspectors discussed the results of the integrated resident inspection with Mr. William Macecevic and other members of Cooper staff at the conclusion of the inspection on April 3, 2001.

On each occasion, Cooper management acknowledged the findings presented. Additionally, the inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. One proprietary document was identified and returned to the licensee. No proprietary information is discussed in this inspection report.

ATTACHMENT

PARTIAL LIST OF PERSONS CONTACTED

Licensee

M. Baldwin, Supervisor, Plant Engineering Department
J. Bebb, Supervisor, Security Services
C. Blair, Licensing Engineer
M. Boyce, Risk and Regulatory Affairs Manager
P. Carlock, Specialist, Security Operations
P. Caudill, Senior Manager of Technical Services
L. Dewhirst, Licensing
F. Diya, Plant Engineering Department Manager
P. Donahue, Manager, Plant Engineering Department
J. Dubois, Acting Supervisor, System Engineering
Z. Easley, Acting Supervisor, Security
C. Fidler, Maintenance Manager
S. Freborg, Engineering Supervisor
R. Gardner, Quality Assurance Senior Manager
M. Gillan, Manager, Outage Group
M. Hale, Senior. Manager, Site Support
M. Hamm, Supervisor, Security Operations
B. Houston, Quality Assurance Operations Manager
A. Jacobs, Performance Analysis Department
K. Jones, Manager, Design Engineering Department
M. Kaul, Operations Support Specialist
J. Lewis, Manager, Reactor Engineering
E. McCutchen, Acting Manager, Licensing
J. McDonald, Plant Manager
W. Macecevic, Manager, Operations
S. Mahler, Licensing
C. Markert, Manager, Engineering Support Department
T. Milke, Supervisor, Security Training, Planning, and Special Projects
B. Rash, Senior Manager, Engineering
L. Schilling, Manager, Administrative Services Dept.
R. Steele, Electrical Engineering
J. Sumpter, Licensing
R. Thorson, Manager, Work Control
D. Vorpahl, System Engineer, Service Water
R. Wachowiak, Supervisor, Risk Management
N. Wetherell, Acting Senior Engineering Manager
R. Yantz, Senior Civil Engineer

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-298/0015-01	URI	Potential Unreviewed Safety Question Related to Offsite ac Sources Design Issue
50-298/0015-02	NCV	Emergency Diesel Generator Controller Design Control
50-298/00-15-03	NCV	Failure to provide adequate compensatory measures following degradation of a segment of the perimeter detection system

Closed

50-298/0015-02	NCV	Emergency Diesel Generator Controller Design Control
50-298/00-15-03	NCV	Failure to provide adequate compensatory measures following degradation of a segment of the perimeter detection system
50-298/2000-S01-00	LER	Failure to provide adequate compensatory measures following degradation of a segment of the perimeter detection system

LIST OF ACRONYMS USED

CFR	Code of Federal Regulations
LER	licensee event report
NCV	noncited violation
URI	unresolved item
VIO	violation

DOCUMENTS REVIEWED

Test Packages

Test Package for Reactor Equipment Cooling Heat Exchanger A, December 2, 2000
Test Package for Reactor Equipment Cooling Heat Exchanger B, November 30, 2000
Test Package for Residual Heat Removal Heat Exchanger A, March 7, 2000
Test Package for Residual Heat Removal Heat Exchanger B, October 14, 2000

Maintenance Packages

Residual Heat Removal Heat Exchanger A Cleaning, March 30, 2000
Residual Heat Removal Heat Exchanger B Cleaning, March 12, 2000
Reactor Equipment Cooling Heat Exchanger A Cleaning, February 1, 2000
Reactor Equipment Cooling Heat Exchanger B Cleaning, January 25, 2000

Calculations

93-184, “Verification of Senior Engineering’s Calculation on the Thermal Performance of the RHR Heat Exchanger,” Revision 0

94-021, “REC-HX-A/B Maximum Allowable Accident Case Fouling,” Revision 3

94-034, “Review of GE Nuclear Analyses GENE-673-020-0993 and GENE-637-045-1293 Supporting the Increase of the RHR Heat Exchangers Tube Plugging Margin,” Revision 0

94-243, “Minimum River Level with Flow only Over Top of Intake Structure Guide Wall,” Revision 1

94-244, “Channel Depth Required Around Intake Structure Guide Wall,” Revision 2

94-253, “Evaluation of Siltation With Opening in Intake Structure Guide Wall,” Revision 1

00-048, “RHR-HX-A/B Performance During Operation of Containment Spray Mode of RHR,” Revision 2

Procedures

7.2.42, “Heat Exchanger Cleaning,” Revision 14

7.2.42.1, “REC Heat Exchanger Maintenance,” Revision 0

13.15.1, “Reactor Equipment Cooling Heat Exchanger Performance Analysis,” Revision 13

13.17, “Residual Heat Removal Heat Exchanger Performance Testing,” Revision 9

13.17.1, “Residual Heat Removal Heat Exchanger DAS Based Performance Testing,” Revision 0 C1

Self-Assessment

Final Report for the Peer Assessment of Nebraska Public Power District’s Cooper SCAQ 97-0742 (RHR HX Train B Silting),” October 2, 1998

Design Change

DC 94-373, “Intake Structure Guide Wall Modification”

Problem Identification Reports

4-00396	4-04148	4-06627	4-08879
4-01871	4-05366	4-07864	4-09917
4-03500	4-06384	4-08538	4-11284

Miscellaneous

“Service Water Sedimentation Study Wrap Up,” October 31, 2000

“Sedimentation Particle Size Profile, Determination of Critical Flow Velocities, and Comparison with Proposed System Models for Service Water,” May 27, 1999

Safety Evaluations

CED 1999-0144; USQE 1999-0075, Revision 1; "Replacement of Valves SW-MOV-89A & B”

CED 2000-0114; "Setpoint Change Requirement (SCR) 2000-16; TRMCR 2000-002

USQE 1998-0067, Revision 1; Overpower Relays Setting Change EE-REL-1FE(32) and EE-REL-1GE(32)

USQE 1999-0050, CED 1999-0082; “Technical Requirements Manual Change (TRMCR) 1999-006 Special Procedure 99-003 Noble Metal Chemical Addition”

TRMCR 1999-0073; “Rerouting of the 161kV from 345/161kV Auto-Transformer to the SU Service Transformer Via New 161kV switchyard”

USQE 2000-019; “PC-PS-119A,B,C,D Upgrade to EQ including SCR and TRMCR”

USQE 2000-0026; “Eliminate internal flooding threat to NW quadrant from 16 to 24" moderate energy RHR line, Chapter X, Section 14.6.2.1 USAR”

USQE 2000-0045; “Change to Reactor Building d/p control setpoint”

Plant Procedures

Administrative Procedure 0.8, “10 CFR 50.59 Reviews,” Revision 7

Other Documents

Design Change 87-152; “Sequential starting of RHR and CS pumps from Start-up Transformer”

NPPD Letter to NRC NLS9000445, dated November 16, 1990, “Withdrawal Request for Proposed Technical Specification Change No. 83 Cooper Nuclear Station”

Problem Identification Reports

2-14776, “ESST incapable of supporting site auxiliaries”
2-21167, “EE system line separation analysis”
4-07203, “Trip of the 345kV St. Joseph line”
4-13716, “Failure to follow procedures”
4-13839, “161kV line GDC 17 qualification”
4-13866, “Potential of unacceptable capacity on the 69kV emergency line”
4-13867, “161kV line to Auburn, Nebraska unanalyzed as a GDC 17 offsite power source”
4-13777, “Inadequate 50.59 evaluation of CED 2000-0114”
4-13878, “Potential LCO 3.8.1 & 3.8.2”