SERP Worksheet for SDP-Related Finding at Cooper Nuclear Station Service Water Gland Seal Water Configuration Deficiency

SERP Date: ~~10/20/04~~ 12/2/04
Cornerstones Affected :
Initiating Events and Mitigating Systems
Proposed Preliminary Results:
Greater than Green - Violation of 10 CFR 50, Appendix B, Criterion V, failure to prescribe appropriate instructions for the restoration service water following maintenance

Licensee: Nebraska Public Power District
Facility/Location:
Cooper Nuclear Station / Brownville, NE
Docket No: 50-298
License No: DPR 46
Inspection Report No:
50-298/2004-014 Special
Date of Exit Meeting:
July 22, 2004
Inspectors: Scott Schwind; Steve Cochrum
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CONTENTS

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FOIA- 2006-0007

DD-14

A. **Brief Description of Issue**

On January 21, 2004, the Division II service water discharge strainer was bypassed for routine maintenance (cleaning). In accordance with operating procedures, the gland water supply for the Division II pumps was cross-connected with the Division I pumps. This is performed to prevent the introduction of large debris into the Division II pump glands. At that time, licensed operators declared the Division II service water subsystem to be inoperable because it was no longer independent from the other division as required. Following maintenance, the discharge strainer was returned to service, and the Division II service water subsystem was declared operable. However, operators restoring the system, failed to realign the gland water supply to the Division II pumps. Therefore, the interdependence between the two divisions remained.

On February 11, licensed operators were conducting a valve alignment verification because several spurious gland water low pressure annunciators had alarmed for Division II pumps. The incorrect alignment was discovered as a result. Licensed operators appropriately declared Division II inoperable. The valves were realigned and the system was restored to an operable status.

B. **Statement of Performance Deficiency**

The licensee failed to provide appropriate procedural guidance for the restoration of the Division II service water pump gland water supply following maintenance and prior to returning the system to service. This configuration resulted in the Division II service water gland sealing system being provided by the Division I service water pumps. In this configuration, a failure of the Division I pumps would result in loss of gland water to the Division II pumps.

C. **Significance Determination Basis**

1.
Phase 1 Screening Logic, Results and Assumptions

In accordance with NRC Inspection Manual Chapter 0612, Appendix B, "Issue Screening," the inspectors determined that the failure to properly realign the system was a licensee performance deficiency because the system was returned to service in a condition that failed to meet the operability requirements of Technical Specification 3.7.2. This specification requires that both divisions of service water be operable. Additionally the failure to properly align the gland water system was fully within the licensee's abilities to control. The issue was more than minor because it affected the reliability of the service water system which provides the ultimate heat sink for the reactor during accident conditions.

The inspectors evaluated the issue using the SDP Phase 1 Screening Worksheet for the Initiating Events, Mitigating Systems, and Barriers Cornerstones provided in Manual Chapter 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations." This issue caused an increase in the likelihood of an initiating event, namely loss of service water, as well as increasing the probability that the service water system would not be available to perform its mitigating systems function. Therefore, the issue was passed to Phase 2.

2.
Phase 2 Estimation for Internal Events

In accordance with Manual Chapter 0609, Appendix A, Attachment 1, "User Guidance for Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors evaluated the subject finding using the Risk-Informed Inspection Notebook for Cooper Nuclear Station, Revision 1. The following assumptions were made:

•The failure of gland water cooling to a service water pump will result in the failure of the pump to meet its risk-significant function.

•The configuration of the service water system increased the likelihood that all service water would be lost.

•The condition existed for 21 days. Therefore, the exposure time window used was 3 - 30 days.

•The initiating event likelihood credit for loss of service water system was increased from five to four by the senior reactor analyst in accordance with Usage Rule 1.2 in Manual Chapter 0609, Appendix A, Attachment 2, "Site Specific Risk-Informed Inspection Notebook Usage Rules." This change reflects the fact that the finding increased the likelihood of a loss of service water, a normally cross-tied support system.

•The configuration of the service water system did not increase the probability that the system function would be lost by an order of magnitude because both pumps in Division I would have to be lost before the condition would affect Division II. Therefore, the order of magnitude assumption was that the service water system would continue to be a multi-train system.

•Because both divisions of service water continued to run and would have been available without an independent loss of Division I, this condition decreased the reliability of the system, but not the function. Therefore, sequences with loss of the service water mitigating function were not included in the analysis.

The last two assumptions are a deviation from the risk-informed notebook that was recommended by the Senior Reactor Analyst. This deviation represents a Phase 3 analysis in accordance with Manual Chapter 0609, Appendix A, Attachment 1, in the section entitled: "Phase 3 - Risk Significance Estimation Using Any Risk Basis That Departs from the Phase 1 or 2 Process."

Table 2 of the risk-informed notebook requires that all initiating event scenarios be evaluated when a performance deficiency affects the service water system. However, given the assumption that the service water system function was not degraded, only the sequences with the special initiator for Loss of Service Water (TSW) and the sequences related to a Loss of A/C are applicable to this evaluation. The sequences from the notebook are as follows:

Initiating Event	Sequence	Mitigating Functions	Results
Loss of Service Water	1	RECSW24-LI	6
Loss of Service Water	2	RCIC-LI	6
Loss of Service Water	3	RCIC-HPCI	6

Using the counting rule worksheet, this finding was estimated to be YELLOW. However, because several assumptions made during the Phase 2 process were overly conservative, a Phase 3 evaluation is required.

3.
Phase 3 Analysis

Internal Initiating Events

Assumptions:

As stated above, the analyst modified the Phase 2 estimation by not including the sequences from initiating events other than a loss of service water. This change alone represents a Phase 3 analysis.

However, the results from the modified notebook estimation were compared with an evaluation developed using a Standardized Plant Analysis Risk (SPAR) model simulation of the cross tied service water divisions, as well as an assessment of the licensee's evaluation provided by the licensee's probabilistic risk assessment staff (Glen A. Seeman). The SPAR runs were based on the following analyst assumptions:

a.The Cooper SPAR model was revised to better reflect the failure logic for the service water system. This model, including the component test and maintenance basic events, represents an appropriate tool for evaluation of the subject finding.

b.NUREG/CR-5496, "Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1980 - 1996," contains the NRC's current best estimate of both the likelihood of each of the loss of offsite power (LOOP) ~~classes (i.e.~~ plant-centered, grid related, and severe weather) and their recovery probabilities.

c.The service water pumps at Cooper will fail to run **50% of the time** if gland water is lost for 30 minutes or more. If gland water is recovered within 30 minutes of loss, the pumps will continue to run for their mission time, given their nominal failure rates.

d.The condition existed for 21 days from January 25 through February 11, 2004 representing the exposure time.

e.The nominal likelihood for a loss of service water, $IEL_{(TSW)}$, at the Cooper Nuclear Station is as stated in NUREG/CR-5750, "Rates of Initiating Events at Nuclear Power Plants: 1987 - 1995," Section 4.4.8, "Loss of Safety-Related Cooling Water System." This reference documents a total loss of service water frequency at 9.72×10^{-4} per critical year.

f.The nominal likelihood for a partial loss of service water, $IEL_{(PTSW)}$, at the Cooper Nuclear Station is as stated in NUREG/CR-5750, "Rates of Initiating Events at Nuclear Power Plants: 1987 - 1995," Section 4.4.8, "Loss of Safety-Related Cooling Water System." This reference documents a partial loss of service water frequency (loss of single division) at 8.92×10^{-3} per critical year.

g.Battery depletion time is best represented as occurring at 8 hours rather than at 4 hours as described in the SPAR. This assumption was based on resident inspector review of the licensee's calculation provided following the regulatory conference.

h.The configuration of the service water system increased the likelihood that all service water would be lost. The increase in loss of service water initiating event likelihood best representing the change caused by this finding is one half the nominal likelihood for the loss of a single division. The analyst noted that the nominal value represents the likelihood that either division of service water is lost. However, for this finding, only losses of Division I equipment result in the loss of the other division.

i.The SPAR HRA method used by Idaho National Engineering and Environmental Laboratories during the development of the SPAR models and published in Draft NUREG/CR-xxxxx, INEEL/EXT-02-10307, "SPAR-H Method," is an appropriate tool for evaluating the probability of operators recovering from a loss of Division I service water.

j.The probability of operators failing to properly diagnose the need to restore Division II service water gland water **to the running pump** upon a loss of Division I service water is 0.4. This assumed the nominal diagnosis failure rate of 0.01 multiplied by the following performance shaping factors:

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Available Time: 10

The available time was barely adequate to complete the diagnosis. The analyst assumed that the diagnosis portion of this condition included all activities to identify the mispositioned valves. A licensee operator took 21 minutes to complete the steps. The analyst noted that this walk through was conducted in a vacuum. During a real incident, operators would have to prioritize many different annunciators. Additionally, operations personnel had been briefed on the finding at a time prior to the walk through, so they were more knowledgable of the potential problem than they would have been prior to the identification of the finding. Therefore, the analyst assumed that the nominal time for this diagnosis was 45 minutes.

♦
Stress: 2

Stress under the conditions postulated would be high. Multiple alarms would be initiated including a loss of the Division I service water and the loss of gland water to Division II. Additionally, assuming that indications of gland water failure were believed, the operators would understand that the consequences of their actions would represent a threat to plant safety.

♦

Complexity: 2

The complexity of the tasks necessary to properly diagnose this condition was determined to be moderately complex. The analyst determined that there was some ambiguity in the diagnosis of this condition. The following factors were considered:

- Division I would be lost and may be prioritized above Division II.

- The diagnosis takes place at both the main control room and the auxiliary panel in the service water structure and requires interaction between at least two operators.

- There have previously been alarms on gland water annunciators when swapping Divisions. Therefore, operators may hesitate to take action on Division II given problems with Division I.

- Previous heat exchanger clogging events may mislead the operators during their diagnosis.

New

K.
The probability of operators failing to properly diagnose the need to restore Division II service water gland water to the standby pump upon failure of the running pump is 0.05. This results in a conditional probability of recovering gland water to the standby pump, given a failure to recover gland water to the running pump, of 0.125. This calculation used the same performance shaping factors as in the case of the running pump with the following exceptions: the available time was was changed from barely adequate to extra time (0.1) because the time to perform this action was now greater than 60 minutes, and Odd's ratio was applied to better quantify the multiple performance shaping factors.

Analysis:

Initiating Event Calc:

The analyst calculated the new initiating event likelihood, $IEL_{(TSW\text{-}case)}$, as follows:

$$IEL_{(TSW\text{-}case)} = IEL_{(TSW)} + [\ ½ * \ IEL_{(PTSW)}\ ] =$$

$$9.72 \times 10^{-4} + [\ 0.5 * 8.92 \times 10^{-3}\ ] =$$

5.43×10^{-3}/ yr ÷ 8760 hrs/yr

6.20×10^{-7}/hr.

Evaluation of Change in Risk

The SPAR Revision 3.03 model was modified to include updated loss of offsite power curves as published in NUREG CR-5496, as stated in Assumption b. The changes to the loss of offsite power recovery actions and other modifications to the SPAR model were documented in Table 2. In addition, the failure logic for the service water system was significantly changed as documented in Assumption a. These revisions were incorporated into a base case update, making the revised model the baseline for this evaluation. The resulting baseline core damage frequency, CDF_{base}, was **5.05×10^{-9} /hr.**

The analyst changed this modified model to reflect that the failure of the Division I service water system would cause the failure of the gland water to Division II. Division II was then modeled to fail either from independent divisional equipment failures, or from the failure of Division I. The analyst determined that the failure of Division II could be prevented by operator recovery action. **The analyst changed the recovery action value to reflect a holistic approach to determining the survivability of the service water system. Given the failure of the first pump, the availability and reliability of the second pump was evaluated. Additionally, the degradation of the pump observed during testing was assumed to degrade the pump. The analyst's model provided a best estimate failure to survive value of 2.65×10^{-2} upon demand with a loss of Division I. The modified SPAR model** was requantified with the resulting current case conditional core damage frequency, CDF_{case}, of **6.26×10^{-9}** /hr.

The change in core damage frequency (ΔCDF) from the model was:

$\Delta CDF = CDF_{case} - CDF_{base}$

$= \mathbf{6.26 \times 10^{-9} - 5.05 \times 10^{-9} = 1.21 \times 10^{-9}}$ **/hr.**

Therefore, the total change in core damage frequency over the exposure time that was related to this finding was calculated as:

ΔCDF = **1.21×10^{-9}** /hr * 24 hr/day * 21 days = **6.10×10^{-7}** for 21 days

The risk significance of this finding is presented in Table 3.a. The dominant cutsets from the internal risk model are shown in Table 3.b.

Table 2: Baseline Revisions to SPAR Model

Basic Event	Title	Original	Revised
ACP-XHE-NOREC-30	Operator Fails to Recover AC Power in 30 Minutes	.22	5.14×10^{-1}
ACP-XHE-NOREC-4H	Operator Fails to Recover AC Power in 4 Hours	.023	6.8×10^{-2}

ACP-XHE-NOREC-90	Operator Fails to Recover AC Power in 90 Minutes	.061	2.35 x 10^{-1}
ACP-XHE-NOREC-BD	Operator Fails to Recover ACP before Battery Depletion	.023	**1.7 x 10^{-2}**
IE-LOOP	Loss of Offsite Power Initiator	5.20 x 10^{-6}/hr	5.32 x 10^{-6}/hr
EPS-DGN-FR-FTRE	Diesel Generator Fails to Run - Early Time Frame	0.5 hrs.	0.5 hrs.
EPS-DGN-FR-FTRM	Diesel Generator Fails to Run - Middle Time Frame*	2.5 hrs.	13.5 hrs.
OEP-XHE-NOREC-10H	Operator Fails to Recover AC Power in 10 Hours	2.9 x 10^{-2}	5.6 x 10^{-2}
OEP-XHE-NOREC-1H	Operator Fails to Recover AC Power in 1 Hours	1.2 x 10^{-1}	3.93 x 10^{-1}
OEP-XHE-NOREC-2H	Operator Fails to Recover AC Power in 2 Hours	6.4 x 10^{-2}	2.49 x 10^{-1}
OEP-XHE-NOREC-4H	Operator Fails to Recover AC Power in 4 Hours	4.5 x 10^{-2}	1.36 x 10^{-1}
* Diesel Mission Time was increased from 2.5 to 14 hours in accordance with NUREG/CR-5496			

Table 3.a: Evaluation Model Results			
Model	Result	Core Damage Frequency	LERF
SPAR 3.03, Revised	Baseline: Internal Risk	**5.1 x 10^{-9}/hr**	**2.0 x 10^{-9}/hr**
	Internal Events Risk	**6.3 x 10^{-9}/hr**	**2.4 x 10^{-9}/hr**
	TOTAL Internal Risk (ΔCDF)	**6.1 x 10^{-7}**	**2.2 x 10^{-7}**
	Baseline: External Risk	**N/A**	**N/A**
	External Events Risk	**N/A**	**N/A**
	TOTAL External Risk (ΔCDF)	**2.3 x 10^{-7}**	**[1]8.3 x 10^{-8}**
	TOTAL Internal and External Change	**8.4 x 10^{-7}**	**3.0 x 10^{-7}**
NOTE 1: The analyst assumed that the ratio of high and low pressure sequences were the same as for internal events baseline.			

Table 3.b: Top Risk Cutsets			
Initiating Event	Sequence Number	Sequence	Importance
Loss of Offsite Power	39-04	EPS-VA3-AC4H	1.4 x 10^{-8}
	39-10	EPS-RCI-VA3-AC4H	7.6 x 10^{-10}
	39-14	EPS-RCI-HCI-AC30MIN	5.2 x 10^{-10}
	39-24	EPS-SRVP2	3.2 x 10^{-10}
	39-22	EPS-SRVP1-RCI-VA3-AC90MIN	8.4 x 10^{-11}
	7	SPC-SDC-CSS-CVS	5.4 x 10^{-11}
	36	RCI-HCI-DEP	4.7 x 10^{-11}
	6	SPC-SDC-CSS-VA1	4.6 x 10^{-11}
	39-23	EPS-SRVP1-RCI-HCI	2.7 x 10^{-11}
Transient	62	SRV-P1-PCS-MFW-CDS-LCS	6.0 x 10^{-10}
	63-05	PCS-SRVP1-SPC-CSS-VA1	2.9 x 10^{-10}
	64-11	PCS-SRVP2-LCS-LCI	1.0 x 10^{-10}
	9	PCS-SPC-SDC-CSS-CR1-VA1	3.7 x 10^{-11}
	63-06	PCS-SRVP1-SPC-CSS-CVS	2.9 x 10^{-11}
	63-32	PCS-SRVP1-RCI-HCI-DE2	2.6 x 10^{-11}

Loss of Service Water System	9	PC1-SPC-SDC-CSS-CR1-VA1	2.2×10^{-11}

External Initiating Events:

In accordance with Manual Chapter 0609, Appendix A, Attachment 1, Step 2.5, "Screening for the Potential Risk Contribution Due to External Initiating Events," the analyst assessed the impact of external initiators because the Phase 2 SDP result provided a Risk Significance Estimation of 7 or greater.

Seismic, High Winds, Floods, and Other External Events:

The analyst determined, through plant walkdown, that the major divisional equipment associated with the service water system were on the same physical elevation as its redundant equipment in the alternate division. All four service water pumps are located in the same room at the same elevation. Both primary switchgear are at the same elevation and in adjacent rooms. Therefore, the likelihood that internal or external flooding and/or seismic events would affect one division without affecting the other was considered to be extremely low. Likewise, high wind events and transportation events were assumed to affect both divisions equally.

Fire:

The analyst evaluated the list of fire areas documented in the IPEEE, and concluded that the Division I service water system could fail in internal fires that did not directly affect Division II equipment. These fires would constitute a change in risk associated with the finding. As presented in Table 4, the analyst identified two fire areas of concern: Pump room fires and a fire in Switchgear 1F. Given that all four service water pumps are located in one room, three different fire sizes were evaluated, namely: one pump fires, three pump fires, and four pump fires.

In the Individual Plant Examination for External Events Report - Cooper Nuclear Station, the licensee calculated the risk associated with fires in the service water pump room (Fire Area 20A). The related probabilities for these fires were as follows:

Parameter	Variable	Probability
Fire Ignition Frequency	L_{Fire}	6.55×10^{-3}/yr
Conditional Probability of a Large Oil Spill	$P_{Large\ Spill}$	0.18
Conditional Probability of Fire less than 3 minutes	$P_{Short\ Fire}$	0.10
Conditional Probability of Unsuccessful Halon	P_{Halon}	0.05
Probability of Losing One Division I Pump in a One Pump Fire	P_{1-1}	0.5
Probability of Losing Both Division I Pumps in a Three Pump Fire	P_{2-3}	0.5
Probability of Losing One Division I Pump in a Three Pump Fire	P_{1-3}	0.5
Conditional Probability of Losing the Running Division I Pump Given a Fire Damaging a Single Pump	P_{run-1}	0.5

Failure to Run Likelihood for a Service Water Pump	L_{FTR}	3.0×10^{-5}/hr
Failure to Start Probability per Demand for a Service Water Pump	P_{FTS}	3.0×10^{-3}

As described in the IPEEE, the licensee determined that there were three different potential fire scenarios in the service water pump room, namely: a fire damaging one pump, caused by a small oil fire, a fire that results from the spill of all the oil from a single pump that damages three pumps; and fires that affect all four pumps. The licensee had determined that fires affecting only two pumps were not likely. The analyst determined that a four-pump fire was part of the baseline risk, therefore, it would not be evaluated. A one-pump fire would not automatically result in a plant transient. However, the analyst assumed that a three-pump fire affecting both of the Division I pumps, would result in a loss of service water system initiating event.

The IPEEE stated that a single pump would be damaged in an oil fire that resulted from a small spill of oil, $L_{One\ Pump}$. The analyst, therefore, calculated the likelihood that a fire would damage a single pump as follows:

$$L_{One\ Pump} = L_{Fire} * (1 - P_{Large\ Spill})$$

$$= 6.55 \times 10^{-3}/yr \div 8760\ hrs/yr * (1 - 0.18)$$

$$= 6.78 \times 10^{-7}/hr$$

As in the IPEEE, the analyst assumed that all pumps would be damaged in an oil fire that resulted from a large spill of oil, that lasted for less than 3 minutes, if the halon system failed to actuate. It should be noted that the intensity of an oil fire is based on the availability of oxygen, and the fire is assumed to continue until all oil is consumed or it is extinguished. Therefore, the shorter the duration of the fire, the higher its intensity and the more likely it is to damage equipment in the pump room. Should the fire last for less than 3 minutes and the halon system successfully actuate, or if the fire lasted for longer than 3 minutes, the licensee determined that a single pump would survive the fire, $L_{Three\ Pumps}$. The analyst, therefore, calculated the likelihood that a fire would damage three pumps as follows:

$$L_{Three\ Pumps} = [L_{Fire} * P_{Large\ Spill} * P_{Short\ Fire} * (1 - P_{Halon})] + [L_{Fire} * P_{Large\ Spill} * (1 - P_{Short\ Fire})]$$

$$= [6.55 \times 10^{-3}/yr \div 8760\ hrs/yr * 0.18 * 0.10 * (1 - 0.05)]$$

$$+ [6.55 \times 10^{-3}/yr \div 8760\ hrs/yr * 0.18 * (1 - 0.10)]$$

$$= 1.34 \times 10^{-7}/hr$$

The likelihood of a single pump in Division 1 being damaged because of a fire, $L_{Div1\ Pump}$ was calculated as follows:

$$L_{Div1\ Pump} = (L_{One\ Pump} * P_{1-1}) + (L_{Three\ Pumps} * P_{1-3})$$

$$= (6.78 \times 10^{-7}/hr * 0.5) + (1.34 \times 10^{-7}/hr * 0.5)$$

$= 4.06 \times 10^{-7}/hr$

The analyst assumed that a fire damaged pump would remain inoperable for the 30-day allowed-outage time. Therefore, the probability that the redundant Division I pump would start and run for 30 days, $P_{Alt\ Fails}$, was calculated as follows:

$P_{Alt\ Fails} = P_{FTS} * P_{run-1} + L_{FTR}$

$= (3.0 \times 10^{-3} * 0.5) + (3.0 \times 10^{-5}/hr * 24\ hrs/day * 30\ days)$

$= 1.5 \times 10^{-3} + 2.16 \times 10^{-2}$

$= 2.31 \times 10^{-2}$

The likelihood of having a loss of all service water as a result of a one-pump fire, $L_{pump\ LOSWS}$, is then calculated as follows:

$L_{pump\ LOSWS} = L_{Div1\ Pump} * P_{Alt\ Fails}$

$= 4.06 \times 10^{-7}/hr * 2.31 \times 10^{-2}$

$= 9.38 \times 10^{-9}/hr$

The likelihood of both pumps in Division 1 being damaged because of a fire, $L_{Div1\ Pumps}$ was calculated as follows:

$L_{Div1\ Pumps} = L_{Three\ Pumps} * P_{2-3}$

$= 1.34 \times 10^{-7}/hr * 0.5$

$= 6.7 \times 10^{-8}/hr$

Given that a fire-induced loss of both Division I pumps results in a loss of service water system gland water, and the assumption was made that the gland water was unrecoverable during large fire scenarios, $L_{Div1\ Pumps}$ is equal to the likelihood of a loss of service water system initiating event.

The analyst used the revised baseline and current case SPAR models to quantify the conditional core damage probability for a fire that takes out both Division I pumps or one Division I pump with a failure of the second pump. A fire that affects both Division I pumps was assumed to cause an unrecoverable loss of service water initiating event. The baseline conditional core damage probability was determined to be **1.74×10^{-8}**. The current case probability was **1.72×10^{-7}**. Therefore, the ΔCDP was **1.55×10^{-7}**.

The analyst also assessed the affect of this finding on a postulated fire in Switchgear 1F. The analyst walked down the switchgear rooms and interviewed licensed operators. The analyst identified that, by procedure, a fire in Switchgear 1F would require deenergization of the bus and subsequent manual scram of the plant. Additionally, the analyst noted that no automatic fire suppression existed in the room. Therefore, the analyst used the fire ignition frequency stated in the IPEEE, namely $3.70 \times 10^{-3}/yr$ ($L_{switchgear}$), as the frequency for loss of Switchgear 1F and a transient.

The analyst used the revised baseline and current case SPAR models to quantify the conditional core damage probabilities for a fire in Switchgear 1F. The resulting CCDPs were **1.92×10^{-4}** ($CCDP_{base}$) for the baseline and **1.30×10^{-3}** ($CCDP_{current}$). The change in core damage frequency was calculated as follows:

$$\Delta CDF = L_{switchgear} * (CCDP_{current} - CCDP_{base})$$

$$= 3.70 \times 10^{-3}/yr \div 8760\ hrs/yr * (\mathbf{1.30 \times 10^{-3} - 1.92 \times 10^{-4}})$$

$$= \mathbf{4.65 \times 10^{-10}/hr}$$

Table 4: Internal Fire Risk				
Fire Areas:	Fire Type	Fire Ignition Frequency	ΔCDP	ΔCDF
Switchgear 1F	Shorts Bus	4.22×10^{-7}/hr	**1.10×10^{-3}**	**4.65×10^{-10}/hr**
Service Water Pump Room	One Pump	9.38×10^{-9}/hr	**1.55×10^{-7}**	**1.45×10^{-15}/hr**
	Both Pumps	6.7×10^{-8}/hr	**1.55×10^{-7}**	**1.04×10^{-14}/hr**
Total ΔCDF for Fires affecting the Service Water System:				**4.65×10^{-10}/hr**
Exposure Time (21 days):				5.04×10^{2} hrs
External Events Change in Core Damage Frequency:				**2.34×10^{-7}**

<u>Potential Risk Contribution from Large Early Release Frequency (LERF):</u>

In accordance with Manual Chapter 0609, Appendix A, Attachment 1, Step 2.6, "Screening for the Potential Risk Contribution Due to LERF," the analyst assessed the impact of large early release frequency because the Phase 2 SDP result provided a risk significance estimation of 7.

In BWR Mark I containments, only a subset of core damage accidents can lead to large, unmitigated releases from containment that have the potential to cause prompt fatalities prior to population evacuation. Core damage sequences of particular concern for Mark I containments are ISLOCA, ATWS, and Small LOCA/Transient sequences involving high reactor coolant system pressure. A loss of service water is a special initiator for a transient. Step 2.6 of Manual Chapter 0609 requires a LERF evaluation for all reactor types if the risk significance estimation is 7 or less and transient sequences are involved.

In accordance with Manual Chapter 0609, Appendix H, "Containment Integrity SDP," the analyst determined that this was a Type A finding, because the finding affected the plant core damage frequency. The analyst evaluated both the baseline model and the current case model to determine the LERF potential sequences and segregate them into the categories provided in Appendix H, Table 5.2, "Phase 2 Assessment Factors - Type A Findings at Full Power, [redacted] Ex5 εps

[redacted]

Following each model run, the analyst segregated the core damage sequences as follows:

- Loss of coolant accidents were assumed to result in a wet drywell floor. The analyst assumed that during all station blackout initiating events the drywell floor remained dry. The Cooper Nuclear emergency operating procedures require drywell flooding if reactor vessel level can not be restored. Therefore, the analysts assumed that containment flooding was successful for all high pressure transients and those low pressure transients that had the residual heat removal system available.

- All Event V initiators were grouped as intersystem loss of coolant accidents (ISLOCA)

- Transient Sequence 65, Loss of dc Sequence 62, Loss of service water system Sequence 71, small loss of coolant accident Sequence 41, medium loss of coolant accident Sequence 32, large loss of coolant accident Sequence 12, and LOOP Sequence 40 cutsets were considered anticipated transients without scram (ATWS)

- All LOOP Sequence 39 cutsets were considered Station Blackouts. Those with success of safety-relief valves to close or a single stuck-open relief valve were considered high pressure sequences. Those with more than one stuck-open relief valve were considered low pressure sequences.

- Transients that did not result in an ATWS were assumed to be low pressure sequences if the cutsets included low pressure injection, core spray, or more than one stuck-open relief valve. Otherwise, the analyst assumed that the sequences were high pressure.

- Small break loss of coolant accident, Sequence 1 cutsets, that represent stuck-open relief valves and other recoverable incidents, were assumed to result in a dry floor. All other cutsets were assumed to provide a wetted drywell floor.

The analyst determined that the predominant accident sequences that affected LERF involved station blackout scenarios that were induced by the loss of service water. The dominant cutsets involved the failure of Diesel Generator A and the resulting failure of Division II service water. These sequences involved high reactor coolant system pressures at the time of vessel breach and included the inability of the operators to flood the drywell floor. Appendix H uses a conservative value of 1.0 for the failure of containment under these circumstances. Therefore, the analyst developed a more realistic multiplier.

The analyst reviewed readily available MELCOR analyses of accident progression timing for SBO sequences in BWRs. MELCOR is the NRC-developed computer code for integrated modeling of core melt progression, fission product behavior, and containment survival during severe accidents. The information reviewed included some 2004 analyses of fast station blackout events in a Mark I containment, as well as some calculations conducted from 1991 through 2001 for fast and slow station blackouts in Mark I, II, and III plants. Although the number of calculations reviewed were relatively limited, they provided a generally consistent picture of accident progression timing.

The available calculations indicate that in a fast station blackout, where the loss of offsite power with failure of all emergency onsite power is followed rapidly by the failure of all steam-driven injection systems, there is approximately 3.5 hours or more (up to 5.5 hours in one calculation) between the time that reactor water level reaches top of active fuel (TAF) and the time at which the reactor vessel lower head is estimated to be breached by molten core debris. The time window would be even longer (up to 9 hours in one calculation) in a slow station blackout, where available steam-driven components fail opon battery depletion. This difference is the result of the lower decay heat level in the fuel at the time of core uncovery resulting in a slower boil down and slower boil off of water in the reactor vessel lower head prior to vessel breach. Similarly, if the onset of station blackout conditions at Cooper is delayed because the service water pumps initially operate for a period of time, the time window would be expanded.

If AC power is recovered and the reactor vessel is reflooded within this time window, it is highly likely that accident progression would be arrested in-vessel, and that reactor vessel breach would be avoided. By avoiding reactor vessel breach, the potential failure of the Mark I containment shell from contact with molten core debris and the associated potential for a large early release would also be eliminated. Credit for recovering power and arresting core damage while the core remains in vessel is consistent with existing severe accident analyses and experiments, the results of the Three Mile Island, Unit 2 accident, and the treatment of melt progression in many probabilistic risk assessment models.

The analyst assumed the following timeline for estimating the in vessel recovery factor at Cooper:

Core Melt Timing	
Time (hours)	Milestone
0.5	Initiation of station blackout conditions induced by loss of service water
1.0	Water at the top of active fuel (core damage in SPAR)
4.5	Reactor pressure vessel failure

The analyst estimated the in-vessel nonrecovery factor based on the following probabilities of failure to recover ac power, that were developed by INEEL personnel utilizing values from NUREG/CR-5496:

Failure to recover ac power within 1.0 hr. = 0.360
Failure to recover ac power within 4.5 hrs. = 0.121

NOTE: Diesel Generator A could have been recovered within the first 30 minutes. Thereafter, neither diesel generator could be recovered because service water was unavailable.

Based on these nonrecovery probabilities, the in-vessel nonrecovery factor can be calculated as the probability of recovering ac power in 4.5 hours, given a failure to recover in 1 hour. The calculation was performed as follows:

In-vessel nonrecovery factor = 0.121/0.360 = 0.34

The analyst revised the analysis to include this factor that represents the potential for recovering ac power prior to the time of reactor vessel breach by molten core debris for high pressure station blackout scenarios. This was developed as a nonrecovery probability that ac power would be recovered prior to vessel breach, given that it was not recovered prior to core damage. The analyst did not adjust the probability of containment failure given reactor vessel breach. Adjustments to this LERF multiplier are possible but have not been pursued as part of the Cooper evaluation.

The in-vessel recovery factor was applied as a multiplier to the large-early release frequency factor for station blackout sequences, as shown in Table 5. For example, if the large-early release frequency factor for a station blackout sequence was originally estimated to be 1.0, when in-vessel recovery is credited, this value would be reduced to 0.34.

[redacted]

Ex 5

Adjustments to LERF Calculation:

The Probabilistic Safety Assessment Branch determined that, in addition to providing an opportunity for ac power recovery, the 3 to 4 hours available between the time of core uncovery and reactor vessel breach provided time for operators to flood the drywell floor prior to vessel breach. Based on information provided in an August 9, 2004 letter from the licensee, the plant-specific Emergency Procedure and Severe Accident Guidelines (EP/SAG) for CNS included guidance to flood the drywell floor prior to vessel breach in order to help mitigate liner melt-through following vessel breach. The branch assumed that the use of diesel-driven fire-water to flood the drywell floor would be recommended if all other injection sources had been lost. It was the branch's judgement that sufficient time and systems were available to provide reasonable assurance that the drywell floor would be flooded prior to vessel breach.

Because of the above, the LERF multipliers provided in Appendix H for a flooded drywell floor can be used. These values represent elimination of the contribution to containment failure from liner melt-through. For a flooded drywell floor, Revised Appendix H indicates factors of 0.6 for sequences with high reactor coolant system pressure at vessel breach, and <0.1 for sequences with low reactor coolant system pressure.

The dominant core damage sequence is characterized as a high pressure sequence in the Level 1 analysis. However, the emergency operating procedures would actually direct the operator to depressurize the reactor coolant system during the boil-down when reactor vessel water level drops to the minimum zero-injection reactor pressure vessel water level. Because the systems required for depressurization would be available, the sequence is expected to proceed to core damage at low rather than high reactor coolant system pressure.

The branch concluded that a recent report sponsored by the Office of Regulatory Research on direct containment heating in a Mark I containment provided additional justification that the reactor coolant system would be at low pressure but for a different reason. The report indicated that the reactor coolant system will be depressurized as a result of creep rupture of the steam line nozzles. Specifically, Report ERI/NRC 03-204, "The Probability of High Pressure Melt Ejection-Induced Direct Containment Heating Failure in Boiling Water Reactors with Mark I Design" includes a detailed thermal-hydraulic analysis of core melt progression that indicating that there is about a 90% probability that the reactor coolant system would be passively depressurized via creep-rupture of the steam line nozzles in both fast and slow station blackout events. Thus, the branch determined that there was a high probability that the reactor coolant system would be depressurized either by operator actions in accordance with the EOPs, or via creep rupture of the reactor coolant system piping.

Based on these adjusted assumptions, the branch concluded that the dominant sequence would most likely involve reactor vessel breach at low reactor coolant system pressure, with a flooded drywell floor. This effectively results in a LERF multiplier of about 0.1. Applying this multiplier results in a total ΔLERF of 8.6×10^{-8} as opposed to the 3.0×10^{-7} calculated as presented in Table 5. Therefore, the branch determined that the finding is of very low risk significance (GREEN).

Ex 5

Licensee's Risk Assessment:

The licensee performed an assessment of the risk from this finding as documented in Engineering Study PSA-ES062, "Risk Significance of SCR 2004-0077, Service Water Gland Water Valve Mis-positioning Event." The licensee's result for internal risk was a ΔCDF of 3.85×10^{-7}. The analyst reviewed the licensee's assumptions and determined that the following differences dominated the difference between the licensee's and the analyst's assessments:

a) The licensee used a Human Error Probability of 9.2×10^{-2} for the probability that operators would fail to realign gland water prior to failure of the Division II pumps.

   The analyst determined that this assumption was responsible for about 30% of the difference in the final results.

b) The licensee's model uses a Loss of Offsite power frequency of 1.74×10^{-8}/hr as opposed the the NUREG/CR-5496 value of 5.32×10^{-6}/hr.

The analyst determined that this assumption was responsible for the vast majority of the difference in the final results. The analyst noted that the majority of risk was from core damage sequences that were initiated by a loss of offsite power.

[redacted]

Ex 5

2. **All Other Inspection Findings (Not IE, MS, B Cornerstones)**

Not Applicable.

D. Proposed Enforcement

1. **Regulatory Requirement Not Met**

10 CFR 50, Appendix B, Criterion V requires that activities affecting quality to be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances.

2. **Proposed Citation**

Criterion V of 10 CFR 50, Apendix B requires that activities affecting quality shall be prescribed by documented instructions, procedures or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings.

Contrary to the above, on January 21, 2004, Division 2 of the service water system was declared operable following routine maintenance using instructions contained in Clearance Order SWB-1-4324147 SW-STNR-B to restore the system to its normal configuration. These instructions did not direct restoration of the Division 2 gland water supply to a normal alignment which remained cross-connected with the Division 1 gland water supply for approximately 21 days. On February 11, 2004, the misalignment was discovered while investigating the cause of a low pressure alarm on the gland water system. This misalignment resulted in the loss of redundancy in the service water system.

3. **Historical Precedent**

E. Determination of Follow-up Review

OE should review final determination letter before issuance.

Attachment 1

SERP Disposition Record

Licensee/Facility: Nebraska Public Power District / Cooper Nuclear Generating Station
EA No:
Panel Date: //04
Issue: Failure to Properly Align Service Water System Gland Water Supply

ATTENDEES:
Chair: **Branch Chief:** **Enf. Reps.:** **OI Rep.:**
Counsel: **Others:**
HQ Reps:

Required Actions (Preliminary Proposed Actions - See OE Strategy Form for official record of panel decision.)

1. Issue choice letter to the licensee for a preliminary Yellow finding

   Responsible Person: **ECD:**

2. Schedule regulatory conference if requested.

   Responsible Person: **ECD:**

3. Prepare and issue final significance determination letter

   Responsible Person: **ECD:**

4.

   Responsible Person: **ECD:**

Counting Rule Worksheet		
Step	**Instructions**	
(1)	Enter the number of sequences with a risk significance equal to 9.	(1) 0
(2)	Divide the result of Step (1) by 3 and round down.	(2) 0
(3)	Enter the number of sequences with a risk significance equal to 8.	(3) 0
(4)	Add the result of Step (3) to the result of Step (2).	(4) 0
(5)	Divide the result of Step (4) by 3 and round down.	(5) 0
(6)	Enter the number of sequences with a risk significance equal to 7.	(6) 0
(7)	Add the result of Step (6) to the result of Step (5).	(7) 0
(8)	Divide the result of Step (7) by 3 and round down.	(8) 0
(9)	Enter the number of sequences with a risk significance equal to 6.	(9) 3
(10)	Add the result of Step (9) to the result of Step (8).	(10) 3
(11)	Divide the result of Step (10) by 3 and round down.	(11) 1
(12)	Enter the number of sequences with a risk significance equal to 5.	(12) 0
(13)	Add the result of Step (12) to the result of Step (11).	(13) 1
(14)	Divide the result of Step (13) by 3 and round down.	(14) 0
(15)	Enter the number of sequences with a risk significance equal to 4.	(15) 0
(16)	Add the result of Step (15) to the result of Step (14).	(16) 0

- If the result of Step 16 is greater than zero, then the risk significance of the inspection finding is of high safety significance (RED).
- If the result of Step 13 is greater than zero, then the risk significance of the inspection finding is at least of substantial safety significance (YELLOW).
- If the result of Step 10 is greater than zero, then the risk significance of the inspection finding is at least of low to moderate safety significance (WHITE).
- If the result of Steps 10, 13, and 16 are zero, then the risk significance of the inspection finding is of very low safety significance (GREEN).

Phase 2 Result: ☐ GREEN ✓ WHITE ☐ YELLOW ☐ RED

Table 6 - Counting Rule Worksheet

DRAFT NOTICE OF VIOLATION

Nebraska Public Power District
Cooper Nuclear Station

Docket No. 50-298
License No. DPR-46
EA-04-XXX

During an NRC inspection conducted on March 25 through July 10, 2004 a violation of NRC requirements was identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," NUREG-1600, the violation is listed below:

[redacted]

Ex 5

Pursuant to the provisions of 10 CFR 2.201, Nebraska Public Power District is hereby required to submit a written statement or explanation to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555 with a copy to the Regional Administrator, Region 4, and a copy to the NRC Resident Inspector at the facility that is the subject of this Notice, within 30 days of the date of the letter transmitting this Notice of Violation (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation; EA-04-XXX" and should include for each violation: (1) the reason for the violation, or, if contested, the basis for disputing the violation or severity level, (2) the corrective steps that have been taken and the results achieved, (3) the corrective steps that will be taken to avoid further violations, and (4) the date when full compliance will be achieved. Your response may reference or include previous docketed correspondence, if the correspondence adequately addresses the required response. If an adequate reply is not received within the time specified in this Notice, an order or a Demand for Information may be issued as to why the license should not be modified, suspended, or revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time.

If you contest this enforcement action, you should also provide a copy of your response, with the basis for your denial, to the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001.

Because your response will be made available electronically for public inspection in the NRC Public Document Room or from the NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html, to the extent possible, it should not include any personal privacy, proprietary, or safeguards information so that it can be made available to the public without redaction. If personal privacy or proprietary information is necessary to provide an acceptable response, then please provide a bracketed copy of your response that identifies the information that should be protected and a redacted copy of your response that deletes such information. If you request withholding of such material, you <u>must</u> specifically identify the portions of your response that you seek to have withheld and provide in detail the bases for your claim of withholding (e.g., explain why the disclosure of information will create an unwarranted invasion of personal privacy or provide the information required by 10 CFR 2.390(b) to support a request for withholding confidential commercial or financial information). If safeguards information is necessary to provide an acceptable response, please provide the level of protection described in 10 CFR 73.21.

Dated this ____ day of ____ 2004