UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
1600 E. LAMAR BLVD.
ARLINGTON, TX 76011-4511

August 14, 2017

EA-17-057

Mr. John Dent
Vice President-Nuclear and CNO
Nebraska Public Power District
Cooper Nuclear Station
72676 648A Avenue
P.O. Box 98
Brownville, NE 68321

SUBJECT: COOPER NUCLEAR STATION – NRC BASELINE INSPECTION REPORT 05000298/2017011 AND PRELIMINARY WHITE FINDING

Dear Mr. Dent:

On June 15, 2017, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Cooper Nuclear Station. On August 11, 2017, the NRC inspectors discussed the results of this inspection with you and other members of your staff. The results of this inspection are documented in the enclosed report.

The enclosed report documents a finding with two associated apparent violations that the NRC has preliminarily determined to be White with low-to-moderate safety significance. This finding involved two apparent violations of Technical Specification 5.4.1.a for the failure to: (1) implement inspection instructions to examine the emergency transformer bus insulation for discoloration and repair the associated components, and (2) maintain adequate instructions for performing high potential testing of the emergency transformer bus bars. As a result, indications of corona-related degradation on the emergency transformer bus were not identified and repaired, which resulted in a bus fault, a loss of the emergency transformer, and a loss of the supplemental diesel generator on January 17, 2017. This finding was assessed based on the best available information, using the applicable significance determination process. The final resolution of this finding will be conveyed in separate correspondence.

The finding is associated with two apparent violations and is being considered for escalated enforcement in accordance with the NRC Enforcement Policy, which can be found at http://www.nrc.gov/about-nrc/regulatory/enforcement/enforce-pol.html.

In accordance with NRC Inspection Manual Chapter 0609, "Significance Determination Process," we intend to issue our final significance determination and enforcement decision, in writing, within 90 days from the date of this letter. The NRC's significance determination process encourages an open dialogue between your staff and the NRC; however, the dialogue should not impact the timeliness of the staff's final determination.

Before we make a final decision on this matter, we are providing you with an opportunity to (1) attend a regulatory conference where you can present to the NRC your perspective on the facts and assumptions the NRC used to arrive at the finding and assess its significance, or (2) submit your position on the finding to the NRC in writing.

If you request a regulatory conference, it should be held within 40 days of your receipt of this letter, and we encourage you to submit supporting documentation at least one week prior to the conference in an effort to make the conference more efficient and effective. The focus of the regulatory conference is to discuss the significance of the finding and not necessarily the root cause(s) or corrective action(s) associated with the finding. If you choose to attend a regulatory conference, it will be open for public observation.

If you decide to submit only a written response, it should be sent to the NRC within 40 days of your receipt of this letter. Written responses should reference the inspection report number and enforcement action number associated with this letter in the subject line. If you choose not to request a regulatory conference or to submit a written response, you relinquish your right to appeal the NRC's final significance determination, in that, by not doing either, you fail to meet the appeal requirements stated in the Prerequisite and Limitation sections of Attachment 2 of NRC Inspection Manual Chapter 0609.

Please contact Jason Kozal at 817-200-1144, and in writing, within 10 days from the issue date of this letter to notify the NRC of your intentions. If we have not heard from you within 10 days, we will continue with our significance determination and enforcement decision. The final resolution of this matter will be conveyed in separate correspondence.

Because the NRC has not made a final determination in this matter, no Notice of Violation is being issued for this inspection finding at this time. In addition, please be advised that the number and characterization of the apparent violations described in the enclosed inspection report may change as a result of further NRC review.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice and Procedure," a copy of this letter and its enclosure will be made available electronically for public inspection in the NRC Public Document Room and in the NRC's Agencywide Documents Access and Management System (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html.

Sincerely,

/RA/

Troy W. Pruett, Director
Division of Reactor Projects

Docket No. 50-298
License No. DPR-46

Enclosure:
Inspection Report 05000298/2017011
w/ Attachments:
1. Supplemental Information
2. Significance Determination

COOPER NUCLEAR STATION – NRC BASELINE INSPECTION REPORT 05000298/2017011 AND PRELIMINARY WHITE FINDING – AUGUST 14, 2017

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ADAMS ACCESSION NUMBER: ML17223A459

☒ SUNSI Review: By:CHY/dll | ADAMS: ☒ Yes ☐ No | ☐ Non-Publicly Available ☒ Publicly Available | ☒ Non-Sensitive ☐ Sensitive | Keyword: NRC-002

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DATE	8/3/2017	6/28/17	6/28/17	8/3/17	8/2/2017	8/2/2017
OFFICE	SRI:DRP/C	RC:ORA	TL:ACES	BC:DRP/C	DD:DRA:NRR	D:DRS
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U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	05000298
License:	DPR-46
Report:	05000298/2017011
Licensee:	Nebraska Public Power District
Facility:	Cooper Nuclear Station
Location:	72676 648A Ave Brownville, NE
Dates:	January 17 through June 15, 2017
Inspectors:	P. Voss, Senior Resident Inspector C. Henderson, Resident Inspector J. Watkins, Reactor Inspector R. Deese, Senior Reactor Analyst
Approved By:	Troy W. Pruett, Director Division of Reactor Projects

SUMMARY

IR 05000298/2017011; 01/17/2017 – 06/15/2017; Cooper Nuclear Station; Problem Identification and Resolution.

The inspection activities described in this report were performed between January 17 and June 15, 2017, by the resident inspectors at Cooper Nuclear Station and inspectors from the NRC's Region IV office. One finding of preliminary low-to-moderate safety significance (White) is documented in this report. This finding involved apparent violations of NRC requirements. The significance of inspection findings is indicated by their color (i.e., Green, greater than Green, White, Yellow, or Red), determined using NRC Inspection Manual Chapter 0609, "Significance Determination Process," dated April 29, 2015. Their cross-cutting aspects are determined using NRC Inspection Manual Chapter 0310, "Aspects Within the Cross-Cutting Areas," dated December 4, 2014. Violations of NRC requirements are dispositioned in accordance with the NRC Enforcement Policy. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," dated July 2016.

Cornerstone: Initiating Events

- AV. The inspectors identified a preliminary low-to-moderate safety significance (White) finding with two NRC-identified apparent violations of Technical Specification 5.4.1.a, for the licensee's failure to implement and maintain Maintenance Procedure 7.3.41, "Examination and High Pot Testing of Non-Segregated Buses and Associated Equipment," Revision 10, during testing and inspection of the emergency station service transformer 4160 V bus bars. Specifically, the inspectors identified:

    1. A violation of Technical Specification 5.4.1.a, for the failure to implement inspection instructions to examine the emergency transformer bus insulation for discoloration and repair the associated components on March 23, 2015; and

    2. A violation of Technical Specification 5.4.1.a, for the failure to maintain adequate instructions for performing high potential testing of the emergency transformer bus bars between March 23, 2015, and April 18, 2017.

    As a result, the licensee did not properly assess corona-related degradation on the emergency transformer bus, which resulted in an emergency transformer bus fault and a loss of the emergency transformer and the supplemental diesel generator on January 17, 2017. Corrective actions to restore compliance included replacement of the faulted portions of the emergency transformer bus, extent of condition inspection and cleaning of the remainder of the emergency transformer bus bars, long term corrective actions to replace the emergency transformer bus insulation, and revision of high potential testing procedure instructions. The licensee entered these issues into the corrective action program as Condition Reports CR-CNS-2017-00223 and CR-CNS-2017-02164.

    The licensee's failure to implement and maintain Maintenance Procedure 7.3.41 to properly assess degradation of the emergency station service transformer bus, in violation of Technical Specification 5.4.1.a, was a performance deficiency. The performance deficiency was determined to be more than minor, and therefore a finding, because it was associated with the equipment performance attribute of the Initiating Events Cornerstone and affected the cornerstone objective to limit the likelihood of events that upset plant stability and

challenge critical safety functions during shutdown, as well as power operations. Specifically, the finding resulted in an emergency transformer bus fault and a loss of the emergency transformer and the supplemental diesel generator. Using NRC Inspection Manual Chapter 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," dated June 19, 2012, the inspectors determined that the finding required a detailed risk evaluation because it involved the partial loss of a support system that contributes to the likelihood of, or causes, an initiating event (loss-of-offsite power), and the finding affected mitigation equipment (supplemental diesel generator).

A senior reactor analyst performed a detailed risk evaluation in accordance with Inspection Manual Chapter 0609, Appendix A, Section 6.0, "Detailed Risk Evaluation." The calculated increase in core damage frequency was dominated by station blackout initiators. The NRC preliminarily determined that the increase in core damage frequency for internal and external initiators was 6.3E-6/year, a finding of low-to-moderate risk significance (White).

The performance deficiency had a cross-cutting aspect in the area of problem identification and resolution associated with evaluation, because the licensee failed to thoroughly evaluate emergency transformer electrical bus discoloration and high potential test failures to ensure that resolutions addressed the causes and extent of conditions commensurate with their safety significance [P.2]. (Section 4OA2)

REPORT DETAILS

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13)

a. Inspection Scope

On January 23, 2017, the inspectors observed portions of one emergent work activity associated with repair of an emergency station service transformer (ESST) bus fault that had the potential to cause an initiating event and affect the functional capability of mitigating systems.

The inspectors verified that the licensee appropriately developed and followed a work plan for these activities. The inspectors verified that the licensee took precautions to minimize the impact of the work activities on unaffected structures, systems, and components (SSCs).

These activities constituted completion of one emergent work control inspection sample, as defined in Inspection Procedure 71111.13.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed one post-maintenance testing activity that affected risk-significant SSCs. On January 23, 2017, the inspectors reviewed the post-maintenance testing activity following the emergent repairs of the ESST. The inspectors reviewed licensing- and design-basis documents for the SSCs and the maintenance and post-maintenance test procedures. The inspectors observed the performance of the post-maintenance tests to verify that the licensee performed the tests in accordance with approved procedures, satisfied the established acceptance criteria, and restored the operability of the affected SSCs.

These activities constituted completion of one post-maintenance testing inspection sample, as defined in Inspection Procedure 71111.19.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

Cornerstones: Initiating Events, Mitigating Systems

4OA2 Problem Identification and Resolution (71152)

Annual Follow-up of Selected Issues

a. Inspection Scope

The inspectors selected one issue for an in-depth follow-up. The inspectors assessed the licensee's problem identification threshold, cause analyses, extent of condition reviews, and compensatory actions for the January 17, 2017, ESST bus fault. The inspectors verified that the licensee appropriately prioritized the planned corrective actions and that these actions were adequate to correct the condition.

These activities constituted completion of one annual follow-up sample, as defined in Inspection Procedure 71152.

b. Findings

Introduction. The inspectors identified a finding of preliminary low-to-moderate safety significance (White) with two associated violations of Technical Specification (TS) 5.4.1.a, for the licensee's failure to implement and maintain Maintenance Procedure 7.3.41, "Examination and High Pot Testing of Non-Segregated Buses and Associated Equipment," Revision 10, during testing and inspection of the ESST 4160 V bus bars. Specifically, the inspectors identified:

1. A violation of TS 5.4.1.a, for the failure to implement inspection instructions to examine the ESST bus insulation for discoloration and repair the associated components on March 23, 2015; and

2. A violation of TS 5.4.1.a, for the failure to maintain adequate instructions for performing high potential testing of the ESST bus bars between March 23, 2015, and April 18, 2017.

As a result, the licensee did not properly assess corona-related degradation on the ESST bus, which resulted in an ESST bus fault and a loss of the ESST and the supplemental diesel generator (SDG) on January 17, 2017.

Description. On January 17, 2017, the plant experienced a phase-to-phase fault of the nonsegregated bus on the secondary side of the ESST. When the fault occurred, the control room received several annunciators alerting the operators to the loss of voltage to the ESST. Operations personnel entered Abnormal Procedure 5.3GRID, "Degraded Grid Voltage," Revision 46, in response to the event. Shortly thereafter, the control room received a report from the Nebraska Public Power District grid operations center, which notified the station that there was an apparent 3-phase fault on the bus bars between the ESST transformer and the plant's safety-related 4160 V buses. Subsequently, the licensee discovered that an area of the nonsegregated ESST bus duct near the turbine building was discolored and at an elevated temperature. The ESST was not loaded, and no ESST-related switching activities were occurring at the time of the fault. The

Nebraska Public Power District grid operations center analyzed the fault and determined that the circuit protection operated correctly.

Station loads are normally powered by the normal transformer, which is fed by the station's main generator or by the startup station service transformer (SSST) when the plant is not generating power. Because the ESST is normally on standby as one of the station's two offsite power sources required by TS Limiting Condition for Operation 3.8.1, "AC Sources – Operating," operations personnel entered TS 3.8.1, Condition A, a 7-day TS action statement, after the fault occurred. In addition, the fault resulted in a loss of the nonsafety-related SDG because the faulted ESST bus bars were common to the SDG. No other equipment was directly impacted by the fault.

The licensee initiated an apparent cause evaluation (ACE) to review the cause of the event. The licensee determined that the direct cause of the fault was due to damage associated with corona, a voltage-related phenomenon that can result in insulation breakdown and generation of a white conductive powder residue. Specifically, the licensee determined that corona present at the interface between the ESST nonsegregated bus bar supports and the bus bars caused degradation of the bus bar insulation, which led to tracking across the ESST bus bar supports and an eventual fault. The licensee also recognized that humidity and moisture increases corona tracking. The licensee concluded that the apparent cause of the event was that the inspection procedure did not give adequate guidance to support operation of the ESST bus until the next scheduled inspection.

The licensee determined that the procedure guidance in Maintenance Procedure 7.3.41 did not ensure that a thorough inspection of the ESST bus was performed to support the 10-year inspection interval. Specifically, the licensee concluded that the procedural guidance was inadequate, in that, it did not direct removal of the ESST bus bar support insulators to allow for inspection of the insulation under the support or specify inspection for signs of tracking on bus support insulators.

The inspectors reviewed the licensee's assessment of the cause of the event. Specifically, the inspectors reviewed the January 17, 2017, event; walked down the faulted ESST bus bars and related equipment; interviewed plant personnel; and reviewed condition reports and work orders associated with the most recent ESST bus bar inspections. The inspectors noted that the ESST bus bar inspection was a preventative maintenance activity with a 10-year frequency, and that the last time the ESST bus bar inspection was performed was between March 23 and 29, 2015. The licensee's ACE noted that corona-related degradation was a slowly developing failure mechanism, and that the degradation would have been present during the 2015 inspection. As a result, the inspectors concluded that during the 2015 ESST inspection, the licensee had failed to identify white corona-related discoloration and insulation damage in the location where the 2017 fault occurred.

The inspectors noted that during the previous 10-year inspection that was completed in 2005, the licensee discovered corona-related degradation on the ESST bus throughout the bus duct and performed an ACE to address the issue. As a result of the 2005 ACE, the licensee added more prescriptive steps to the inspection procedure to require more thorough inspections. The procedure steps that were added were labeled as protected steps, which meant that they were referenced to the 2005 ACE and the associated deficient condition for which they were created. Specifically, Step 5.9 stated, "Examine nonsegregated bus insulations for discoloration. IF insulation discoloration is present, THEN clean as necessary. Remove bus bar supports, if necessary, to clean insulation." The inspectors concluded that the added steps contained adequate direction to allow for identification of corona-related condition degradation, and that the licensee's 2017 ACE that was performed in response to the ESST bus fault had not fully identified the cause of the event.

The inspectors challenged licensee personnel on their conclusion that insufficient detail in the inspection instructions was the apparent cause of the inadequate 2015 inspection, as concluded by the 2017 ACE. The NRC did not independently perform a causal analysis for this event. However, the inspectors concluded that the procedure, which was even less detailed during the 2005 inspection, was adequate to allow identification of corona-related degradation.

The inspectors identified that the procedure directed inspection and/or cleaning of all "insulations," which should reasonably have included the ESST bus bar insulator supports. The inspectors noted that because tracking across the insulator support bars was a necessary contributor to the fault, maintenance personnel should not have needed to remove the support bars in order to identify the discoloration and tracking across them. As a result, the inspectors questioned the licensee on whether the inadequate 2015 ESST bus inspection was due to weaknesses in the training of the individuals performing the inspection, inadequate corrective actions for bus discoloration when it was identified, an inadequate high potential (hipot) testing process, and/or a failure to utilize internal operating experience from the last ESST bus inspection in 2005 to ensure the workers knew what they were looking for and what to expect to find.

The licensee's ACE did not address or discredit these potential causal factors. In addition, the inspectors challenged the licensee's 2017 extent of condition review, because it was narrowly scoped and only directed a 'spot check' of the X winding of the SSST bus section immediately below where the ESST fault occurred. The inspectors discussed these concerns with the licensee, and the licensee entered these issues into the corrective action program as Condition Report-CR-CNS-2017-04126.

The inspectors reviewed Maintenance Procedure 7.3.41, the licensee's procedure for performing maintenance on the ESST, SSST, and normal transformer buses. The inspectors noted that on March 23, 2015, the licensee changed the method of performing bus testing from megger to hipot testing. The inspectors noted that Step 5.16 of Maintenance Procedure 7.3.41, required, in part, "High Pot each bus phase to ground at approximately 14kV for a minimum of 30 seconds."

The inspectors determined that the licensee's hipot testing practice was not consistent with industry Institute of Electrical and Electronics Engineers (IEEE) standards. The inspectors determined that IEEE Standard C37.23-2003, "IEEE Standard for Metal-Enclosed Bus," was applicable for this condition because the licensee was relying on the adequacy of the hipot test in combination with the visual inspection to verify functionality of the ESST bus bars. This IEEE standard states, in part, that for nonsegregated buses, "test voltages shall be applied between each phase (or pole) individually and ground, with the other phases and the enclosure grounded."

The inspectors noted that with the IEEE test configuration, the test would check for both phase-to-phase and phase-to-ground degradation for each phase. However, the inspectors determined the configuration described in the licensee's procedure would only test for phase-to-ground degradation. As a result, the hipot testing performed in 2015 and again in 2017 would not have identified the existence of the conditions that led to the January 2017 bus fault. In addition, the inspectors noted that the IEEE standard stated that the test voltage should be increased gradually from zero to reach the required test value and held at that value for 1 minute. Contrary to the IEEE standard, the licensee's procedure only required holding the test voltage for 30 seconds.

The inspectors noted that the licensee implemented a permanent change during the 2015 hipot test, which allowed station personnel to test the bus at a voltage of 10kV rather than the 14kV described in the procedure. The inspectors observed that Section 6.4.2 of the IEEE standard allowed test voltages up to 75 percent of the values specified in Tables 1, 2, 3, and 4 of the document. Tables 1, 2, 3, and 4 allowed testing at up to 14.25kV ac (75 percent of 19kV rms (ac)) or 20.25kV dc (75 percent of 27kV (dc)) for the ESST bus in question. The inspectors observed that the decreased 10kV ac test voltage appeared nonconservative. The inspectors concluded that the instructions contained in Procedure 7.3.41 for performance of hipot testing were inadequate.

The inspectors observed that the station had a history of corona-related degradation in the ESST bus duct. As previously discussed, in 2005 the ESST bus inspection revealed corona-related degradation (CR-CNS-2005-03946), which prompted the site to clean and repair the affected locations. In 2011, the site experienced additional corona-related degradation when an ESST work window was extended as a result of discovery of corona damage to the ESST bus insulation (CR-CNS-2011-03839).

During the 2015 inspection, which took place March 23-29, 2015, the licensee identified black discoloration (not corona-related) on all three phases of the horizontal section of the ESST bus duct that ran from the entrance to the noncritical switchgear room to an area near the SSST (CR-CNS-2015-01745). This long horizontal run included the location where the 2017 ESST bus fault eventually occurred. Although the inspection procedure directed workers to clean the insulation if discoloration was found, the licensee instead evaluated that the black discoloration would not impact the function of the ESST bus. As a result, this section of the ESST bus duct was not cleaned, and the licensee relied on an improperly performed hipot test to verify that bus function was not impacted. The licensee concluded that the black discoloration was the result of dust and debris accumulation on the bus bar insulation.

The inspectors noted that contamination in the form of dust, oils, fluids, or other particulate on conductors and insulators would result in increased corona generation and tracking, and that not cleaning it could exacerbate the degradation. In addition, the inspectors noted that the dust could have obscured the evidence of corona tracking and degradation. Finally, the inspectors concluded that if the licensee had cleaned the discoloration identified during the 2015 inspection, as described by their procedure, it would likely have resulted in the removal and replacement of the ESST bus bar supports to facilitate cleaning. Those repair activities could have prevented the ESST bus fault from occurring. At the end of the March 2015 inspection and work window, the ESST bus failed the initial hipot test, indicating that there was a ground somewhere on the bus. The licensee isolated segments of the ESST bus and identified the ground, but did not revisit the adequacy of the inspection or perform an extent of condition evaluation.

As a result of their review of the ESST bus fault event, the inspectors determined that the most likely contributor to the failure to implement Maintenance Procedure 7.3.41 was the licensee's failure to thoroughly evaluate deficiencies identified with the condition of the ESST bus duct during the 2015 inspection. Specifically, the licensee failed to thoroughly evaluate ESST bus discoloration identified during the 2015 inspection, the hipot testing failures that followed the inspection, and the extent of condition of the 2015 testing and inspection deficiencies.

Analysis. The licensee's failure to implement and maintain Maintenance Procedure 7.3.41 to properly assess degradation of the ESST bus, in violation of Technical Specification 5.4.1.a, was a performance deficiency. The performance deficiency was determined to be more than minor, and therefore a finding, because it was associated with the equipment performance attribute of the Initiating Events Cornerstone, and affected the cornerstone objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown, as well as, power operations. Specifically, the finding resulted in the licensee's failure to identify and repair indications of corona-related degradation on the ESST bus, which resulted in an ESST bus fault, and a loss of the ESST and SDG on January 17, 2017.

The inspectors used Inspection Manual Chapter (IMC) 0609, Attachment 4, "Initial Characterization of Findings," and determined that the finding could be evaluated using the significance determination process. In accordance with Table 3, "SDP Appendix Router," the inspectors determined that the finding should be processed through Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," Exhibit 1, "Initiating Events Screening Questions," dated July 1, 2012. Using IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," dated June 19, 2012, the inspectors determined that the finding required a detailed risk evaluation because it involved the partial loss of a support system that contributes to the likelihood of, or causes, an initiating event (loss-of-offsite power) and the finding affected mitigation equipment (SDG).

A senior reactor analyst performed a detailed risk evaluation in accordance with IMC 0609, Appendix A, Section 6.0, "Detailed Risk Evaluation." The calculated increase in core damage frequency was dominated by station blackout initiators. The NRC preliminarily determined that the increase in core damage frequency for internal and external initiators was 6.3E-6/year, a finding of low-to-moderate risk significance (White). The results of the detailed risk evaluation are included in Attachment 2 of this report.

The performance deficiency had a cross-cutting aspect in the area of problem identification and resolution, associated with evaluation because the licensee failed to thoroughly evaluate ESST bus discoloration and hipot test failures to ensure that resolutions addressed the causes and extent of conditions commensurate with their safety significance. Specifically, the licensee failed to thoroughly evaluate ESST bus discoloration identified during the 2015 inspection, the hipot testing failures that followed the inspection, and the extent of condition of the 2015 testing and inspection deficiencies [P.2].

Enforcement. The two apparent violations described below are associated with a preliminary White significance determination process finding.

1. Technical Specification 5.4.1.a requires, in part, that procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2. Section 9.a of Appendix A to Regulatory Guide 1.33, Revision 2, requires, "Procedures for Performing Maintenance." The licensee established Maintenance Procedure 7.3.41, "Examination and High Pot Testing of Non-Segregated Buses and Associated Equipment," Revision 10, to meet the Regulatory Guide 1.33 requirement. Step 5.9 of Procedure 7.3.41 requires maintenance personnel to, "Examine nonsegregated bus insulations for discoloration. IF insulation discoloration is present, THEN clean as necessary. Remove bus bar supports, if necessary, to clean insulation."

   Contrary to the above, between March 23-29, 2015, maintenance personnel failed to fully examine nonsegregated bus insulations for discoloration; and when insulation discoloration was present, did not clean as necessary. Specifically, during inspection and testing of the ESST nonsegregated bus, the licensee failed to implement inspection instructions to examine the bus insulations for evidence of corona deposits and repair the associated components.

2. Technical Specification 5.4.1.a requires, in part, that procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2. Section 9.a of Appendix A to Regulatory Guide 1.33, Revision 2, requires, "Procedures for Performing Maintenance." The licensee established Maintenance Procedure 7.3.41, "Examination and High Pot Testing of Non-Segregated Buses and Associated Equipment," Revision 10, to meet the Regulatory Guide 1.33 requirement.

   Contrary to the above, between March 23, 2015, and April 18, 2017, the licensee failed to maintain adequate written procedures covering the applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2. Specifically, the licensee failed to maintain Procedure 7.3.41 with adequate instructions for performing hipot testing of the ESST bus bars to ensure that the buses were appropriately tested for phase-to-phase degradation in addition to phase-to-ground degradation. In particular, the test instructions did not ensure that test voltages were applied between each phase individually and ground, with the other phases and the enclosure grounded, so that the phase-to-phase degradation that resulted in the ESST bus fault could be identified.

As a result of these apparent violations, the licensee did not properly assess corona-related degradation on the ESST bus, which resulted in a bus fault and a loss of the ESST and SDG on January 17, 2017. Corrective actions to restore compliance included replacement of the faulted portions of the ESST bus, extent of condition inspection and cleaning of the remainder of the ESST bus bars, long-term corrective actions to replace all of the ESST bus insulation, and revision of hipot testing procedure instructions.

The licensee entered these issues into the corrective action program as Condition Reports CR-CNS-2017-00223 and CR-CNS-2017-02164. These apparent violations have preliminarily been determined to be associated with a finding of low-to-moderate safety significance (White), and are being treated as apparent violations (AVs), consistent with the Enforcement Policy, pending a final significance determination.

(AV 05000298/2017011-01, “Emergency Transformer Bus Failure due to Inadequate Inspection and Testing Activities”)

4OA6 Meetings, Including Exit

Exit Meeting Summary

On August 11, 2017, the inspectors presented the inspection results to Mr. John Dent, Vice President-Nuclear and CNO, and other members of the licensee staff. The licensee acknowledged the issues presented. The licensee confirmed that any proprietary information reviewed by the inspectors had been returned or destroyed.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

M. Bakker, System Engineer
T. Barker, Manager, Engineering Program and Components
D. Buman, Director, Nuclear Safety Assurance
B. Chapin, Manager, Maintenance
J. Dent, Vice President, Chief Nuclear Officer
L. Dewhirst, Manager, Corrective Action and Assessment
K. Dia, Director, Engineering
J. Ehlers, Supervisor, System Engineering
T. Forland, Engineer, Licensing
G. Gardner, Engineering Design Manager
D. Goodman, Manager, Operations
K. Higginbotham, Former Vice President, Chief Nuclear Officer
J. Kalamaja, General Manager Plant Operations
J. Reimers, Manager, System Engineering
J. Shaw, Manager, Licensing

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000298/2017011-01	AV	Emergency Transformer Bus Failure due to Inadequate Inspection and Testing Activities (Section 4OA2)

LIST OF DOCUMENTS REVIEWED

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Miscellaneous Documents

Number	Title	Revision
2.3_C-1	Panel C – Annunciator C-1	30
2.3_C-2	Panel C – Annunciator C-2	52
2.3_C-3	Panel C – Annunciator C-3	50
2.3_C-4	Panel C – Annunciator C-4	31

Procedures

Number	Title	Revision
2.2.17	Emergency Station Service Transformer	64
2.2.18	4160V Auxiliary Power Distribution System	210
5.3Grid	Degraded Grid Voltage	46

Procedures

Number	Title	Revision
0-CNS-WM-100	Work Order Generation, Screening, and Classification	7
0-CNS-WM-104	On-Line Schedule Risk Assessment	3
0-PROTECT-EQP	Protected Equipment Program	36

Condition Reports (CRs)

CR-CNS-2017-00222 CR-CNS-2017-00223

Work Orders

5173717 5373718

Section 1R19: Post-Maintenance Testing

Condition Reports (CRs)

CR-CNS-2017-00222 CR-CNS-2017-00223

Work Orders

5115615 5115616 5173717 5173718

Section 4OA2: Problem Identification and Resolution

Miscellaneous Documents

Number	Title	Revision
00-003	NEDC, CNS Aux Power System Load Flow and Voltage Analysis	3C2

Procedures

Number	Title	Revision
2.2.18	4160V Auxiliary Power Distribution System	212
6.2DG.302	Undervoltage Logic Functional, Load Shedding, and Sequential Loading Test (DIV 2)	79
7.3.40	Inspection and Meggering of 4160 Volt Buses	25
7.3.41	Examination and High Pot Testing of Non-Segregated Buses and Associated Equipment	10, 11

Condition Reports (CRs)

CR-CNS-2005-03946	CR-CNS-2011-03681	CR-CNS-2011-03839	CR-CNS-2015-01731
CR-CNS-2015-01743	CR-CNS-2015-01745	CR-CNS-2015-01746	CR-CNS-2015-01790
CR-CNS-2015-01817	CR-CNS-2017-00223	CR-CNS-2017-01273	CR-CNS-2017-02164

Work Orders

5173717	5173718	5180895	5064989

Significance Determination

Preliminary Significance Determination Conclusion:

The NRC preliminarily determined that the increase in core damage frequency for internal and external initiators was 6.3E-6/year, a finding of low-to-moderate risk significance (White).

Significance Determination Basis:

Screening Logic

Minor Question: The performance deficiency was determined to be more than minor, and therefore a finding, because it was associated with the equipment performance attribute of the Initiating Events Cornerstone, and affected the cornerstone objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown, as well as, power operations. Specifically, the finding resulted in a bus fault and a loss of the emergency transformer and supplemental diesel generator.

Initial Characterization: Using Inspection Manual Chapter (IMC) 0609, Attachment 4, "Initial Characterization of Findings," the inspectors determined that the finding could be evaluated using the significance determination process. In accordance with Table 3, "SDP Appendix Router," the inspectors determined that the finding should be processed through Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," Exhibit 1, "Initiating Events Screening Questions," dated July 1, 2012.

Issue Screening: Using IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," dated June 19, 2012, the inspectors determined that the finding required a detailed risk evaluation because the finding involved the partial loss of a support system that contributes to the likelihood of, or causes, an initiating event (loss-of-offsite power) and the finding affected mitigation equipment (supplemental diesel generator). A senior reactor analyst performed a detailed risk evaluation in accordance with IMC 0609, Appendix A, Section 6.0, "Detailed Risk Evaluation."

Results: The total increase in core damage frequency was estimated to be between 1.5E-6/year and 1.0E-5/year, with a best estimate of 6.3E-6/year.

Detailed Risk Evaluation

Assumptions:

1. Exposure time: The exposure time was estimated to be 151 hours, which included the time from which the bus duct could no longer meet its probabilistic risk assessment (PRA) mission time plus the repair time.

   Exposure time was estimated by considering the bus to be a continuously operated component. The guidance in Section 2.0, "Exposure Time Modeling," of Volume 1, "Internal Events," of the Risk Assessment Standarization Project (RASP) Handbook suggested that for failure of a component that is normally in continuous operation while at-power, the exposure time should be the PRA mission time. The analyst assumed a

24-hour PRA mission time, comprised of the 24 hours prior to January 17, 2017, at 4:44 pm, the time of bus duct failure. The RASP Handbook proposes considering repair time as the period from identification of a component failure until it is returned to service. The bus duct was reenergized at 11:42 pm on January 22, 2017. The analyst considered this as the time to end the repair time, making the repair time 127 hours. Combining the 24 hour continuous operation assumed time and the repair time, the analyst estimated the exposure time to be 151 hours.

2. Recovery: The bus duct was assumed to be nonrecoverable during the entire exposure time. This rendered the ESST and the SDG unavailable for all postulated events. Also, for those events in which the SSST failed due to common cause, the SSST was assumed nonrecoverable and unavailable.

3. Component treatment: The analyst assumed the nonsegregated bus work between the motor operated disconnect associated with the ESST and electrical safety buses 1F and 1G was a component and needed to be included in the PRA model such that failure of the bus work would fail the ESST and the SDG. A basic event was created in the Standardized Plant Analysis Risk (SPAR) model using template ZT-BAC-LP, “AC Bus Fails to Operate.” This basic event was added as a failure mechanism for the ESST with “OR” logic under the sub-fault trees ACP-1F-SWY-2 and ACP-1G-SWY-2 which are under fault trees ACP-1F-SWY, “Cooper Switchyard AC Service to Swgr Bus 1F,” and ACP-1G-SWY, “Cooper Switchyard AC Service to Swgr Bus 1G,” respectively. This basic event was also added with “OR” logic under sub-fault trees OEP22111, “Failure of Power from ESST to 1F,” and OEP222111, “Failure of Power from ESST to 1G.” Similarly a basic event for the bus work from the X-winding of the SSST (SSST-X) feeding the plant (which did not fail the SDG) was created and applied under fault trees ACP-1F-SWY, “Cooper Switchyard AC Service to Swgr Bus 1F,” and ACP-1G-SWY, “Cooper Switchyard AC Service to Swgr Bus 1G,” as well as under sub-fault trees OEP222110, “Failure of Power from SSST to 1F,” and OEP222110, “Failure of Power from SSST to 1G.”

4. Common Cause: The ESST nonsegregated bus work was considered to be part of a common cause group which also included the bus work from the SSST-X feeding the plant. The analyst correspondingly increased potential for failure of the SSST-X bus work feeding the plant due to common cause.

   The RASP Handbook, Volume 1, “Internal Events,” Section 5, “Common-Cause Failure Modeling,” provides guidance for the treatment of common-cause failure (CCF) dependencies among components in a common-cause component group (CCCG) given an observed failure of one or more components in the CCCG.

   In the RASP Handbook, a CCCG is considered as a group of usually similar components (in mission, manufacturer, maintenance, environment, etc.) that are considered to have a high potential for failure because of the same cause or causes. The analyst assumed that the ESST and SSST-X bus works comprised a CCCG. The following table lays out these attributes:

Attribute	NRC Consideration
Mission	The mission of the ESST and SSST-X bus work is to provide offsite power during plant upset conditions.

Manufacturer	The ESST and SSST-X-winding bus works feeding the plant were manufactured similarly and were of similar design.
Maintenance	The SSST-X and ESST had similar maintenance schedules with the same inspections performed at the same prescribed periodicities
Environment	The ESST and SSST-X bus ducts are routed along the same path external to the turbine building and were therefore assumed to be in the same environment.

The licensee provided information that back-feeding power through the NSST bus work was possible as a conduit for offsite power to the emergency buses, but the analyst did not include the NSST in the CCCG because the implementation of the strategy was judged to be untimely.

To create the common cause failure event, the analyst consulted with Idaho National Laboratory (INL) and included the basic events for each of the ESST and SSST-X bus work failures and applied the common cause alpha factors, "ZA-CCF-RATE-02A01," and "ZA-CCF-RATE-02A02." These alpha factors are for 2 components in a 2 component CCCG for generic common cause rate failures. Generic factors were chosen since bus work failure data is not explicitly collected and estimated for the SPAR models by INL. This common cause failure basic event was applied with "OR" logic under sub-fault trees ACP-1F-SWY-1 and ACP-1G-SWY-1 under fault trees ACP-1F-SWY, "Cooper Switchyard AC Service to Swgr Bus 1F," and ACP-1G-SWY, "Cooper Switchyard AC Service to Swgr Bus 1G," respectively. Also, this basic event was added with "OR" logic under sub-fault trees OEP22111, "Failure of Power from ESST to 1F," and OEP222111, "Failure of Power from ESST to 1G," as well as sub-fault trees OEP22111, "Failure of Power from ESST to 1F," and OEP222111, "Failure of Power from ESST to 1G."

5. Loss of SSST-X Duct during Arc Fault Events: The fault in the bus work released a large amount of energy such that a hole developed in the bottom of the duct due to the event. Charring and arc fault events byproducts were present on top of the SSST-X duct. The analyst assumed that arc faults in other locations could damage the duct housing the SSST-X bus work and render the SSST-X bus work unavailable.

   For a lower bound, the analyst noted an expansion boot in the SSST-X duct and assumed it was susceptible to failure had the fault in the ESST occurred above the expansion boot because the boot would not withstand the failure event. The analyst estimated that the length of bus work where a fault would occur that could cause a hole in the bottom of the ESST duct and subsequently propagate through the expansion boot and fail the SSST-X bus work to be approximately the 2 percent of ESST bus work.

   For the best estimate, the analyst assumed that for 25 percent of arc fault events which could occur due to the performance deficiency, the SSST-X duct work would be rendered unavailable. A review of the photographs from the arc fault that occurred on January 17, 2017, revealed that the energy from the fault was deflected by a duct support which shielded the SSST-X duct and bus from worse damage. The analyst viewed the external arrangement of the bus duct supports and assumed various spacing configurations of internal bus bar supports to estimate that from 17 to 75 percent of the internal bus bar supports were located such that a fault at their location would not shield the SSST-X bus duct and would render the bus duct unavailable through arc fault blast shock effects on the bus duct. To obtain a point estimate, the analyst assumed 25 percent of arc fault events would render the SSST-X bus unavailable.

6. Credit for FLEX equipment: The licensee indicated that they had FLEX procedures and equipment available at the site. The NRC has not made a final decision on the crediting of FLEX in significance determination process analyses. The analyst was aware of Nuclear Energy Institute (NEI) position papers on crediting FLEX in probabilistic risk assessments and document NEI 16-06, "Crediting Mitigating Strategies in Risk-Informed Decision Making," Revision 0, and noted that these documents have not been endorsed by the NRC. The analyst conducted a best estimate analysis which considered FLEX strategies as recoveries, recognizing that incorporating FLEX credit into the Cooper SPAR model requires much more effort and approval. The analyst used an estimated failure probability of 1.0E-1 which NEI 16-06 describes as mitigating actions are "likely to succeed," for the electrical and mechanical FLEX strategies. For the electrical strategy the analyst set basic event EPS-XHE-XM-PDG to 1.0E-1. For the mechanical strategy the analyst added a new basic event representing the mechanical strategy with a failure probability of 1.0E-1 under the late injection fault trees LI, LI01, LI02, LI03, LI06, and FWS.

Model

The analyst used Cooper SPAR model, Revision 8.50, run on SAPHIRE Version 8.1.5, with the previously described modifications to the model. Truncation was set at 1E-13. Additionally, modifications to the model were made to ensure that recoveries of offsite power were not inappropriately being applied. Under fault tree OPR, "Offsite Power Recovery," the analyst added the sub-fault tree OEP-3. The analyst applied similar "AND" gates under Fault Trees OPR-04H, "Offsite Power Recovery in 4 hours," OPR-08H, "Offsite Power Recovery in 8 hours," OPR-12H, "Offsite Power Recovery in 12 hours," OPR-30M, "Offsite Power Recovery in 30 minutes."

The analyst also replaced the values of the basic events for the licensee's portable diesel generator (PDG) failure to run (basic event EPS-DGN-FR-PDG) and failure to start (basic event EPS-DGN-FS-PDG) to values supplied by the licensee from their PRA model after noting that the SPAR model used values for these basic events that were identical to the emergency diesel generators.

The analyst also added additional failure modes for the SSST to more accurately model additional failure modes of supplying offsite power via the SSST. The analyst added a maintenance event to depict testing and maintenance of the SSST using the licensee's value of 3.40E-3 for the probability of the SSST being in maintenance. A rule to prohibit the SSST and one of the emergency diesel generators in maintenance simultaneously was created since this condition is prohibited by plant procedures. Also, the analyst added basic events for the potential for failure of breakers 1AS and 1BS under sub-fault trees OEP222110, "Failure of Power from SSST to 1F," and OEP222110, "Failure of Power from SSST to 1G," because their failures would prohibit power from the SSST to reach safety buses 1F and 1G, respectively.

Internal Events

The analyst applied the assumptions and model modifications and also performed hand calculations to apply the effects of the fraction of events that would cause loss of both the ESST and SSST-X bus works. The increase in core damage frequency was estimated to be 5.8E-6/year due to internal events. Dominant sequences were transients and losses of offsite power which progressed to station blackout events.

External Events

The analyst estimated the increase in core damage frequency due to external events to be 5.1E-7/year, derived of fire, tornado, and seismic events.

Fires: The analyst ran numerous fire cases informed by the results of the internal events from the Cooper SPAR model and the licensee's fire PRA information. For each of these postulated fire scenarios, the increase in core damage frequency was estimated by calculating the effects of the fire with and without the performance deficiency present. Fire ignition frequencies from the licensee's National Fire Protection Association (NFPA) 805 risk-informed fire protection model were used in combination with conditional core damage probabilities derived using the Cooper SPAR model, which were informed from the licensee's damaged equipment for the different fire scenarios. The results were applied over the 151 hour exposure time. The table below summarizes the results.

Fire Scenario	Damaged Equipment	Fire Ignition Frequency	Increase in Core Damage Frequency
Zone 11J – Condensate Pump Area	Condensate Pumps A, B, and C	2.41E-3/year	7.8E-9/year
Zone 12A – Isophase Duct Area	Circuit breakers 1AN and 1BN	2.55E-3/year	2.5E-7/year
Zone 13B-A – 4160A – Switchgear Room	4160V Switchgear A and SSST bus duct	2.23E-4/year	2.3E-8/year
Zone 13B-AH - 4160A – Switchgear Room	Circuit breaker 1AS and SSST bus duct	2.58E-4/year	2.7E-9/year
Zone 13B-B – 4160B – Switchgear Room	SSST bus duct	1.70E-4/year	1.7E-8/year
Zone 13B-BH – 4160B – Switchgear Room	SSST bus duct	1.97E-4/year	1.9E-8/year
Main Control Board	Offsite power	7.21E-4/year	1.9E-8/year
Zone 3A – Switchgear 1F	Switchgear 1F	2.86E-4/year	6.0E-9/year
Zone 3B – Switchgear 1G	Switchgear 1G	2.86E-4/year	6.0E-9/year
Yard – Normal offsite power	Main and Normal Transformers	5.96E-3/year	1.9E-8/year
Total			3.8E-7/year

The analyst also reviewed control room abandonment fire scenarios and the impact of the performance deficiency for fires which would have required the control room to be abandoned. To estimate the increase in core damage frequency, the analyst first summed the fire ignition frequencies from the 48 fire scenarios listed in Appendix D-6, "All Fire Scenarios Sorted by CDF – Post NFPA 805," of NEDC 09-085, "Fire Risk Quantification," Revision 2, to obtain a total fire ignition frequency of 6.94E-5/year for fires which require control room abandonment. The analyst then used Figure 1, "Main Control Room Abandonment Tree – Base Case," in Calculation 17712-004, "Main Control Room Analysis," Revision 2, to determine the conditional core damage probability in those cases where the Division 2 emergency diesel generator failed (4.02E-2) and applied a 1E-1 failure probability for failure to align to offsite power to the event tree. The analyst reasoned that if the emergency diesel generator failed that the procedures were written such that operators could and would attempt to regain power manually via offsite power. The analyst then assumed that the 9E-1 success probability would fail due to the performance deficiency and used this as the conditional core damage probability (9E-1 x 4.02E-2 = 3.62E-2) to apply to the fire ignition frequency. The increase in core damage probability from control room abandonment fires was estimated to be 1.3E-7/year.

The analyst combined all fire scenarios to estimate the increase in core damage frequency from fires to be 5.1E-7/year.

Tornadoes/High Winds: A Category EF2 or greater tornado could result in loss of the offsite power lines that would not be quickly repairable. The analyst estimated the frequency of a Category EF2 or greater tornado occurring onsite to be 2.20E-4/year using the data developed by the Office of Nuclear Reactor Research utilizing the methodology from, "Review of Methods for Estimation of High Wind and Tornado Hazard Frequencies," dated December 2012. The analyst conservatively assumed that these high wind events would not damage the SDG and it would be available until the failure of the ESST bus work. This yielded a conditional core damage probability of 1.80E-5 that, when applied to the tornado/high wind initiating event frequency, yielded an estimate in the increase of core damage frequency of 1.2E-8/year.

Seismic: A postulated seismic event could result in a long-term demand for the supplemental diesel generator if the seismic event was large enough to destroy the switchyard insulators causing a nonrecoverable loss-of-offsite power. The analyst obtained the frequency of a seismically induced loss-of-offsite power of 1.33E-4/year using the suggested methodology from Volume 2, "External Events," of the RASP Handbook. The analyst conservatively assumed that an earthquake would not damage the SDG and it would be available until the failure of the ESST bus work. This yielded a conditional core damage probability of 1.80E-5 that, when applied to the seismically induced loss-of-offsite power frequency, yielded an estimate in the increase of core damage frequency of 7.2E-9/year.

Large Early Release Frequency

The analyst reviewed the dominant sequences contributing to core damage to evaluate their impact on large early release frequency (LERF). Manual Chapter 0609, Appendix H, "Containment Integrity Significance Determination Process," describes that long term accident sequences that involve failure of containment heat removal and ultimately progress to containment failure are assumed not to contribute to LERF. The licensee provided information from their Level 2 PRA model which the analyst reviewed to ascertain which sequences involved long term accident sequences. The analyst also performed a sequence review of a similar boiling water reactor plant, Peach Bottom, compared their identical sequences, and applied the LERF factors of those sequences to the Cooper sequences. From these applications, the analyst estimated the increase in LERF to be 7.8E-8/year and concluded that the results of this issue were best evaluated by the increase in core damage frequency.

Sensitivities

No Common Cause Effect. The analyst considered that there was not the potential for common cause failure on the SSST-X bus work. This sensitivity yielded a total estimate of the increase in core damage frequency of 1.6E-6/year.

Larger Common Cause Group. Instead of the common cause group size of 2 components used in the main estimate, the analyst ran a sensitivity that considered the NSST bus work could be included in the common cause group, making the common cause group contain 3 components. This would serve to lower the probability of a second failure event of the common cause group components. This sensitivity yielded a total estimate of the increase in core damage frequency of 2.7E-6/year.

Different Common Cause Factor. The analyst used the common cause failure alpha factors for the battery, a passive component. This sensitivity yielded a total estimate of the increase in core damage frequency of 5.6E-6/year.

Loading of the Transformer. To inform the results with any unknown effects which could cause the ESST bus work to fail when transitioning from an unloaded state to a loaded state, the analyst expanded the exposure time in a “t/2 plus repair time” application from the last time the ESST was loaded on October 21, 2016. This sensitivity was run with a 2 percent cascading effects factor and yielded a total estimate of the increase in core damage frequency of 1.0E-5/year.

No Recirculation Pump Seal Failure. The analyst removed core damage sequences in which the reactor recirculation pump seals failed. This sensitivity yielded a total estimate of the increase in core damage frequency of 4.7E-6/year.

Conclusion/Overall Results

The analyst estimated the total increase in core damage frequency was estimated to be between 1.5E-6/year and 1.0E-5/year. The sum of the internal events and external events best estimates was 6.3E-6/year and is within this range. The lower end of the range represents the major assumptions and that 2 percent of postulated faults could breach and fail the SSST-X bus duct. The upper end of the range represents the major assumptions and assumes the fault location was such that 75 percent of postulated faults could breach and fail the SSST-X bus duct. The best estimate represents the major assumptions and assumes the fault location was such that 25 percent of postulated faults could breach and fail the SSST-X bus duct.

Uncertainties

The generic alpha factors that were used for the development of the common cause basic event were derived from mostly active type failures and their application the bus work, which is a nominally passive component, and create additional uncertainty. This and other uncertainties were run as sensitivities to ascertain their influence on the changes in core damage frequency.

Licensee Analysis

Using data supplied by the licensee, the analyst estimated that the licensee's models would estimate that the total increase in core damage frequency from internal events and fires to be 4.2E-7/year using their model. The licensee believes their fire PRA model is conservative and the actual estimate should be approximately 5.9E-8/year from internal events and fires. These estimates did not consider common cause effects and cascading failure effects in their analysis and used a lower failure probability for aligning the PDG, therefore the analyst ran a SPAR analysis to compare the licensee's results to the SPAR results with similar inputs. The SPAR estimated the increase in core damage frequency to be 2.7E-7/year from internal events before considering the effect of the event cascading to the SSST-X bus, compared to the licensee's model. The analyst considered the difference in the two results to be derived mainly from differences in initiating event frequencies and basic event failure rates for mitigating systems and components.