UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

April 15, 2005

EA-05-038

R. T. Ridenoure
Vice President
Omaha Public Power District
Fort Calhoun Station FC-2-4 Adm.
P.O. Box 550
Fort Calhoun, NE 68023-0550

SUBJECT: FINAL SIGNIFICANCE DETERMINATION FOR A WHITE FINDING AND NOTICE OF VIOLATION – FORT CALHOUN STATION – NRC INSPECTION REPORT 05000285/2005010

Dear Mr. Ridenoure:

On February 24, 2005, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Fort Calhoun Station. The purpose of the inspection was to follow up on the failure of Emergency Diesel Generator 2 during surveillance testing. The enclosed inspection report documents an inspection finding which was discussed on March 2, 2005, with Mr. R. Phelps, Division Manager of Nuclear Engineering, and other members of your staff.

As described in Section 1R15 of this report, a finding was identified involving the failure to promptly identify and correct a condition adverse to quality resulting in Emergency Diesel Generator 2 being inoperable for a period of approximately 29 days, a violation of plant Technical Specifications. The inspection finding was assessed using the Significance Determination Process and was characterized as White, a finding with low to moderate increased importance to safety, which may require additional NRC inspection.

This finding does not present a current safety concern because Emergency Diesel Generator 2 was returned to an operable condition following repairs involving replacement of a failed component.

During the exit meeting conducted on March 2, 2005, your staff acknowledged the finding and indicated that Omaha Public Power District agreed with the safety significance of the finding being characterized as White. In addition, on March 23, 2005, in a telephone conversation with Dr. Bruce Mallett, Region IV Regional Administrator, you stated Omaha Public Power District's intention to decline an opportunity to discuss this issue in a Regulatory Conference or provide a written response.

You have 30 calendar days from the date of this letter to appeal the staff's determination of significance for the identified White finding. Such appeals will be considered to have merit only if they meet the criteria given in NRC Inspection Manual Chapter 0609, Attachment 2.

The NRC also has determined that the finding involves a violation of 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Actions, which resulted in a violation of plant Technical Specifications. The violation is cited in the enclosed Notice of Violation, and the circumstances surrounding the violation are described in the subject inspection report. In accordance with the NRC Enforcement Policy, the Notice of Violation is considered escalated enforcement action because it is associated with a White finding.

You are required to respond to the violation and should follow the instructions specified in the enclosed Notice of Violation when preparing your response.

Because plant performance for this issue has been determined to be in the regulatory response band, we will use the NRC Action Matrix to determine the most appropriate NRC response for this condition. We will notify you, by separate correspondence, of that determination.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

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

Sincerely,

for

Bruce S. Mallett
Regional Administrator

Docket: 50-285
License: DPR-40

Enclosures:
1. Notice of Violation
2. NRC Inspection Report 05000285/2005010

cc w/enclosures:
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APR 15 2005

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SISP Review Completed: _yes__ ADAMS: ✖ Yes ☐ No Initials: ___mch
✖ Publicly Available ☐ Non-Publicly Available ☐ Sensitive ✖ Non-Sensitive

S:\RAS\ACES\ENFORCEMENT\EA CASES - OPEN\Fort Calhoun EDG\Final Action\EA-05-038 Fort Calhoun White-NOV.wpd

RIV:D:ACES	RI:DRP/C	SRI:DRP/C	C:DRP/C	SRA:DRS	D:DRS
GFSanborn	LMWilloughby	JDHanna	MCHay	DPLoveless	DDChamberlain
/RA/	***E - WCWalker***	***T - WCWalker***	***/RA/***	***/RA/***	***KSWest for***
4/2/05	3/30/05	3/30/05	3/29/05	3/30/05	3/31/05

D:DRP	RC	D:OE	DRA	RA	
ATHowell III	KSFuller	FJCongel	TPGwynn	BSMallett	
Vegel for	***/RA/***	**C. Nolan for**	**Unavailable**	~~**Chamberlain for**~~	
4/12/05	4/13 /05	4/14/05 via E	4/ /05	4/12/05	

ML051050540

NOTICE OF VIOLATION

Omaha Public Power District
Fort Calhoun Station

Docket 50-285
License DPR-40
EA-05-038

During an NRC inspection conducted from August 20, 2004, through February 24, 2005, 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:

> 10 CFR Part 50, Appendix B, Criterion XVI, requires, in part, that measures shall be established to ensure that conditions adverse to quality, such as failures, malfunctions, etc., are promptly identified and corrected.
>
> Fort Calhoun Technical Specification 2.7(1), Minimum Requirements, states, in part, that the reactor shall not be heated up or maintained at temperatures above 300°F unless the following electrical systems are operable: two emergency diesel generators (DG-1 and DG-2). Technical Specification 2.7(2), Modification of Minimum Requirements, states, in part, that the minimum requirements may be modified under certain conditions. Item 2.7(2)(j) states that either one of the emergency diesel generators may be inoperable for up to 7 days (total for both) during any month, provided certain conditions are met.
>
> Contrary to the above, on July 21, 2004, during surveillance testing of an emergency diesel generator, DG-2, the licensee failed to promptly identify and correct a condition adverse to quality. Specifically, the licensee failed to identify the failure of Fuse 2FU in the emergency diesel generator excitation circuit. The failure to promptly identify this failure and correct it resulted in DG-2 being inoperable from July 21 to August 19, 2004, a period of 10 days in July and 19 days in August. This exceeded the total allowed time in Technical Specification 2.7 for either emergency diesel generator to be inoperable during any month.
>
> This violation is associated with a White significance determination process finding.

Pursuant to the provisions of 10 CFR 2.201, Omaha 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, U.S. Nuclear Regulatory Commission, Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011, 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-05-038" and should include: (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, U.S. 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 must 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 15th day of April 2005

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket.:	50-285
License:	DPR-40
Report:	05000285/2005010
Licensee:	Omaha Public Power District
Facility:	Fort Calhoun Station
Location:	Fort Calhoun Station FC-2-4 Adm. P.O. Box 399, Highway 75 - North of Fort Calhoun Fort Calhoun, Nebraska
Dates:	August 20, 2004, through February 24, 2005
Inspectors:	J. Hanna, Senior Resident Inspector L. Willoughby, Resident Inspector D. Loveless, Senior Reactor Analyst
Approved By:	A. Howell III, Director, Division of Reactor Projects

SUMMARY OF FINDINGS

IR05000285/2005010; 08/20/04 - 02/24/05; Fort Calhoun Station; Operability Evaluation.

The report documents the NRC's inspection for Emergency Diesel Generator 2 being inoperable for 29 days. The inspection identified one finding whose safety significance has been determined to be White. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, "Significance Determination Process." The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- White. A violation of 10 CFR Part 50, Appendix B, Criterion XVI, was identified for the failure to ensure that conditions adverse to quality, such as failures, malfunctions, etc., are promptly identified and corrected. Specifically, on July 21, 2004, during surveillance testing of Emergency Diesel Generator 2, the licensee failed to promptly identify and correct a failure of Fuse 2FU in the emergency diesel generator excitation circuit. The failure to identify and correct this condition resulted in Emergency Diesel Generator 2 being inoperable from July 21 to August 19, 2004, a period of 29 days, exceeding Technical Specification 2.7 allowed outage time of 7 days during any month when the reactor coolant system temperature was greater than 300°F.

  This finding was considered more than minor because it was associated with the equipment performance attribute of the mitigating systems cornerstone in that the licensee failed to promptly identify and correct a failed fuse in the Emergency Diesel Generator 2 excitation circuit that left the emergency diesel generator inoperable for a period of 29 days. The finding was characterized under the significance determination process as having low to moderate safety significance because Emergency Diesel Generator 2 was unavailable to respond upon demand for a loss of off-site power and would have been unable to perform its mitigating system function (Section 1R15).

REPORT DETAILS

1. REACTOR SAFETY

Cornerstones: Mitigating Systems

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the events and the root cause analysis regarding Emergency Diesel Generator 2 being inoperable for 29 days.

b. Findings

Introduction. A violation of 10 CFR Part 50, Appendix B, Criterion XVI, was identified for the failure to ensure that conditions adverse to quality, such as failures, malfunctions, etc., are promptly identified and corrected. On July 21, 2004, during surveillance testing of Emergency Diesel Generator 2, the licensee failed to promptly identify and correct a failure of Fuse 2FU in the emergency diesel generator excitation circuit. The failure to identify and correct this condition resulted in Emergency Diesel Generator 2 being inoperable from July 21 to August 19, 2004, a period of 29 days, exceeding Technical Specification 2.7 allowed outage time of 7 days when the reactor coolant system temperature was greater than 300°F.

Description. On July 21, 2004, at 8:30 a.m., Emergency Diesel Generator 2 was declared inoperable and Technical Specification 2.7(2)j was entered to support conducting the monthly diesel generator surveillance in accordance with Operating Procedure OP-ST-DG-0002. Emergency Diesel Generator 2 was started to idle speed and allowed to warm up. Following warmup, the Emergency Diesel Generator 2 speed was increased to normal operating speed.

Emergency Diesel Generator 2 ran fully loaded for over an hour as required by the surveillance test. Following the loaded run, Emergency Diesel Generator 2 was unloaded and the output breaker opened. Within a minute of opening the diesel generator output breaker, the diesel generator output voltage decreased to approximately 2200 volts and the Emergency Response Facility Computer (Plant Computer) annunciated an urgent low alarm for low voltage on Emergency Diesel Generator 2. The inspectors noted this alarm was acknowledged by a licensed operator who failed to recognize that this was an indication for an abnormal low voltage condition. Additionally, at this time, WH/D2 Power Distribution Indicator D-2, a watt-hour meter, stopped indicating.

Emergency Diesel Generator 2 was operated at normal speed, unloaded, for approximately 12 minutes to cool down the turbo charger. During this time operators discussed the loss of indication on the watt-hour meter and decided to write a condition report on the discrepancy. The inspectors noted that the unexpected low voltage condition was not identified and entered into the corrective action process. Following cooldown, Emergency Diesel Generator 2 was then shut down. Operators determined the surveillance test was successfully completed and declared Emergency Diesel Generator 2 operable at 11:18 a.m., exiting Technical Specification 2.7(2)j.

No other Emergency Diesel Generator 2 operations occurred until August 18, 2004. On August 18, 2004, at 10:30 a.m., Emergency Diesel Generator 2 was declared inoperable and Technical Specification 2.7(2)j was entered to support conducting the monthly diesel generator surveillance test per Procedure OP-ST-DG-0002. Emergency Diesel Generator 2 was started to idle speed at 10:51 a.m. and allowed to warm up. Following warmup, the Emergency Diesel Generator 2 speed was increased to normal operating speed.

At 11:06 a.m. Emergency Diesel Generator 2 was secured because Emergency Diesel Generator 2 output voltage had only increased to approximately 2200 volts following field flash vice its normal value of approximately 4200 volts. Trouble shooting of the problem commenced at 12:35 p.m. and was completed at 4:55 p.m. A failed fuse, 2FU, was found in the generator excitation circuit and was replaced. Following successful testing, Emergency Diesel Generator 2 was declared operable at 5:25 p.m. and Technical Specification 2.7(2)j was exited. Diesel Generator 1 was also tested to ensure no common cause failure existed.

On August 19, 2004, Emergency Diesel Generator 2 successfully passed its monthly surveillance test. The licensee believed Fuse 2FU failed when Emergency Diesel Generator 2 was started on August 18 when the generator field was flashed.

On October 19, 2004, the licensee notified the NRC that Fuse 2FU failed on July 21, 2004, when the Emergency Diesel Generator 2 output breaker was opened. This signified that Emergency Diesel Generator 2 was inoperable from July 21 to August 19, 2004.

After a review of this event, the inspectors noted that the licensee had several opportunities to promptly identify the degraded voltage condition that affected the safety function of Emergency Diesel Generator 2. These opportunities included:

- The failure to recognize the alarm for low emergency diesel generator output voltage was indicative of a degraded voltage condition.
- The failure to recognize that the watt-hour meter turns off when emergency diesel generator output voltage goes below the watt-hour trigger setpoint, indicative of a degraded voltage condition.
- The failure to recognize that the emergency diesel generator output voltage meter indications were reading approximately half their normal value, indicative of a degraded voltage condition.

- The failure to recognize that data obtained during surveillance Operating Procedure OP-ST-DG-0002, performed on July 21, 2004, showed the emergency diesel generator output voltage decreasing to approximately 2200 volts, indicative of a degraded voltage condition. This surveillance procedure was reviewed and determined satisfactory by three operations personnel and the system engineer.

Analysis. The licensee failed to promptly identify and correct a condition adverse to quality. Specifically, on July 21, 2004, during surveillance testing of Emergency Diesel Generator 2, the licensee failed to promptly identify and correct a failure of Fuse 2FU in the emergency diesel generator excitation circuit. The failure to promptly identify and correct this condition resulted in Emergency Diesel Generator 2 being inoperable from July 21 to August 19, 2004, a period of 29 days.

The issue was more than minor because it is similar to Example 4.f in NRC Inspection Manual Chapter 0612, Appendix E, "Examples of Minor Issues," and met the "not minor if" statement because the failed fuse affected the operability of the diesel generator. The finding was determined to be of low to moderate safety significance based on a Phase 1 screening analysis, Phase 2 evaluation, and Phase 2 confirmation analysis.

Significance determination process Phase 1:

In accordance with NRC Inspection Manual Chapter 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors conducted a significance determination process Phase 1 screening and determined that the finding resulted in loss of the safety function of Emergency Diesel Generator 2 for greater than the Technical Specification allowed outage time. Therefore, a significance determination process Phase 2 evaluation was required.

Significance determination process Phase 2:

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 Fort Calhoun Station, Revision 1. The following assumptions were made:

- Emergency Diesel Generator 2 was not functional upon the Fuse 2FU failure and would not have responded upon demand.

- Emergency Diesel Generator 2 was out of service for 28 days 10 hours. Therefore, the exposure window used was 3 to 30 days.

- The failure of Emergency Diesel Generator 2 only affected the risk associated with a loss of offsite power (LOOP) initiating event, as provided in Table 2 of the risk-informed notebook.

- While Fuse 2FU was failed, Emergency Diesel Generator 2 could not have been recovered prior to postulated core damage because of the following:

  - No direct indication existed that Fuse 2FU had failed

  - Required use of multimeter to identify that the fuse had failed

  - Fuse 2FU was of unique design and replacements were not immediately available to the operators

Table 2 of the risk-informed notebook requires that only the LOOP worksheet be evaluated when a performance deficiency affects the diesel generators. All core-damage sequences requiring emergency power were evaluated. The sequences from the notebook are as follows:

Initiating Event	Sequence	Mitigating Functions	Results
Loss of Offsite Power	5	EAC-REC8	6
Loss of Offsite Power	6	EAC-REC1-TDAFW	7

Using the counting rule worksheet, this finding was estimated to be WHITE for internal initiators. In accordance with Inspection Manual Chapter 0609, Attachment 1, "Significance and Enforcement Review Process," the NRC conducted an independent confirmation of this Phase 2 result.

Phase 2 confirmation analysis:

The NRC compared the results from the modified notebook estimation with an evaluation developed using a Standardized Plant Analysis Risk (SPAR) model simulation of the failed Emergency Diesel Generator 2, as well as an assessment of the licensee's evaluation provided by the licensee's probabilistic risk assessment staff. The SPAR runs were based on the following NRC assumptions:

- The Fort Calhoun SPAR, Revision 3.11, model represents an appropriate tool for evaluation of the subject finding.

- Draft NUREG/CR-XXXX (INEEL/EXT-04-02326), "Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1986 - 2003," contains the

NRC's current best estimate of both the likelihood of each of the LOOP classes (i.e., plant-centered, switchyard-centered, grid-related, severe weather-related, and extreme weather-related) and their recovery probabilities.

- Emergency Diesel Generator 2 was unavailable to respond upon demand for the entire time that Fuse 2FU was failed.
- The condition existed for 29 days. The diesel generator was removed from service at 8:30 a.m. on July 21, 2004, and Fuse 2FU failed prior to the machine being restored to an operable condition. Repairs were completed on August 18, 2004, at 5:25 p.m. Additionally, the diesel generator had to be removed from service again on August 19, 2004, to repeat the required surveillance. The actual outage time was 28 days, 10 hours.
- Operators would have been unable to recover Emergency Diesel Generator 2 prior to postulated core damage.
- The nominal likelihood for a LOOP was unaffected by the subject finding.

Initial SPAR Evaluation:

The Fort Calhoun Station SPAR Revision 3.11 model, with the associated LOOP curves from the draft NUREG, was used for the evaluation of this finding. The resulting baseline core damage frequency, CDF_{base}, was 1.44×10^{-5}/yr.

The NRC developed a change set, to adjust Basic Event EPS-DGN-FS-1B, "Emergency Diesel Generator 2 Fails to Start," to the House Event "TRUE," indicating failure of the component. The SPAR model was requantified with the resulting current case conditional core damage frequency, CDF_{case}, of 2.28×10^{-4}/yr.

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

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

$$= 2.28 \times 10^{-4} - 1.44 \times 10^{-5} = 2.14 \times 10^{-4}/\text{yr}.$$

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

$\Delta CDF = 2.14 \times 10^{-4}/\text{yr} \div 365 \text{ days/yr} * 29 \text{ days} = 1.70 \times 10^{-5}$ over the period.

This result indicated that the significance of the finding was inconsistent with the Phase 2 result. Therefore, the finding was further evaluated.

Adjustments to SPAR:

The NRC noted that the results of the initial SPAR evaluation were more significant than both the licensee's evaluation and the risk-informed notebook. In reviewing these differences, it was noted that the licensee's model provided for recovery of auxiliary feedwater during a station blackout, following battery depletion. The licensee stated that Fort Calhoun Station had a unique arrangement for auxiliary feedwater. Auxiliary Feedwater Pump FW-54 is diesel driven and does not rely on vital ac or dc power. The pump is supplied with fuel from Diesel Fuel Oil Storage System Tank FO-10. Tank FO-10 has a minimum volume of 10,000 gallons of diesel fuel as required by Technical Specification 2.7. Eight thousand gallons of the tank's inventory are readily available for use by Pump FW-54. Therefore, the pump could run for 24 hours without fuel addition. The NRC noted that the condensate storage tank would provide about 30 hours of water based on licensee calculated steam generator steaming rates. Therefore, makeup water sources were not assessed.

Traditionally, SPAR methodology assumes that auxiliary feedwater fails upon loss of vital batteries. This failure assumes that instrumentation is lost and operators overfill the steam generators. Once the steam generators fill to the main steam lines, water flowing into the steam lines suppresses the steam supply to the turbine-driven pump. Given the postulated failure of the turbine-driven pump, the steam generators boil dry and the scenario leads to core damage. Providing a reliable diesel-driven pump resolves this problem, and the pump could theoretically continue to feed the steam generators for the 24-hour mission time.

To give credit for Pump FW-54, the failure mechanisms of the system, including the operator actions required to continue to feed the steam generators for 24 hours were evaluated. These included the following:

- Pump FW-54 must continue to run for 24 hours, including fuel supply, suction source, and the operator attention necessary.

- Operators must transfer the discharge of the system to the auxiliary feedwater nozzles and manually throttle discharge Valves HCV-1107B and HCV-1108B prior to battery depletion.

- Operators must ensure that there is sufficient auxiliary feedwater flow to prevent core damage.

- The reactor coolant pump seals must remain intact for 24 hours without vital ac or dc power. The NRC determined that the reactor coolant pump seals at Fort Calhoun Station were of the upgraded seal design. Therefore, the NRC utilized the value for the probability of seal failure during an extended loss of power, documented in the SPAR model. This value was 8.9×10^{-3}.

- Operators must isolate the condensate storage tank prior to loss of pressure in the associated nitrogen bottle. This action requires manual isolation of the hotwell supply line before the air-operated valve fails open and the condensate storage tank inventory is vacuum dragged to the condenser.

- Operators have a varying amount of time to perform these actions, depending on the success or failure of two operator actions: (1) operators minimize dc loads on the battery quickly following a station blackout and; (2) operators flood the steam generators to 94 percent wide-range level prior to battery depletion using either Pump FW-54 or the turbine-driven auxiliary feedwater pump.

  The NRC used generic steam generator data and certain plant-specific information from the Final Safety Analysis Report to calculate the approximate time that operators would have to successfully operate Pump FW-54 following battery depletion conditional upon the success or failure of these two actions. The following table documents those times:

Table 3.a

Time to Steam Generator Dryout During Station Blackout

Case	Minimize dc Loads	Time to Depletion	Flood Generators	Time for Boil Down	Total Time
1	Success	8 hours	Success	5 hours	13 hours
2	Success	8 hours	Failure	2.6 hours	10.6 hours
3	Failure	2.6 hours	Success	4 hours	6.6 hours
4	Failure	2.6 hours	Failure	2 hours	4.6 hours

The NRC quantified the probability that the operators fail to minimize dc loads in a short period of time using the SPAR-H method described in draft NUREG/CR-XXXX (INEEL/EXT-02-01307), "The SPAR-H Human Reliability Analysis Method." The procedural requirements in Emergency Operating Procedure EOP-00, "Standard Post Trip Actions," and Emergency Operating Procedure

Attachment 6, "Minimizing DC Loads," were evaluated. The NRC assumed that this particular action did not require a significant amount of diagnosis because the EOP-00 has a step and multiple notes reminding the operators to take the action when necessary. The NRC adjusted the nominal human error probabilities using the following performance shaping factors:

- Available time was 15 minutes. The NRC assumed that this was just enough time to coordinate with two plant operators and to open breakers in the turbine building and the auxiliary building. Therefore, a factor of 10 was used.

- The stress was assumed to be high because of an ongoing station blackout. Therefore, a factor of 2 was used.

- The complexity was assumed to be moderate because of the coordination needed with plant operators at two different locations and the low lighting during the station blackout conditions. Therefore, a factor of 2 was used.

In addition to these three shaping factors, the NRC adjusted the final result using the Odd's ratio[1] as documented in the draft NUREG, Section 2.5. The probability that operators would fail to minimize dc loads within 15 minutes of a station blackout was calculated to be 3.8×10^{-2}.

Using a similar approach, the NRC calculated probabilities of human error for each of the required operator actions listed above. The times available documented in Table 3.a. were used to modify the performance shaping factors based on the time operators had to respond to the particular action. The HRA values calculated are documented in Table 3.b.

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[1]Odd's ratio is a method of accounting for the number of successes as well as failures when calculating a conditional human error probability. This method of accounting for uncertainties associated with individual performance shaping factors is described in draft NUCREG-CR-XXXXX (INEEL/EXT-02-10309), "SPAR-H METHOD," and tends to provide a less conservative result.

Table 3.b
Operator Failure Probabilities

		Performance Shaping Factors				
Operator Action	Time Available	Time	Stress	Procedure	Experience	Failure Probability
Minimize dc Loads[7,8,9]	15 minutes	10	2.0	1.0	1.0	3.9×10^{-2}
Flood S/Gs to 94%[4,9]	2.6 hours	1.0	2.0	1.0	0.5	1.0×10^{-3}
	8 hours	0.1	2.0	1.0	0.5	1.0×10^{-4}
Swap to AFW nozzle and throttle AFW Valves[3,8]	< 3 hours	1.0	1.0/2.0[2]	0.5/2.0[5]	1.0/3.0[7]	3.8×10^{-1}
	> 4.5 hours	0.1	1.0/2.0[2]	0.5/2.0[5]	1.0/3.0[7]	5.7×10^{-2}
Provide Sufficient Flow[4,9]	2 - 8 hours	0.1	2.0	0.5	1.0	1.0×10^{-4}
Isolate CST[4]	4 hours	1.0/0.1[1]	2.0	0.5/1.0[6]	1.0	1.2×10^{-3}

Notes:

[1] Nominal time was available for diagnosis, but there was barely adequate time to take the action.

[2] Nominal stress was used for diagnosis because of control room environment and verbatim emergency operating procedure compliance. High stress in the field because actions would affect plant safety.

[3] The following items also had the Complexity PSF changed to 0.1 for an obvious diagnosis, and 2.0 for a moderately complex action: minimize dc loads and swap to AFW nozzles.

[4] Complexity values adjusted to indicate an obvious diagnosis based on emergency operating procedure review.

[5] The procedures for diagnosing the need for this step were symptom based, but the procedures for implementation were considered by the NRC to be poor.

[6] The procedures for diagnosing the need for this step were symptom based, but the procedures for implementation were considered by the NRC to be nominal.

[7] The experience of operators is nominal for diagnosing this need, but they do not routinely operate the valve gags in this situation.

[8] The ergonomics were considered poor for swapping the AFW nozzle because an unfamiliar task would have to be done without normal lighting.

[9] These actions did not include a significant amount of diagnosis. Therefore, only the action failure probability was calculated.

The NRC created an event tree to model the actions required to successfully use Pump FW-54 following battery depletion. This event tree, provided as Attachment 2 to this analysis, covered each of the functions required to achieve success, as well as the probability that actions affecting the time available (i.e., minimizing dc loads) would be completed. The NRC used the SPAR to quantify Fault Tree AFW-FW54, "Fort Calhoun PWR G AFW FW-54," and provide a probability that the Pump FW-54 train would fail from nominal reasons at any time during the accident sequence. The probability of failure was determined to be 3.14×10^{-2}. The NRC then quantified the event tree using the human reliability values listed in Table 3.b and the solution from the SPAR fault tree for Pump FW-54 as split fractions. This quantification provided the total failure probability of the Pump FW-54 train during an unrecovered station blackout, upon depletion of the station vital batteries. The probability was quantified as 1.08 x 10-1.

The failure probability was a factor of 2, lower than that calculated by the licensee, using the EPRI Human Reliability Calculator, Revision 2.01. However, given that all human reliability analysis values used in the SPAR were developed using similar methods, it was determined that this was a valid best estimate. The sensitivity evaluation documented below, indicates that the final risk value is very sensitive to this assumption.

Results of Adjusted Analysis:

The NRC evaluated cutsets from the initial SPAR model evaluation ascertained that 90.4 percent ($P_{(Deplete)}$) of the risk involved cutsets with auxiliary feedwater failing upon battery depletion. The NRC determined that these cutsets should be adjusted by the new failure probability of Pump FW-54, $P_{(54)}$. Therefore, the best estimate change in core damage frequency was calculated as follows:

$$\Delta CDF = (\text{Initial } \Delta CDF) * ((P_{(54)} * P_{(Deplete)}) + (1 - P_{(Deplete)}))$$

$$= (1.70 \times 10^{-5}) * ((1.08 \times 10^{-1} * 90.4\%) + (1 - 90.4\%))$$

$$= 3.3 \times 10^{-6}$$

This best estimate value was in line with the licensee's internal evaluation and appropriately accounted for the unique design of the Fort Calhoun Station auxiliary feedwater system. Therefore, it was concluded that the Phase 2 estimation was valid and should stand as the agency's preliminary risk significance for internal events. This resulted in determining that the finding was of low to moderate risk significance (WHITE).

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 NRC assessed the impact of external initiators because the Phase 2 significance determination process result provided a Risk Significance Estimation of 7 or greater. The methodology used to assess the impact of external events evaluated each initiator for the potential to:

- Increase the likelihood of a LOOP.
- Impact the reliability or availability of mitigating systems used during a LOOP.

High Winds, Floods, and Other External Events:

The NRC reviewed the licensee's Phase I report on the Individual Plant Examination for External Events (IPEEE) for Fort Calhoun, dated December 29, 1993. The licensee evaluated these external events in the following categories:

- **High Winds**

  During the IPEEE development, the licensee had quantified the risk related to high winds at 5.3×10^{-8}/yr. The NRC assumed that high wind events happen frequently enough that the impact of these severe weather events are already incorporated into the LOOP frequency. Therefore, only events with winds high enough to damage safety-related structures (and thus mitigating systems) could affect the subject finding.

  Most of the calculated risk, presented in the IPEEE, was from tornados of Categories F4 and F5. The frequency of these events hitting the Fort Calhoun site was estimated as 4.3×10^{-6}/yr. This results in a probability of 3.4×10^{-7} that a tornado would hit during any 29-day period. Given the very low probability of event initiation, it was determined that the change in core damage frequency caused by the subject finding would be very low.

- **External Floods**

  As documented in the IPEEE, the licensee evaluated two types of external floods: those that result from above normal precipitation and/or snow melt (periodic flooding), and those that result from failure of upstream earthen dams. Both events could cause a LOOP while affecting mitigating systems.

  The NRC reviewed Table 5.2.1, "Flood Frequency and Equipment Impact," to assess the impact of periodic flooding on the risk related to the subject finding. It was noted that flooding below 1007.5 feet mean sea level (MSL) had no major impact on plant operations, and flooding above 1013.5 was assumed to fail the diesel generators as a baseline assumption. Therefore, the NRC evaluated the change in risk from periodic flooding that resulted in water levels between 1007.5 and 1013.5. The following table, Table 4.a, shows the calculated flooding frequencies for these events and the equipment expected to be lost at each level. This information was extracted from Table 5.2.1 of the licensee's IPEEE. Additionally, the conditional core damage probabilities (CCDPs) were developed using the SPAR model and are also documented in Table 4.a.

Table 4.a **Risk Affects to External Flooding**				
Flood Elevation	Frequency (per year)	Equipment Lost	CCDP	ΔCDF
1007.5 - 1009.5	3.3×10^{-3}	LOOP only [5]	7.8×10^{-4}	3.8×10^{-8}
1009.5 - 1010.8	6.0×10^{-4}	Intake (1%)[1,2,6]	8.0×10^{-4}	8.3×10^{-9}
1010.8 - 1012.3	9.0×10^{-5}	Intake (10%)[1,3,7]	1.5×10^{-1}	8.4×10^{-7}
1012.3 - 1013.5	1.0×10^{-6}	Intake (90%)[1,4,7]	9.0×10^{-1}	3.2×10^{-10}

NOTES:

[1]Probability of sandbagging failure developed in accordance with Regulatory Guide 1.59, "Design Basis Floods for Nuclear Power Plants."
[2]Quantified assuming LOOP with 1% common cause failure of raw water pumps
[3]Quantified assuming LOOP with 10% common cause failure of raw water, ECCS, and AFW pumps
[4]Quantified assuming LOOP with 90% common cause failure of raw water, ECCS, and AFW pumps
[5]Modified value as discussed in the internal events "Results of Adjusted Analysis" section, assuming similar cutset ratio as for internal events
[6]Modified value as discussed in the internal events "Results of Adjusted Analysis" section, but assuming that sandbagging fails to protect Pump FW-54 5% of the time
[7]Values not modified because Pump FW-54 fails from flooding

Attachment 3 of this analysis is a spreadsheet showing the calculations used to determine the ΔCDF values shown in Table 4.a. The assumptions and adjustments used are documented in the notes section of the table. Because each of the flood elevations are statistically independent, the sum of the four flood scenarios obtained the result of 8.8×10^{-7} over the exposure period.

- **Other External Events**

  Finally, the licensee used the NUREG 1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities," dated April 1991, to screen out aircraft accidents and other external initiators from further review. Therefore, the NRC assumed that the subject finding would have no significant change in the risk associated with these events.

<u>Internal Fire</u>:

Within the Individual Plant Examination for External Events - Fort Calhoun Station, the licensee used a screening criteria of 1×10^{-7} as the threshold for determining that the fire risk in a given area was negligible. The NRC determined that this screening was low enough to identify those areas important to the subject finding. The IPEEE documents 14 fire areas, with 59 fire zones that yielded a ΔCDF greater than the screening criteria.

In the internal events evaluation, it was determined that over 99 percent of the internal risk was related to station blackouts with failures of the auxiliary feedwater system. Therefore, the NRC reviewed the unscreened fire areas at Fort Calhoun Station to identify any fires that could result in a LOOP and/or affect the auxiliary feedwater system. The NRC documented those areas, as potentially significant, in Table 4.b, and conducted further analyses of these areas.

Table 4.b

Potentially Significant Internal Fire Areas

Fire Areas	Fire Affects	Fire Ignition Frequency (per year)	Screened by NRC?	ΔCDF
Compressor Area	AFW	1.88×10^{-4}	YES	N/A
East Switchgear Area	LOOP, AFW	8.29×10^{-3}	NO	3.45×10^{-6}
West Switchgear Area	AFW	8.29×10^{-3}	YES	N/A
Cable Spreading Room	LOOP, AFW	7.80×10^{-4}	NO	3.0×10^{-7}
Main Control Room	LOOP, AFW	9.50×10^{-3}	NO	1.2×10^{-6}
Transformer Yard Area	LOOP	9.88×10^{-3}	YES	N/A
Turbine Building	AFW	5.83×10^{-2}	YES	N/A
Internal Fire Change in Core Damage Frequency:				5.0×10^{-6}

The NRC reviewed each of these areas as follows:

- Transformer Yard Area

  It was assumed that internal fire events happen frequently enough and that the rate of event initiation from these fires is already incorporated into the initiating event frequencies. To validate this assumption, the NRC took the highest fire ignition frequency for a fire zone that could cause a LOOP, 8.29×10^{-3}, and multiplied it by the nonsuppression probability for the area, 5×10^{-2}. This resulted in a fire mitigation frequency of 4.1×10^{-4}, which is two orders of magnitude below the LOOP likelihood (3.3×10^{-2}). Therefore, it was determined that the fire effects on the subject finding were negligible in the Transformer Yard Area and screened this area from further review.

- Compressor, West Switchgear, and Turbine Building Areas

  It was assumed that areas that only affected auxiliary feedwater and did not result in a LOOP would not have a major impact on risk. To validate this assumption, the NRC evaluated Fire Zone FA46F containing the diesel-driven auxiliary feedwater pump, Pump FW-54. The ignition frequency was 6.27×10^{-3} and the nonsuppression probability was 5×10^{-2}. Multiplying these resulted in a conservative fire mitigation frequency of 2.1×10^{-5}. The fire mitigation frequency for 29 days was then calculated as follows:

  $$FMF = 2.1 \times 10^{-5} \div 365 * 29 = 1.67 \times 10^{-6}$$

  It was noted that, for these areas, a LOOP would have to occur following or coincident with the fire, but prior to the licensee placing the plant in a safe condition. Assuming that the licensee took 3 days to shut down and cool the reactor to shutdown cooling pressures, the NRC calculated the probability that a LOOP occurred during this time, IEL_{LOOP}, as follows:

  $$IEL_{LOOP} = 3.31 \times 10^{-2} \div 365 * 3 = 2.72 \times 10^{-4}$$

  Therefore, the likelihood that a large fire would occur and a LOOP occurred while the reactor was being shut down and cooled, $IEL_{FIRE\text{-}LOOP}$, was calculated as follows:

  $$IEL_{FIRE\text{-}LOOP} = 1.67 \times 10^{-6} * 2.72 \times 10^{-4} = 4.54 \times 10^{-10}$$

  This value is low enough to support the assumption that areas where fires would only affect auxiliary feedwater had a negligible risk increase related to the subject performance deficiency. Therefore, the NRC screened the compressor, west switchgear, and turbine building areas from further review.

- East Switchgear Area

  In the paragraph regarding the transformer yard above, the NRC calculated a fire mitigation frequency of 4.1×10^{-4}/yr for this area. This represents the probability that a fire ignites and the Halon system is unsuccessful. This scenario is the only one deemed credible that could result in both a LOOP and a loss of the motor-driven auxiliary feedwater pump. The likelihood that this event is initiated within the 29 days exposure time, $IEL_{FIRE\text{-}LOOP}$, can be calculated as follows:

  $$IEL_{FIRE\text{-}LOOP} = 4.1 \times 10^{-4}/yr / 365 * 29 = 3.25 \times 10^{-5}$$

The area has cabling that feeds offsite power to Switchgear 1A4 in addition to Switchgear 1A3 itself. Therefore, a large fire without suppression is assumed to cause a Station Blackout instead of a LOOP, because of the failure of Emergency Diesel Generator 2.

Given the failure of Emergency Diesel Generator 2, it was determined that this event would go to core damage without Auxiliary Feedwater Pump FW-54. Therefore, the NRC set the conditional core damage probability for a fire in the east switchgear area, with the failure of Emergency Diesel Generator 2, P_{CASE}, to the failure probability of the diesel-driven auxiliary feedwater pump upon battery depletion, calculated previously to be 1.08×10^{-1}.

To determine the baseline risk for an unsuppressed fire in this area, the NRC quantified an unrecoverable (extreme weather) LOOP with a failure of Switchgear 1A3. The resulting CCDP was 1.8×10^{-2}. It was determined that the actual CCDP was that quantified multiplied by the failure probability of the diesel-driven auxiliary feedwater pump upon battery depletion, calculated previously to be 1.08×10^{-1}. Therefore the final baseline CCDP, P_{BASE}, was 1.94×10^{-3}.

The NRC then calculated the change in risk for this area as follows:

$$\Delta CDF = (3.25 \times 10^{-5} * 1.08 \times 10^{-1}) - (3.25 \times 10^{-5} * 1.94 \times 10^{-3})$$

$$= 3.45 \times 10^{-6}$$

- Cable Spreading Room

In their IPEEE, the licensee concluded that there were essentially no installed ignition sources in the cable spreading room. However, hot work and transient combustibles were considered credible sources of fire in this area. The fire ignition frequency for hot work was set as 6.7×10^{-4}/yr and the frequency for transient ignition sources was set at 1.1×10^{-4}/yr by reviewing the Fire Events Database. This fire area is protected by an automatic Halon system. The assumed success rate for the Halon system was 95 percent, leading to a nonsuppression probability of 5×10^{-2}. Therefore, the probability that a large fire would occur in this area, P_{LARGE}, is:

$$P_{LARGE} = (6.7 \times 10^{-4}/yr + 1.1 \times 10^{-4}/yr) * 5 \times 10^{-2}$$

$$= 3.9 \times 10^{-5}/yr$$

The licensee used the same procedures for a large fire in the cable spreading room as for a main control room evacuation. Therefore, the NRC used the accepted screening value of 0.1 for the probability of failure to shut down the reactor from outside the main control room. The NRC also assumed that the total conditional core damage probability, P_{BASE}, would be the failure of remote shutdown plus the probability of failure of Pump FW-54.

$$P_{BASE} = 3.9 \times 10^{-5}/yr * (1.08 \times 10^{-1} * 0.1)$$

$$= 4.21 \times 10^{-7}/yr$$

$$P_{CASE} = 3.9 \times 10^{-5}/yr * 1.08 \times 10^{-1}$$

$$= 4.21 \times 10^{-6}/yr$$

The NRC calculated the following ΔCDF over the 29-day exposure time:

$$\Delta CDF = (4.21 \times 10^{-6}/yr - 4.21 \times 10^{-7}/yr)\ )\ 365\ days/yr * 29\ days$$

$$= 3.0 \times 10^{-7}$$

It was determined, based on the IPEEE data, that fires in the cable spreading room, not requiring control room evacuation, were likely not of importance to this risk evaluation.

- Main Control Room

The NRC reviewed a series of main control room fire scenarios documented in the IPEEE - Fort Calhoun Station. Two major categories of fire were of interest: (1) fires leading to evacuation, and (2) fires leading to a LOOP and/or auxiliary feedwater system failures.

Main Control Room Evacuation:

There are 66 electrical cabinets in the Fort Calhoun Station main control room. Seven cabinets contain automatic Halon suppression systems, while 59 cabinets would require manual suppression. The basic fire initiation frequency was 1.44×10^{-4}/cabinet/yr. Therefore, the total fire ignition frequency for those cabinets with automatic suppression, FIF_{AUTO}, and for those requiring manual suppression, FIF_{MANUAL}, can be calculated as follows:

$$FIF_{AUTO} = 1.44 \times 10^{-4}/cabinet/yr * 7 = 1.01 \times 10^{-3}$$

$$FIF_{MANUAL} = 1.44 \times 10^{-4}/cabinet/yr * 59 = 8.50 \times 10^{-3}$$

The assumed success rate for the Halon system was 95 percent, leading to a nonsuppression probability of 5×10^{-2}. The IPEEE provides that control room evacuation would be required if a fire was unsuppressed for 20 minutes. Assuming that a fire takes 2 minutes to be detected by automatic detection and/or by the operators, there are 18 minutes remaining in which to suppress the fire prior to control room evacuation being required. NRC Inspection Manual Chapter 0609, Appendix F, Attachment 6, Table 48.1, "Non-suppression Probability Values for Manual Fire Fighting Based on Fire Duration (Time to Damage after Detection) and Fire Type Category," provides a manual nonsuppression probability for the control room of 1.3×10^{-2}, given 18 minutes from time to detection until time to damage. Using these values for suppression, the fire mitigation frequency can be calculated as follows:

$$FMF_{AUTO} = 1.01 \times 10^{-3} * 5 \times 10^{-2} = 5.04 \times 10^{-5}/yr$$

$$FMF_{MANUAL} = 8.50 \times 10^{-3} \bullet 1.3 \times 10^{-2} = 1.11 \times 10^{-4}/yr$$

The NRC reviewed the licensee's control room evacuation procedure contained in Abnormal Operating Procedure AOP-07, "Evacuation of Control Room." The licensee's strategy required isolating the vital switchgear from offsite power, then reenergizing Switchgear 1A3 using Emergency Diesel Generator 2. Given the failure of Emergency Diesel Generator 2, the NRC determined that this event would proceed to core damage without Auxiliary Feedwater Pump FW-54. Therefore, the NRC set the CCDP for a control room evacuation with a loss of Emergency Diesel Generator 2, P_{CASE}, to the failure probability of the diesel-driven auxiliary feedwater pump upon battery depletion, calculated previously to be 1.08×10^{-1}.

In the IPEEE, the licensee had used the accepted screening value of 0.1 for the probability of failure to shutdown the reactor from outside the main control room. The NRC assumed that the total CCDP, P_{BASE}, would be the failure of remote shutdown plus the probability of failure of Auxiliary Feedwater Pump FW-54.

$$P_{BASE} = (5.04 \times 10^{-5}/yr + 1.11 \times 10^{-4}/yr) * (1.08 \times 10^{-1} * 0.1)$$

$$= 1.74 \times 10^{-6}/yr$$

$$P_{CASE} = (5.04 \times 10^{-5} + 1.11 \times 10^{-4}) * (1.08 \times 10^{-1})$$

$$= 1.74 \times 10^{-5}/yr$$

The NRC calculated the following ΔCDF over the 29-day exposure time:

$$\Delta CDF = (1.74 \times 10^{-5}/yr - 1.74 \times 10^{-6}/yr) \div 365 \text{ days/yr} * 29 \text{ days}$$

$$= 1.2 \times 10^{-6}$$

- Main Control Room Cabinets:

  The NRC reviewed each of the control room cabinet fire scenarios presented in the licensee's IPEEE. Only four scenarios involved fires leading to a LOOP and/or auxiliary feedwater system failures. These scenarios were:

  - Fire in Cabinet CB-4

    The NRC determined that this fire scenario affected main feedwater and Auxiliary Feedwater Pump FW-54. As stated above, it was assumed that fires affecting auxiliary feedwater but not resulting in a direct LOOP would not have a major impact on risk. Therefore, this scenario screened from further analysis.

  - Fire in Cabinets CB-10, CB-11, and part of CB-20

    This fire scenario could result in a total LOOP. However, it would not directly cause the failure of auxiliary feedwater system components. As stated previously, it was assumed that internal fire events happen frequently enough and that the rate of event initiation from these fires is already incorporated into the initiating event frequencies. In the case of this fire scenario, the fire ignition frequency was 4.32×10^{-4}/yr. This value is two orders of magnitude below the LOOP likelihood. Therefore, it was determined that the fire effects on the subject finding were negligible in these cabinets and screened this scenario from further review.

  - Fire in Cabinet CB-20

    This fire scenario could result in a total LOOP. However, it would not directly cause the failure of auxiliary feedwater system components. As stated previously, it was assumed that internal fire events happen frequently enough and that the rate of event initiation from these fires is already incorporated into the initiating event frequencies. In the case of this fire scenario, the fire ignition frequency was 1.44×10^{-4}/yr. This value is two orders of magnitude below the LOOP likelihood. Therefore, it was determined that the fire effects on the subject finding were negligible in these cabinets and screened this scenario from further review.

  - Fire in Cabinet AI-30A

    This fire scenario could result in a reactor trip with the loss of all ac power to Switchgear 1A3. The NRC determined that for Emergency Diesel Generator 2 to be required following this fire scenario, offsite power would have to be lost to Switchgear 1A4. In the case of this fire scenario, the fire ignition frequency was 5.76×10^{-4}/yr. The frequency of a LOOP to Switchgear 1A4 is assumed to be (3.31×10^{-2}/yr • 1.75) = 4.8×10^{-4} over the 72 hours, assuming that it would take 72 hours to stabilize and cool the reactor. Therefore, the likelihood that a fire initiates sometime over a 29-day period followed within 72 hours by a LOOP to Switchgear 1A4 is:

$$FIF_{LOOP} = 5.76 \times 10^{-4}\text{/yr} / 365 \text{ days/yr} * 29 \text{ days} * 4.8 \times 10^{-4}$$

$$= 2.2 \times 10^{-8}$$

Therefore, it was determined that the fire effects on the subject finding were negligible in these cabinets and screened this scenario from further review.

Main Control Room Internal Fire ΔCDF:

The NRC determined that all main control room fires, not requiring evacuation, were either screened out or it was determined quantitatively that the risk increase from the subject finding was negligible with respect to those fire scenarios. Therefore, the total internal fire ΔCDF quantified was the change in risk from fires requiring main control room evacuation.

External Events Summary:

As documented above, the NRC determined that the external events important to the risk associated with the subject finding were external flooding and internal fire. The four flood scenarios evaluated resulted in a ΔCDF of 8.8×10^{-7} over the exposure period. The seven fire areas evaluated resulted in a ΔCDF of 5.0×10^{-6} over the exposure period. Therefore the risk of the subject finding related to external events was the sum of the two, 5.9×10^{-6}. The Phase 2 estimation resulted in a single sequence with a result of six and another with a result of seven. Using the counting rule, this can be estimated as a ΔCDF of 3.6×10^{-6}. Therefore total ΔCDF for the subject finding can be calculated as the sum of the internal and external risk:

$$\Delta CDF = 3.6 \times 10^{-6} + 5.9 \times 10^{-6} = 9.5 \times 10^{-6}$$

This result indicates that the change in risk from external initiators caused by this finding does not cause the significance to increase above the next threshold. Therefore the finding is of low to moderate risk significance (WHITE).

Potential Risk Contribution from Large Early Release Frequency:

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

In pressurized water reactors, 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 this type of reactor are intersystem loss of coolant accidents, steam generator tube ruptures, and station blackouts.

In accordance with Manual Chapter 0609, Appendix H, "Containment Integrity SDP," it was determined that this was a Type A finding, because the finding affected the plant core damage frequency. The NRC evaluated the risk-informed notebook results and determined that Sequences 2 and 3 were both induced by a LOOP that did not proceed to a station blackout. In accordance with Appendix H, Section 5.1, step 2, "Accident Sequence Screening," LOOP sequences with successful emergency ac power operation will not generally contribute to the large-early release frequency and therefore are screened out. Additionally, station blackout sequences (Sequences 5 and 6) are screened from further analysis for large dry containments as described in Appendix H, Table 5.1, "Phase 1 Screening - Type A Findings at Full Power." Therefore, it was determined that the subject performance deficiency was not significant to the large-early release frequency.

Licensee's Risk Assessment:

The licensee evaluated the failure of Emergency Diesel Generator 2 using their probabilistic risk assessment model. The result of their internal events evaluation was approximately 3.6×10^{-6}. As stated above, the licensee's model provided for recovery of auxiliary feedwater during a station blackout, following battery depletion. The licensee stated that Fort Calhoun Station had a unique arrangement for auxiliary feedwater. Auxiliary feedwater Pump FW-54 is diesel-driven and does not rely on vital ac or dc power. The pump is supplied with fuel from Diesel Fuel Oil Storage System Tank FO-10. Tank FO-10 has a minimum volume of 10,000 gallons of diesel fuel as required by Technical Specification 2.7. Eight thousand gallons of the tank's inventory are readily available for use by Pump FW-54. Therefore, the pump could run for 24 hours without fuel addition. To address this unique design, the licensee used Basic Event XSBO8DC to address the probability that operators would fail to properly run Pump FW-54 following battery depletion. The licensee had used the EPRI Human Reliability Calculator, Revision 2.01, to quantify this value. The failure probability used, 2.02×10^{-1}, was a factor of 2 higher than that calculated by the NRC. However, given that all human reliability analyses values used in the SPAR were developed using similar methods, the NRC determined that this was a valid best estimate.

<u>Sensitivity Studies</u>:

The NRC performed sensitivity studies on major assumptions using the internal events model. Table 6 summarizes the assumptions and the results. It was determined that the analysis is very sensitive to the probability of failure selected for running Auxiliary Feedwater Pump FW-54 during a station blackout following battery depletion. Additionally, the NRC assessed diesel generator recovery times and the total exposure.

Table 6

Sensitivity Studies

Parameter	Condition	Initial Value	New Value	New Result
Pump FW-54	Licensee's	1.08×10^{-1}	2.02×10^{-1}	1.6×10^{-5}
	No Credit		1.0	7.0×10^{-5}
	Single Train		1×10^{-2}	2.9×10^{-6}
Emergency Diesel Generator 2	Recovery 1 and 4 hours	8.41×10^{-1}	9.21×10^{-1}	1.4×10^{-5}
		5×10^{-1}	7.5×10^{-1}	
Exposure	Run Time	29 days	61 days	2.2×10^{-5}

NOTES:
1) Three evaluations were run for Pump FW-54: a) using the licensee's value; b) assuming no credit beyond battery depletion; and c) giving the system single train credit.
2) Diesel Generator recovery is based on one machine. However, for certain conditions, it may be appropriate to increase the failure probability for recovery if one machine is unrecoverable.
3) The exposure time assumed that the licensee's performance deficiency started when they failed to recognize the blown fuse. Had there been reason to know the circuit would have failed, the machine was not functional for its mission time for longer than 29 days.

All Other Inspection Findings (Not IE, MS, BI Cornerstones)

Not Applicable.

<u>Enforcement</u>. Title 10 of CFR Part 50, Appendix B, Criterion XVI, requires, in part, that measures shall be established to ensure that conditions adverse to quality, such as failures, malfunctions, etc., are promptly identified and corrected.

Fort Calhoun Station Technical Specification 2.7(1), Minimum Requirements, states, in part, that the reactor shall not be heated up or maintained at temperatures above 300°F unless the following electrical systems are operable: two emergency diesel generators (DG-1 and DG-2). Technical Specification 2.7(2), Modification of Minimum Requirements, states, in part, that the minimum requirements may be modified under certain conditions. Item 2.7(2)j states that either one of the emergency diesel generators may be inoperable for up to 7 days (total for both) during any month, provided certain conditions are met.

Contrary to the above, on July 21, 2004, during surveillance testing of DG-2, the licensee failed to promptly identify that Fuse 2FU in the emergency diesel generator excitation circuit had failed. The failure to promptly identify and correct this condition resulted in DG-2 being inoperable from July 21 to August 19, 2004, a period of 29 days, violating Technical Specification 2.7(1). This violation of 10 CFR Part 50, Appendix B, Criterion XVI, is being treated as a violation, consistent with the Enforcement Policy (VIO 05000285/2005010-01). This violation is in the licensee's corrective action program as Condition Report 200403634.

4OA6 Meetings, Including Exit

On March 2, 2005, the inspectors presented the results of the resident inspector activities to Mr. R. Phelps, Division Manager of Nuclear Engineering, and other members of his staff who acknowledged the finding.

The inspectors confirmed that proprietary information was not provided by the licensee during this inspection.

ATTACHMENT 1: SUPPLEMENTAL INFORMATION
ATTACHMENT 2: EVENT TREE
ATTACHMENT 3: SPREADSHEET

ATTACHMENT 1

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

G. Cavanaugh, Supervisor, Nuclear Licensing
M. Core, Manager, System Engineering
P. Cronin, Manager, Shift Operations
M. Frans, Assistant Plant Manager
A. Hackerott, Supervisor, Probabilistic Risk Assessment
R. Haug, Manager, Chemistry
J. Herman, Manager, Nuclear Licensing
R. Kellogg, Senior Nuclear Design Engineer
K. Naser, System Engineering Supervisor
R. Phelps, Division Manager, Nuclear Engineering
C. Sterba, Supervisor, Design Engineering
D. Trausch, Manager, Quality

NRC

M. Hay, Branch Chief
T. Vegel, Deputy Director, Division of Reactor Projects
J. Hanna, Senior Resident Inspector
L. Willoughby, Resident Inspector

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000285/2005010-01	VIO	Emergency Diesel Generator 2 Inoperable in Excess of Technical Specifications due to Failed Fuse (Section 1R15)

LIST OF DOCUMENTS REVIEWED

Part 21 Report, "Interim Report Concerning Failures of Gould-Shawmut Fuses," May 8, 1995

Computer plots of Diesel Generator Frequency and Voltage for surveillance testing performed on August 18, 2004

Evaluation of Plant Risk (CDF & LERF) of Diesel Generator Unavailable for 29 days, performed on November 24, 2004

Plant Review Committee Agenda for November 17, 2004, Meeting

Memorandum from Peter Graffy (Exelon) to Richard Ronning (OPPD), "Ongoing Failure Analysis/Special Test Shawmut Amptrap Fuse A25X100 Type 4," dated November 11, 2004

Control Room Operator Logs for July 21, 2004

LER 05000296/1993-002-00, "An Emergency Diesel Generator Auto-Started as a Result of Degraded Voltage Condition on 4KV Shutdown Caused by a Blown Fuse," January 3, 1994

LER 05000346/2004-002-00, "Reactor Trip During Reactor Trip Breaker Testing Due to Fuse Failure," October 4, 2004

LER 05000424/2000-002-00, "Manual Reactor Trip Following Main Steam Isolation Valve Closure," June 27, 2000

LER 05000457/1991-006-00, "Generator Trip Caused by Spurious Actuation of Neutral Ground Relay," December 23, 1991

LER 05000483/1996-001-00, "Licensed Operators Initiated a Manual Reactor Trip," April 25, 1996

LER 05000457/2000-002-00, "Automatic Reactor Trip on Power Range Neutron Flux High Negative Rate Due to Stationary Gripper Fuse FU15 Failure for Control Rod P10 Causing the Rod to Drop into the Core," May 12, 2000

Level 'A' Root Cause Analysis Report, "Inoperability of DG-2 Diesel Generator During Engine Shutdown," Revision 0

Emergency Response Facility Computer (Plant Computer) alarm printout for July 21, 2004

Surveillance Test Procedures:

OP-ST-DG-0002, "Diesel Generator 2 Check," Revision 41 performed on July 21, 2004
OP-ST-DG-0002, "Diesel Generator 2 Check," Revision 41 performed on August 18, 2004
OP-ST-DG-0002, "Diesel Generator 2 Check," Revision 41 performed on August 19, 2004
OP-ST-DG-0002, "Diesel Generator 2 Check," Revision 41 performed on September 15, 2004
OP-ST-DG-0001, "Diesel Generator 2 Check," Revision 42 performed on July 7, 2004

OP-ST-DG-0001, "Diesel Generator 2 Check," Revision 42 performed on August 4, 2004
OP-ST-DG-0001, "Diesel Generator 2 Check," Revision 42 performed on September 1, 2004

Standing Orders:

SO-G-23, "Surveillance Test Program," Revision 51
SO-G-96, "Planned LCO Entry Criteria and Equipment Reliability Control," Revision 11
SO-G-7, "Operating Manual," Revision 52
SO-O-30, "Testing Safety Related Equipment," Revision 8
SO-0-1, "Conduct of Operations," Revision 56
SO-G-26, "Training and Qualification Programs," Revision 46
SO-G-56, "Qualified Life Program," Revision 24

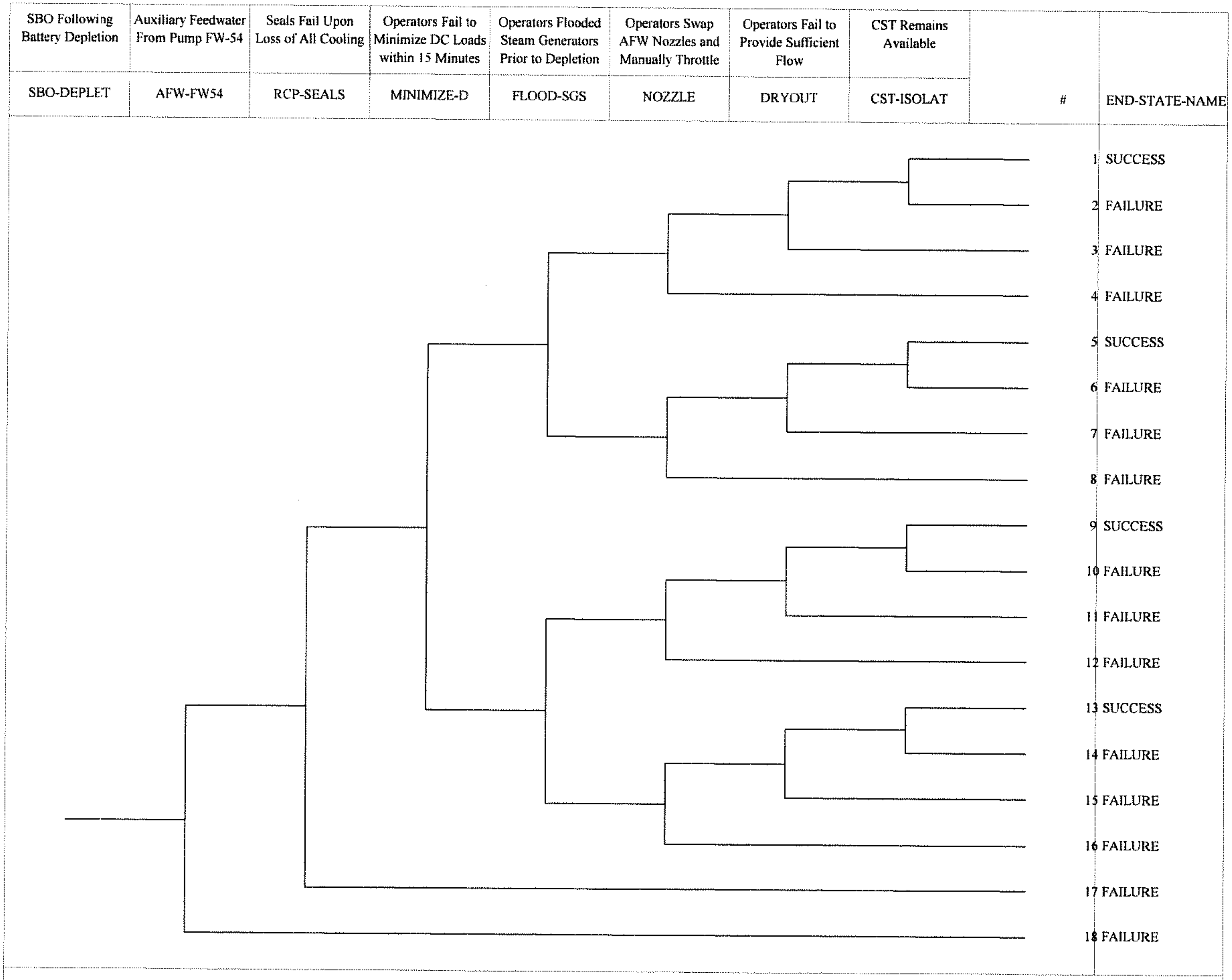
Drawings and Schematics:

File No. 57227, "DG-2 Diesel Generator One Line Diagram P&ID," Revision 5
File No. 17397, "Schematic Engine Control," Revision 16
File No. 9808, "Elementary Diagram AI-30A," Revision 17
File No. 9809, "Elementary Diagram AI-30A," Revision 15
File No. 9819, "Elementary Diagram AI-30B," Revision 16
File No. 9818, "Elementary Diagram AI-30B," Revision 15
File No. 6623, "1 Phase Full Static Exciter," Revision 7
File No. 17396, "Schematic Engine Control," Revision 6
File No. 17398, "Schematic Engine Control," Revision 8
File No. 56795, "Component List for Static Exciters AI-133a-28 & AI-133B-28," Revision 3

Condition Reports:

200402518
200403634
200403662
200404060

ATTACHMENT 2



SBO-DEPLETION - SBO Following Battery Depletion 2005/02/04 Page 1

ATTACHMENT 3

Periodic Flooding

Event	Min. Flood	Model	Case	Base	Delta CCDP	IEL	Case CDF	Base CDF	delta CDF /yr	Exposure	Delta CDF	Recovery	Delta CDF
	(feet MSL)		SPAR Results			(per year)	Calculated (per year)			(days)			(Recovery)
LOOP	1007.5	Extreme-FLOOD	7.80E-04	4.20E-05	7.38E-04	3.30E-03	2.57E-06	1.39E-07	2.44E-06	2.90E+01	1.93E-07	1.94E-01	3.75E-08
LOOP	1009.5	Severe-FLOOD2	8.00E-04	5.90E-05	7.41E-04	6.00E-04	4.80E-07	3.54E-08	4.45E-07	2.90E+01	3.53E-08	2.34E-01	8.26E-09
LOOP	1010.8	Severe-FLOOD	1.50E-01	3.30E-02	1.17E-01	9.00E-05	1.35E-05	2.97E-06	1.05E-05	2.90E+01	8.37E-07	1.00E+00	8.37E-07
LOOP	1012.3	Severe-FLOOD3	9.04E-01	9.00E-01	4.00E-03	1.00E-06	9.04E-07	9.00E-07	4.00E-09	2.90E+01	3.18E-10	1.00E+00	3.18E-10
Totals:							**1.75E-05**	**4.04E-06**			**1.07E-06**		**8.83E-07**

Sandbagging Failure Probability:	0.05
Probability of Pump FW-54 Recovery:	0.108
Percent Cutsets to Battery Depletion:	0.904