WOLF CREEK
NUCLEAR OPERATING CORPORATION

Terry J. Garrett
Vice President Engineering

August 31, 2005

ET 05-0016

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555

Reference: WCNOC letter WO 03-0057 dated October 30, 2003 from B. T. McKinney, WCNOC, to the NRC

Subject: Docket No. 50-482: Response to Request for Additional Information – Extensions of AC Electrical Power Distribution Completion Times

Gentlemen:

The Reference provided Wolf Creek Nuclear Operating Corporation's (WCNOC) application to revise Technical Specification (TS) 3.8.1, "AC Sources – Operating," to extend the Completion Times for the Required Actions associated with an inoperable diesel generator (DG). The amendment application also proposed revising TS 3.8.9, "Distribution Systems – Operating," to extend the Completion Time for one AC vital bus subsystem inoperable. The proposed changes were based on the methodology provided in WCAP-15622, "Risk-Informed Evaluation of Extensions to AC Electrical Power System Completion Times."

On October 20, 2004, the NRC Project Manager provided by electronic mail a request for additional information (RAI) based on the Reference and the NRC staff's draft safety evaluation (SE) for WCAP-15622. The RAIs were given in two parts: those from the Probabilistic Safety Assessment Branch (SPSB) and the Electrical and Instrumentation and Controls Branch (EEIB). WCNOC provided a response to the RAIs by electronic mail on December 13, 2004.

NRC letter dated July 1, 2005, "Draft Safety Evaluation for Topical Report WCAP-15622, "Risk-Informed Evaluation of Extensions to AC Electrical Power System Completion Times" (TAC NO. MB2257)" formally issued the draft SE for WCAP-15622. Appendix E identifies the additional information needed for plant specific applications. On July 20, 2005, the NRC Project Manager requested WCNOC to submit the responses to the RAIs provided to WCNOC in October 2004 and provide the additional information per Appendix E of the July 1, 2005 draft SE that has not previously been provided.

A001

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Attachment I to this letter provides WCNOC's response to the October 2004 RAI. Attachment II provides a table of the Appendix E requested additional information to the information previously provided in the Reference and in the December 2004 WCNOC responses to the October 2004 RAI. Attachment II also provides information requested by Appendix E that has not previously been provided. Attachment III provides a response to an additional question that was provided by electronic mail on August 2, 2005.

Attachment III, page 3 of 5, of the Reference provided the proposed Note to the Completion Time of Required Action B.4. The proposed Note states: "A Completion Time of 7 days and 10 days from discovery of failure to meet the LCO may be used once per cycle per DG." The "and" in this Note should be considered a Logical Connector per TS Section 1.2. As such, the "and" should be capitalized and underlined.

Reference 1 requested approval of the proposed changes in support of Refueling Outage 14 that occurred in March 2005. The proposed changes affect the scheduling of DG maintenance and testing activities, including which activities are to be performed during plant operation and which are to be performed during refueling outages. WCNOC is planning to utilize this amendment in support of Refueling Outage 15, scheduled for October 2006. To support Refueling Outage 15, WCNOC is planning on performing on-line DG maintenance activities in the first quarter of 2006. As such, WCNOC is requesting the approval of this license amendment request by December 23, 2005.

There are no regulatory commitments made in this submittal. If you have any questions concerning this matter, please contact me at (620) 364-4084, or Mr. Kevin Moles at (620) 364-4126.

Very truly yours,

Terry J. Garrett

TJG/rlg

Attachments: I - Response to Request for Additional Information
II - Table of Draft Safety Evaluation Appendix E Items
III - Additional Request for Additional Information dated August 2, 2005

cc: J. N. Donohew (NRC), w/a
W. B. Jones (NRC), w/a
B. S. Mallett (NRC), w/a
Senior Resident Inspector (NRC), w/a

STATE OF KANSAS)
) SS
COUNTY OF COFFEY)

Terry J. Garrett, of lawful age, being first duly sworn upon oath says that he is Vice President Engineering of Wolf Creek Nuclear Operating Corporation; that he has read the foregoing document and knows the contents thereof; that he has executed the same for and on behalf of said Corporation with full power and authority to do so; and that the facts therein stated are true and correct to the best of his knowledge, information and belief.

By _______________
Terry J. Garrett
Vice President Engineering

SUBSCRIBED and sworn to before me this 31 day of Aug., 2005.

NOTARY PUBLIC STATE OF KANSAS RHONDA L. GLEUE My Appt. Exp. 5-11-2006

Rhonda L. Gleue
Notary Public

Expiration Date May 11, 2006

RESPONSES TO REQUEST FOR ADDITIONAL INFORMATION

This Attachment provides Wolf Creek Nuclear Operating Corporation's (WCNOC's) response to an electronic request on October 20, 2004 for additional information from the NRC Project Manager. An electronic response was previously provided on December 13, 2004. In the responses to the below requests for additional information (RAI), reference is made to specific RAIs. These references are referring to Attachment II of WO 03-0057 that provided Wolf Creek Nuclear Operating Corporation (WCNOC) responses to certain NRC RAI's associated with WCAP-15622, "Risk-Informed Evaluation of Extensions to AC Electrical Power System Completion Times."

A. <u>SPSB Questions, Based on WCAP-15622</u>:

1. Address whether weather conditions would be evaluated before entering the extended completion times (CTs) for an inoperable diesel generator (DG), or vital AC bus, due to planned maintenance. Would restrictions be placed on voluntary planned maintenance during severe weather conditions.

Response:

This question has been previously addressed in Section 4.1.1.2, "Tier 2: Avoidance of Risk-Significant Plant Conditions," and Section 4.1.1.3, "Tier 3: Risk-Informed Plant Configuration Control and Management," on page 19 of Attachment I in WO 03-0057. Further discussion is included on page 10 of Attachment II (response to RAI 7) in WO 03-0057. The Tier 2 restrictions are proposed to be incorporated into the TS Bases as shown by INSERT C on page 7 of Attachment V in WO 03-0057.

2. Address whether the condition of the offsite power supply and switchyard, including grid reliability, would be evaluated before entering an extended DG CT, or vital AC bus (see Regulatory Issue Summary RIS 2004-05, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power").

Response:

This question has been previously addressed in Section 4.1.1.2, "Tier 2: Avoidance of Risk-Significant Plant Conditions," and Section 4.1.1.3, "Tier 3: Risk-Informed Plant Configuration Control and Management," on page 19 of Attachment I in WO 03-0057. The Tier 2 restrictions are proposed to be incorporated into the TS Bases as shown by INSERT C on page 7 of Attachment V in WO 03-0057.

3. A condition for the amendment is that there would be no discretionary switchyard maintenance or discretionary maintenance on the main or startup transformers that would impact the availability of the offsite power would be performed during the extended CT for an inoperable DG, or vital AC bus. Address if this conditions exists for maintenance during the extended CT for an inoperable DG.

Response:

This question has been previously addressed in Section 4.1.1.2, "Tier 2: Avoidance of Risk-Significant Plant Conditions," and Section 4.1.1.3, "Tier 3: Risk-Informed Plant Configuration Control and Management," on page 19 of Attachment I in WO 03-0057.

4. A condition for the amendment is that there would be no maintenance or testing that affects the operable DG would be performed during the extended CT for an inoperable DG. Address if this conditions exists for maintenance during the extended CT for an inoperable DG, or vital AC bus.

Response:

This question has been previously addressed in Section 4.1.1.2, "Tier 2: Avoidance of Risk-Significant Plant Conditions," and Section 4.1.1.3, "Tier 3: Risk-Informed Plant Configuration Control and Management," on page 19 of Attachment I in WO 03-0057. In response to RAI 11, Attachment II, page 16, provides a discussion concerning the WCGS Operational Risk Assessment Program and indicates that where possible, online testing and maintenance of redundant equipment shall be avoided when the opposite components are out of service. Additionally, there are more restrictive TS Completion Times in the event both trains are inoperable (e.g, TS 3.8.1, Required Action E.1 requires restoration of one DG to OPERABLE status in 2 hours).

5. Address whether external events would be evaluated before entering the extended CTs for an inoperable DG, or vital AC bus, due to planned maintenance. Would restrictions be placed on voluntary planned maintenance for external events.

Response:

The response to Question 1 is directly relevant here. The first three items in Section 4.1.1.2 address the environmental and grid conditions. Excluding the extended EDG maintenance from a specific time period minimizes the exposure to historical periods of severe weather. The excluded time period is also one of concern for high grid demand conditions.

Procedure AP 22C-003, "Operational Risk Assessment Program," serves the purpose of ensuring that operational risks are managed and contingencies are addressed. If the activity is Risk Significant, a more detailed assessment for contingency plans is required. This planning considers items such as breach permits, fire protection impairments, and spill consequences. Performing risk assessments in this manner ensures that factors that could impact external events are controlled.

The above conditions are consistent with the commitments made in Sections 4.1.1.2 and 4.1.1.3 of Attachment I in WO 03-0057.

The results of the Individual Plant Examination For External Events (IPEEE) were reviewed for this question. The location and design of the Sharpe Station is judged to have no impact to the conclusions of the nearby transportation and nearby facility hazards.

Based on the above, there are no plans to restrict voluntary entry into a planned maintenance due to external events.

6. Provide the change in large early release frequency (ΔLERF) or the incremental conditional large early release probability (ICLERP) for the extended CT for an inoperable DG, or vital AC bus.

Response:

The ΔLERF has previously been provided in Table RAI 9-2 on page 14 of Attachment II in WO 03-0057. The ICLERP has been previously provided in Table RAI 16-1 on page 21 of Attachment II in WO 03-0057.

7. Address if the risk of DG, or vital AC bus, maintenance will be managed by the on-line maintenance programs and procedures of the 10 CFR 50.65(a)(4) maintenance rule program for the plant.

Response:

This question has been previously addressed in Section 4.1.1.3 on page 19 of Attachment I in WO 03-0057. Section 4.1.1.3 provides a discussion of the 10 CFR 50.65(a)(4) maintenance rule program at WCGS. Further discussion of this program (i.e., Operational Risk Assessment Program) is discussed in the response to RAI 11 on page 16 of Attachment II in WO 03-0057.

8. If alternate power sources are being used as a basis for the proposed extended DG, ot [to] vital AC bus, CT, provide a design description including resistance to external events (including weather), environmental protection, and operational parameters, such as the ability to supply safety-related and non-safety-related loads. The alternate source's availability, reliability (including any black start capability), and surveillance requirements, as related to DG, or vital AC bus, maintenance activities, should be provided. Required operator actions and their human reliability probabilities should be provided, as well as procedural modifications or requirements. Finally, a discussion of the applicability of Information Notice 97-21 should also be provided.

Response:

This question has been previously discussed in WO 03-0057. In the WCNOC response to RAI 5 (starting on page 6 of Attachment II), it was identified that the Sharpe Station is credited as an additional AC power source in the 1998 PSA model modified for the DG Completion Time extension and is not credited as an alternate AC power source as defined in Regulatory Guide 1.155. Additional discussion concerning the Sharpe Station is provided in WO 03-0057 at the following locations: page 4 of Attachment I; response to RAI 6 (page 9 of Attachment II); response to RAI 7 (page 10 of Attachment II); and the response to RAI 10 (page 14 of Attachment II).

NRC Information Notice 97-21, "Availability of Alternate AC Power Source Designed for Station Blackout Event," was issued to alert licensees to potential unavailability of an alternate AC power source during a station blackout event. The events described in Information Notice 97-21 involve failures and/or interactions of on-site systems, and the delayed use of the back-up AC power systems.

KEPCo's primary purpose for constructing the Sharpe Station is to supply power to its member distribution cooperatives. Sharpe Station was intended to satisfy this purpose mainly during periods of reduced owner system reserve, typically during the summer period and opposite the pre-planned period of the extended DG Completion Time. The purpose for siting Sharpe Station near WCGS is to provide emergency back-up power for WCGS. The generating equipment used at the station is similar to that used commercially for protection against loss of power from a local utility. The Sharpe Station has been modified for blackstart of the gensets. The equipment at Sharpe Station will be maintained consistent with the manufacturers' recommendations and prudent utility practice.

In the application for extended DG Completion Time, the need for AC power will cause pre-planned actions to take place without delay. Battery issues noted in Information Notice 97-21 are lessened with this strategy.

9. For licensees crediting a crosstie or cross-connecting safety buses, provide information on the human error probability and operator action required to perform this action, and on operator training, including procedures and demonstrated capability.

Response:

No credit is taken for a crosstie or cross-connecting of energized safety busses.

A simplified one-line diagram of Sharpe Station power to WCGS is shown on page 5 of Attachment I of WO 03-0057. In the event of a station blackout event, the figure illustrates the connection of the Sharpe Station through the WCGS switchyard and on to XNB01. Operator action is included as a generic, top-level, event in the Sharpe Station fault tree with a value of 0.035. With two dead ESF busses, XNB01 may be used to feed the Sharpe Station power over to NB02. Training with Operations personnel has been conducted on the Sharpe Station blackstart draft procedure, including walkdowns of the gensets and electrical busses.

10. Provide the following information regarding Maintenance Rule implementation goals and a comparison of actual DG performance with station blackout (SBO) commitments (including alternate ac sources, if applicable):

- DG fail to start and fail to run values
- DG maintenance unavailability with a 3-day and a 7-day CT
- alternate AC source failure probability values (if applicable)
- alternate AC source maintenance unavailability (if applicable)
- a discussion of the above values with respect to Maintenance Rule goals, actual DG performance, and SBO commitments, ensuring that the proposed CT meets the objectives of the Maintenance Rule (10 CFR 50.65) and the Station Blackout Rule (10 CFR 50.63)

Response:

This question has been previously addressed in the response to RAI 6 on page 9 of Attachment II in WO 03-0057.

11. With respect to availability of the DGs following the completion of additional online preventive maintenance activities and the potential for induced electrical transients during maintenance or postmaintenance testing, discuss the following:

- Testing that is used following at-power maintenance activities to demonstrate DG operability.
- Confirmation that the DG is disconnected from the plant electrical system during at-power preventive maintenance activities.
- Precautions taken to ensure that plant electrical distribution system transients that could impact plant operation do not occur during maintenance activity or postmaintenance testing.

Response:

This question has been previously addressed in the response to EP RAI 3 on page 22 of Attachment II in WO 03-0057.

12. Address the reactor coolant pump (RCP) seal model employed and its conformance to NRC staff WCAP-15603 safety evaluation (SE) limitations, conditions, and modifications.

Response:

In Westinghouse Owners Group letter OG-02-052, "Transmittal of RAI Responses for WCAP-15622, "Risk-Informed Evaluation of Extensions to AC Electrical Power System Completion Times" (MUHP-3010)," dated November 27, 2002, the response to RAI 4 provided a discussion of and sensitivity results for different seal LOCA models.

Section 4.1.1.1.5 of WO 03-0057 contained a brief mention that "Values from the Brookhaven National Laboratory Technical Report W6211-08/99 (August 1999) were obtained for the higher temperature, qualified seal materials for model re-quantification."

Additional text on seal LOCA modeling from the WCGS Emergency Diesel Generator and Vital 120 VAC Bus Technical Specification Allowed Outage Time Extension Probabilistic Risk Assessment calculation is provided below:

> "The methodology for the determination of the probability of core uncovery due to a potential Reactor Coolant Pump (RCP) Seal LOCA by the time of power recovery is described in WCGS PSA Reactor Coolant Pump Seal Cooling Notebook – 98 Update (Reference 8). Determination of these values began with a probabilistic RCP seal LOCA model which was developed by Westinghouse to quantify the "core not uncovered" (CNU) top event for the Westinghouse IPE Projects. The RCP model developed is similar to the one presented in Chapter 10 of WCAP-10541, Rev. 2, except that some conservatisms were incorporated to address NRC concerns related to the postulated "binding" and "popping" modes of RCP seal failure. At the time of creation of this calculation [2003 EDG/Vital AC CT Extension], the current [1998] WCGS PRA model's RCP seal LOCA model values were based upon proprietary Westinghouse numbers discussed in Attachment B of Reference 8 and RCP seal material composition of the older, unqualified material. As previously mentioned, this calculation utilizes RCP seal failure values based on "Guidance Document for Modeling of RCP Seal Failures," Brookhaven National Laboratory Technical Report W6211-08/99, August 1999. This calculation also assumes that the RCP seals are composed of the newer qualified high-temperature seal material. The methodology for calculating the RCP seal LOCA core uncovery probabilities presented in Table 4, however, is consistent with that presented and discussed in Reference 8."

Letter WO 03-0057, page 19 of Attachment 1, WCNOC specific WCAP Table 8-4, contains data from the Table 4 mentioned immediately above.

13. Discuss the restrictions, commitments, or limitations on CT entry during an operating cycle, consistent with the probabilistic risk assessment (PRA) analysis for Callaway.

Response:

WCNOC is assuming that this question pertains to WCGS even though the question indicates Callaway. This question has been previously addressed in Section 4.1.1.2, "Tier 2: Avoidance of Risk-Significant Plant Conditions," on page 19 of Attachment I in WO 03-0057. Further discussion is included on page 10 of Attachment II (response to RAI 7) in WO 03-0057. The Tier 2 restrictions are proposed to be incorporated into the TS Bases as shown by INSERT C on page 7 of Attachment V in WO 03-0057.

14. Discuss the impact of the proposed CT on dominant accident sequences with respect to risk outliers for Callaway.

Response:

WCNOC is assuming that this question pertains to WCGS even though the question indicates Callaway.

The requested change involves the extension of Completion Times for a DG, and separately, a vital AC bus. These changes do not alter the design of the WCGS and do not alter the overall importance listings. Station blackout contributed approximately 50% to the total Level I internal events Core Damage Frequency (CDF) in the 1998 Probabilistic Safety Assessment (PSA) model, excluding internal fires and flood. Credit for the Sharpe Station was not included in the model. Changes to the 1998 PSA model as discussed in Section 4.1.1.1.5 of Attachment I in WO 03-0057 are unlikely to alter those high level results. Intuitively, with the additional capability and redundancy of the Sharpe Station, the total risk due to station blackout is less. Indeed, if Sharpe Station were not available as another independent off-site power source, then station blackout would be a greater contribution to the total at-power CDF with the extended DG Completion Time.

RAI 12 on page 18 of Attachment II in WO 03-0057, discusses the risk impact due to removing DG maintenance from the refueling outage. For some refueling schedules, the risk benefit of performing the DG maintenance can be significant. With the additional capability of Sharpe Station, it is believed that the overall risk impact during the entire fuel cycle is improved.

15. Discuss the cumulative risk on a plant-specific basis, consistent with the guidance given in NRC Regulatory Guide (RG) 1.174, including the guidance in the RG for combined change requests.

Response:

This question has been previously addressed in the response to RAI 9 on page 13 of Attachment II in WO 03-0057.

16. The extended CT for LCO 3.8.1, "Electrical Power Systems—AC Sources," Operating Condition B, "One [required] DG inoperable," Required Actions B.3.1, "Determine operable DG(s) is not operable due to common cause failure" or B.3.2, "Perform SR 3.8.1.2 for operable DG(s)," will require an analysis of the DG CT to ensure the assumptions for common cause are consistent with the proposed common cause extended CT. This evaluation will also verify that the DG CT (LCO 3.8.1, Condition B, Required Action B.4, "Restore [required] DG to operable status," will remain within the acceptance guidance of RGs 1.174 and 1.177. Provide the analysis of the DG CT discussed above.

Response:

Section 2.0 of WO 03-0057 identifies the proposed changes to the WCGS Technical Specifications. WCNOC did not propose to extend the Completion Time for Required Action B.3.1 or B.3.2. As such, this question is not applicable to WCNOC.

17. Address if the proposed Technical Specification (TS) changes are based on TSTF-439. TSTF-439 revises the markups provided with WCAP-15622 such that the phrase "or more" is now bracketed to reflect the analysis provided in WCAP-15622. For Condition B, WCAP-15622 evaluates increasing the CT for only one inoperable vital ac bus. The proposed CT of 24 hours only applies to the first inoperable vital AC bus.

Response:

The above reference to TSTF-439 is incorrect. TSTF-439 is associated with the elimination of second Completion Times. It is believed that the question is referring to TSTF-417, "AC Electrical System Completion Times (WCAP-15622)." The proposed changes to the WCGS Technical Specifications are based on TSTF-417. However, WCGS Technical Specification Required Action C.1 of TS 3.8.9 does not have the "or more" language in the Condition. The Condition states: "One AC vital bus subsystem inoperable." Insert 7 associated to TSTF-417 provides a Reviewers Note indicating that WCAP-15622 modeled only one inoperable AC vital bus subsystem. Therefore, the proposed change is consistent with the WCAP and plant specific analysis.

18. Discuss if credit is being taken for a reduced loss of offsite power (LOSP) initiating event frequency based on the implementation of compensatory measures. In such cases, the compensatory measures will become part of the licensing basis for the proposed CT change. In addition, licensees electing to apply this method will discuss the incorporation of these compensatory measures into the plant PRA model. The discussion will include the modeling of the compensatory measure, human error probabilities for operator action, and the contribution of the proposed compensatory measure to CT risk.

Response:

RAI 8 in Attachment II of WO 03-0057 describes the modification to the loss of offsite power initiating event frequency. Section 4.1.1.1.6 of Attachment I in WO 04-0057 contains the WCNOC specific WCAP 15622 Table 8-2, where the revised loss of offsite power initiating event frequencies are listed. Subsection 4.1.1.2 of Attachment I in WO 03-0057 provided a discussion of weather related restrictions and is included in the list of Tier 2 restrictions. Operator action is included as a generic, top-level, event in the Sharpe Station fault tree with a value of 0.035.

A conservatism contained within the PSA evaluation resides in the calculation of the loss of offsite power initiating event frequency. The values used for this evaluation are based upon generic industry historical data and do not explicitly include WCGS specific data. To include WCGS data, a Bayesian update would be performed. The results from Bayesian updating the loss of offsite power initiating event frequency would effectively lower the WCGS frequency since the plant has not experienced a loss of all offsite power events in the history of its operation.

The resulting risk values are 3.485E-05 (CDF) and 7.735E-07 (LERF) for normal model values and 5.170E-05 (CDF) and 1.169E-06 (LERF) for protected model numbers. The protected model refers to the short period of time when the DG is out of service for an extended outage and additional controls placed on switchyard work and other concurrent major maintenance.

19. Discuss if the quality of the plant-specific PRA is acceptable in accordance with the guidelines given in RG 1.174.

Response:

This question has been previously addressed in the response to RAI 2 on page 1 of Attachment II in WO 03-0057. RAI 2 requested a discussion of the PRA quality measures, including peer reviews, and how WCAP-15622 addressed individual plant PRA quality for the proposed plants and PRA quality guidance for subsequent plant specific submittal, including those plants not included in WCAP-15622. This information has been provided.

B. <u>EEIB Questions</u>:

20. The Wolf Creek Updated Safety Analysis Report (USAR) states that each offsite circuit (a) has the capacity and capability to provide the necessary power to both 4.16kV Class 1E distribution systems or load groups, (b) can be manually aligned to supply power to the opposite or both 4.16kV Class 1E busses, and (c) can be electrically separated from the other circuit by controlled switching of Wolf Creek switchyard breakers. Each offsite circuit is, therefore, designed (pursuant with the requirements of GDC 17) to be available in sufficient time to ensure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded following a loss of all onsite power sources and the remaining offsite power circuit to assure that specified

acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded.

Wolf Creek TS, pursuant with the requirements of 50.36, includes an LCO and required actions for offsite circuits; however, SRs are not include to assure each circuit (a) can be manually aligned to supply power to the opposite or both 4.16kV Class 1E busses and (b) can be electrically separated from the other circuit by controlled switching of Wolf Creek switchyard breakers.

a. Provide justification for not including surveillance requirements (SRs) as part of the TS limiting condition for operation (LCO) for offsite circuits to assure each circuit can be manually aligned to supply power to the opposite or both 4.16kV Class 1E busses and can be electrically separated from the other circuit.

b. Identify testing performed to assure each circuit can be manually aligned to supply power to the opposite or both 4.16kV Class 1E busses and can be electrically separated from the other circuit.

   i. Define the frequency the identified testing is performed, and

   ii. Given a test failure for each test identified, describe impact on each offsite circuit's operability and required actions pursuant with TS.

c. Describe the extent the alignment of an offsite circuit to the opposite or both 4.16kV Class is utilized to establish risk for the CT for an inoperable DG.

d. Describe the extent electrical separation of each circuit from the other circuit by controlled switching of Wolf Creek switchyard breakers is utilized to establish risk for the CT for an inoperable DG.

Response:

a./b. This question appears to go beyond the scope of the proposed change (i.e., it does not pertain to extending the Completion Time for an inoperable DG or inoperable AC vital bus) and is questioning the original licensing basis of the plant and the TSs that were approved for Wolf Creek. The current WCGS TS were based on NUREG-1431, Rev. 1, "Standard Technical Specifications, Westinghouse Plants," as approved in Amendment No. 123 on March 31, 1999. As discussed in the TS Bases of NUREG-1431, the SRs for demonstrating the OPERABILITY of the DGs are in accordance with the recommendations of Regulatory Guide 1.9. The WCGS TS are consistent with the NRC endorsed/approved standard TSs and Regulatory Guide 1.9 except where deviations have been specifically approved by the NRC in license amendments.

WCGS TS Surveillance Requirement (SR) 3.8.1.1 ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its correct position to ensure that distribution buses and loads are connected to their preferred power source, and that appropriate independence of off-site circuits is maintained. In USAR Section 8.1.4.3, Design Criteria; Regulatory Guides, IEEE Standards and IE Bulletins, the following is stated:

> "Compliance with General Design Criteria 17 and 18 is discussed in Section 3.1.
>
> The Class IE system is divided into redundant load groups so that loss of any one group does not prevent the minimum safety functions from being performed.
>
> Each ac load group has connections to two preferred (offsite) power supplies and to a single diesel generator. Each diesel generator is exclusively connected to a single Class IE 4.16-kV load group and has no automatic connection to the redundant load group.
>
> No provisions exist for automatic transfer of loads between redundant onsite power supplies.
>
> The diesel generator of one load group cannot be automatically paralleled with the diesel generator of the redundant load group.
>
> Interlocks are provided to assure that a single operator error would not parallel the standby power sources of redundant load groups."

In the WCGS safety analysis only one train of 4.16-kV is required to safely shutdown the plant and maintain a safe shutdown condition. There is no interconnection of load groups assumed in the safety analysis. WCNOC does not take credit in its accident analysis the fact that each offsite source and its associated ESF transformer can supply both 4.16-kV busses. Based on this there is no reason to test the equipment and circuits used to supply both 4.16-kV busses from one offsite source and it's associated ESF transformer.

c. See the response to Question 9.

d. Section 3.1.1 of Attachment I in WO 03-0057 describes the Class IE power systems at WCGS. The 1998 PSA model described in Section 4.1.1.1.1 of WO 03-0057 followed this design. The response to Question 9 contains additional information.

21. In regard to periodic testing of DGs, Regulatory Position C.2.3.2, "Surveillance Testing," of RG 1.9 (Revision 3, July 1993), "Selection, Design, Qualification, and Testing of Emergency Diesel Generator Units Used as Class 1E Onsite Electric Power Systems at Nuclear Power Plants," and Section 6.5, "Periodic Tests," of IEEE Std 387-1984, "IEEE Standard Criteria for Diesel Generator Units Applied as Standby Power Supplies for Nuclear Power Generating Stations," provide recommendations for assuring sufficient testability. It has been generally accepted by the industry and the NRC that compliance

with these recommendation meets the GDC 17 requirement for sufficient testability to demonstrate the continued capacity and capability of DGs. The Wolf Creek USAR, however, conveys that periodic testing of DGs complies with these recommendations except for the test that the DG be operated for a period of 2 hours with the DG's rated short time load applied once each 18 months with the plant shutdown.

a. Provide the evaluation and/or analyses with supporting tests demonstrating sufficient testability to demonstrate the continued capacity and capability of DGs pursuant with the requirements of GDC 17 based on periodic testing recommended by Regulatory Guide 1.9 Rev. 3 and IEEE 387 except for the test that the DG be operated for a period of 2 hours with the DG's rated short time load applied once each 18 months with the plant shutdown.

b. Describe the extent the design capability of the DG to be automatically loaded following a loss of offsite power is credited as part of the risk evaluation to extend the CT for an inoperable DG.

c. The response to RAI 6 provided in attachment 2 to WO 03-0057 amendment request provides a DG fail to run (per hour) number of 2.86E-02. Describe the extent this number increases if the DG were tested for a period of 2 hours with the DG's rated short time load applied.

Response:

Note 2 to TS SR 3.8.1.14 states: "The DG may be loaded to ≥ 5580 kW and ≤ 6201 kW for the entire test period, if auto-connected loads are less than 6201 kW." This allowance was previously approved by the NRC in Amendment No. 101 dated August 9, 1996. The following WCNOC submittals are associated with this amendment: CO 94-0010 (7/29/94), ET 95-0099 (9/15/95), WO 96-0037 (3/8/96), WO 96-0065 (4/18/96), ET 96-0040 (6/14/96), and ET 96-0047 (7/12/96). As such, WCNOC believes that a response to the question is not required based on the information previously provided.

22. The Wolf Creek TSs conveys that reverse power, loss of field, generator over-current, generator voltage restrained over-current, generator ground over-current, over-excitation and under-frequency DG protection are provided but cause a trip only during tests when the diesel generator is operating in parallel with the preferred power system. Under-frequency protection is provided for safely separating the diesel generators from the preferred source (when previously synchronized to it) without damage to or shutdown of the diesel generators. Wolf Creek TSs, pursuant with the requirements of 50.36, includes an LCO and SRs for the onsite standby power supplies. SR 3.8.1.13 requires the DG's automatic trips to be verified bypassed once per 18 months on actual or simulated loss of voltage signal on the emergency bus concurrent with an actual or simulated ESF actuation signal except engine overspeed, generator differential current, low lube oil pressure, high crankcase pressure, start failure relay, and high jacket coolant temperature. The SR required by the Wolf Creek's TSs does not appear to reflect the actual Wolf Creek design as described in the USAR. Provide clarification.

Response:

In the first sentence of the above question which states: "The Wolf Creek TSs conveys ....with the preferred power system.", WCNOC believes that this was intended to refer to the USAR since this discussion is taken directly from USAR Section 8.3.1.1.3 (page 8.3-12). As discussed on TS Bases page B 3.8.1-14, the SRs for demonstrating the OPERABILITY of the DGs are in accordance with the recommendations of Regulatory Guide 1.9, Regulatory Guide 1.108, and Regulatory Guide 1.137 as addressed in the USAR. Regulatory Guide 1.9, Position 2.2.12, "Protective Trip Bypass Test," states: "Demonstrate that all automatic emergency diesel generator trips (except engine overspeed, generator differential, and those retained with coincident logic) are automatically bypassed upon an SIAS." SR 3.8.1.13 is the Regulatory Guide 1.9 protective trip bypass test.

During surveillance testing requiring the DG to be paralleled to the offsite source (e.g., SR 3.8.1.3, the 31 day load-run test), the DG protection circuits are configured for all generator protective functions providing full trip protection. This full generator trip protection includes reverse power, loss of field, generator overcurrent, generator voltage-restrained overcurrent, generator ground overcurrent, overexicitation and underfrequency (i.e, DG noncritical protective functions) as well as engine overspeed, generator differential current, low lube oil pressure, high crankcase pressure, start failure relay, and high jacket coolant temperature (i.e., DG critical protective functions).

On a valid safety injection signal or loss of offsite power (referred to as emergency operation), the DG protection circuits are configured such that only the DG critical protective functions are providing trip protection. The performance of SR 3.8.1.13 demonstrates that the DG noncritical protective functions are bypassed on a loss of voltage signal concurrent with an ESF actuation test signal. As such, WCNOC believes that SR 3.8.1.13 does reflect the design as described in USAR Section 8.3.1.1.3 and that the SR is consistent with the regulatory position in Regulatory Guide 1.9.

23. RG 1.9 and IEEE 387 requires a subsystem test to demonstrate the capability of the control, surveillance, and protection systems to function in accordance with the requirements of their intended application. With regard to protection systems, the improved standard TSs (ISTS) referenced by WCAP-15622 does not include these subsystem tests. The Wolf Creek TSs similarly do not appear to include these subsystem tests.

    a. Describe testing performed at Wolf Creek to assure that protection systems for engine overspeed, generator differential, and those retained with coincident logic will not cause loss of the diesel generator.

    b. Describe the extent protection systems for engine overspeed, generator differential, and those retained with coincident logic can impact DG capacity and capability and are credited as part of the risk evaluation for increasing the current DG CT of 72 hours.

Response:

a. The current WCGS TS were based on NUREG-1431, Rev. 1, "Standard Technical Specifications, Westinghouse Plants," as approved in Amendment No. 123 on March 31, 1999. As discussed in the TS Bases of NUREG-1431, the SRs for demonstrating the OPERABILITY of the DGs are in accordance with the recommendations of Regulatory Guide 1.9. The WCGS TS are consistent with the NRC endorsed/approved standard TSs and Regulatory Guide 1.9 except where deviations have been specifically approved by the NRC in license amendments.

WCNOC maintains additional preventative maintenance, inspection, and testing programs in addition to the surveillance testing required by the TSs. Procedures STN IC-805A, "Channel Calibration Diesel Generation Trips KKJ01A," and STN IC-805B, "Channel Calibration Diesel Generation Trips KKJ01B," provide for steps for testing and calibrating diesel engine trips (i.e., high jacket water temperature, high crankcase pressure, low lube oil pressure) and the logic for these trips. Procedure RNM C-0552, "Generator Differential Relay Type SA-1", covers the calibration check of the generator differential current relay. The calibration procedure is performed on an 18-month frequency. Procedures SYS KJ-123, "Post Maintenance Run of Emergency Diesel Generator A," and SYS KJ-124, "Post Maintenance Run of Emergency Diesel Generator B," provide steps for performing the dynamic over-speed trip testing of the engines. The dynamic over-speed trip testing is performed every three years. Inspection of the trip mechanism is performed every 18 months.

b. Typical PSA model fault tree basic events for the DGs include fail-to-start, fail-to-run, and test-and-maintenance. Each of these terms can account for the protection equipment listed, and a subsequent DG model failure. Other 'signal-based' logic failures could also cause the EDG to not function. Since the type of testing and frequency of the testing is not being changed from what is currently performed, there should be no increase in risk if the Completion Time is increased.

24. The licensee's response to RAI 7 provided in attachment 2 to its application states: "...There are no commonalities between the WCGS DGs and the Sharp Station..." When a Wolf Creek DG is connected to the offsite system for post maintenance testing, describe why there are no commonalities between the DG and the Sharp Station.

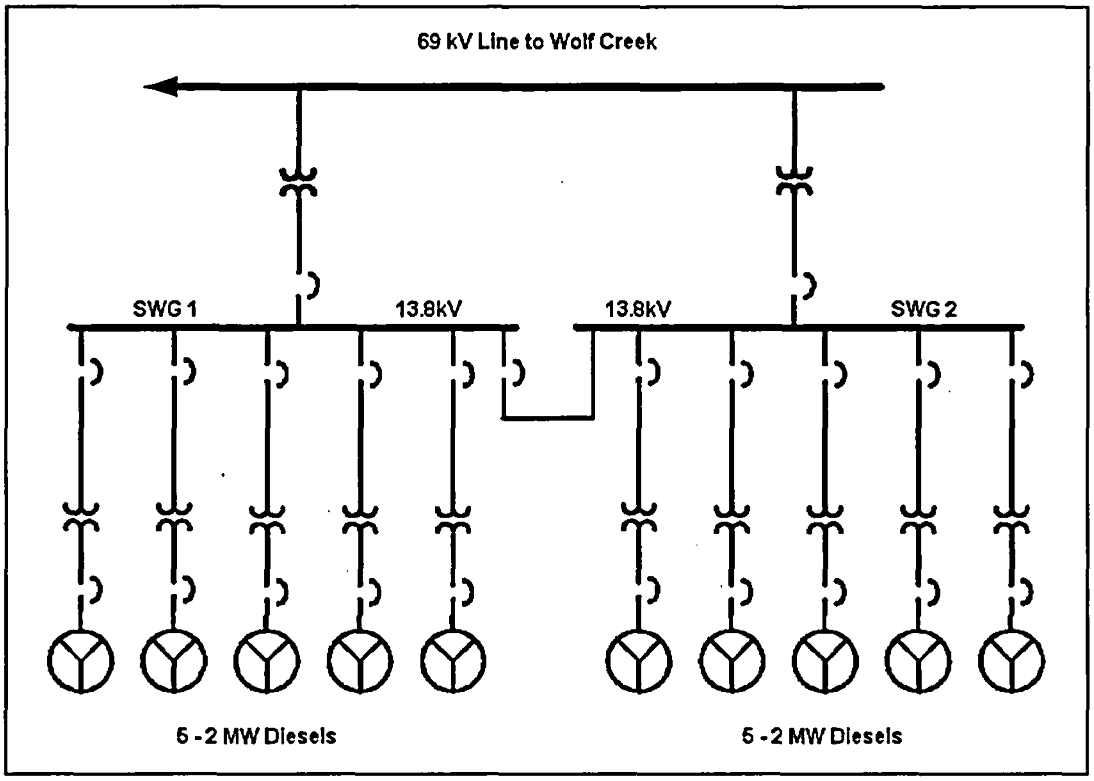
Response:

The 69 kV line can be aligned to be common between the WCGS DGs and the Sharpe Station (see the simplified one-line diagram on page 4 of Attachment I to WO 03-0057). But typically this is not the case. The Sharpe Station gensets are peaking units and are not generally connected to the grid (69 kV line). Use of the Sharpe Station gensets would be during periods of challenged high load grid conditions. WCNOC response to RAI 7 in Attachment II to WO 03-0057 indicated that extended DG maintenance period are selected during historical time frames of low severe weather frequency and favorable weather periods tend to avoid periods of high grid demand. Prior to connecting to the offsite system for post maintenance testing WCNOC will contact the grid operator to review grid stability issues. Additionally the WCNOC DGs are of the Fairbanks Morris –Colt Pielstick PCV2.5 design and the Sharpe Station gensets are Caterpillar 3516B design. There are no commonalities in the two designs.

25. The licensee's response to RAI 7 provided in attachment 2 to its application states: "...Due to the Sharpe station design, common cause is not an important contributor of failure to deliver power to the emergency plant equipment..." Describe the Sharpe station design which makes common cause an unimportant contributor of failure to deliver power to the emergency plant equipment.

Response:

Sharpe Station consists of ten, two-megawatt Caterpillar 3516B engine-generator sets (gensets). They are arranged in two banks of five with separate transformers. The gensets are sited at a single location proximate to an existing 69 kV substation near Sharpe, Kansas, approximately two miles north of Wolf Creek. A "Simplified One-Line Diagram of Sharpe Station Power to WCGS" on page 4 of Attachment I to WO 03-0057 shows the relationship of Sharpe Station to the WCGS Switchyard and the ESF busses (NB01, NB02). The WCNOC emergency diesel generators are of the Fairbanks Morris-Colt Pielstick PCV2.5 design and the Sharpe Station gensets are Caterpillar 3516B design. Based on the above, there are no commonalties between the WCGS DGs and the Sharpe Station gensets. A more detailed one-line layout of the gensets at Sharpe Station is shown below.



Severe weather that impacts the WCGS switchyard can be postulated to affect the normal offsite power sources and the Phillips 69kV (Lyon-Coffey REC) line. To minimize this possibility, WCNOC intends to perform the extended DG maintenance period during time frames that historically have demonstrated low severe weather frequency. Favorable weather periods also tend to avoid time periods of high grid demand. Prior to entering the planned DG maintenance, weather forecasts for severe weather predictions will be checked. If the forecast is not favorable, the maintenance will be delayed or rescheduled as appropriate. Other external events, such as flooding and transportation do not constitute significant hazards to the generating station due to its distance from major highways and water sources.

Four (4) gensets are required to support one safety bus with LOCA loads. This becomes the basis for the success criteria. Common cause is a very minor contributor to Sharpe Station failure, given the total number of gensets available, the number of gensets required for LOCA loads, and the station configuration.

26. The licensee's response to RAI 5 provided in attachment 2 to its application indicates that the Sharpe Station located near Wolf Creek provides emergency back-up power for Wolf Creek, specifically, to improve availability and reliability of sufficient ac power for planned onsite DG maintenance and emergent failure of one onsite DG.

    a. Describe the extent the Sharpe Station gensets and their electrical connection to the Class 1E distribution system meet the requirements of a Class 1E onsite power supply.

    b. Describe testing that will be performed to assure the Sharpe Station gensets and their electrical connection to the Class 1E distribution system have sufficient capacity and capability to supply one safety system load group.

    c. For emergent failure of one onsite Class 1E DG, define and justify the completion time for which the gensets and 69kV transmission network will be credited to repair the emergent failure and return the DG to operable status.

Response:

a. The Sharpe Station gensets do not meet the requirements of a Class 1E onsite power supply. As stated in the response to RAI 5 (page 6) in Attachment II to WO 03-0057, the Sharpe Station gensets are credited as an additional AC power source. Four-out-of-ten gensets sets are required to support one safety bus with LOCA loads. The Sharpe Station gensets can be started and aligned in a timely manner to provide power to a safety buss in a loss of grid event.

b. An analysis has been performed to determine the minimum Sharpe Station gensets required to supply all the LOCA loads, to include an out of sequence start of the largest motor last. The minimum number of gensets required to supply all LOCA loads on one safety bus is four out of the ten available. Eight Sharpe Station gensets are required to power all the LOCA loads on both safety busses.

c. Letter WO 03-0057, Attachment I (page 1), requested an increased Completion Time only on a once per cycle basis for each DG, and would be applicable only for the performance of voluntary, planned maintenance activities, as further described in Subsections 2.1 and 4.1 of Attachment I to WO 03-0057. The existing 72-hour Completion Time would still be retained and would apply in the same manner as it currently applies. The 69kV transmission network and Sharpe Station are not required during this period.

Text including the words 'emergent failure of one onsite DG' was drawn from the Operating Agreement for the Sharpe Station between WCNOC and KEPCO. The statement was an acknowledgment that an additional, nearby power source would be beneficial in a severe plant event and concurrent grid failure. Use of the Sharpe Station is credited in the submittal only for pre-planned maintenance in accordance with the Tier 2 and Tier 3 items discussed in Section 4.1.1.2 and 4.1.1.3 of Attachment I to WO 03-0057.

27. The addition of the Note to Required Action A.3 and Required Action B.4 of TS 3.8.1 provides an additional second Completion Time of 10 days (changed from 6 days) from discovery of failure to meet the LCO. Provide the impact from a risk perspective of some combination of an inoperable offsite circuit and/or the same or another DG for 3 days following the proposed 7 day CT for a DG being made inoperable for planned maintenance.

Response:

The NRC transmitted a letter to NEI in November 2001 discussing a staff concern identified during their review of Topical Reports WCAP-15622, "Risk-Informed Evaluation of Extensions to AC Electrical Power System Completion Times" (TSTF-417) and CE NSPD-1045, "Joint Applications Report, Modification to the Containment Spray System, and the Low Pressure Safety Injection System Technical Specifications" (TSTF- 409). Specifically, the NRC indicated that increases in Improved Standard Technical Specification (ISTS) Completion Time limits by adding together risk informed and deterministic values using engineering judgment would not be approved. Additionally, the NRC provided a Request for Additional Information to the WOG on the method of determining the new second Completion Time during their review of the WOG Topical Report, WCAP-15622 in December 2001. WOG letter OG-02-052, dated November 27, 2002, RAI 1, indicated that the industry submitted TSTF-439 in response to this issue.

On September 10, 2002, the NRC stated in a letter that TSTF-430, "AOT Extension to 7 Days for LPI and Containment Spray (BAW-2295-A, Rev. 1)" cannot be approved because it modifies a second Completion Time based on time of discovery of failure to meet an LCO, similar to the concerns raised in their November 2001 letter.

In response to the above, the industry submitted TSTF-439, "Eliminate Second Completion Times Limiting Time From Discovery of Failure to Meet an LCO," in June 2002. During September and October 2003, the TSTF and the NRC held several discussions on the history and purpose of the "discovery of failure to meet the LCO" Completion Times. The "discovery of failure to meet the LCO" Completion Times are an administrative limit intended to prevent plants from successively entering and exiting ACTIONS associated with different systems governed by one LCO without ever meeting the LCO (e.g., "flip-flopping"). The "discovery of failure to meet the LCO" Completion Times are generally the sum of the longest and shortest Completion Times that could be successively entered. This administrative limit is calculated without regard to the method used to determine the component Completion Times. Therefore, an extension of one of the component Completion Times will result in a corresponding extension of the "discovery of failure to meet the LCO" Completion Time. The NRC determined that increasing the "discovery of failure to meet the LCO" Completion Times based on adding a risk-based and deterministic Completion Time was consistent with the Staff's approval of Grand Gulf Nuclear Station, Unit 1, Amendment No. 151, dated July 16, 2002. This information is documented in Revision 2 to TSTF-409, which has been approved by the NRC.

Based on the above, the impact from a risk perspective on the second Completion Time is not required.

28. Section 3.1.1 of the amendment request indicates that undervoltage relays are provided on each 4.16kV bus to detect an undervoltage condition and automatically start the DG in response to an undervoltage condition. In response to an undervoltage condition, Section 3.1.1 also indicates the load sequencer will function to shed selected loads and automatically start the DG. In response to an undervoltage condition, the Wolf Creek USAR indicates that the undervoltage relays and logic will send a signal to shed selected loads, start the DG, and trip 4.16-kV preferred power supply breakers. In response to an undervoltage condition, the Wolf Creek TSs indicates that the undervoltage relays and logic only send a signal to start the DG.

    a. Clarify the function of the undervoltage relays provided on each 4.16-kV bus.

    b. Describe the extent the design capability of the undervoltage relays to automatically trip 4.16-kV preferred power supply breakers is credited as part of the risk evaluation to extend the CT for an inoperable DG.

Response:

a. Four instantaneous undervoltage relays with an associated time delay are provided for each 4.16 kV Class 1E NB system bus for detecting a loss of bus voltage. The outputs are combined in a two-out-of-four logic to generate an LOP signal if the voltage is below approximately 80% for 1 second (nominal delay). Upon recognition of a loss of voltage at the 4.16 kV bus, a logic signal generated by the load shedder and emergency load sequencer (LSELS) initiates: a) a trip of the 4.16 kV preferred normal and alternate bus feeder breakers to remove the deficient power source to protect Class 1E equipment from damage; b) shed all loads from the bus except the Class 1E 480 Vac load centers and centrifugal charging pumps to prepare the buses for re-energization by the LSELS; and c) generate a loss of power DG start signal. This information is discussed in USAR Section 8.3.1.1.3 and in the TS Bases for TS 3.3.5, "LOP DG Start Instrumentation." Section 3.1.1 of the amendment request was not intended to provide all of the design functions of the Class 1E power systems.

b. Loss of Power on either 4.16kV ESF bus(NB01 or NB02) results in a loss of all AC power to the affected separation group.

Certain actuation relays are relied upon to actuate the DG, to open the normal offsite power supply breaker(s), to close the DG output breakers, and to start the SGK05A/SGK05B air conditioning units. The failure of these actuation relays is modeled within the Reactor Protection System (RPS) fault trees. These basic events include:

K1102 - Failure of load shed relay K1102 to open normal NB01 feeder breaker NB0112
K1115 - Failure of load sequence relay K1115 to start Class IE A/C Unit SGK05A
K1173 - Failure of load shed relay K1173 to start diesel generator NE01 on shutdown sequence
K4101 - Failure of load shed relay K4101 to open normal NB02 feeder breaker NB0209
K4115 - Failure of load sequence relay K4115 to start Class IE A/C Unit SGK05B
K4173 - Failure of load shed relay K4173 to start diesel generator NE02 on shutdown sequence

29. Section 3.1.1 of the application indicates that the Class 1E dc system includes four separate 125-VDC battery supplies for Class 1E controls, instrumentation, power, and control inverters. Attachment I of the licensee's letter dated April 30, 2003 (WO 03-0009) further indicates that the 125 VDC electrical power system consists of two independent and redundant Class IE 125 VDC electrical power subsystems (Train A and Train B). Each DC electrical subsystem consists of two 125 VDC batteries, two battery chargers, one swing battery charger and all the associated control equipment and interconnecting cabling. The DC electrical power subsystems also provides DC electrical power to the inverters (two per subsystem, one associated with each battery/charger combination), which in turn power the AC vital buses (one associated with each inverter). The Wolf Creek USAR states: "...Power for the vital reactor instrumentation and protection systems is provided by the Class 1E instrument ac power system. This system is composed of four independent 120-volt ac power supplies to provide power for the four channels of the vital reactor protection and instrumentation systems. With one channel inoperable, the remaining three channels are capable of monitoring the vital reactor parameters continuously and safely shutting down the reactor. Each essential power panel is fed from a dedicated Class 1E inverter, which, in turn, is fed from one of four independent Class 1E batteries..." The Wolf Creek TS bases states: "....The onsite Class 1E AC, DC, and AC vital bus electrical power distribution systems are divided by train into two redundant and independent AC, DC, and AC vital bus electrical power distribution subsystems..."

a. The amendment application conveys that the Wolf Creek design includes two independent vital buses while the Wolf Creek USAR conveys four independent vital buses. Provide clarification

b. The USAR indicates that the Wolf Creek design includes four independent ac vital buses however the TS indicate that there are four separate but only two independent vital buses. 10 CFR 50.36 requires the TS to reflect the design described in the USAR. Provide justification (or clarification) of this apparent inconsistency with 50.36.

Response:

The Class IE AC System is divided into two redundant load groups (load groups 1 and 2). Either one of the load groups is capable of providing power to safely reach cold shutdown. Each ac load group consists of a 4.16-kV bus (either NB01 or NB02), 480-V load centers, 480-V motor control centers, and lower voltage ac supplies.

WCGS also has four independent Class IE 120-V vital instrument AC power supplies. The Class IE 120-V vital instrument ac power supply the four channels of the protection systems and reactor control systems. Each vital instrument AC power supply consists of one inverter, one distribution bus, and one manual transfer switch. Normally, the inverter is operating to supply the AC vital bus. Each inverter is supplied by a separate Class IE battery system, as described in Section 8.3.2 of the USAR.

WCNOC believes that there is no inconsistency with 10 CFR 50.36 as the TSs reflect the design of the plant as described in the USAR. The question is quoting the TS Bases and subpart b. of the question states that 50.36 requires the TS to reflect the design described in the USAR. 10 CFR 50.36, states, in part, "The technical specifications will be derived from the analyses and evaluation included in the safety analysis report." For clarification purposes, the TS Bases are not considered a part of the technical specifications. 10 CFR 50.36(a), states, in part: "A summary statement of the bases or reasons for such specifications, other than those covering administrative controls, shall also be included in the application, but shall not become part of the technical specifications." The TS Bases quoted in the question is in the Background section of B 3.8.9. This section further states: "The 120 VAC vital buses are arranged in two load groups per train and are normally powered through the inverters from the 125 VDC electrical power subsystem. Refer to B 3.8.7 for further information on the 120 VAC vital system." In the LCO section of B 3.8.7, a table is provided identifying the two trains and the two load groups per train (i.e., 4-120 VAC vital busses – NN01, NN03, NN02, and NN04). Therefore, the TS and TS Bases reflect the design of the plant as described in the USAR.

30. The Wolf Creek USAR states: "...Four independent Class IE 120-V vital instrument ac power supplies are provided to supply the four channels of the protection systems and reactor control systems. Each vital instrument ac power supply consists of one inverter, one distribution bus, and one manual transfer switch. Normally, the inverter is operating to supply the vital ac bus. Each inverter is supplied by a separate Class IE battery system..... If an inverter is inoperable or is to be removed from service, the vital ac bus can be supplied from the 120-V ac inverter backup bus associated with the same load group through the manual transfer switch. A key interlock is provided to ensure that only a single transfer to the inverter backup bus can be made at one time...."

    The Wolf Creek TS states: "...OPERABLE vital bus electrical power distribution subsystems require the associated buses to be energized to their proper voltage from the associated inverter via inverted DC voltage, or Class 1E constant voltage (Sola) transformer. ....With a required inverter inoperable, its associated AC vital bus is inoperable until it is re-energized from its Class 1E constant voltage (Sola) transformer."

a. Provide the evaluation and analyses demonstrating that the ac vital power supplies meet the requirements of IEEE 279-1971 when one of the four independent vital busses is energized from the Class 1E constant voltage (Sola) transformer.

b. Define risk associated with the design that has one vital busses energized from the Class 1E constant voltage (Sola) transformer and three vital busses energized from the dc battery.

c. Describe the extent this risk (from item b above) is utilized as part of the risk evaluation to extend the CT for an inoperable ac vital bus.

Response:

a. WCGS has four independent Class 1E 120-V vital instrument AC power supplies, which supply the four channels of protection systems and reactor control systems. Protection system channels 1 and 3 are both powered from load group 1. Protection channels 2 and 4 are powered by load group 2. Load group 1 and protection channels 1 and 3 and load group 2 and protection channels 2 and 4 cables are routed through separate cables chases and cable spreading rooms. Channel separation is discussed in USAR Section 8.3.1.3 where load group 1 and protection channel 1 are assigned as part of Separation Group 1. Channel 2 is assigned Separation Group 2. Channel 3 is assigned Separation Group 3. Load group 2 and protection channel 4 is assigned Separation Group 4. IEEE Standard 279-1971, "Criteria for Protection Systems for Nuclear Power Generation Stations," Section 4.6, Channel Independence, is met by the above discussion.

As stated in the USAR Section 8.3.1.1.5, Vital Instrument AC Power Supply, each vital instrument AC power supply consists of one inverter, one distribution bus, and one manual transfer switch. Normally the inverter operates to provide the vital ac distribution bus with ac power. The inverter is supplied dc power from the 125 VDC battery bus. With the required inverter inoperable ac power to the AC vital bus is lost and the required Completion Time to restore the inverter to OPERABLE status is 24 hours. Power can be restored to the AC vital bus by re-energizing using the Class 1E constant voltage (Sola) transformer. This transformer can only be used to energize one AC vital bus at a time by use of key-interlocked breakers, within it's own respective load group (see Figure 1 in WO 03-0057). For example, AC vital bus NN02 losses inverter and is realigned to Sola transformer XNN06, which is fed Class 1E power from load group 2 (as before without the uninterruptible power source- 125VDC battery).

As discussed in the Technical Specification Bases B 3.8.7 (Required Action A.1) for an inoperable inverter, the 24 hours to fix the inoperable inverter and return it to service is based on engineering judgment taking into account repairing the inverter. When the AC vital bus is powered from its Class 1E constant voltage (Sola) transformer, it is relying upon interruptible ac electrical power sources (offsite and onsite). The uninterruptible inverter source to the AC vital buses is the preferred source for powering instrumentation the AC vital bus.

b. Based on the wording of the question, selected background text from the WCGS PSA Electrical calculation may be worthwhile.

The loss of Class IE 125 V DC (NK) bus NK01 or NK04, will result in a reactor trip (due to closure of the FWIVs) and significantly degrade the ability of the associated train to mitigate the event. Therefore these initiating events (INIT-DC1 and INIT-DC4) are specifically considered in the Wolf Creek PSA. Loss of NK02 and/or NK03 are not considered as initiating events in the Wolf Creek PSA, as they do not directly cause a reactor trip (although they power a single NN channel through an inverter that could potentially result in reactor trip if operator action is not taken to ensure that all critical control functions are promptly transferred to an operable power source).

Loss of 125 V DC Bus NK01 or NK04

A comprehensive listing of the response of Wolf Creek systems to a loss of power on bus NK01 or NK04 is detailed in [Reference 11]. From a PSA perspective, the important impacts on safety systems modeled in the PSA include the following:

- Control power is lost to the MSFIS Cabinet (SA075A for a loss of NK01 and SA075B for loss of NK04) resulting in closure of the Main Feedwater (MFW) Isolation Valves and the Main Feedwater Regulating Valves. This will result in a loss of MFW flow which will lead to a reactor trip on low-low steam generator level.

- Control power for the associated train Diesel Generator Field Flashing Panel and the power supply to the DG Control Panel is lost resulting in loss of starting capability for the associated DG.

- Power is lost to the associated inverter (NNII or NN14) resulting in loss of the primary power supply to the associated vital 120 V AC Instrument Bus and the loss of one train of class instrumentation. This results in a loss of power to the associated sequencer, and the loss of sequencer functionality.

- Control power is lost for control of the associated Class IE 4.16-kV Bus breakers, and therefore if the need arises to start any pumps powered from the associated 4160 volt bus local operator action is required.

Loss of 125 V DC Bus NK02 or NK03

A comprehensive listing of the response of Wolf Creek systems to a loss of power on bus NK02 or NK03 is detailed in [Reference 11]. Unlike NK01 or NK04, failure of either of these buses is not expected to result in plant trip. Failure of either of these buses would result in the loss of power from the associated inverter, which would result in the loss of the primary power supply to the associated train of instrument AC. The NK02 bus also supplies control power for the turbine driven AFW pump

Trip and Throttle Valve, which is assumed to render the turbine driven AFW pump inoperable (although local control of the pump may be possible).

Loss of 120 V AC Bus NNQ1, NNQ2, NN03 OR NN04

A comprehensive listing of the response of Wolf Creek systems to a loss of instrument AC power on bus NN01, NN02, NN03 or NN04 is detailed in WCGS Off-Normal Procedure 'Loss of Vital 120 VAC Instrument Bus' [OFN NN-021 Reference 12]. Loss of a single instrument AC bus is not expected to result in a reactor trip provided that appropriate operator action is promptly performed in accordance with the guidance of [Reference 12]. Although a reactor trip has occurred at Wolf Creek due to a loss of instrument AC power, the human factors engineering was subsequently improved to reduce the likelihood of reoccurrence of such an event. Additionally the severity of a trip is not substantially worse than for other transient initiating events which occur at a much greater frequency. The major PSA impact of losing an instrument AC bus is that automatic sequencing is disabled on the associated train if NN01 or NN04 is lost, and the remote operation of a single steam generator ARV is lost when either of the four buses fail.

The question is read to pose a hypothetical configuration not in accordance with the amendment request or plant operation. The statement seems to imply failures of AC power to three-out-of-four NK busses. Thus, the NK busses feed up to three AC vital busses (NN01, NN02, NN03, and NN04) via the batteries and inverters. The fourth NN bus is then said to be powered from XNN05 or XNN06, (by NB01/NB02, respectively). For this last statement to be true, either the diesel generator is operating, or off-site power is supplying the NB bus. The net effect of the hypothetical configuration has one ESF bus able to take the plant to cold shutdown. With three-out-of-four NN busses being supplied by station batteries, instrument failures will occur when the batteries deplete. Major AC-powered pumps would remain available. Technical Specification 3.8.9, Condition F, requires entry into LCO 3.0.3 (requires shutdown of the plant) with the plant in a condition of two trains with inoperable distribution subsystems that result in a loss of safety function. Additionally, since TS 3.8.9 does not have a Condition for two inoperable AC vital busses, entry into LCO 3.0.3 would be required with two or more AC vital busses inoperable.

c. The risk metrics for one AC vital bus subsystem inoperable has been previously been provided in WCNOC specific WCAP Table 8-6 on page 17 of Attachment I to WO 03-0057, and Tables 9-1 and 9-2 on pages 13 and 14 respectively, of Attachment II to WO 03-0057.

31. The licensee's letter dated April 30, 2003, states that the length of time that the DG is parallel with the offsite circuit can be on the order of minutes, depending on what test is being performed, up to a minimum time of 24 continuous hours such as required by the endurance and margin test per SR 3.8.1.14. The licensee's application indicates that the endurance and margin test may also be performed following online preventive maintenance of the DG.

GDC 17 of 10 CFR Part 50, Appendix A, requires, in part, provisions to minimize the probability of losing electric power from the remaining electric power supplies as the result of loss of power from the unit, the offsite transmission network, or the onsite power supplies.

a. Provide the evaluation and analyses demonstrating compliance with this requirement of GDC 17 to minimize the probability of losing electric power from the remaining electric power supplies as the result of loss of power from the unit, the offsite transmission network, or the onsite power supplies for the diesel generators at Wolf Creek when the onsite system is operating in parallel with the offsite system during the endurance and margin testing.

b. Provide the evaluation and analyses demonstrating compliance with this requirement of GDC 17 to minimize the probability of losing electric power from the remaining electric power supplies as the result of loss of power from the unit, the offsite transmission network, or the onsite power supplies for the diesel generators at Wolf Creek when the onsite system is operating in parallel with the offsite system during post maintenance testing.

Response:

The above referenced letter dated April 30, 2003 was a license amendment request that included a change to SR 3.8.1.14 (endurance and margin test) to delete the Note that prevented performing this SR in MODES 1, 2, 3, or 4. The proposed change was approved by the NRC in Amendment No. 154 dated July 12, 2004. The NRC safety evaluation concluded:

"The design of the onsite and offsite electric power systems for WCGS to permit the functioning of structures, systems, and components that are important to safety is not being changed by the proposed amendment. Further, the amendment does not change the testing of the EDG, only the modes in which the testing is conducted. Therefore, the plant continues to meet GDC 17."

As such, WCNOC believes that the necessary information has previously been provided and a response to the question is not required to support NRC review of the proposed changes in letter WO 03-0057.

32. GDC 17 of 10 CFR Part 50, Appendix A, requires, in part, sufficient testability to demonstrate the continued capacity and capability of the standby diesel generator system at Wolf Creek.

a. As part of the evaluation and analyses demonstrating compliance with this sufficient testability requirement of GDC 17 for the diesel generators at Wolf Creek, describe why sufficient testability to demonstrate the continued capacity and capability of the DG pursuant with GDC 17 is maintained following online maintenance of the DG.

b. The WOG indicates (based on engineering judgement and the type of online maintenance) that operability, the capacity and capability to perform its design function, is demonstrated by monthly start and load tests with the plant online.

The refueling tests with the plant shutdown would not be performed following online maintenance to demonstrate DG operability. Describe the impact on risk and regulatory requirements when only monthly start and load tests are used following online maintenance.

Response:

a./b. The WCNOC response to RAI 11 on page 14 of Attachment II in the amendment request discusses the post-maintenance testing and surveillance testing that could be performed following on-line maintenance of the DG.

The following additional information is provided. The required scope of post-maintenance testing, and the degree to which such testing provides a high level of assurance of DG OPERABILITY following DG maintenance, is dependent on the scope and nature of the maintenance that was performed (i.e., what was done to the DG). The intent is to sufficiently challenge the DG to verify proper performance in light of what maintenance was performed. In general, for most maintenance activities performed on the DGs, the start-and-load test (that is otherwise routinely performed on a monthly basis) is typically all this is required to provide assurance of OPERABILITY following maintenance, even for significant tear-downs and inspections. Experience shows that this test(s) is capable of detecting the most likely failure modes and maintenance errors. Testing per other SRs verifies the widest spectrum of all of the various design aspects of the machine, but many of the tests overlap in scope, and for the most part the additional testing is not likely to reveal failure modes that the start-and-load testing would not also reveal.

As such, WCNOC believes that the above described testing provides sufficient testability to demonstrate the continued capacity and capability of the DG is maintained following online maintenance of the DG

33. To demonstrate sufficient capacity and capability of the DG pursuant with the requirements of GDC 17, it is the NRC staff's position that surveillance testing following maintenance, as a minimum, should include starting, load acceptance, rated load, load rejection, and subsystem tests recommended by Section 6.5 of IEEE 387.

    a. Describe the extent the Wolf Creek Surveillance testing following DG maintenance meets this position.

    b. Provide justification for exceptions identified to this staff position.

Response:

IEEE Std 387-1984, Section 6.5.2 provides no discussion about the operational testing (i.e., starting test, load acceptance test, rated load tests, load rejection test, and subsystem tests) being performed following maintenance. This standard only indicates that the testing be performed at least once every 18 months. WCNOC could not locate any formal documentation of the above NRC staff's position.

However, this question has been addressed in Attachment II to WO 03-0057 starting on page 16. The WCNOC Response to RAI 11 provides information regarding the extent of surveillance testing that would be performed following DG maintenance. WCNOC believes that this testing is consistent with the testing recommended by IEEE 387.

TABLE OF DRAFT SAFETY EVALUATION APPENDIX E ITEMS

On July 1, 2005, the NRC issued the draft Safety Evaluation for topical report WCAP-15622, "Risk-Informed Evaluation of Extensions to AC Electrical Power System Completion Times." Appendix E of the draft Safety Evaluation identified additional information needed in plant specific applications that reference the topical report. The below table provides the results of a review of Appendix E and identifies the specific location in previously provided WCNOC documents. For those items that identify the needed information was not provided, the information is provided following this table.

Draft SE Appendix E Item	LOCATION OF WCNOC INFORMATION
E.1.1	WO 03-0057: Attachment I (page 16) – WCAP-15622, Table 8-2. Also see Attachment II, page 11 – response to RAI-8
E.1.2	Information not previously provided
E.1.3	12/13/04 RAI Response – see response to Question 9
E.1.4	12/13/04 RAI Response – see response to Question 8
E.1.5	Information not previously provided
E.1.6	Information not previously provided
E.2.1.(a)	WO 03-0057: Attachment I (page 10) Section 4.1.1.1.1
E.2.1.(b)	WO 03-0057: Attachment II (page 1) – response to RAI 2
E.2.1.(c)	WO 03-0057: Attachment II (page 1) – response to RAI 2
E.2.1.(d)	WO 03-0057: Attachment I (page 14) – Section 4.1.1.4
E.2.1.(e)	Information not previously provided
E.2.1.(f)	Information not previously provided
E.2.1.(g)	12/13/04 RAI Response – see response to Question 6 and 14
E.2.1.(h)	First part of question is addressed in 12/13/04 RAI Response – Question 15 Second part of question – information not provided
E.2.2	WO 03-0057: Attachment I (page 19) – Section 4.1.1.1, 4.1.1.2 and 4.1.1.3
E.2.3	Information not previously provided
E.3	Information not previously provided.
E.4.1	12/13/04 RAI Response – see response to Question 1
E.4.2	12/13/04 RAI Response – see response to Question 2
E.4.3	12/13/04 RAI Response – see response to Question 3
E.4.4	12/13/04 RAI Response – see response to Question 4
E.4.5	12/13/04 RAI Response – see response to Question 13
E.5.1	The Sharpe Station is being credited as an additional AC power source but is not considered an alternate AC power source as defined in Regulatory Guide 1.155. The use of the Sharpe Station was discussed in the following: WO 03-0057: Attachment I (page 4) Attachment II (page 6) – response to RAI 5 Attachment II (page 9) – response to RAI 6 Attachment II (page 10) – response to RAI 7 Attachment II (page 14) – response to RAI 10 12/13/04 RAI Response – response to Questions 8 and 9
E.5.2	12/13/04 RAI Response – see response to Question 8

E.5.3	12/13/04 RAI Response – see response to Question 9
E.6	12/13/04 RAI Response – see response to Question 12
E.7.1	E.7.1(a) – 12/13/04 RAI Response – see response to Questions 21, 32, and 33 12/13/04 RAI Response – see response to Question 11
E.7.2	12/13/04 RAI Response – see response to Question 7
E.8	12/13/04 RAI Response – see response to Question 10

In the responses to the below additional information needed items, reference is made to specific requests for additional (RAIs). These references are referring to Attachment II of WO 03-0057 which provided Wolf Creek Nuclear Operating Corporation (WCNOC) responses to certain NRC RAI's associated with WCAP-15622, "Risk-Informed Evaluation of Extensions to AC Electrical Power System Completion Times."

E.1.2 Provide a short discussion of the LOOP events that have occurred at the plant and compare this frequency to the LOOP frequency used in the PRA model.

Response:

In Attachment II (page 11) the response to RAI 8 discusses review of LOOP events. In developing WCNOC's input to Item B.1.b of Temporary Instruction (TI) 2515/156, "Offsite Power System Operational Readiness," WCNOC determined that there have been no LOOP events (as defined in the TI) experienced at WCGS.

E.1.5 Provide the CDF for station blackout (SBO) events as reported for the individual plant evaluation (IPE). Provide the failure rates for DG failure to start (per demand) and failure to run (per hour), as well as the LOOP initiating event frequency used in the IPE.

Response:

The CDF for SBO events as reported for the IPE is 1.88E-05/year, as indicated in Table 3.4-2 of the IPE Submittal (WCNOC letter WM 92-0152 dated September 28, 1992). The failure rates used in the IPE for DG failure to start and failure to run are 4.608E-03/demand and 4.347E-03/hour, respectively. The LOOP initiating event frequency used in the IPE is 5.1E-02/year. The EDG failure rates and LOOP initiating event frequency are provided in Table 3.3-1 of the IPE Submittal.

E.1.6 Provide the CDF for SBO events as calculated for this study and explain the difference between this value and the value reported in the IPE. Consider revised LOOP initiating event frequency, credit for alternate AC sources, credit for crossties, and the completion time (CT) change.

Response:

The mean annual CDF for SBO events as calculated for this study is 7.885E-06. This CDF is an annualized value comprised of an SBO events CDF of 7.316E-06 (associated with a DG Completion Time of 72 hours) for all but 14 days of a fuel cycle; combined with an SBO events CDF of 2.836E-05 (associated with an DG Completion Time of 7 days) for 14 days of a fuel cycle. The SBO events CDF of 2.836E-05 for the proposed extended DG Completion Time of 7 days is determined assuming one of the DGs is out of service.

Differences between this SBO CDF value and the SBO CDF value reported in the IPE associated with the DGs are due to changes in the DG failure rates and mission time. The DG failure to start probability is 5.43E-03/demand. The DG failure to run failure rate is 4.08E-03/hour. The DG mission time was increased from a value of 2.5 hours used in the IPE, to a value of 7 hours in order to provide consistency with most other internal events PRA models. These values are provided in Table 8-2 in Section 4.1.1.1.6 of Attachment I to WO 03-0057.

Two different LOOP initiating event frequency values are utilized in the determination of this SBO CDF value. As indicated in Table 8-2 in Section 4.1.1.1.6 of Attachment I to WO 03-0057, the LOOP event frequency for the "normal" configuration (72 hour DG Completion Time) is 2.848E-02. The LOOP event frequency for the "protected" configuration (7 day DG Completion Time) is 1.557E-02. These values are provided in Table 8-2 in Section 4.1.1.1.6 of Attachment 1 to WO 03-0057. A brief description of the approach utilized to determine these LOOP initiating event frequency values is provided in the response to RAI 8 in Attachment II to WO 03-0057. The LOOP initiating event frequency value of 2.848E-02 was determined from generic industry data using information from EPRI technical reports. The LOOP initiating event frequency value of 1.557E-02 was determined by excluding those industry LOOP events that were associated with plant or switchyard testing and maintenance activities consistent with the limitation of these activities during the proposed extended Completion Time period. The LOOP event frequency for the "protected" configuration is also decreased to account for the reduced probability of occurrence of severe weather events during the portion of the year where DG maintenance in the proposed extended Completion Time would be allowed.

For the non-weather related portion of both of the above LOOP initiating event frequency values, the evaluation for the proposed extended Completion Time considers alignment of AC power to at least one plant ESF bus from the Sharpe Station GenSets (additional AC source). No credit for cross-ties is specifically included in the evaluation for the proposed extended Completion Time; although plant design will allow alignment of AC power from the Sharpe Station to either or both ESF buses.

E.2.1.(e) To address the applicability of WCAP-15622 to a licensee's plant, additional information on the plant-specific PRA is required in the following areas: Assurance that there is PRA adequacy, completeness, and applicability with respect to evaluating the risk associated with the proposed CT extensions.

Response:

The attributes of PRA adequacy, completeness, and applicability are all associated with the consideration of PRA quality. The response to RAI 2 in Attachment II of WO 03-0057 provides a discussion of WCGS PRA quality including consideration of IPE findings, PRA self-assessment findings and PRA Peer Review findings that might have an impact on the AC Power Systems. Changes to the PRA model needed to adequately and completely evaluate the risk associated with the proposed extended Completion Time are described in Section 4.1.1.1.5 of Attachment I to WO 03-0057 and are directly related to Question E.2.1.(f). The PRA model changes identified in Section 4.1.1.1.5 of Attachment I to WO 03-0057, along with the determination that no assessment or review findings have an impact on AC Power Systems, provide assurance that the PRA model utilized is adequate, complete and applicable with respect to evaluating the risk associated with the proposed Completion Time extensions.

E.2.1.(f) To address the applicability of WCAP-15622 to a licensee's plant, additional information on the plant-specific PRA is required in the following areas: Assurance that plant design or operational modifications that are related to or could impact the proposed CT extensions are reflected in the PRA revision used in the plant-specific application, or a justification is provided for not including these modifications in the PRA

Response:

Section 4.1.1.1.4 of Attachment I to WO 03-0057 includes a brief description of the consideration of plant changes associated with maintenance of the WCGS PRA model. Plant design or operational modifications were reviewed to determine those changes that were related to or could impact the proposed Completion Time extension. Changes that were made to the PRA utilized for the evaluation of the risk associated with the proposed Completion Time extension are identified in Section 4.1.1.1.5 of Attachment I to WO 03-0057. The changes incorporated into the PRA model are seal leakage parameters associated with installation of high temperature qualified seal materials for all four RCPs, and addition of the Sharpe Station GenSets (described in the response to RAI 5 in Attachment 2 to WO 03-0057).

E.2.1.(h) With respect to previous submittals and the extended CTs in WCAP-15622, licensees will evaluate cumulative risk on a plant-specific basis consistent with the guidance given in RG 1.174. In addition, licensees will address the guidance for combined change requests provided in RG .174.

Response:

Previous risk-informed submittals of the same type (changes in Completion Time allowed by technical specifications) are: 1) WO 98-0082 (dated October 23, 1998) – Accumulator allowed outage time (Completion Time) increase, and 2) WO 03-0059 (dated December 15, 2003)– Reactor Trip System (RTS) and Engineered Safety Feature Actuation System (ESFAS) Instrumentation Completion Times, test bypass times, and surveillance frequency changes.

The evaluation for increase in the Accumulator allowed outage time was performed generically by Westinghouse in WCAP-15049, "Risk Informed Evaluation of an Extension to Accumulator Completion Times." From Table 1 of Attachment I to WO 98-0082, the generically determined CDF increase applicable to the WCGS is 3.60E-08. WCAP-15049 did not perform any quantitative evaluations of the potential impact on LERF. However, the LERF increase would be negligible given the small increase in CDF, the fact that the success or failure of containment systems is independent of the accumulators, and the dominant contributors to LERF being containment bypass sequences (Interfacing Systems LOCA and Steam Generator Tube Rupture) for which the WCGS PRA does not consider accumulators for event mitigation.

The evaluation for technical specification changes related to the RTS and ESFAS Instrumentation was performed generically by Westinghouse in WCAP-14333-P-A, Revision 1, "Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times," and WCAP-15376-P-A, Revision 1, "Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times." From Attachment I to WO 03-0059, the increase in CDF is 8.0E-07; and the increase in LERF is 3.09E-08.

From Tables RAI 9-1 and RAI 9-2 included in the response to RAI 9 in Attachment II to WO 03-0057, the increase in CDF and LERF for the proposed Completion Time extensions is 7.43E-07 and 1.56E-08, respectively.

The PRA model to which the changes indicated in the response to Question E.2.1.(f) were applied included the accumulator safety injection fault tree changes from WCAP-15049. Therefore, it may be concluded that any increases in risk associated with the accumulator allowed outage time extension are already included in the baseline risk for the model used to evaluate the proposed Completion Time extensions. However, even if the 3.60E-08 CDF increase for the accumulator allowed outage time extension were included, it would provide minimal contribution to cumulative risk results.

The cumulative CDF and LERF for the RTS and ESFAS Instrumentation changes and the proposed Completion Time extensions are 1.543E-06 (8.0E-07 + 7.43E-07) and 4.65E-08 (3.09E-08 + 1.56E-08), respectively.

It is noted that the individual CDF and LERF increases for the previous risk-informed technical specification allowed outage time (Completion Time) extension submittals indicated above, and the proposed AC Sources Completion Time extensions, are in the "Very Small Changes" region [Region III] of Figure 3 and Figure 4 in Regulatory Guide 1.174. In addition, the cumulative LERF increase of 4.65E-08 is in the "Very Small Changes" region [Region III] of Figure 4 in Regulatory Guide 1.174.

The cumulative CDF increase of 1.543E-06 falls marginally above the 1.0E-06 threshold placing it in the "Small Changes" region [Region II] of Figure 3 in Regulatory Guide 1.174. For this region, a closer assessment of the baseline risk is indicated. The evaluation of the CDF impact for the proposed Completion Time extensions was performed using an internal events model. The mean annual CDF for the internal events PRA model to which the changes indicated in the response to RAI E.2.1.(f) were applied, is 5.479E-05. Upon incorporation of the changes indicated in Section 4.1.1.1.4 of Attachment I to WO 03-0057, the mean annual internal events CDF is 3.485E-05. The mean annual CDF value of 3.485E-05 represents the internal events portion of the baseline CDF risk for Figure 3 in Regulatory Guide 1.174.

For the most part, external events considered in the IPEEE were evaluated against screening criteria specific to each event in accordance with methodologies listed as acceptable in Generic Letter 88-20, Supplement 4. For all external events except fire, evaluation indicated low risk significance and the events were screened out. For fire areas that did not screen out using the progressive screening of the EPRI Fire-Induced Vulnerability Evaluation (FIVE) methodology, quantitative evaluations using conventional PRA approaches was performed. For the unscreened fire areas, the quantified CDF due to fire was 7.59E-06, which was approximately 15% of the internal events CDF determined in the IPE. In 1998, the fire risk evaluation was revisited, using the same methodology, with a resultant quantified CDF due to fire of 8.14E-06. This represented approximately 13% of the internal events CDF of 6.31E-05 for the PRA model current at the time the fire risk was evaluated. The fire risk evaluation has not been updated subsequent to the 1998 time frame.

The fire risk evaluations performed indicate a contribution due to fire that represents less than 20% of the internal events CDF. The remaining external events met the appropriate associated screening criteria and may be considered to be of low safety significance. If the baseline internal events CDF of 3.485E-05, from the PRA model used to evaluate these Completion Time extensions, were increased by 50% to conservatively account for contributions due to external events, the total baseline CDF (5.23E-05) would still remain well below the Region II upper bound CDF of 1.0E-04 from Figure 3 in Regulatory Guide 1.174.

Given that the total baseline CDF value is expected to be well below 1.0E-04; and given that the cumulative CDF increase of 1.543E-06 is only marginally above the Region II lower bound of 1.0E-06; it is considered that the cumulative CDF impact is acceptably small.

The mean annual internal events CDF prior to incorporation of the changes indicated in the response to Question E.2.1.(f) was 5.479E-05. With incorporation of the changes indicated in the response to Question E.2.1.(f), the mean annual internal events CDF is 3.485E-05. A substantial portion of this CDF reduction is due to the addition of the Sharpe Station GenSets. With incorporation of the changes indicated in the response to Question E.2.1.(f), and the proposed Completion Time extensions, the mean annual internal events CDF is 3.531E-05. Approval of the proposed Completion Time extensions will provide important operational flexibility while retaining most of the safety benefit (over the previous CDF of 5.479E-05) due to addition of the Sharpe Station GenSets.

E.2.3 Licensees should confirm that, when evaluating the proposed CT extensions, the diesel generator (DG) PRA model repair/recovery has been modified with respect to the increased DG CT.

Response:

Diesel generator repair/recovery is not explicitly included in the WCGS PRA model.

E.3 The NRC staff did not consider an associated CT for the LOOP DG start instrumentation as part of its review of WCAP-15622. If such an association exists with the CTs for this instrumentation as part of the plant-specific application, the licensee must provide the impact and basis for such an association, or propose TS changes to separate the CT in the plant Technical Specifications (TSs) for ISTS LCO 3.5.5, Condition C from the CTs for an inoperable DG.

Response:

WCNOC's application (WO 03-0057) did not request any changes to TS 3.3.5, "LOP DG Start Instrumentation." Additionally, for WCGS Required Action B.1 of LCO 3.3.5 requires declaring the load shedder and emergency load sequencer inoperable which would further require entry into TS 3.8.1, Condition F, and then entry into TS 3.8.1, Condition D, for an inoperable DG and inoperable offsite circuit with a Completion Time of 12 hours.

ADDITIONAL REQUEST FOR ADDITIONAL INFORMATION DATED AUGUST 2, 2005

Question:

To demonstrate DG operability, Section 6.5 of IEEE 387 recommends that testing should include starting, load acceptance, rated load, load rejection, and subsystem tests. Following on line maintenance and to assure sufficient testability pursuant with the requirements of GDC 17, DG surveillance requirements (SRs) should, as a minimum, include testing recommended by IEEE 387 - the industry consensus standard for selection, design, qualification, and testing of DG units used as Class 1E onsite electric power systems at nuclear power plants. The proposed SR for post maintenance testing, limited to a start and load test, does not demonstrate DG operability pursuant with industry recommendations and thus does not assure sufficient testability pursuant to GDC 17. The proposed TS to allow on line maintenance of the DG is therefore considered unacceptable.

In addition, current SRs performed each refueling do not include the rated load test recommended by IEEE 387 and the WOG STS. Without this test, DG reliability (used as part of risk calculations to extend the allowed DG CT) may be non-conservatively inflated; the sufficient testability requirement of GDC 17 is not being met; and, current Wolf Creek testing is not consistent with WCAP-15622 which is based on the WOG STS recommended testing.

Response:

Similar questions were previously responded to on December 13, 2004. The responses to Questions 32 and 33 discussed the post-maintenance testing that would be performed to ensure OPERABILITY of the DGs. WCNOC currently performs limited maintenance and associated post-maintenance testing at power under the existing 72 hour Completion Time of TS 3.8.1 Required Action B.4.

The response to Question 21 identified that the NRC had previously approved changes to the endurance and margin test (current SR 3.8.1.14) in Amendment No. 101 dated August 9, 1996. The NRC safety evaluation stated, in part: "The above exception to RG 1.9, Revision 3, is acceptable on the basis of the Wolf Creek Generating Station emergency bus loading, the rated EDG capacity, the potential for increase[d] EDG aging and wearing, and the added TS requirement of verifying the diesel generator operates for ≥ 2 hours loaded to an indicated 105 to 110 percent of continuous rated load if auto connected loads increase above 6201 kW." This approval eliminated that portion of the surveillance that required verifying the DG operates for 2 hours at a load equal to 105 to 110 percent of the continuous rating. Plant specific risk evaluations consistent with the methodology provided in WCAP-15622 and Regulatory Guide 1.174 and Regulatory Guide 1.177 were performed for justifying the change to the Completion Time. The performance of the margin test (2 hours at 105 to 110 percent of continuous rated load) does not significantly impact any of the important PRA assumptions and modeling features relevant to the DG Completion Time extension discussed in Section 4.1.1.1.6 of WO 03-0057.