Nebraska Public Power District
Nebraska's Energy Leader

NLS2001005
January 17, 2001

U.S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, D.C. 20555-0001

Gentlemen:

Subject: Licensee Event Report No. 2000-012
Cooper Nuclear Station, NRC Docket 50-298, DPR-46

The subject Licensee Event Report is forwarded as an enclosure to this letter.

Sincerely,

J. A. McDonald
Plant Manager

/rar
Enclosure

cc: Regional Administrator
USNRC - Region IV

Senior Project Manager
USNRC - NRR Project Directorate IV-1

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NRC FORM 366 (6-1998)	U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB NO. 3150-0104 EXPIRES 06/30/2001
LICENSEE EVENT REPORT (LER) (See reverse for required number of digits/characters for each block)		Estimated burden per response to comply with this mandatory information collection request: 50 hrs. Reported lessons learned are incorporated into the licensing process and fed back to industry. Forward comments regarding burden estimate to the Records Management Branch (T-6 F33), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, and to the Paperwork Reduction Project (3150-0104), Office of Management and Budget, Washington, DC 20503. If an information collection does not display a currently valid OMB control number, the NRC may not conduct or sponsor, and a person is not required to respond to, the information collection.

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TITLE (4)

Human Error Results in Automatic Engineered Safety Features Actuation

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER 05000
12	18	2000	2000	-- 012 --	00	01	17	2001	FACILITY NAME	DOCKET NUMBER 05000

OPERATING MODE (9)	1	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)							
POWER LEVEL (10)	100		20.2201(b)		20.2203(a)(2)(v)		50.73(a)(2)(i)		50.73(a)(2)(viii)
			20.2203(a)(1)		20.2203(a)(3)(i)		50.73(a)(2)(ii)		50.73(a)(2)(x)
			20.2203(a)(2)(i)		20.2203(a)(3)(ii)		50.73(a)(2)(iii)		73.71
			20.2203(a)(2)(ii)		20.2203(a)(4)	X	50.73(a)(2)(iv)		OTHER
			20.2203(a)(2)(iii)		50.36(c)(1)		50.73(a)(2)(v)		Specify in Abstract below or in NRC Form 366A
			20.2203(a)(2)(iv)		50.36(c)(2)		50.73(a)(2)(vii)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
Sharon Mahler, Assistant Licensing Manager	402-825-5236

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO EPIX

SUPPLEMENTAL REPORT EXPECTED (14)				EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
	YES (If yes, complete EXPECTED SUBMISSION DATE).	X	NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines) **(16)**

On December 18, 2000, at 14:36 Central Standard Time (CST), with the plant operating at 100% power, a personnel error was made in performing the Division I undervoltage logic surveillance procedure relay calibration that resulted in the load shedding of the Division I 4160V Critical Bus 1F. Service Water (SW) pump C tripped causing low pressure isolation of the non-critical header, Control Rod Drive pump A tripped, and several Motor Control Centers were lost resulting in the trip of Reactor Recirculation Motor Generator A, Reactor Water Cleanup pump B, Off-Gas Dilution Fan A, Reactor Building Exhaust Fan 1A, and the loss of Elevated Release Point radiation monitoring. The plant stabilized at approximately 65% power in single-loop operation. Reactor Pressure Vessel level and pressure responded as expected.

A detailed review of the electrical system response indicated that the trip circuits for Division I Emergency Core Cooling System pumps were energized by the load shedding event, thus preventing their operation for a period of approximately four minutes. In addition, during recovery from the event SW Pump B started, tripped, and would not re-start on operator demand.

At 14:40 CST on December 18, 2000, SW header pressure was returned to normal. The plant was restored to two loop operation at 21:25 CST on December 18, 2000, and 100 percent power was achieved at 08:00 CST on December 19, 2000.

This event is attributed to a management failure to reinforce standards and expectations which resulted in inadequate supervision, and the resultant personnel error, during the performance of a Division I undervoltage surveillance procedure.

TEXT *(If more space is required, use additional copies of NRC Form 366A)* **(17)**

PLANT STATUS

Cooper Nuclear Station (CNS) was in Mode 1 at approximately 100 percent power at the time of this event.

BACKGROUND

Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power sources for energizing the various components such as pump motors, motor operated valves, and the associated control components. The Loss of Power (LOP) instrumentation monitors the 4.16 kV emergency buses and the power to the buses. Offsite power is the preferred source of power for the 4.16 kV emergency buses. If the monitors determine that insufficient power is available, the buses are disconnected from the offsite power sources and connected to the onsite diesel generator (DG) power sources.

Each 4.16 kV emergency bus has its own independent LOP instrumentation and associated trip logic. The voltage for each bus is monitored at two levels, which can be considered as two different types of undervoltage protection: Loss of voltage protection and degraded voltage protection. There are three loss of voltage relays associated with each 4.16 kV Emergency Bus or power supply to that bus constituting three separate functions. Relay numbers and breakers below are for Bus 1F only, Bus 1G is similar.

Function 1: Relay 27/1F1, 4.16 kV Emergency Bus Undervoltage (loss of voltage)

Function 2: Relay 27/1FA1, 4.16 kV Emergency Bus Normal Supply Undervoltage (loss of voltage)

Function 3: Relay 27/ET1, 4.16 kV Emergency Bus Emergency Station Service Transformer (ESST) Supply Undervoltage (loss of voltage)

These three functions constitute the first level of undervoltage protection. Upon sensing a loss of voltage to the Emergency Bus, the Function 1 relay will initiate the following:

- A start signal to DG1.
- Load shedding of all motors on 4.16 kV Emergency Bus 1F.
- Load shedding of the non-essential Motor Control Centers (MCC) and non-essential motors fed from Emergency 480 V Bus 1F.

The Function 2 undervoltage relay will then trip breaker 1FA if Emergency Bus 1F is being supplied from its normal source (either the normal station service transformer (NSST) or the startup station service transformer (SSST)); or,

The Function 3 undervoltage relay will trip breaker 1FS if the 4.16 kV Emergency Bus is being supplied from its alternate source, the ESST. Opening these breakers will then allow the diesel generator to connect to 4.16 kV Emergency Bus.

The three loss of voltage relays are each arranged in a one-out-of-one logic configuration.

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The second level of undervoltage protection is a degraded voltage scheme. Voltage on the 4.16 kV Emergency Bus is monitored by relay 27/1F2 and voltage on the normal supply bus tie to emergency bus is monitored by relay 27/1FA2. When the 4.16 kV Emergency Bus is energized from its normal source, a degraded voltage condition will be sensed by these two relays. When the 4.16 kV Emergency Bus is energized from the ESST, a degraded voltage condition on the Emergency Bus will be sensed by relay 27/1F2 only. When the 4.16 kV Emergency Bus is powered from the normal supply, a degraded voltage condition on the Emergency Bus for approximately 12.5 seconds will trip the tie breaker 1FA unless an Residual Heat Removal (RHR) initiation seal-in is present, in which case breaker 1FA will trip on a degraded voltage on the bus after approximately 7.5 seconds. When the 4.16 kV Emergency Bus is powered from the ESST, a degraded voltage condition on the Bus for approximately 15 seconds will trip breaker 1FS.

The two degraded voltage relays are arranged in a two-out-of-two logic configuration if the emergency bus is powered from its normal source, or in a one-out-of-one logic configuration if the emergency bus is powered from the ESST.

The channels include electronic equipment (e.g., internal relay contacts, coils, solid state logic, etc.) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a LOP trip signal to the trip logic.

The LOP instrumentation is required for Engineered Safety Features to function in any accident with a loss of offsite power. The required channels of LOP instrumentation ensure that the ECCS and other assumed systems powered from the DGs, provide plant protection in the event of any of the analyzed accidents in which a loss of offsite power is assumed. The initiation of the DGs on loss of offsite power, and subsequent initiation of the ECCS, ensure that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

EVENT DESCRIPTION

On December 18, 2000, at 14:36 Central Standard Time (CST), with the plant operating at 100% power, a personnel error was made in performing the Surveillance Procedure (SP) 6.1EE.302, 4160V Bus 1F Undervoltage Relay and Relay Timer Functional Test (DIV 1) relay calibration. This personnel error resulted in a mis-positioned test switch which subsequently caused the load shedding of 4160V Bus 1F [EIIS:EA]. Load shedding caused the following equipment actuations: Service Water (SW) [EIIS:KW] pump [EIIS:P] C tripped causing SW-MOV-36 and SW-MOV-37 to isolate on low header pressure, Control Rod Drive [EIIS:AA] pump A tripped, and MCCs [EIIS:MCC] M, N, OG1, and P were lost. The loss of these MCCs led to Reactor Recirculation [EIIS:AD] Motor Generator [EIIS:MG] A tripping on low oil pressure, Reactor Water Cleanup [EIIS:CE] pump B loss, Off-Gas [EIIS:WF] Dilution Fan A loss, Reactor Building Exhaust [EIIS:VL] Fan 1A loss, and the loss of the Normal and High Range Elevated Release Point radiation monitiors. The undervoltage control logic initiated a Diesel Generator [EIIS:DG] start signal. However, the Division I diesel generator did not start due to installed relay contact boots. Other minor equipment was lost when the MCCs load shed. The plant stabilized at approximately 65% power in single-loop operation. Reactor Pressure Vessel level and pressure responded as expected.

A detailed review of the electrical system response was performed to ensure the plant responded correctly. In addition to the affected equipment noted above, the trip circuits for Residual Heat Removal Service Water pumps A and C, SW pump A, Core Spray [EIIS:BM] pump A, and RHR pumps A and B were energized thus preventing their operation (manual and automatic) for a period of approximately four

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minutes. At approximately 14:40, the mis-positioned test switch which resulted in the inadvertent load shedding signal was returned to the correct position.

There were no unexplained equipment responses upon receipt of the induced load shed and all plant equipment operated as expected given the initiating event. However, during recovery from the event SW pump B was started and tripped immediately on high system pressure and would not re-start on operator demand.

Following placement of the test switch in the correct position, the Service Water system and the Control Rod Drive system were restored. Single loop operations were addressed and the load shed MCCs recovered. At 14:40 CST on December 18, 2000, SW header pressure was returned to normal. The plant was restored to two loop operation at 21:25 CST on December 18, 2000, and 100 percent power was achieved at 08:00 CST on December 19, 2000.

BASIS OF REPORT

Ensuring adequate power sources are available to energize ECCS components is considered an engineered safety feature. In addition, the Division I diesel generator start signal was initiated by the undervoltage control logic. The DG did not start due to relay contact boots installed for the performance of this surveillance. Therefore, this event is being reported under the requirements of 10CFR50.73(a)(2)(iv) as an event or condition that resulted in a manual or automatic actuation of any engineered safety feature.

CAUSE

The cause of this event was a management failure to reinforce standards and expectations which resulted in inadequate supervision, and the resultant personnel error, during the performance of the surveillance procedure. This is demonstrated by the following:

Operations Shift Management, i.e., the Shift Supervisor and the Control Room Supervisor are the appointed guardians ensuring that Operations Management standards and expectations are in place during all modes of operation at CNS. In reviewing the results and findings as documented in this report, it is evident that the Operations Shift Management did not ensure nor demand present Operations Management Standards and Expectations during conduct of this evolution.

1. Operations Shift Management failed to ensure that Operations Management expectations were established and in place for conduct of this evolution.
   - Operations Shift Management was not present at the pre-evolution brief.
   - Command and Control of the evolution was not clearly established.
   - Pre-evolution brief did not meet Operations Management expectations.
     Roles and Responsibilities were not clearly established.
     Expected Communications of the evolution were not defined.
   - Attachment 7 of the Surveillance Procedure (SP) 6.1EE.302, 4160V Bus 1F Undervoltage Relay and Relay Timer Functional Test (DIV 1), for calibration of a time delay relay was not briefed prior to performance.

2. The Licensed Operator in charge of the surveillance assumed an additional responsibility as the Performer of the surveillance.
   - The Oversight role was negated with the concurrent responsibility of Performer.

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3. Failure to follow a Continuous Use procedure as written.
   - Attachment 7 of the Surveillance Procedure was not performed as written as established from interviews and confirmed following a review of the annunciator system (RONAN) data.

4. An individual was allowed to be an active participant in the Surveillance Procedure even though it was known that he was not present at the pre-evolution brief.

In review of the causal factors two (2) contributing factors to the Root Cause were identified.

1. The methodology in calibration of relays is not consistent between the Operations and Electrical Department.
   - This was confirmed following a review of the Surveillance Procedure and the Maintenance Procedure for in place testing and adjustment of timing relays (MP 7.3.7.1), i.e., the number of successful repeatability timings required following the calibration setting. This may have contributed to the confusion over steps completed between the surveillance director and team members and the resulting omission of a critical step in Attachment 7 of the Surveillance Procedure (i.e., the personnel error).

2. There were several instances when the team members recognized an inconsistency and did not demonstrate a questioning attitude necessary to ensure resolution.
   - Both electricians questioned the fact that an individual not present at the pre-evolution brief was participating in the surveillance, yet failed to voice their concern to the surveillance director.
   - Confusion existed between the electrician and surveillance director on the meaning / intention of the "Performed by" signature.
   - On two separate instances the Control Room Operator questioned the performers on "place keeping."
   - The electrician performer's unfamiliarity with the Surveillance Procedure Attachment being used and failure to voice that to the team surveillance director.
   - The confusion over steps completed between the surveillance director and the remaining team members during the performance of Attachment 7 of the Surveillance Procedure.

SAFETY SIGNIFICANCE

The load shedding event which occurred during the performance of the 4160V Bus 1F undervoltage surveillance testing resulted in the tripping of the Division I Reactor Recirculation pump. This plant transient is described in the Safety Analysis Report (SAR). The results of the SAR analysis are as follows:

> "This transient was analyzed using the REDY transient model. Calculations using the REDY model are based upon end-of-cycle conditions and utilize conservative multipliers on void, Doppler and scram reactivities (0.95, 1.05, and 0.8 respectively). As shown in [USAR] Figure XIV-5-14, there is essentially no increase in fuel temperature or surface heat flux during the transient. Nucleate boiling is maintained throughout the transient (MCHFR remains above 1.3)."

This event is classified as an incident of moderate frequency.

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The plant configuration immediately following the initiating event in which the Division I ECCS systems were unavailable for automatic or manual initiation for a period of approximately four minutes, and the unavailability of one Division II SW pump, is bounded by the Loss of Coolant Design Basis Accident. This accident scenario assumes a loss of the reactor coolant pressure boundary, a loss of off-site power and a limiting single failure. The available Division II ECCS systems/components following the undervoltage event meet the minimum requirements to safely shut down the plant during the DBA.

A Probabilistic Safety Assessment review was performed to evaluate the risk significance of the conditions resulting from this event. This evaluation determined that the risk significance of this event was low due to the short duration of the condition, and the successful actions taken in response to the event. The Core Damage Frequency (CDF) for this event remained below the CDF limit for planned maintenance configurations.

This event was also evaluated to determine if the event should be classified as a Safety System Functional Failure (SSFF). The results of the evaluation demonstrated that CNS retained the ability to:

A. Shut down the reactor and maintain it in a safe shutdown condition.
B. Remove residual heat.
C. Control the release of radioactive material.
D. Mitigate the consequences of an accident.

Therefore, this event is not reportable as a SSFF in accordance with the guidance contained in Nuclear Energy Institute 99-02, Revision 0, or under the provisions of 10CFR50.73(a)(2)(v).

In conclusion, the safety significance of this event is low.

CORRECTIVE ACTIONS

Immediate Actions

1. CNS Site Stand Down conducted on December 21, 2000 at 11:30 hours to review/discuss this event.

2. An E-mail was sent to CNS operations personnel from the Operations Supervisor, dated December 20, 2000, detailing the contributing factors that were discovered during the review of this event.

3. CNS procedures for 4160V Bus 1F(G) Undervoltage Relay and Relay Timer Functional Test were placed on administrative hold, pending incorporation of the following additional requirements: 1. Concurrent verification on the installation / removal of jumpers, boots, and fuses. 2. A Licensed Operator shall coordinate the surveillance. The procedures were issued December 20, 2000 and January 5, 2001.

4. The Plant Manager and the Operations Manager verbally counseled the Shift Supervisor on the significance of the event and Management's expectations for the conduct of the Shift Supervisor on January 5, 2001.

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5. The Operations Manager and the Operations Supervisor verbally counseled the Control Room Supervisor and crew involved regarding Operations Management expectations on conduct of operations and expected standards on January 6, 2001.

6. Operations Management has assigned two Senior Operations Management personnel to dedicate time to coaching/mentoring the operations shift crews on Standards and Expectations on shift and in the training environment. This action was completed January 15, 2001. These two Senior Operations Management personnel will continue to provide coaching/mentoring to operations shift crews until April 15, 2001.

Long Term Actions

Operations management has recently defined the Operations Department Standards and Expectations as stated in the CNS procedure, Conduct of Operations, (implemented December 2000) and the CNS procedure, Operations Procedure Policy (implemented September 2000). Operations management has and will continue to communicate these expectations to the department.

1. CNS Operations Department will implement a performance improvement plan for Operations personnel that do not meet minimum Operations Management expectations. This action will be complete by March 9, 2001.

2. CNS will evaluate/correct differences, as required, between SP 6.1(2)EE.302 and Maintenance Procedure 7.3.7.1 on number of required successful timings following relay calibration by April 9, 2001.

3. CNS will require by procedure, the presence of either the Shift Supervisor or Control Room Supervisor at the pre-evolution brief for evolutions that are evaluated as non-green by the schedule risk assessment (ORAM-SENTINEL) process by February 15, 2001.

4. The Plant Manager and Operations Manager will communicate to all Shift Supervisors the significance of the event and the expectations and standards for conduct of the Shift Supervisor position. This action will be completed by January 31, 2001.

PREVIOUS EVENTS

The previous events have been reported as Human Performance errors.

LER 1998-009, Operator Error Results In Unexpected Full Scram on High Scram Discharge Volume Level While in Mode 5, reported a failure to follow procedure while resetting a scram. This was attributed to an inadequate pre-shift brief. Corrective actions included a revision to Operations Instructions to require brief for time critical tasks, and additional emphasis on peer checking.

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LER 1999-007, Sump Z Inoperability Results in Technical Specification Required Shutdown, reported an event where both trains of Standby Gas Treatment were declared inoperable due to a hydrogen ignition during start-up of the Augmented Off Gas (AOG) system. An inadequate pre-job brief was considered a significant contributing factor to this event. Corrective actions included a revision to the system operating procedures to require a pre-job brief in accordance with Station Procedure 2.0.1.1, Conduct of Infrequently Performed Tests or Evolutions.

LER 1999-008, Troubleshooting Activities Causes Critical Bus Undervoltage and ESF Actuations, reported an event caused by the installation of test equipment which resulted in an erroneous undervoltage being sensed on a non-critical electrical bus. This event was attributed to a lack of appropriate training in the use of the test equipment, and a failure to follow procedures for identifying work boundaries and for performing pre-job briefs. Corrective actions included additional training on the use of test equipment, and procedure revisions to address repeating the pre-job brief when a job spans several shifts or several days.

Corrective actions for the above events have been focused at the performer. However, the previous corrective actions did not address a reinforcement of supervisory/management expectations for job performance.

Correspondence Number: NLS2001005

The following table identifies those actions committed to by the District in this document. Any other actions discussed in the submittal represent intended or planned actions by the District. They are described to the NRC for the NRC's information and are not regulatory commitments. Please notify the NL&S Manager at Cooper Nuclear Station of any questions regarding this document or any associated regulatory commitments.

COMMITMENT	COMMITTED DATE OR OUTAGE
CNS Operations Manager will implement a performance improvement plan for Operations personnel that do not meet minimum Operations Management expectations.	March 9, 2001
CNS will evaluate/correct differences, as required, between SP 6.1(2)EE.302 and Maintenance Procedure 7.3.7.1 on number of required successful timings following relay calibration.	April 9, 2001
CNS will require by procedure the presence of either the Shift Supervisor or Control Room Supervisor at the pre-evolution brief for evolutions that are evaluated as non-green by the schedule risk assessment (ORAM-SENTINEL) process.	February 15, 2001
The Plant Manager and Operations Manager will communicate to all Shift Supervisors the significance of the event and the expectations and standards for conduct of the Shift Supervisor position.	January 31, 2001