ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket No.:	50-298
License No.:	DPR-46
Report No.:	50-298/96-26
Licensee:	Nebraska Public Power District
Facility:	Cooper Nuclear Station
Location:	P.O. Box 98 Brownville, Nebraska
Dates:	October 20 through November 30, 1996
Inspectors:	Mary Miller, Senior Resident Inspector Chris Skinner, Resident Inspector
Approved By:	Elmo Collins, Chief, Project Branch C Division of Reactor Projects
ATTACHMENT:	Supplemental Information

EXECUTIVE SUMMARY

Cooper Nuclear Station
NRC Inspection Report 50-298/96-26

Operations

- Inspectors found several examples of inadequate or nonexistent documentation of operations information, including an inspector-identified violation with two examples of failure to document Technical Specifications required common cause failure evaluations associated with diesel generator failures. Written guidance had not been provided to the operators, and shift supervisors had an inconsistent understanding of how to implement this requirement. Additionally, night orders documentation was not timely.

- Inspectors noted examples of operations identification of inadequate work packages submitted to the control room, indicating higher control room standards for work packages as a result of corrective actions to prior problems. In one instance, the NRC questioned plant conditions to support maintenance and found an ineffective evaluation of system interdependencies. Control room operators were challenged by these work packages.

- Initial assessment of Operation's immediate response to a fire in the protected area, and to a separate concern involving slush buildup in circulating water bays due to lack of the design ice deflector, found that operations performed in an appropriate manner.

Maintenance

- Maintenance activities were generally conducted in an appropriate manner with only minor problems observed. Contradictory administrative procedure guidance regarding the need to perform surveillance procedures steps in sequence was found.

- A noteworthy strength was identified in that instrument and controls technicians have achieved a high level of safety focus in problem identification. Continued improvements in quality and number of problems identified in design, procedures, and human performance area have been demonstrated.

Engineering

- An example of strong problem identification which found that a relief valve in a sample line was set too high, in that a system valve may be vulnerable to exceeding design pressure. The licensee addressed isolating the sample line.

Plant Support

- Inspectors found a personnel thermoluminescent dosimeters, which had been lost, in a pump room.

- Inspectors observed an example of weak contamination control practices.

Report Details

Summary of Plant Status

The plant was maintained at 100 percent power, except for quarterly turbine valve testing, during which power was reduced to 70 percent.

I. Operations

O1 Conduct of Operations

O1.1 Ice in Circulating Water Intake Bays (93702)

a. Inspection Scope (71707)

The inspectors reviewed plant conditions and licensee response to an occurrence of ice slush in the circulating water intake bays.

b. Observations and Findings

On November 26, 1996, the licensee noted alarms for high differential pressure across intake screens and determined that slush from pad ice on the surface of the Missouri River had become entrained in the circulating water flow, pulled downward 10 feet below the river's surface, and collected in the circulating water intake. Although the river temperature was above freezing at 33.5°F, the entrainment of slush from the surface of the river resulted in high differential pressure across the surface of the circulating water screens and slush buildup in the circulating water intake bays. The licensee noted that the safety-related service water bays were not experiencing slush buildup because of the low flow required by service water.

The licensee ensured de-icing channel flow (recirculation from the outfall) was available to the service water and circulating water bays. The licensee used fire hoses to break up slush packs in the circulating water intake bays for more efficient slush melting and placed main condensers in recirculation (use of one circulating water pump for both condenser bays on each of the two condensers). This lineup resulted in a higher outfall temperature as well as reducing the circulating water intake flow by half. The lower cross-sectional flow area into the intake resulted in less slush entrainment and higher outfall temperature, thus more efficient de-icing of the circulating water bays. The licensee was not required to reduce power to conserve condenser vacuum. The licensee determined that no operational effects were caused by this condition.

Resident inspector activities involved observation of the slush entrained from the river surface outside the intakes, inspection of the service water bay's lack of slush buildup, inspection of de-icing channel lineup and use of fire hoses to break up slush, and review of the licensee's immediate evaluation of service water operability. Circulating water bay temperatures were 36°F after recirculation was initiated, and de-icing flow was established and verified. No slush buildup occurred

in the service water bays. The concern regarding entrainment of slush did not appear to apply to the service water bays due to the low cross-sectional flow areas down to the intake, approximately 10 feet beneath the surface of the river.

The licensee stated that the major cause of the ice buildup was due to the lack of the installation of an ice deflector upstream of the intake, normally installed in mid-November in anticipation of cold weather conditions, after the river level drops in the late fall. The seasonal river level drop occurs by reduction of river flow controlled by upstream dam throughput.

In mid-November, the licensee had identified that river levels would be too high for installation of an ice deflector at the usual time.

The NRC identified that the ice deflector was described in the Undated Safety Analysis Report (USAR) as being in place to deflect ice during cold weather and was to be in place during the winter months. The inspectors identified several other issues associated with the ice deflector and the lack of evaluations in accordance with 10 CFR 50.59. The licensee is continuing efforts concerning evaluation of this condition as well as operational and maintenance procedure changes to address installation and appropriate use of ice deflectors to prevent intake icing. This issue will be followed in a subsequent resident inspection after licensee review and corrective action activities have concluded (Unresolved Item (URI) 298/96026-02).

c. Conclusion

The licensee's failure to install an ice deflector upstream before icing conditions developed on the river resulted in a potential challenge to plant operation. Resident inspection is continuing and will be addressed in the next inspection.

O1.2 Notice of Unusual Event (NOUE) Concerning Fire in the Protected Area

a. Inspection Scope (93702)

Inspectors responded to observe the licensee's response to a fire in the protected area.

b. Observation and Findings

At about 2:50 p.m. (CST) on November 18, 1996, during a full scale emergency exercise, a station operator noticed smoke in the turbine building hallway which shares a common wall with the main steam tunnel (secondary containment). At 3:01 p.m., the source of the smoke was identified to be in the seismic gap between the main steam tunnel roof and the turbine building roof. The fire brigade responded to fight the fire.

At 3:11 p.m., a NOUE was declared due to a fire not being extinguished within 10 minutes. At 3:18 p.m., the fire was extinguished and a reflash watch set. The NOUE was terminated at 4:23 p.m. The licensee concluded that the operability of structures (reactor building, steam tunnel, and turbine building) was not degraded by the fire.

The licensee has preliminarily determined that the fire was ignited by personnel replacing the steam tunnel roof covering. Fibrous material, possibly debris, lodged in the 4-inch seismic gap between the buildings, was probably ignited by a torch used to seal the roofing material. The negative turbine building pressure and incomplete turbine building seal allowed smoke and, later, water from firefighting, to enter the turbine building (not a Class I structure).

The licensee suspended roofing operations, initiated a root cause evaluation, and planned not to continue roofing operations until the root cause of the fire was identified and corrected.

The Senior Resident Inspector, participating in the exercise, immediately responded to the control room to observe the licensee's response to the event. The states of Nebraska and Missouri were notified of both the initiation and termination of the NOUE.

During the event, the full scale emergency drill was suspended, and the fully staffed technical support center and emergency operating facility stood by to assist if necessary, in accordance with exercise contingency plans.

Two fire protection inspectors, onsite for a scheduled team inspection, will follow the licensee's root cause evaluation and document it in NRC Inspection Report 50-298/96-25. The NRC exercise evaluators will document the licensee's emergency response to this event in NRC Inspection Report 50-298/96-22.

c. Conclusion

The licensee's response to a fire in the protected area was timely and appropriate. The fire brigade was not dispatched until the fire location was understood, the emergency exercise in progress was suspended and did not distract the fire event response, engineering was requested and responded immediately to the control room, and the fire location, on a roof in a seismic gap between two adjacent buildings, was quickly diagnosed. NRC emergency notifications were made in a timely manner.

O3 Operations Procedures and Documentation

O3.1 Night Order Log Not Updated

a. Inspection Scope (71707)

The inspectors reviewed the night order log.

b. Observations and Findings

On October 13, 1996, a night order was entered to document that, if the outside temperature dropped to below 20°F, both trains of standby gas treatment systems would be declared inoperable due to the insulation rating on Sump Z. The insulation problem was corrected on October 20, but the night order log was not updated until questions were raised by the inspector on October 24.

The Operations Manager stated that failure to update logs was an infrequent occurrence and the night order log was immediately updated.

Additionally, inspectors noted that November 26 actions by operators required to mitigate the slush buildup in circulating water bays, such as use of fire hoses and alignment of condenser backwash, were recorded in shift supervisor logs, but were not documented in night orders to provide information to future crews. Until procedure changes were implemented, information to crews was needed as an interim corrective measure. Inspectors noted documentation of required slush buildup response in night orders on December 2.

c. Conclusion

The inspectors concluded that operations did not update the night order log in a timely manner.

O4 Operator Knowledge and Performance

O4.1 Work Package Deficiencies Identified by Operations

a. Inspection Scope (71707)

Inspectors reviewed instances where control room crews identified deficiencies in packages and returned them for correction.

b. Observations and Findings

The inspectors noted two instances where work packages submitted to the control room for work had not properly identified the need to enter a Technical Specification action statement and an instance in which a work package intended to use test

equipment on control rod drive circuitry did not include an evaluation of the configuration in accordance with the requirements of 10 CFR 50.59. The control room documented these deficiencies in problem identification reports for corrective action to strengthen the work control process. The individual work packages were returned to work control for correction.

c. Conclusion

The control room crew demonstrated appropriate safety standards and a good questioning attitude in identifying these deficiencies.

04.2 Emergency Diesel Generator Failure Evaluation

a. Inspection Scope (71707)

The inspectors reviewed Technical Specification Surveillance Requirement 4.5.F.1.c to determine if the surveillance requirement was properly performed for two occasions. The inspectors held discussion with licensee management and control room shift supervisors and reviewed applicable procedures, evaluations, and training documents.

b. Observations and Findings

Technical Specification Surveillance requirement 4.5.F.1.c requires that, with one diesel generator inoperable, determine within 24 hours if the operable diesel generator is not inoperable due to a common cause failure or perform Technical Specification Surveillance Requirement 4.9.A.2.a.1, to demonstrate operability of the remaining diesel generator by actual operation.

On October 21, 1996, Diesel Generator 2 was declared inoperable by the shift supervisor due to a fuel leak. The leak was repaired. On October 23, during the postmaintenance test, the motor potentiometer failed, preventing test completion and verification of diesel operability. The inspectors evaluated these two failures to determine if Technical Specification 4.5.F.1.c was properly performed. The inspectors found no written common cause determinations and no documentation that common cause determinations were performed. Additionally, Technical Specification 4.9.A.2.a.1 was not performed on the operable diesel generator, which was required if a common cause determination was not performed.

The Operations Manager, system engineer, and shift supervisor on duty when the first failure occurred each stated they had performed a common cause determination and determined that the other diesel generator was operable. Each failed to document the determination. The system engineer concluded that the failure was a potential common cause problem (there have been similar failures on both diesel generators in the past), but the occurrence of the failures was infrequent and did

not result in inoperability. The system engineer did not communicate the results of his determination to Operations.

After discussions with licensee management, a formal common cause determination was performed on November 25 for the fuel leak and, at the end of the inspection period, the motor operated potentiometer common cause determination was in the review process.

The inspectors interviewed shift supervisors and found a wide variance on the understanding of the existence of guidance or procedures on how to perform the surveillance requirement and the format, if required, of documentation that a common cause determination had been performed.

Based on the lack of written common cause determinations, lack of documentation that common cause determinations were performed, lack of written guidance or procedures, and lack of performance of Technical Specification 4.9.A.2.a.1 on the operable diesel generator within 24 hours after a diesel generator was declared inoperable, the inspectors concluded that Technical Specification 4.5.F.1.c was not met within the time frame required for both failures. The failure to perform a common cause determination or perform Technical Specification 4.9.A.2.a.1 within 24 hours for both failures of Diesel Generator 2 on October 21 and 23, is a violation of Technical Specification 4.5.F.1.c (298/96026-01).

c. Conclusions

Inspectors identified that, after two separate failures on Diesel Generator 2, the licensee did not perform common cause evaluations for Diesel Generator 1. The evaluations are required by Technical Specifications. Additionally, the licensee had not provided written guidance to the operators on Technical Specification 4.5.F.1.c implementation. Shift supervisors had an inconsistent understanding of how to implement this requirement.

O4.3 Failure to Recognize Electrical Dependence of Reactor Equipment Cooling Heat Exchanger B on Diesel Generator 2 Operability

a. Inspection Scope (71707)

The inspectors reviewed the Technical Specification tracking logs and clearance order logs and held discussions with the control room staff.

b. Observations and Findings

On November 18, 1996, the inspector noted that the control room had authorized removal of Diesel Generator 2 from service at the same time that Reactor Equipment Cooling Heat Exchanger A was inoperable with the service water isolated. The Technical Specification for the Reactor Equipment Cooling Heat Exchanger A

required that the opposite train heat exchanger be operable, including its associated emergency power supplies. Removal of the Diesel Generator 2 from service brought into question compliance with this Technical Specification requirement. Inspectors questioned the appropriateness of this activity.

The licensee determined that this activity was not permitted by Technical Specifications and wrote a problem identification report. The licensee did not remove Diesel Generator 2 from service until after Reactor Equipment Cooling Heat Exchanger B was returned to service 3 days later.

c. Conclusions

The licensee's failure to identify an operability dependence on Diesel Generator 2 during an abnormal system line-up until after questioning by the NRC inspector was an example of ineffective evaluation of safety-related system dependencies.

O4.4 Division I Reactor Protection System (RPS) Equipment Problems

a. Inspection Scope (71707)

The inspectors reviewed the Technical Specification, control room logs, and annunciator printout and interviewed the control room staff.

b. Observations and Findings

On November 22, during a surveillance test of Division I Average Power Range Monitor (APRM) E, alarms indicated an unexpected condition in the Division I RPS. Instrument and Controls technicians correctly diagnosed that the low side voltage to the Division 1 flow bias unit power supply appeared to have failed. The unit provided scram signal input for all three APRMs in Division 1, not only to APRM E, which was under a surveillance test and in bypass at that time.
The shift supervisor allowed troubleshooting to initiate on that flow bias unit while concurrently determining the need to enter a Technical Specification action statement. A half scram is required while a flow bias trip unit is inoperable. The flow bias unit problem was identified and corrected in approximately 40 minutes. During this time, the RPS Division I flow bias affected by this failure was not placed in a trip (half scram) condition.

The licensee stated that, because the instrument and control technicians had asserted a high likelihood of identifying and correcting the problem in a timely fashion, the decision to determine the correct Technical Specification action, in parallel with instrument and control troubleshooting and repair activities, was appropriate.

Additionally, the licensee stated that 3 days after the occurrence, engineers were not able to determine if the unit actually had been inoperable and, therefore, the

shift supervisor would not be expected to declare it inoperable. The Technical Specification 3.1 request for inoperable flow bias scram circuitry requires promptly placing the affected RPS division in a trip (half scram) condition. To have initiated troubleshooting conditions without first identifying and complying with the action statement associated with inoperable equipment appeared to have been nonconservative. Since the condition was fixed within 40 minutes, the action statement requirement to complete a reactor plant shutdown within 8 hours was not reached. However, risk associated with troubleshooting activities in panels without placing the affected RPS division in half scram resulted in a vulnerability to misdirected troubleshooting or the potential failure of RPS to function under a transient condition.

c. Conclusion

Failure to place the Division I RPS in a half scram condition when a failure was suspected but actual cause unknown, and allowing troubleshooting and repair activities in this condition for 40 minutes appeared to have been nonconservative operations. Operability aspects of this issue were being evaluated at the close of this inspection report and will be followed in the next resident inspection report (Inspection Followup Item (IFI) 298/96026-07).

O8 Miscellaneous Operations Issues

O8.1 (Closed) Licensee Event Report (LER) 95-012-00: RPS trip signal and primary containment group isolations during shutdown for refueling outage. During a scheduled end-of-cycle shutdown, and after manual plant trip, operator actions in response to feedwater pump anomalies resulted in a feedwater control lockout, low reactor vessel level, and subsequent group isolations. These actions were based on simulator modeling which was not representative of feedwater system response, as well as failure to incorporate lessons learned from prior plant shutdowns into plant procedures. The plant was stabilized and procedures revised to address lessons learned. This issue appeared to be of minor safety significance, therefore, this issue is closed.

O8.2 (Closed) Violation 50-298/94019-01: Failed to maintain positive pressure in control room. The corrective actions for this violation were verified and documented in NRC Inspection Report 50-298/94-31. Therefore, this issue is closed.

O8.3 (Open) Violation 298/9508-01: lack of proper correction for emergency procedure for station blackout. The inspectors reviewed Procedure 5.2.5.1, "Loss of All AC Power (Station Blackout)," Revision 11. On November 27, 1996, during the followup, the inspector noted that the commitment documented in the Safety Evaluation Report which stated that the high pressure coolant injection pump would be run for one cycle (estimated at about 10 minutes) had not been implemented in a clear manner. The procedure stated that reactor vessel level should be recovered using the high pressure coolant injection pump with subsequent transfer to the

reactor core isolation cooling system for level and pressure control. No time limit of approximately 10 minutes or one cycle was provided in the procedure. The licensee noted that reactor operators had been trained to promptly place the reactor core isolation cooling system on line after high pressure coolant injection had recovered vessel level, which would occur within once cycle under design basis conditions, and stated that simulator training had emphasized the need to promptly secure high pressure coolant injection when the reactor core isolation cooling system cam on line. Since the licensee's design basis assumes the reactor core isolation cooling system is operable, the licensee stated that allowance of use of high pressure coolant injection if reactor core injection cooling was unavailable, would be an acceptable practice since it would be outside the design basis and, therefore, not be included in the Safety Evaluation Report.

The inspector noted that the reasons for securing the high pressure coolant injection system stated in the Safety Evaluation Report included the high pressure coolant injection system room heatup, as well as concerns that high pressure coolant injection would reduce battery capacity during operation.

The licensee revised the emergency procedure to reflect that high pressure coolant injection be used for only one cycle, approximately 10 minutes, in accordance with the safety evaluation, and noted in the procedure that additional use of high pressure coolant injection would be under 10 CFR 50.54(x). This appeared appropriate.

Violation 298/9508-01 remains open pending review of the remaining examples; however, this example of the violation is closed based on the licensee's corrective action.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspections Scope (62707 and 61726)

The inspectors observed all or portions of the following work activities:

Procedure	Title
6.2ADS.304	Automatic Depressurization System Water Level Calibration and Functional
6.1DG2	Diesel Generator 1 Surveillance Run

6.2CSCS.301	Core Standby Cooling System Water Level Calibration and Functional
MWR 96-0708	Replacement of Pressure Switch for Reactor Pressure Permissive
MWR 96-0711	Replacement of Pressure Switch to Low Set (NBI-OS-51D)
MWR 06-1608	Replacement of a Pressure Switch (NBI-PS-51C) Switch Metering Valve
MWR 96-1627	Diesel Generator Fuel Leak Repair
MWR 95-1465	Reactor Equipment Cooling Heat Exchanger Outlet Valve Replacement

b. Observations and Findings

The inspectors observed all or portions of several maintenance activities. In general, maintenance was accomplished according to procedures and using appropriate radiological controls practices. Tagout boundaries and system lineups appeared to have been implemented correctly. Reference materials were appropriate, and parts used were controlled in a manner that indicated proper materials were used to support the observed activities. Postmaintenance testing appeared to address proper requirements. Exceptions to the above general findings are documented in other sections of this report.

c. Conclusions

Maintenance observed by inspectors appeared appropriate, with exceptions noted in this report.

M1.2 Adequacy of Tolerances for Core Spray Actuation Instrumentation

a. Inspections Scope (61726)

On November 4, 1996, the inspectors observed performance of Procedure 6.2CSCS.301, "CSCS Water Level Calibration and Functional (Div 2)," Revision 0.2, which calibrates and functionally checks Level Indicating Switches NBI-LIS-72B and -72D and their associated indicators (Yarway).

b. Observations and Findings

The inspectors observed portions of the surveillance at Instrument Rack IR-25-6A. While observing indicator calibration during Step 8.1.21, the inspector noted that

the maintenance technicians did not record the first "as found" reading (increasing), which was outside the procedure calibration tolerance. The maintenance technicians increased the calibration pressure and then decreased the pressure. The second reading (decreasing) was within the calibration tolerance. The maintenance technicians recorded the second indicator reading in the procedure "as found" reading. This was performed without specific steps in the procedure. The maintenance technicians stated that they were trained to perform these steps based on an introduction of a hysteresis effect. The licensee was unable to explain why the hysteresis effect did not always occur.

The licensee stated that the safety consequences of hysteresis is minor because the level indicator does not actuate safety signals. Also, the licensee determined that the level indicators were used only for Procedure 5.2.5.1, "Loss of All AC Power (Station Blackout)," and calibration tolerances of 3 percent of scale appeared to be too conservative.

The inspector identified that Step 8.1.28.3 involving valve manipulation, test equipment removal, and independent verification could not be performed as written. The licensee stated that these actions were included in one step, in an ambiguous manner, and stated that technicians had performed the original intent of the step properly. The safety consequence is minor based on the independent verifier verifying the correct part of the step, but a weakness was identified by the inspector for not stopping and changing the procedure. The licensee stated that the step would be changed.

c. Conclusions

The inspectors concluded that the licensee's understanding of the safety function of the level indicators and the basis for the calibration tolerances was weak and the fact that the independent verifier failed to stop and change the procedure when the procedure could not be performed as written showed a lack of rigor in procedure use.

Since inspectors identified that the level indicators used in emergency operating procedures, for reactor fuel range level, are the same design as the indicators discussed above, this issue will be followed in a subsequent report (IFI 298/96026-06).

M1.3 Contradictory Administrative Procedure Requirements Allowed Performance of Surveillance Procedure Steps Out of Sequence

a. Inspection Scope (62707)

On November 6, 1996, the inspectors observed portions of Maintenance Work Requests MWR 96-0708 and MWR 96-0711.

b. Observations and Findings

During the performance of the maintenance work request, the inspectors noted that the maintenance technicians were performing steps out of sequence and the work packages did not specifically address whether work could be performed in any order. When questioned by the inspector, the maintenance technicians stated Procedure 0.40, "Work Control Program," Revision 5, allowed them to perform the steps in any order.

The inspectors reviewed the licensee's procedures and guidance on procedural adherence, which included Procedure 0.1, "Introduction to CNS Operations Manual," Revision 14, CNS Directive Number 12, "Requirements for the Use of Procedures," Revision 1, and Procedure 0.40. Procedure 0.40, Step 8.5.14, stated, in part, that work instructions may be performed out of sequence. Procedure 0.1 and CNS Directive 12, both stated that deviation from or omission of work instruction steps is not acceptable unless flexibility was provided within the work instructions.

The inspectors questioned the licensee regarding the three procedures. A problem identification report was initiated to document the contradiction and to correct the procedure problem to preclude steps out of sequence without specific guidance.

c. Conclusion

The inspectors concluded that the steps that the maintenance technicians were performing out of sequence were of low safety consequences. This finding illustrates an administrative procedure inconsistency, which provided improper guidance for work on safety systems.

M7 Quality Assurance in Maintenance Activities

a. Inspection Scope (62706)

Inspectors reviewed problem identification reports initiated during this inspection period.

b. Observations and Findings

Inspectors noted that throughout this inspection period the instrument and control shop continued to identify a large fraction of problems with plant procedures, design, and individual performance. Their problem identification reports evidenced consistently high standards for problem identification. Several problems identified involved well-focused issues concerning adequacy and enhancement of procedures and individual performance. Problem identification has consistently improved and has reached a strong level of performance in the instrument and control area.

c. Conclusion

The instrument and control shop demonstrated a strong questioning attitude by the high quality and number of problems which were self-identified in systems, procedures, and personnel performance.

M8 Miscellaneous Maintenance Issues (92902)

M8.1 (Closed) LER 95-004-00: primary containment group isolations caused by surveillance procedure deficiencies. This procedure performed a reactor coolant system hydrostatic test and also performed excess check valve leakage testing on instrument lines. Isolations had occurred because the procedure allowed performance of sections out of sequence, but did not properly isolate the system within sections to prevent group isolations. The steps to isolate the system were located in an earlier section. The licensee revised the procedure to ensure initial conditions isolated the instrument lines before testing.

The licensee's failure to provide instructions which precluded unexpected group isolations is a violation of 10 CFR Part 50, Appendix B, Criteria V, which requires, in part, that activities be controlled by procedures appropriate to the circumstances. This licensee-identified and corrected violation is being treated as a noncited violation, consistent with Section VII.B.1 of the NRC Enforcement Policy (298/96026-05).

M8.2 (Closed) LER 95-006-00: improper methodology for calibrations of source range monitors which resulted in missed Technical Specification surveillance requirements. This report describes a failure by the licensee to test a preamplifier in the source range monitor circuit when performing Technical Specification surveillance tests. The lack of full surveillance testing was addressed as a programmatic issue in 1994, the year in which this issue was raised. NRC Inspection Report 50-298/94-31 Section 4.2 addresses this programmatic issue and its satisfactory resolution. Since this issue was one of many identified by the licensee in that time frame associated with their corrective action, no further NRC action concerning this report is required. This issue is closed.

M8.3 (Closed) LER 96-008-00: scram discharge volume high level RPS trip channel anomaly. During a surveillance procedure, the licensee identified that an isolation valve to a scram discharge valve level switch had failed in the closed position. This was revealed by the switch actuating unexpectedly during the surveillance procedure, causing a half scram. The licensee dislodged the valve and returned it to the open position. The licensee also addressed the vulnerability that similar valves may fail in the closed position with an engineering evaluation and revised procedures to diagnose similar failures. This issue was properly corrected.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Installation of Ice Deflector Upstream of Intake Structure

a. Inspection Scope (37828)

The inspectors reviewed the licensee's engineering of an support of an installation of an ice deflector upstream of the intake structure.

b. Observations and Findings

On November 26, 1996, the licensee experienced slush buildup in the circulating water bays of the intake structure. This event is more fully described in Section 01.1 of this report. The inspectors questioned the lack of an ice deflector as described in the USAR to preclude ice buildup in the intake structure and questioned if an evaluation in accordance with 10 CFR 50.59 had been performed regarding the lack of this deflector during the cold weather. The licensee stated that an evaluation had not been done, but agreed that it should be addressed. The inspectors reviewed the licensee's assessment that service water intake icing was not a concern based on the low cross-sectional flow area for slush entrainment 10 feet beneath the surface of the river. The inspectors noted that the service water bay temperature of 36°F was not conducive to ice formation or deposition in the event river water level dropped before ice deflector installation. Further, the licensee stated that the ice deflector, used for the past several years, would be installed when river water dropped approximately 2 more feet, which would allow ice deflector barges and booms to be attached to structures already on the river bank. Although the ice dropped, the licensee determined that the deflector should not be installed until after Station Operations Review Committee approval of the ice deflector. This had not occurred as of December 10, precluding evaluation and installation of the ice deflector. This issue concerning procedures, evaluations, and ice deflector installation will be followed in a subsequent resident inspection report under URI 298/96026-02.

E4 Engineering Staff Knowledge and Performance

E4.1 Licensee Actions to Identify a Valve Vulnerable to Pressure Above Design Margin

a. Inspection Scope (37751)

The inspector reviewed actions the licensee took to identify and respond to an engineering issue.

b. Observations and Findings

On November 24, 1996, the licensee identified that a sample line for reactor coolant appeared to have an inadequate relief valve setpoint, which may allow the pressure regulator on that line to exceed maximum valve operability pressure. The licensee identified that Pressure Regulator PC-PRV-PCB-632 may exceed design pressure because the relief valve, PC-RV-17RV, was set too high, which could exceed design pressure for Valves RR-SOV-SPV-740 and -741, potentially causing them to fail close or to spuriously open.

After identification of this issue, the licensee isolated the sample line and issued a report in accordance with 10 CFR 50.72, since the failure of the automatic isolation valve may have allowed the design pressure to be exceeded. The licensee planned to modify the system in the upcoming outage. The licensee stated that this sample pathway was not required under design basis conditions and, therefore, no design or operation requirements were affected by isolation of these lines. The licensee documented this finding in Problem Identification Report 2-07855 and appeared to have taken appropriate action to address this concern. Inspectors concluded that vulnerability to this failure did not pose an immediate safety concern. The licensee's actions to isolate the line eliminated the vulnerability. Further inspector review of this issue will be followed during closure of the associated LER.

c. Conclusions

The licensee identified a design problem in the plant associated with a reactor coolant sample line and took appropriate corrective action to change the valve lineup to assure the valve was isolated, initiate engineering review, and issue a notification in accordance with 10 CFR 50.72.

E8 Miscellaneous Engineering Issues

E8.1 (Closed) LER 298/94-035-00: inoperable standby gas treatment system due to a potential backflow of water from Sump Z under design basis accident conditions. The licensee discovered that, under design accident conditions with a coincident loss of offsite power, Sump Z pumps and high level alarm would lose power. This could allow the condensation from the standby gas treatment effluent cooling to collect in the underground piping and accumulate in the sump, filling the standby gas treatment drain and discharge lines and rising backpressure above system design valves. Therefore, the standby gas treatment system operability could not be assured, which could cause secondary containment to be inoperable.

The inspectors verified that the following corrective actions were completed:

(1) a printout from the equipment data file showed that the appropriate components in Sump Z system were classified as essential;

(2) replacement of insulation and heat tracing on the sump pump discharge line was done under Maintenance Work Request 95-C262 and Design Change DC 95-033;

(3) Procedure 5.1.3, "Flood," Revision 20.2, was revised to include actions to take during an external flooding event to maintain standby gas system operability;

(4) a tailgate session was held on February 23, 1995, which provided training to plant personnel involved in the development/validation of design change documents on the interaction of nonessential systems with safety-related systems; and

(5) training of operations personnel and engineering personnel on this event in Lesson Plans INTRO23-99-26, "Industry Events," Revision 1, and INTRO35-95-16, "CR 94-1282," Revision 0.0, for the operators and engineers, respectively.

NRC Inspection Report 50-298/94-31 documented that inspectors reviewed two design modifications and documentation generated by the licensee to check for a generic concern of the failure of nonessential components affecting essential components in other systems. The inspectors did not identify any concerns.

The licensee's failure to properly translate design specifications into plant configuration is a violation of 10 CFR Part 50, Appendix B, Criterion III, which requires, in part, that the design basis for those structures, systems, and components to which this appendix applies are correctly translated into specifications, drawings, procedures, and instructions, that appropriate quality standards are specified and included in design documents, and that deviations from such standards are controlled. This licensee-identified and corrected violation is being treated as a noncited violation, consistent with Section VI.B.1 of the NRC Enforcement Policy (298/96026-03).

E8.2 (Closed) LER 298/95-018-01 and 00: maintenance activity could compromise steam tunnel blowout panel. This event was discussed in NRC Inspection Report 50-298/96-04 and escalated enforcement action was issued to address this concern (EA 96-062). Resolution of this issue will be closed under Violation 298/960004-01. No new issues were revealed by the LERs.

E8.3 (Closed) LER 298/96-014-00: fuel preparation machine upper limit stops set in violation of Technical Specifications. The licensee has issued a revision to this LER. The issue will be addressed by closure of the revision.

E8.4 (Closed) LER 298/96-010-00: previous unavailability of the muffler bypass valve on Diesel Generator 2 due to bowing in actuator shaft. After a Diesel Generator 2 surveillance, the licensee tested the muffler bypass valve, a safety-related valve

which provides an analyzed diesel exhaust path. The valve failed to operate. The licensee identified that prior testing had not been performed while the valve was heated by diesel operation, and the bow in the shaft was not identified during dedication activities to upgrade the originally nonsafety-related valve installation. The licensee found that the similar valve for Diesel Generator 1 operated properly while hot. The cause was identified as a slightly bowed valve shaft which did not affect operation while the valve was cold. The licensee has failed both valves to the open (safety) position and performed an analysis in accordance with 10 CFR 50.59, while determining a replacement configuration for the use of muffler valves.

The licensee's failure to properly translate design specifications into plant configuration is a violation of 10 CFR Part 50, Appendix B, Criterion III, which requires that the design basis for those structures, systems, and components to which this appendix applies are correctly translated into specifications, drawings, procedures, and instructions, that appropriate quality standards are specified and included in design documents, and that deviations from such standards are controlled. This licensee-identified and corrected violation is being treated as a noncited violation, consistent with Section VII.B.1 of the NRC Enforcement Policy (298/96026-04).

E8.5 (Closed) LER 50-298/94-004-00: reactor scram due to partial closure of turbine governor valves. The licensee identified that the governor valve partial closure, resulting in a reactor scram, was caused by a failure of a digital component in the nonsafety-related turbine electrohydraulic control system. Feedwater problems and subsequent group isolations at low reactor vessel level, which occurred after the scram, were found to be caused by an improper setpoint in the feed pump lock and hold circuitry. The licensee performed corrective action for these concerns. No enforcement for this issue was indicated.

Radiation

IV. Plant Support

R2 Status of ~~Reactor~~ Protection and Control Facilities and Equipment

R2.1 Health Physics

a. Inspection Scope (71750)

The inspector located a personnel thermoluminescent dosimeters detached from a worker's badge.

b. Observations and Findings

On November 26, 1996, the inspector found a personnel thermoluminescent dosimeter in the service water pump area. This thermoluminescent dosimeter had apparently become detached from an individual's badge. The licensee concluded

that the individual had lost the dosimeter shortly before its discovery by the inspector, since security records indicated entry into the service water pump room on the prior day. Past entries into the service water pump room had also occurred.

The licensee had also verified that the individual had not entered the radiological controlled area within the past several days and, therefore, estimated that additional exposure had not been obtained while the individual was not monitored with thermoluminescent dosimeters.

c. Conclusions

Inspectors identified that the licensee failed to identify that an individual's dosimeter became detached, resulting in lack of monitoring for up to a few days. This issue is minor.

R4 Staff Knowledge and Performance in Radiation Protection and Control

R4.1 Radiation Protection Coverage during Maintenance Activity

a. Inspection Scope (71750)

On November 6, 1996, the inspectors observed contamination control concerns during portions of Maintenance Work Requests MWR 96-0708 and MWR 96-0711.

b. Observations and Findings

The maintenance technicians were replacing two pressure switches filled with potentially contaminated water. Radiation protection has been contacted and technicians could proceed. If any water was spilled, radiation protection was to be contacted. The maintenance technicians verified the verbal instructions with radiation protection prior to disconnecting the pressure switches. A radiation protection technician was dispatched to assist in ensuring that all of the system water was captured. The radiation protection technician appropriately captured the water as the pressure switches were removed, but failed to drain the first pressure switch. As the pressure switch was handed from one maintenance technician to another, potentially contaminated water was spilled on the work package. The radiation protection technician was not alerted. As the radiation protection technician turned to leave the work area, the inspector called him back and pointed out the need for a survey of the work package for contamination. The work package was found to be free from contamination.

c. Conclusion

The inspectors concluded that the maintenance technicians took the appropriate actions in verifying that the verbal instructions were correct, but failed to point out that water was spilled on the work document to the radiation protection technician.

The safety consequences of this particular event were low because the work document was not contaminated, but demonstrated a weakness in preventing the spread of contamination.

F8 Miscellaneous Fire Protection Issues

F8.1 (Closed) LER 298/94-036-02, -01, and -00: fire suppression water system did not meet the minimum requirements for operability. The electric-driven fire pump and the fire water jockey pump lost power due to an electrical transient on the 12.5 kV system and during planned power outages to perform maintenance on the 12.5 kV system.

The licensee made these three reports to comply with Technical Specifications Action Statement 3.15.C.2.b, which required a special written report that outlines the action taken, the cause of the inoperability, and the plans and schedule for restoring the system to operable status. The inspectors concluded from a review of the LERs that the licensee met the Technical Specification action statement. In each case, power was restored and the electric-driven fire pump and fire water jockey pump were returned to an operable status.

V. USAR

A recent discovery of a licensee operating facility in a manner contrary to the USAR description highlighted the need for a special focused review that compares plant practices, procedures, and/or parameters to the USAR description. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the USAR that related to the areas inspected. The licensee identified a number of USAR discrepancies in the licensee's corrective action for a 1994 TS surveillance violation. The inspectors verified that these discrep es were not corrected to date. These discrepancies will be documented in N. Inspection Report 50-298/96-24, the safety system functional inspection.

Section 01.1 discusses that the USAR describes that operation of the facility in cold weather is with the intake structure ice deflector in place. On November 26, 1996, some ice slush collected at the intake and the ice deflector was not installed. This is an unresolved item.

VI. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the exit meeting on December 2, 1996. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

Jack Dillich, Maintenance Manager
Rick Gardner, Operations Manager
Robert Godley, Plant Engineering Manager
Mike Hale, Radiation Protection Manager
Bradford Houston, Licensing Manager
Mike Peckham, Plant Manager

INSPECTION PROCEDURES USED

IP 37751: Onsite Engineering
IP 37828: Engineering - Install and Test Modifications
IP 61726: Surveillance Observation
IP 62707: Maintenance Observation
IP 71707: Plant Operations
IP 71750: Plant Support Activities
IP 92901: Followup - Plant Operations
IP 92902: Followup - Maintenance
IP 92903: Followup - Engineering
IP 92700: Onsite Followup of Written Reports of Non-Routine Events at Power Reactor Facilities
IP 93702: Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPENED, OPENED AND CLOSED, CLOSED, AND DISCUSSED

Opened

298/96026-01	VIO	no documentation for Technical Specification surveillance requirement (Section 04.2)
298/96026-02	URI	slush buildup in circulating water intake bays (Section O1.1)
298/96026-06	IFI	design basis for level indicator calibration tolerance for fuel range level indicators (Section M1.2)
298/96026-07	IFI	failure of APRM flow bias unit low side voltage operability evaluation (Section 04.4)

Opened and Closed

298/96026-03	NCV	single failure of standby gas (Section E8.1)
298/96026-04	NCV	Diesel Generator 2 muffler bypass valve bowed shaft (Section E8.4)
298/96026-05	NCV	primary containment group isolations caused by inadequate surveillance procedures (Section M8.1)

Closed

298/94019-01	VIO	failure to maintain positive pressure in control room (Section O8.2)
298/94-004-00	LER	reactor scram due to partial closure of turbine governor valves (Section E8.5)
298/94-035-00	LER	inoperable standby gas treatment system (Section E8.1)
298/94-036-02, -01, -00	LER	fire suppression water system did not meet the minimum requirements for operability (Section F8.1)
298/95-004-00	LER	primary containment group isolations caused by surveillance procedure deficiencies (Section M8.1)
298/95-006-00	LER	improper methodology for calibrations of source range monitors which resulted in missed Technical Specification surveillance requirements (Section M8.2)
298/95-012-00	LER	RPS trip signal and primary containment group isolations during shutdown for refueling outage (Section O8.2)
298/95-018-00, -01	LER	maintenance activity could compromise steam tunnel blowout panel (Section E8.2)
298/96-008-00	LER	scram discharge volume high level RPS trip channel anomaly (Section M8.3)
298/96-010-00	LER	previous unavailability of the muffler bypass valve on Emergency Diesel Generator 2 due to bowing in actuator shaft (Section E8.4)
298/96-014-00	LER	fuel preparation machine upper limit stops set in violation of Technical Specifications (Section E8.3)

Discussed

298/9508-01	VIO	Inadequate Procedures (Section O8.3)