Luminant

Thomas P. McCool
Site Vice President

Comanche Peak
Nuclear Power Plant
(Vistra Operations
Company LLC)
P O. Box 1002
6322 North FM 56
Glen Rose, TX 76043

T 254.897.6042

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U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

Ref 10 CFR 50.90
10 CFR 50.91(a)(6)
10 CFR 50.91(b)(1)

Subject: Comanche Peak Nuclear Power Plant (CPNPP)
Docket Nos. 50-445 and 50-446
Second Supplement to License Amendment Request (LAR) 20-006
APPLICATION TO REVISE TECHNICAL SPECIFICATIONS TO ADOPT RISK INFORMED COMPLETION TIMES, TSTF-505, REVISION 2, "PROVIDE RISK-INFORMED EXTENDED COMPLETION TIMES – RITSTF INITIATIVE 4b (Accession No. ML21131A233)"

Reference:

1. Letter TXX-21046 from Thomas P. McCool to the NRC, License Amendment Request (LAR) 20-006, APPLICATION TO REVISE TECHNICAL SPECIFICATIONS TO ADOPT RISK INFORMED COMPLETION TIMES, TSTF-505, REVISION 2, "PROVIDE RISK-INFORMED EXTENDED COMPLETION TIMES - RITSTF INITIATIVE 4b," dated May 11, 2021 (Accession No. ML21131A233)
2. Letter TXX-21093 from Thomas P. McCool to the NRC, Supplement to License Amendment Request (LAR) 20-006 APPLICATION TO REVISE TECHNICAL SPECIFICATIONS TO ADOPT RISK INFORMED COMPLETION TIMES, TSTF-505, REVISION 2, "PROVIDE RISK-INFORMED EXTENDED COMPLETION TIMES – RITSTF INITIATIVE 4b (Accession No. ML21194A078)"

Dear Sir or Madam:

Pursuant to 10 CFR 50.90 and 10 CFR 50.91, Vistra Operations Company LLC (Vistra OpCo) hereby submits a supplement to the license amendment request for the Comanche Peak Nuclear Power Plant (CPNPP) Unit 1 and Unit 2 Technical Specifications in connection with LAR 20-006, Revision to multiple specifications as requested in References 1 and 2. This second change supplement applies to both units.

This second supplement to the proposed amendment will modify Technical Specifications (TS) requirements for CPNPP to permit the use of Risk Informed Completion Times in accordance with TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times – RITSTF Initiative 4b", (ADAMS Accession No. ML18183A493). A model safety evaluation was provided by the NRC to the TSTF on November 21, 2018 (ADAMS Accession No. ML18267A259). This supplement includes revised Attachments and Enclosures listed below.

In accordance with 10 CFR 50.91(b)(1), a copy of this second supplement for the proposed license amendment is being forwarded to the State of Texas.

Vistra OpCo has determined that this supplement does not change the No Significant Hazards Consideration provided in the Enclosure submitted by Reference 1.

This communication contains no new commitments regarding CPNPP Units 1 and 2.

Should you have any questions, please contact Garry Struble at (254) 897-6628 or Garry.Struble@luminant.com.

I state under penalty of perjury that the foregoing is true and correct.

Executed on February 17, 2022.

Sincerely,

Thomas P. McCool

Executive Summary: License Amendment Request (LAR) 20-006 Second Supplement to Application to Revise Technical Specifications to Adopt Risk Informed Completion Times, TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b"

Attachments:

1. Revised Attachment 1, Description and Assessment of the Proposed Changes
2. Revised Attachment 2, Proposed Technical Specification pages (markup)
3. Revised Attachment 3, Proposed Technical Specification Bases pages (For Information Only - markup)
4. Revised Attachment 4, Cross-Reference of TSTF-505 and CPNPP Technical Specifications

Enclosures:

1. Revised Enclosure 1, List of Required Actions to Corresponding PRA Functions, including Tables and Figures. Tables E1-1, E1-2, E1-3, and E1-4 are revised and included
2. Revised Enclosure 2, Information Supporting Consistency with Regulatory Guide 1.200
3. Revised Enclosure 4, Information Supporting Justification of Excluding Sources of Risk Not Addressed by the PRA Models
4. Revised Enclosure 5, Baseline Core Damage Frequency (CDF) and Large Early Release Frequency (LERF)
5. Revised Enclosure 9, Key Assumptions and Sources of Uncertainty
6. Revised Enclosure 11, Monitoring Program
7. Revised Enclosure 12, Risk Management Action Examples

c (email) -

Scott Morris, Region IV [Scott.Morris@nrc.gov]
Dennis Galvin, NRR [Dennis.Galvin@nrc.gov]
John Ellegood, Senior Resident Inspector, CPNPP [John.Ellegood@nrc.gov]
Neil Day, Resident Inspector, CPNPP [Neil.Day@nrc.gov]

Mr. Robert Free [robert.free@dshs.state.tx.us]
Environmental Monitoring & Emergency Response Manager
Texas Department of State Health Services
Mail Code 1986
P.O. Box 149347
Austin, TX 78714-9347

LICENSE AMENDMENT REQUEST (LAR) 20-006 SECOND SUPPLEMENT to APPLICATION TO REVISE TECHNICAL SPECIFICATIONS TO ADOPT RISK INFORMED COMPLETION TIMES, TSTF-505, REVISION 2, "PROVIDE RISK-INFORMED EXTENDED COMPLETION TIMES - RITSTF INITIATIVE 4b"
[Original submittal is found under Accession No. ML21131A233]
[First supplemental submittal is found under Accession No. ML21194A078]

<u>Executive Summary</u>

The following items describe the supplemental changes to the original LAR and first supplemental submittals based on the license amendment request audit performed between November 30, 2021 and December 9, 2021. After review of the scope of the changes, supplementing the license amendment request is the best method of ensuring the most current and accurate information is available for approval.

<u>NRC Audit of TSTF-505 License Amendment Request Results Summary and CPNPP Response</u>

This summary provides the NRC LAR audit questions and Comanche Peak response to those questions. This summary also includes the location of docketed changes made to the license amendment, including affected Attachments, Enclosures, Tables, and Figures. The audit questions and responses are provided for information only.

The following changes will replace documents included in either the original or the first supplement to update the license amendment request;

1. Replace Attachment 1, Description and Assessment of the Proposed Changes with Attachment 1, Description and Assessment of the Proposed Changes to this letter TXX-22002.
2. Replace Attachment 2, Proposed Technical Specification pages (markup) with Attachment 2, Proposed Technical Specification pages (markup) to this letter TXX-22002.
3. Replace Attachment 3, Proposed Technical Specification Bases pages (markup) with Attachment 3, Proposed Technical Specification Bases pages (markup) to this letter TXX-22002.
4. Replace Attachment 4, Cross-Reference of TSTF-505 and CPNPP Technical Specifications with Attachment 4, Cross-Reference of TSTF-505 and CPNPP Technical Specifications to this letter TXX-22002.
5. Replace Enclosure 1, List of Required Actions to Corresponding PRA Functions with Enclosure 1, List of Required Actions to Corresponding PRA Functions, including Tables and Figures to this letter TXX-22002.
6. Replace Enclosure 2, Information Supporting Consistency with Regulatory Guide 1.200 with Enclosure 2, Information Supporting Consistency with Regulatory Guide 1.200 to this letter TXX-22002.
7. Replace Enclosure 4, Information Supporting Justification of Excluding Sources of Risk Not Addressed by the PRA Models with Enclosure 4, Information

Supporting Justification of Excluding Sources of Risk Not Addressed by the PRA Models to this letter TXX-22002.

8. Replace Enclosure 5, Baseline Core Damage Frequency (CDF) and Large Early Release Frequency (LERF) with Enclosure 5, Baseline Core Damage Frequency (CDF) and Large Early Release Frequency (LERF) to this letter TXX-22002.

9. Replace Enclosure 9, Key Assumptions and Sources of Uncertainty with Enclosure 9, Key Assumptions and Sources of Uncertainty to this letter TXX-22002.

10. Replace Enclosure 11, Monitoring Program with Enclosure 11, Monitoring Program to this letter TXX-22002.

11. Replace Enclosure 12, Risk Management Action Examples with Enclosure 12, Risk Management Action Examples to this letter TXX-22002.

The following questions include the Comanche Peak response in RED text. RED text which is BOLD directs the user to which Attachments, Enclosures, Tables, and Figures have been changed in the license amendment request.

<u>Comanche Peak RICT LAR Audit Questions and Response 1 through 28</u>

QUESTION 01 – Evaluation of Common Cause for Planned Maintenance (APLA)

NEI 06-09, Revision 0-A, states that no common cause failure (CCF) adjustment is required for planned maintenance. The NRC safety evaluation (SE) for NEI 06-09, Revision 0, dated May 17, 2007 (ADAMS Accession No. ML071200238), is based on conformance with Regulatory Guide (RG) 1.177, Revision 1, "An Approach for Plant- Specific, Risk-Informed Decisionmaking: Technical Specifications," dated May 2011 (ADAMS Accession No. ML100910008). Specifically, the NRC SE, Section 2.2, states that,"specific methods and guidelines acceptable to the NRC staff are [...] outlined in RG 1.177 for assessing risk-informed TS changes." The NRC SE, Section 3.2, further states that compliance with the guidance of RG 1.174, Revision 1, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," dated November 2002 (ADAMS Accession No. ML023240437), and RG 1.177, Revision 1, "is achieved by evaluation using a comprehensive risk analysis, which assesses the configuration-specific risk by including contributions from human errors and common cause failures."

RG 1.177, Revision 2, dated January 2021 (ADAMS Accession No. ML19206A493) provides one acceptable approach to addressing the guidelines in RG 1.177, Revision 1.RG 1.177, Revision 2, Section 2.3.3.1, states that, "CCF modeling of components is not simply dependent on the number of remaining in service components; it is also dependent on the reason the components were removed from service (i.e., whether for preventative or corrective maintenance)." In relation to CCF for preventive maintenance, the guidance in RG 1.177, Appendix A, Section A-1.3.1.1, states:

> *If the component is down because it is being brought down for maintenance (but not failed), the CCF contributions involving the component should be modified to remove the component and to only include failures of the remaining components(also see Section C.2.3.3 of this RG).*

According to the guidance of RG 1.177, Revision 2, if a component from a CCF group of three or more components is declared inoperable, the CCF of the remaining components should be

modified to reflect the reduced number of available components in order to properly model the as-operated plant.

The LAR does not discuss how CCFs are treated in the PRA models for planned maintenance. Therefore, address the following:

a) Explain how CCFs are included in the PRA model (e.g., with all combinations in the logic models as different basic events or with identification of multiple basic events in the cut sets);

CCF is modeled using the NRC/INL CCF dataset and the EPRI CAFTA CCF Tool. The Comanche Peak PRA model uses the Multiple Greek Letter (MGL) model for generating CCF basic event probabilities. Consistent with the recommendations from EPRI, the most conservative choice of the final parameter for a CCF group is chosen to represent all group sizes above three. For MGL, this is the delta parameter; for the Alpha method, it would be the sum of remaining parameters. The different combinations of failures are included as separate basic events. Modifications to the MGL parameters are not made for planned (preventive) maintenance activities. This treatment is consistent with the guidance provided in RG 1.177, Revision 2 Section A-1.3.1.1.

b) Describe how the treatment of CCF is evaluated for configuration-specific risk when quantifying a risk-informed completion time (RICT). Explain how the quantification and/or models will be changed when, for example, one train of a 3×100 percent train system is removed for preventative maintenance vs. corrective maintenance.

The calculated base CCF probabilities are not altered for the RICT calculation. As discussed in the LAR, because the front stop has passed before the RICT is applied, it would be known whether a CCF exists for the failure mode(s) exhibited by the failed components.That is, the plant ensures that there is reasonable assurance that the sister components are OPERABLE and are not exhibiting similar failure conditions as the component that has been removed from service. In general, RMAs, in lieu of CCF factor adjustments, are relied upon to address potential CCFs, consistent with the NEI guidance. For emergent conditions during a RICT requiring additional RICT entries, additional RMAs, developed specifically for the emergent condition are relied upon to address potential CCFs. For the CPNPP model there is no difference between preventative and corrective maintenance removal from service. The RMAs are created based on what components are out of service and what components require protection.

Comanche Peak uses the following process for identifying RMAs for emergent conditions during the RICT:

RMAs are identified and implemented to:

- Prevent or minimize the probability of emergent events while a RICT is active
- Ensure that mitigating and control features are available
- Maintain defense-in-depth

RMAs encompass the following three categories:

- Actions to increase risk awareness and control.
- Actions to reduce the duration of maintenance activities.
- Actions to minimize the magnitude of the risk increase.

License Amendment Request docketed change is found in Enclosure 9, Section 2.0, Table 1, that has been revised to clarify the treatment of Common Cause Failures, consistent with RG 1.177.

QUESTION 02 – Internal Events PRA Supporting Requirements (SRs) that are Capability Category (CC) I (APLA)

RG 1.200, Revision 3, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," (ADAMS Accession No. ML20238B871) provides guidance for addressing PRA acceptability. LAR Enclosure 2 states that the Comanche Peak PRA was developed in accordance with the guidance in this regulatory guide. Regulatory Guide 1.200, Section C.2.1 specifies that, generally, the NRC staff anticipates that CC II of the ASME/ANS PRA standard ASME/ANS-RA-Sa-2009, "Addenda to ASME/ANS RA-S-2008, Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications," is the level of detail that is acceptable for the majority of applications, but that CC I may be acceptable for some requirements.

LAR Enclosure 2, Section 2.0 presents the assessment of supporting requirement (SR) LE-C11 which addresses in part those sequences that would result in a large early release. SR LE-C11 was assessed by the peer review to be met at CC I. This SR was assessed to meet CC I because mitigating equipment and operator actions are not credited in the PRA after containment failure. The assessment of this SR states that mitigating equipment and operator actions are not credited because "there are none that are significant." However, the assessment of this SR further states that the "impact on specific applications will be evaluated as needed." Not fully crediting structures, and components (SSCs) in technical specifications (TSs) that are included in the RICT program may lead to a non-conservative treatment for the TSTF-505 application because this may result in underestimating associated RICTs. The LAR does not explain how the impact of CC I will be evaluated for the TSTF-505 application (or on the calculation of RICTs). Therefore, address the following:

a) Provide justification that not crediting operation of mitigating equipment and operator actions after failure of containment does not result in non-conservative RICTS or has a non-significant impact on calculated RICTs.

CPNPP's Level 2 model follows the guidance of WCAP-16341-P, "Simplified Level 2 Modeling Guidelines", which in this case (LE- C11) results in CC-I being Met. This report provides a common simplified Level 2 methodology for large dry containments that, in conjunction with appropriate plant specific assessments, would meet the technical adequacy of the ASME PRA Standard Capability Category II for assessment of the Large Early Release Frequency (LERF). This report provides a Level 2 methodology that is consistent with the approach outlined in NUREG/CR-6595, Revision 1. The ASME Standard (LE-C11, CC-I) allows for not crediting equipment beyond containment failure because it is conservative to assume failure of the equipment at that time or the equipment operation is not relevant to LERF. Note that containment equipment (e.g., sprays, isolation valves) is credited prior to containment failure in the PRA; the assumption of failure is only applicable given that the containment has failed. An example scenario is where containment failure does not allow containment pressure to increase to the point that containment sprays will actuate; thus, containment sprays are not available for radioisotope scrubbing. RICT for systems that are unrelated/unaffected by containment failure are not impacted by this conservative assumption. RICT for systems that can be impacted by containment failure (e.g., containment spray) will have the appropriate equipment out of service in the model for all LERF scenarios. Credit is not taken for these systems following containment failure because they are not significant to the LERF results. Note that the example (containment spray) is not required for LERF scenarios, per the referenced WCAP and NUREG. The operation of sprays (containment heat removal) in these guidance documents is modeled to lead to scrubbed (small) and/or late releases (i.e., not

LERF), and is not credited following containment failure. Thus, this topic is largely limited to containment isolation, which is not relevant beyond containment failure for defining LERF (i.e., simplified Level 2 model that does not consider source terms in detail) since the containment is already failed.

b) Alternatively, explain how meeting CC I will be evaluated for impact on the RICT program (i.e., on calculated RICTs).

Credited containment systems subject to impacts from containment failure may be considered explicitly when they are the target of a RICT; however, it is not expected that there will be any significant impact based on WCAP-16341-P (NUREG/CR-6595) implementation, and the approach is conservative.

The following is a summarization of the referenced WCAP report discussed above.

WCAP-16341-P provides a common simplified Level 2 methodology for large dry containments that, in conjunction with appropriate plant specific assessments, would meet the technical adequacy of the ASME PRA Standard Capability Category II for assessment of the Large Early Release Frequency (LERF). This report provides a Level 2 methodology that is consistent with the approach outlined in NUREG/CR-6595, Revision 1, but further concentrates on gathering the data necessary to generate models and data necessary to realistically treat severe accident management actions, direct containment heating failures, and Thermally Induced Steam Generator Tube Ruptures (TI-SGTR). The model includes the capability to compute LERF, as well as later contributions to plant risk. These later contributions can impact risk importance of containment systems and are of importance as input in Level 3 risk assessments. The LERF model specifically: (1) includes capability to model thermally and pressure induced steam generator tube ruptures, and (2) considers operator actions within the scope of Westinghouse and Combustion Engineering Severe Accident Management Guidance. Level 2 aspects of the event tree have been explicitly developed with simplified treatment of basemat melt-through, delayed hydrogen combustion, and consideration of long-term containment heat removal.

License Amendment Request docketed change is found in Enclosure 2, Section 2.0, that has been revised to clarify the use of WCAP-16341 and NUREG/CR-6595.

QUESTION 03 – Total Risk and Accounting for the State of Knowledge Correlation (SOKC) (APLA)

RG 1.174 provides the risk acceptance guidance for total core damage frequency (CDF)(1E-04 per year) and Large Early Release Frequency (LERF) (1E-05 per year). NRC staff notes based on RG 1.174 and Section 6.4 of NUREG-1855, Revision 1, “Guidance on the Treatment of Uncertainties Associated with PRAs in Risk-Informed Decision Making,” dated March 2017 (ADAMS Accession No. ML17062A466), for a CC II risk evaluation, the mean values of the risk metrics (total and incremental values) need to be compared against the risk acceptance guidelines. The mean values referred to are the means of the probability distributions that result from the propagation of the uncertainties on the PRA input parameters and model uncertainties explicitly reflected in the PRA models. In general, the point estimate CDF and LERF obtained by quantification of the cutset probabilities using mean values for each basic event probability does not produce a true mean of the CDF/LERF. Under certain circumstances, a formal propagation of uncertainty may not be required if it can be demonstrated that the SOKC is unimportant (i.e., the risk results are well below the acceptance guidelines).

LAR Enclosure 5, Section 2 presents the hazard-specific and the total CDF and LERF values in Table 1 for both Comanche Peak units. NRC staff notes that for Comanche Peak Unit 1, the

total LERF presented in the LAR is 8.2E-06 per year. The LAR does not explain how the CDF and LERF values were calculated for the internal events, internal flood, and internal fire hazards. If they are "point estimate" values, then they are likely lower than the mean CDF and LERF values where in SOKC is accounted for in the quantification. In addition, NRC staff notes that the current PRA models could potentially be updated in response to information requests (e.g., such as the response to requests on the acceptability of fire PRA methods). Therefore, the total LERF could approach the RG 1.174, Revision 3 guideline value of 1E-05 per year when the total mean LERF is used accounting for the SOKC and potential risk increases associated with model updates. Therefore, address the following:

a) Demonstrate that, after the total mean internal events and fire CDF and LERF values are calculated to account for the SOKC and for potential changes in risk due to any updates to PRA models performed in response to NRC staff information requests, the total risk for Unit 1 and 2 is in conformance with RG 1.174 risk acceptance guidelines (i.e., CDF <1E-04 per year and LERF < 1E-05 per year). Include identification of the fire PRA parameters that are assumed to be correlated in the parametric uncertainty analysis of fire events.

For internal events, the analysis results in R&R-PN-041 identify less than a 5% impact from the SOKC, comparing the point estimate and mean, both derived by UNCERT for consistency. The point estimates from UNCERT LERF are 3.59E-06 and 1.91E-07, while the mean CDF and LERF are 3.75E-06 and 1.97E-07, respectively; negligible differences between units. Internal flooding is a small percentage of overall CDF/LERF and also has little influence on SOKC because (1) flood-induced failures are assumed (i.e., 1.0) and the major correlation of data comes from the initiating event data (pipe rupture data), for which events are mutually exclusive.

The fire PRA is sampled on distributions assigned for ignition frequency, heat release rate, circuit failure likelihood, and spurious operation duration, going beyond the state of practice in general (CN-RAM-17-011). CN-RAM-13-038 identifies less than 1% impact from SOKC, again comparing to the point estimate derived by UNCERT for consistency.The mean CDF and LERF are 5.65E-05 and 7.85E-06, respectively. Unit 1 results bound Unit 2.

Thus, the total mean CDF and LERF are around 6E-05/reactor-year and 8E-06/reactor-year, respectively, which are well below the RG 1.174 guidelines.

b) Alternatively, propose a mechanism that ensures calculation of the mean internal events, internal flood, and internal fire CDFs and LERFs, account for the SOKC and updates to the PRA models performed in response to NRC staff information requests prior to implementation of the RICT program. The mechanism must also ensure confirmation that the updated total CDF and LERF values are still in conformance with the RG 1.174 risk acceptance guidance (i.e., CDF < 1E-04 per year and LERF < 1E-05 per year) prior to implementation of the RICT program.

See above.

c) Discuss how the SOKC will be addressed for the RICT program, and how this treatment is consistent with NUREG-1855, Revision 1 when the risk increase associated with SOKC is considered.

SOKC is negligible for flood and fire, and within the acceptance criteria for internal events. SOKC is assessed via proper parametrization of events in the PRA model and propagation via a sampling method (Monte Carlo). If SOKC is significant (greater than 10%, as defined in EPRI 1016737, and consistent with NUREG-1855 (which refers to the EPRI report for guidance on SOKC treatment)), the missing correlation would be artificially introduced to the

cutsets. This cutset manipulation involves determining multiplicative factors that can be added to cutsets. RICT in general does not influence the underlying reliability data, which is the source of SOKC for PRAs. Thus, it is not expected that a RICT for any particular component would require a reassessment of SOKC.

License Amendment Request docketed change is found in Enclosure 5, Section 2.0, including Table 1, that has been revised to include a discussion of the consideration of SOKC in the uncertainty evaluations, and

License Amendment Request docketed change is found in Enclosure 9, Section 2.0, including Table 1, that has been revised to include a discussion of the consideration of SOKC in the uncertainty evaluations.

QUESTION 04 – PRA Model Uncertainty Analysis Process (APLA)

The NRC staff SE to NEI 06-09, Revision 0, specifies that the LAR should identify key assumptions and sources of uncertainty and to assess and disposition each as to their impact on the RMTS application. NUREG-1855, Revision 1, presents guidance on the process of identifying, characterizing, and qualitative screening of model uncertainties.

LAR Enclosure 9 states that the process for identifying key assumptions and sources of uncertainty for all PRA models (internal events, internal flood, and internal fire) was performed using the guidance in NUREG-1855, Revision 1. The LAR indicates that plant-specific sources of uncertainty were identified and characterized by a review of all PRA notebooks, but that generic sources of uncertainty were also identified and characterized. The LAR further explains that both the plant-specific and generic assumptions and uncertainties were evaluated for impact on the baseline PRA model and on the TSTF-505 application, and that applicable sensitivity analyses were performed as necessary to assess the impacts of assumptions/uncertainties on the baseline PRA model while no additional sensitivity analyses were needed to assess the impacts of assumptions/uncertainties on the TSTF-505 application. Table 1 of Enclosure 9 of the LAR provides the dispositions to 11 key sources of assumptions and uncertainties that were determined to have a potential impact on the TSTF-505 application. Additional information is needed for the NRC staff to make a determination that the key assumptions and sources of uncertainty have been appropriately identified and assessed for impact on the TSTF-505 application, including that impacts on the LCOs to be included within the scope of the RMTS program have been considered.

Address the following:

a) Describe the process for identifying a comprehensive list of generic assumptions and sources of uncertainty for each of the PRA models (i.e., internal events, internal flooding, and internal fire). In the response, specifically address how the guidance in NUREG- 1855, Revision 1 was implemented with regard to use of EPRI Topical Report (TR) 1016737, "Treatment of Parameter and Model Uncertainty for Probabilistic Risk Assessments" and EPRI TR 1026511, "Practical Guidance of the Use of Probabilistic Risk Assessment in Risk-informed Applications with a Focus on the Treatment of Uncertainty."

In Section 5.2 of R&R-PN-041, a description is provided of how every analysis associated with the internal events model was reviewed for sources of uncertainty and potentially warranted sensitivity analyses to be conducted. Section 5.1 of R&R-PN-041 also addresses the generic sources of uncertainty required by EPRI 1016737 for meeting CC-II of applicableASME/ANS Standard supporting requirements, including internal flooding. Furthermore, generic sources of uncertainty for other hazards as specified in EPRI 1026511 are dispositioned in each of the individual hazard PRA notebooks. These reports identify a “minimum set” of significant sources

of uncertainty to be considered, that are generally applicable across the industry, along with examples of characterization for those sources of uncertainty. Section 5.4 of R&R-PN-021 and Section 5.5. of CN-RAM-13-038 discuss the uncertainties associated with the internal flooding PRA model and internal fire PRA model, respectively. The process defined in the internal events uncertainty analysis received a Best Practice for inclusion of warranted sensitivities, and it includes the process developed in EPRI 1016737 for meeting CC-II of the ASME/ANS Standard. This process is consistent with NUREG-1855 in terms of applicable sources of uncertainty to consider (i.e., model, parameter and completeness uncertainty) and in terms of setting up appropriate sensitivities (bounding, use of reasonable alternative assumptions, etc.) for characterizing the uncertainty of various assumptions for the PRA. Enclosure 9 of the LAR discusses the extension of this process for the RICT application.

EPRI document – 1016737 presents guidance on parametric uncertainty characterization for use in meeting the ASME/ANS PRA standard. In particular, the guidance addresses state-of-knowledge correlation (SOKC) when evaluating the risk metrics under PRA. Note that NUREG-1855 refers to SOKC as epistemic correlation. It continues to discuss how a previously developed, long list of potential sources of uncertainty was reviewed, leading to the earmarking of certain issues as candidates for modeling uncertainty. Now that the narrower list of candidates exists, a plant-specific issue characterization for the base PRA model can be provided in order to meet the relevant supporting requirements from the standard for the base PRA model. Finally, it provides guidance on characterizing modeling uncertainties in the context of risk informed applications. A framework for the selection, preparation, assessment, and reporting of results of sensitivity studies to account for uncertainties in the context of decision making is laid out.

EPRI document – 1026511 provides a general guidance for the treatment of uncertainties in PRAs to supplement and complement the guidance in NUREG-1855 (Revision 0, March 2009) and also provided an assessment of the sources of model uncertainty and associated assumptions in PRAs for the internal events hazard group. The current document provides supplementary practical guidance for the development of a risk-informed application to include the implementation of the techniques discussed in Revision 1 of NUREG-1855 for the treatment of uncertainty.

b) For each of the PRA models (i.e., internal events, internal flooding, and internal fire), describe the general evaluation criteria used to consistently screen assumptions and sources of uncertainty from an initial comprehensive list (including those associated with plant specific features, modeling choices, and generic industry concerns) in order to produce the list of key assumptions and sources of uncertainty that is presented in the LAR. In the response, specifically address how this criterion considered potential impacts on each LCO included within the scope of the RMTS program.

In the general uncertainty analyses for the hazards, screening was performed for sources of uncertainty based on a judgment of impact to the model or whether sufficient justification was included in the analysis (i.e., little was screened in terms of uncertainty characterization for the baseline models). Nothing was screened relative to EPRI 1016737. For the LAR, the process included (1) reviewing the existing uncertainty analyses for the baseline PRA models, (2) assessing those insights in context of the application, and (3) determining if any additional sensitivities were needed for the application. Key sources are identified in Enclosure 9 of the LAR based on whether or not the source of uncertainty could potentially be influenced by the RICT application.

These key sources are then dispositioned in more detail with respect to the application and specifically whether they can influence the results in the RICT. Non-key sources were also

dispositioned but without a detailed inclusion in Enclosure 9 because they are not key to the application.

From RG 1.200:

A key assumption is one that is made in response to a key source of model uncertainty in the knowledge that a different reasonable alternative assumption would produce different results, or an assumption that results in an approximation made for modeling convenience in the knowledge that a more detailed model would produce different results. For the base PRA, the term "different results" refers to a change in the risk profile (e.g., total CDF and total LERF, the set of initiating events and accident sequences that contribute most to CDF and to LERF) and the associated changes in insights derived from the changes in the risk profile. A "reasonable alternative" assumption is one that has broad acceptance within the technical community and for which the technical basis for consideration is at least as sound as that of the assumption being challenged.

A key source of uncertainty is one that is related to an issue in which there is no consensus approach or model and where the choice of approach or model is known to have an impact on the risk profile (e.g., total CDF and total LERF, the set of initiating events and accident sequences that contribute most to CDF and to LERF) such that it influences a decision being made using the PRA. Such an impact might occur, for example, by introducing a new functional accident sequence or a change to the overall CDF or LERF estimates significant enough to affect insights gained from the PRA.

For this application the following general guidance was used to determine whether an assumption or source of uncertainty would be key for the TSTF-505 application:

- Conservative modeling – If the assumption or source of uncertainty resulted in a conservative impact on the baseline PRA model, the assumption or source of uncertainty was assessed to not have a significant impact on the calculation of risk-informed completion times. It is expected that for a conservative modeling choice to have a significant impact on a RICT, the impact on the baseline PRA model would need to be significantly conservative. Modeling of this type typically is not included in the PRA as it would mask risk insights.
- Consensus Model or Method – If the assumption or source of uncertainty was introduced as part of a consensus model or method the assumption or source of uncertainty was assessed to be "state-of-practice" and was not considered a key assumption or source of uncertainty for the application. Modeling choices based on consensus models or methods are generally supported by NRC safety evaluations (SEs) or industry standard practices where no reasonable alternative exists.
- Modeling area – In some cases, assumptions and sources of uncertainty were classified based on the respective PRA model area (e.g., component screening, seasonal variations, CCF modeling, alignments, etc.). It is expected that items of this type could have the largest impact on a calculated completion time. For example, given a component is taken out of service for corrective maintenance, choices in CCF modeling could have a significant impact on the result. These items were further dispositioned in Enclosure 9 of the LAR.

c) Concerning the evaluation criteria used to evaluate and screen uncertainties addressed in part (b) above:

   i. Discuss the criteria used to consistently determine when a sensitivity study was used to address the identified source of uncertainty.

The criteria used to determine whether additional sensitivities are warranted for a source of uncertainty were (1) Is the source of uncertainty adequately characterized in the source analysis? and (2) Is the impact conservative or easily assessed as being negligible qualitatively? This is with respect to performing additional sensitivities specific to the application since most sources of uncertainty include some sensitivity analysis within the source analysis document or the baseline uncertainty analysis (e.g., R&R-PN-041) or are otherwise adequately characterized for the baseline model.

ii. Discuss the criteria used to consistently determine when additional risk management actions (RMAs) should be implemented because of modelling uncertainty.

Enclosure 12 describes the process for developing/implementing RMAs, which refers to Enclosure 9 to consider the key sources of uncertainty. None of the key sources of uncertainty are considered to be significant (e.g., they typically represent a conservatism or are irrelevant in configuration risk); however, the process would consider equipment and actions related to those modeling choices and the impact that the related assumptions have on the RICT calculation. An example might be the inclusion of a discussion of important related operator actions in the pre-job brief.

A sensitivity case was done to show the potential impact of the modeling choice to assume equipment whose cable routing was unknown in the FIRE PRA was assumed to always be failed. The conclusion of that case was that the RICT CT was not sensitive to that modeling choice. Refer to Question 16 subsection f.ii for details of this sensitivity.

License Amendment Request docketed change is found in Enclosure 9 has been revised to include a discussion of the process used to identify key sources of uncertainty (see sections 1.0, 2.0, and Table 1).

QUESTION 05 – Dispositions of PRA Model Assumptions and Sources of Uncertainty (APLA)

The NRC staff SE to NEI 06-09, Revision 0, specifies that the LAR should identify key assumptions and sources of uncertainty and to assess and disposition each as to their impact on the RMTS application. NUREG-1855, Revision 1, presents guidance on the process of identifying, characterizing, and qualitative screening of model uncertainties.

LAR Enclosure 9 Table 1 provides dispositions for 11 candidate key assumptions and sources of uncertainty. In most cases, the LAR concludes that RICT program calculations are not impacted by the modeling uncertainty and no RMAs are required to address the uncertainty. Regarding Items 1 and 4 in Table 1 on development and application of testing and maintenance (T&M) unavailability, there is not enough information for NRC staff to conclude that the assumption or source of modeling uncertainty would not have an impact on the RMTS program. Specifically, from Item 1, the following statement is made:

> "For the average T&M quantification, systems with trains that alternate throughout the year (running (or protected) vs. standby) have been set with Train A running; however, the interpretation in this case is that it is a generic train (similar to the unit alignments),with the understanding that the represented train is alternating throughout the year."

This statement appears to imply that the Comanche Peak PRA model does not model alternate system alignments or account for asymmetries in each train. Because system failure probabilities could be different for alternate system alignments, the quantification of CDF and LERF could be impacted by system alignment assumptions. With regards to this issue , address the following:

a) Clarify how alternate system alignments and system asymmetries are considered in the

PRA models for applicable systems and provide justification that these treatments do not underestimate CDF and LERF. If CDF and LERF are underestimated, then justify that this non-conservatism is inconsequential to the RMTS program.

Split fractions or point estimates are not used in the CPNPP PRA for alignments; however, all necessary alignments are explicitly modeled. Plant alignments are entered into the Phoenix RM RICT model to reflect the 'actual' plant configuration. The alignment inputs can be modified to reflect which trains of equipment are running and which are in standby. They can also be adjusted to reflect "protected train", off-site power alignment, position of PORV block valves or containment relief valves. The model includes house events to allow the alignments to be changed prior to quantification. Therefore, they are all accounted for and it does not result in any undue optimism.

For the baseline (average-maintenance) model, it means that some interpretation of the results is needed in order to recognize that the average-maintenance model would include failures of either alignment spread out over the year, whereas the model shows only one alignment for the period. This is numerically equivalent but requires the one alignment to be interpreted symmetrically. For configuration risk, this is irrelevant because the alignments are known and set in the model appropriately. Therefore, treatment of alignments does not in general underestimate CDF and LERF; on the other hand, this approach avoids the need for basic events using large numbers (e.g., 0.5) to account for alignments, which would violate the small number approximation assumed in CAFTA and introduce some potential to impact the calculation of CDF/LERF. For a few selected systems that are periodically rotated, such as instrument air, a conservative approach was taken with regard to operating/standby configurations (both included without house events). This was done to simplify the model for those less important systems. With respect to FIRE related 'always failed' components, a sensitivity study was performed to show a relatively small change in CDF/LERF and negligible impact to calculated extended RICT.

b) The evaluation of the TSTF-505 impact for both Items 1 and 4 state "Average test & maintenance probabilities are substituted in the configuration risk model." Explain the meaning of this statement and justify that the treatment oftest and maintenance probabilities in the configuration risk model is in accordance with NEI 06-09.

Test and Maintenance event probabilities are set to zero for the RICT calculations as required by NEI 06-09 in order to accurately model the actual plant configuration.

c) R&R-PN-041, "Sensitivity and Uncertainty," provides the results of sensitivity studies from any sources of modeling uncertainty. While the sensitivity study results do not specifically address the potential impact on the RICT program, there are those that appear to have the potential to impact RICT calculations. Address the following specific uncertainties identified from this report.

   a. Section 5.2.7 identifies that assumptions regarding the operator action to control auxiliary feedwater upon battery depletion can have a significant impact on CDF (the impact on LERF was not evaluated). It is noted that the LAR proposes to include within the scope of the RICT program TSs for the auxiliary feedwater and battery systems, which would appear to further increase the importance of this operator action when systems leading to this scenario are out-of-service. Therefore, address the following:

      i. Provide the bases for concluding that human failure events (HFE) assumptions regarding this operator action are not significant or key to the RICT application. In the response address its importance to all hazards modeled in the PRA (i.e.,

internal events, internal flood, internal fire).

ii. If, in response to part (1) above, it cannot be determined that the cited assumptions have an inconsequential impact on the estimated RICTs, then identify what programmatic changes will be considered to compensate for this uncertainty and the basis for their consideration (e.g., identification of additional RMAs).

b. Section 5.2.10 identifies that the ability to cross-tie the service water and the component cooling systems between units is modeled in the PRA and can have a significant impact on CDF (the impact on LERF was not evaluated). It is noted that the LAR proposes to include within the scope of the RICT program TSs for both the service water and component cooling systems, and that TS 3.7.8.A is specifically for the inoperability of a service water system cross-tie to the other unit. There is no similar TS for the cross-tie of the component cooling system. Therefore, address the following:

i. Provide the bases for concluding that the availability of the component cooling system cross-tie is not significant or key to the RICT application. In the response address its importance to all hazards modeled in the PRA (i.e., internal events, internal flood, internal fire).

ii. If, in response to part (1) above, it cannot be determined that the cited assumptions have an inconsequential impact on the estimated RICTs, then identify what programmatic changes will be considered to compensate for this uncertainty and the basis for their consideration (e.g., identification of additional RMAs).

The assumptions of the AFW action were reviewed in the context of RICT. The action is important for the baseline model, regardless of the application, largely because the assumptions are conservative; and it should be included in pre-job briefs for any RICTs potentially influenced by the action, as part of associated RMAs. Significant operator actions, in general, should be considered in a pre-job brief for RICTs that are directly related to those actions; for example, a RICT associated with batteries (AFW is not relevant because the function would be unavailable when this action would be credited).This action is in response to total function loss. Because multiple trains will never be impacted by a RICT, the assumptions of the action are not significantly impacted, and therefore its influence on the associated RICTs is not significant. For this reason and the conservative assumptions for the action, the uncertainty is not key to the application.

As for the cross-ties, they are explicitly modeled and the impact of RICTs involving them will be reflected in the RICT calculation. The availability of the cross-ties is explicitly modeled. This scenario is similar to a RICT impacting a modeled train of SW, where the train is "assumed" to be available, normally. The train is modeled and therefore the impact will be captured in the calculation. It does not imply that there is a significant or key source of uncertainty related to the SW train that can impact the RICT results.

QUESTION 06 – Modeling of RCP Shutdown Seals (APLA)

The NRC staff SE to NEI 06-09, Revision 0, specifies that the LAR should identify key PRA model assumptions and sources of uncertainty and to assess and disposition each as to their impact on the RMTS application.

LAR Enclosure 9 provides a listing of key sources of assumptions and uncertainties for the TSTF-505 application and associated dispositions to each. While not addressed in this

enclosure, LAR Enclosure 2 explains that the Comanche Peak PRA model includes modeling of the reactor coolant pump (RCP) shutdown seals (SDSs) in accordance with the NRC-approved version of PWROG-14001-P-A, "PRA Model for the Westinghouse Shutdown Seal," dated October 2017 (ADAMS Package Accession No. ML18019A190).The NRC safety evaluation (SE) for this topical report, dated August 23, 2017 (ADAMS Package Accession No. ML17200A116), identifies limitations and conditions regarding its use in risk-informed applications. LAR Enclosure 2 states that the Comanche Peak PRA models are consistent with PWROG-14001-P-A and addresses all the NRC limitations and conditions. However, while LAR Enclosure 2 specifically addresses Limitations and Conditions #2 and #4, other Limitations and Conditions relevant to risk-informed applications are not addressed. In light of this, address the following:

a) Limitation and Condition #5 specifies that plant-specific human error probabilities (HEP) are to be developed and factored into the model-of-record and that there are to be provided in risk-informed licensing application submittals.

    i. Provide and justify the HEPs used for the modeling of the RCP SDSs and discuss the uncertainty associated with these HEPs.

    ii. Discuss whether these HEPs are key assumptions or sources of uncertainty for the TSTF-505 application. If not key assumption or sources of uncertainty, provide justification for this determination.

    iii. If these HEPs are key assumptions or sources of uncertainty, identify appropriate RMAs for these key assumptions consistent with the treatment of key assumptions in NEI 06-09-A, prior to implementation of the RICT program.

Section 5.3 of R&R-PN-027 describes the inclusion of relevant operator actions, which are quantified in R&R-PN-020. Section 5.2.5 of R&R-PN-041 discusses uncertainty related to the RCP seal LOCA model. While it does not explicitly address these operator actions, the impacts of the associated functions (shutdown seal (SDS) success/failure and asymmetric steam generator cooldown) are characterized, which should be proportional to the respective operator actions. Section 5.2.4 in R&R-PN-041 includes some generic sensitivities for operator actions and the sampling approach described in the same document includes parametrization of operator actions.

The HEP for tripping the RCPs to protect the SDS is not affected by the RICT. The same requirements (e.g., rapid response) regardless of the RICT entry apply to the action. That is, it is predicated on the loss of RCP seal cooling and, given that loss of function, then the RCPs must be tripped within a certain time frame. Therefore, the RCP HEP does not feed directly into any component to which we would apply the RICT. The LCOs that are part of the RICT submittal can affect the seal cooling function (seal injection using the CCPs and TBC using CCW); RICT cannot be entered for those LCOs if there is a loss of function (either seal injection or TBC). It should be noted that this specific operator action is not one of the top 5 operator actions identified in the Fire or internal events PRA results; though, there is a strong emphasis on tripping the RCPs in operator training and procedures, for the scenario.

These actions (trip the RCPs and cooldown with asymmetric secondary cooling) are not considered key for the application. The modeling is generally conservative, and it is not expected that a RICT will directly impact RCPs/LOCA frequencies. Also, it follows a consensus approach, which generally precludes the need to identify the assumptions as key (i.e., the consensus is that there are no other reasonable assumptions that are justified to be equivalent), and for which the guidance for developing these actions is based on a sophisticated analysis.

Licensed Operator training is provided both in the classroom and simulator regarding RCP seals. The classroom training provides the basic layout and function of the seals. The simulator training is more focused on responding to seal/seal cooling malfunctions in order to maintain seal integrity. Abnormal Condition Procedure, ABN-101, "Reactor Coolant Pump Trip/Malfunction is implemented for RCP Number 1 Seal Failure where the actions intended to maintain seal integrity are performed against a standard of performance to ensure repeatability and proficiency for all control room operators. Actions include tripping the reactor, stopping the affected RCP, isolating number 1 seal leakoff, and monitoring RCP cooling from Component Cooling Water (CCW) for the Thermal Barrier Heat Exchanger and pump motor. Also seal injection from the Chemical and Volume Control System (CVCS) is maintained if possible. ABN-101 also provides instructions for response to RCP number 2 and number 3 RCP seal failures. The procedure (ABN-101) also provides actions when seal injection from CVCS fails with a simultaneous loss of thermal barrier heat exchanger cooling from CCW. This section requires tripping the reactor, stopping affected RCP(s), verifying the # 1 seal leakoff valve(s) are open, isolating seal injection, isolating CCW flow to the thermal barrier heat exchanger(s), and monitoring Reactor Coolant System (RCS) leakage.

b) Limitation and Condition #10 specifies that if the SDS PRA model is used for plant-specific conditions and procedures that are different than typically assumed for Westinghouse plants then a description and justification for this model is to be provided in the risk-informed licensing applications that rely on this model.

   i. Confirm and justify that the Comanche Peak plant-specific conditions and procedures are typical of those for Westinghouse plants.

   ii. If it cannot be justified that the Comanche Peak plant-specific conditions and procedures are typical of those for Westinghouse plants, provide a description of and justification for the Comanche Peak SDS PRA model and its impact on the RICT program.

   iii. If justification cannot be provided for the Comanche Peak SDS model (e.g.,that it does not represent a key assumption or source of uncertainty), identify appropriate RMAs prior to implementation of the RICT program.

The CPNPP seal LOCA model follows PWROG-14001-P-A without significant deviation. The PRA use is consistent with that topical report, and plant-specific conditions and procedures (e.g., EOP inclusion and training for tripping the RCPs early) are typical for Westinghouse plants. R&R-PN-027 describes the seal LOCA model implementation and its consistency with PWROG-14001-P and WCAP-15603 (WOG2000).

QUESTION 07 – Digital Instrumentation and Control (I&C) Modeling (APLA)

NEI 06-09 state concerning the quality of the PRA model that "RG 1.174, Revision 1, and RG1.200, Revision 1 define the quality of the PRA in terms of its scope, level of detail, and technical adequacy. The quality must be compatible with the safety implications of the proposed TS change and the role the PRA plays in justifying the change."

Regarding digital I&C, NRC staff notes the lack of consensus industry guidance for modeling these systems in plant PRAs to be used to support risk-informed applications. In addition, known modeling challenges exist such as the lack of industry data for digital I&C components, the difference between digital and analog system failure modes, and the complexities associated with modeling software failures including common cause software failures. Also, though reliability data from vendor tests may be available, this source of data is not a substitute for in-the-field operational data. Given these challenges, the uncertainty associated with modeling a digital I&C system could impact the RICT program. However, it is not clear to

NRC staff whether the licensee credited digital system in the PRA models that will be used in the RICT program or whether this modeling can impact the RICT calculations.

Therefore, address the following:

a) Clarify whether digital I&C systems are credited in the PRA models will be used in the RICT program.

b) If digital I&C systems are credited in the PRA models that will be used in the RICT program, then justify that the modeling uncertainty associated with crediting digital I&C systems in the PRA models. Describe its impact on the RICT calculations.

Digital systems are not included in the CPNPP RICT program LCOs. There are digital systems installed in the plant (e.g., BOP), but they are not credited in the systems that are explicitly modeled in the PRA model. There are no risk significant I&C systems at CPNPP. In the higher-level systems, digital controllers are used for the main feedwater pump speed controller and the main generator voltage control. Failure modes for these applications are considered in the PRA as part of the IEF (reactor/turbine trip or loss of main feed water).

License Amendment Request docketed change is found in Enclosure 2, Section 1.0, that has been revised to explicitly note that digital systems are not included in the CPNPP RICT Program LCOs.

QUESTION 08 – Consideration of Shared Systems in RICT Calculations (APLA)

The Tier 3 requirement of RG 1.177 stipulates that a licensee should develop a program that ensures that the risk impact of out-of-service equipment is appropriately evaluated prior to performing any maintenance activity.

LAR Enclosure 2, Section 1.0 states that the internal events PRA model is a combined PRA model that represents both units, that it is a common one-top fault tree having individual basic events for components for both units, and that differences between the two units are activated by flags to produce unit-specific PRA results. The LAR does not explain how the various PRA models address dual unit events for systems or SSCs that are shared between units (e.g., common power buses). NRC staff notes that for certain events such as dual unit events (e.g., loss of offsite power) it may be appropriate to only credit the shared systems for one unit in the RICT calculations.

Therefore, address the following:

a) Explain whether shared systems are credited in the internal events, including flood, and fire PRA models for both units and, if so, identify those systems.

There are several shared systems between the units and several capabilities to cross-tie functions. Those that are included or considered in the PRA model are identified below. Regarding the cross-ties, the SSW and CCW systems are credited for limited scenarios in the model. By procedure, the supplying unit will sacrifice one train, given a total loss in the other unit.

The systems that are shared at CPNPP include systems that can be used to supply either unit (e.g., instrument air common compressors) and those that can be cross-connected between units (e.g., Station Service Water). For the latter, where the "Other Unit" can be cross-connected, the PRA model includes those systems' supports as part of the "Other Unit" modeled logic.

The PRA shared and cross-tied systems are summarized below:

- Instrument Air common compressors (use Turbine Plant Cooling Water vice Component

Cooling Water for compressor cooling)
- Fire protection system (Common system for both units - Two diesel fire pumps)
- SW intake structure (Houses both unit's SSW system pumps)
- Uninterruptible Power Supply (UPS) HVAC (Chillers are backup to safety chilled water fan cooler units)
- Control Room HVAC (Common system for both units)
- Component Cooling Water System (Safeguards loops Note 1)
- Safety Chilled Water System (SFP, CCP, and CCW pump room coolers)
- Station Service Water System (Manual cross-tying of trains and units)
- 6.9 kV and DC electrical (Startup Transformers are capable of providing power to both units / DC Battery chargers have alternate power supplies from 25 kV loop)
- Common electrical buses (480 VAC Common MCCs)
- Turbine Plant Cooling Water (Common loads - Instrument Air Compressors X-01 and X-02 can be cooled by either unit TPCW)

Note 1 - Residual Heat Removal (RHR) pump seal cooler, Containment Spray (CT) pump seal coolers (2 pumps per train), RHR heat exchanger, CT heat exchanger, Safety Chiller, Control Room Air Conditioner (2 air conditioners per train), and UPS Air Conditioner.

The CCW unit cross-tie is credited only for the loss of CCW initiator. The existing model includes basic events representing the probability that the other unit has a concurrent loss of CCW initiator (or any event that would generate a safety injection signal with failure to isolate the non-safeguards train). These events are generally negligible in the baseline model results.

The SSW unit cross-tie is credited for specific failure modes and excluded for others. Credit is not included for LOOP scenarios, and it is explicitly excluded for any induced LOOP or subsequent failure of 6.9 kV bus-level equipment. Credit is also excluded for ATWT.

The RICT model includes several dual-unit issues. For example:

- Dual-unit initiator impacts, such as LOOP affecting both units (for example, disallowing credit for other-unit equipment)
- Dual-unit CCF for station SSW, CCW, Safety Chilled Water and emergency power systems
- Disallowing credit for cross-ties and shared functions for any situations that might preclude the ability to credit them (which are only credited in very limited and carefully reviewed scenarios)
- Including probabilities for the other unit being unavailable due to a concurrent initiator that would impact common/shared functions
- Including probabilities for the other unit systems being unavailable due to T&M

b) If shared systems are credited in the Real Time Risk (RTR) model that supports the RICT calculations, then explain how the shared system is modeled for each unit in a dual unit event demonstrating that shared systems are not over-credited in the PRA models.

Shared systems that are credited in the Real Time Risk (RTR) model that supports the RICT calculations are explicitly modeled. The RTR model contains logic (basic events) that represent the portions of systems that are credited. The plants risk assessment process (as well as the RICT process) requires the inclusion of these shared components when they are removed from service. For RICT assessments, the analyzed-unit out of service (OOS) components and the "Other Unit" modeled/credited OOS components are imported/entered into the RICT CRM tool. Once imported, the Phoenix RM software (CPNPP CRM tool) calculates the risk associated from the configuration, including the impacts of the shared

systems being out of service.

As noted above, these shared/cross-tied systems are credited for limited scenarios. Any impacts to the other unit explicitly disallow credit for cross-tied systems and shared system impacts can be assessed explicitly in the model, impacting whichever unit alignment is being assessed.

c) If a shared system is credited in the RTR model that support the RICT calculations and the impact of events that can create a concurrent demand for the system shared by both units is not addressed in the PRA models, then justify that this exclusion has an inconsequential impact the RICT calculations.

Credited shared systems in the RICT PRA model that can create a concurrent demand for the system shared by both units are addressed in the PRA models. Shared systems credited in the PRA are used within their design capacities or capabilities.

Operation of shared systems is controlled by station procedures. The procedures have warnings that make the operators aware of limitations. For example, when cross-tying SSW between units, the procedure has steps that inform the operators that the train in service being cross-tied to the other unit will become inoperable once aligned.

License Amendment Request docketed change is found in Enclosure 2, Section 1.0 that has been updated to explicitly state that all shared systems credited in the PRA are used within their design capacities and capabilities.

QUESTION 09 – Impact of Seasonal Variations (APLA)

The Tier 3 requirement of RG 1.177 stipulates that a licensee should develop a program that ensures that the risk impact of out-of-service equipment is appropriately evaluated prior to performing any maintenance activity. NEI 06-09 and the NRC SE to this guidance state that for the impact of seasonal changes either conservative assumptions should be made or, the PRA should be "adjusted appropriately to reflect the current (e.g., seasonal or time of cycle) configuration."

LAR Enclosure 8 on attributes of the RTR model, Section 2 states: "For systems where some trains are in service and some in standby, the Real-Time Risk Monitor model addresses the actual configuration of the plant including defining in service trains as needed." In LAR Enclosure 9 Table 1, the disposition to ID #5 regarding key sources of modeling assumptions and uncertainties states: "House events are included in the model to specify seasonal conditions (e.g., XHOSCWSUMMER)." Based on this statement, adjustments are made to the RTR model to address the impact of seasonal variations. For example, in the summary of the assumption/uncertainty for ID #5, when the XHOSCWSUMMER event is set to TRUE additional cooling from the vent-chilled water system is required for summer operation. It is not clear to NRC staff whether other modeling adjustments besides this adjustment are needed to account for seasonal dependencies and what kind of adjustments will be made. It is also not clear what criteria is used to know when PRA adjustments due to seasonal variations need to be made in the RTR. Address the following to clarify the treatment of seasonal variations:

a) Discuss the modeling that will be subject to adjustment due to seasonal variations such as hot or cold weather or other environmental factors (e.g., water levels) that can impact the performance of plant systems. Explain what kind of adjustments will be made and clarify whether they will be made conservatively like the adjustments that will be made for heating, ventilation, and air conditioning dependency

The CPNPP RICT PRA model modifies the success criteria based on outside air temperatures for several supporting functions. The first application defines the number of Circulating Water

pumps required to support cooling of the TPCW system. The second use of outside temperature to support system level success criteria is applied to the Vent Chilled Water system. The third application defines the number of diesel generator ventilation fans required to maintain temperatures in the diesel generator rooms.

For each of the three temperature-based applications, the number of pumps, fans or cooling support systems is adjusted as outside temperatures increase. These changes in success criteria were based on system operations guidelines and are selected in the RICT CRM software by choosing the corresponding alignment based on temperature. There are 4 temperature ranges to select from:

Temp < 90F, 90F < 99.4F, 99.4F < 106.9F and > 106.9F

In addition, the RICT PRA model has several 'Environmental Change' factors that when implemented, increase the probability of specific Initiating Event frequencies. These include Peak (Grid) Demand, Severe Weather, Switchyard Work, activities that could induce a Reactor or Turbine Trip, activities that could induce a loss of Feedwater and activities that may cause an inadvertent Safety Injection Signal. These are applied based on review of work packages/ activities, entry into specific Abnormal Operating Procedures or ERCOT/Plant defined conditions.

b) Explain what criteria (e.g., trigger) are used to know when PRA adjustments due to seasonal variations need to be made in the RTR and justify that this approach is consistent with the guidance in NEI 06-09.

Plant procedures, RICT CRM guides and training of plant personnel responsible for the RICT process/implementation provide instructions as to when any of the above seasonal or environmental factors are to be applied. The temperature-based alignments are selected based on the temperatures expected to be seen during the time of the RICT and adjusted as required. For the 'Environmental Change' factors, severe weather is based on procedural guidance in ABN-907. Peak Demand factors is entered when ERCOT or the Plant enters a "hands-off" condition. ABN-907 discusses, actions to be taken for severe weather. Included in those actions is the requirement to escalate risk (adjusting the 'Environmental Change' factors) and evaluating the risk of the configuration and suspend, complete or postpone work on systems that would be necessary to mitigate a loss of offsite power or might impact continued power operations.

The remainder of these factors are applied based on work activity review by Operations or Work Control personnel. For example, A test procedure or work order activity, if they contain a caution or warning statement or following review by the Operations Work Control personnel resulted in a similar caution that the activity has the potential to cause a reactor or turbine trip, then the 'Environmental Change' factor is added to the configuration that is being addressed.

QUESTION 10 – PRA Model Update Frequency (APLA)

The NRC SE to NEI 06-09, Revision 0, specifies that the LAR will provide a discussion of the licensee's programs and procedures which assure the PRA models which support the RMTS are maintained consistent with the as-built, as-operated plant. This NRC SE also specifies that a process must be in place to monitor plant modifications and other changes which may impact the PRA model to assure that the RTR correctly reflects the as-built, as-operated plant. NEI 06-09 specifies that the PRA and configuration risk management tool "shall be maintained and updated in accordance with approved station procedures on a periodic basis not to exceed two refueling cycles."

Section 2.0 of LAR Enclosure 7 states that PRA updates for plant changes are performed at

least once every 48 months. In the LAR and LAR Supplement dated July 13, 2021, the justification for this PRA update frequency is that, because Comanche Peak is a dual unit facility with a common PRA for both units, an update of every 48 months is necessary to ensure that it includes two 18-month refueling cycles for each unit (while not exceeding two refueling cycles on either unit), which are staggered by nine months. The NRC staff notes that increasing trends in the failure of plant components can have an impact on RICT calculations and that one of the units may be more than 50 percent into its third cycle since the last PRA update before the update process is completed. The LAR does not explain if or how increasing trends in component failure rates are tracked for consideration to be incorporated into an interim update of the PRA model or otherwise considered in the RICT program (e.g., via bounding analyses or implementation of appropriate administrative restrictions).

Address the following with regards to this concern:

a) Explain how increasing trends in component failure rates are tracked for consideration to be incorporated into an interim update of the PRA model or otherwise considered in the RICT program.

There is no programmatic tracking of increasing component failure trends within the RICT program.

That tracking function is performed within the Maintenance Rule Program (safety and non-safety components), which is used to monitor component failures and initiate Corrective Actions prior to the development of any trend. The Maintenance Rule alert levels are set conservatively (through global increases in the unavailabilities and unreliabilities) to prompt remedial action at an early stage. Components associated with RICT related hazards are addressed either as part of the Maintenance Rule program or under the Corrective Action Program. Negative trends of component/system performance are addressed under these programs.

The Maintenance Rule alert levels are set to conservatively prompt action to correct any adverse trend and include sensitivities performed for the Maintenance Rule performance criteria where the associated increases in unavailabilities and unreliabilities were applied for the entire model.

Further, periodic PRA model updates include evaluation of industry and plant-specific data which would explicitly incorporate any risk-significant changes in component failure rates.

In addition, the MSPI program at CPNPP requires, on a quarterly basis, an assessment of the impact of plant changes on the internal events model. As part of this process significant changes in the overall cumulative risk metrics, CDF/LERF, are reviewed to determine if a model of record change is necessary.

b) If not tracked for potential impact on the RICT program, provide justification that increasing trends in component failure rates have an insignificant impact the RICT program.

See above.

QUESTION 11 – In-Scope LCOs and Corresponding PRA Modeling (APLA)

The NRC SE to NEI 06-09 specifies that the LAR should provide a comparison of the TS functions to the PRA modeled functions to show that the PRA modeling is consistent with the licensing basis assumptions or to provide a basis for when there is a difference. LAR Enclosure1, Table E1-1 identifies each TS LCO proposed for the RICT program, describes whether the systems and components participating in the TS LCO are implicitly or explicitly

modeled in the PRA and compares the design basis and PRA success criteria. For certain TS LCO Conditions, the table explains that the associated SSCs are not modeled in the PRAs but will be represented using a surrogate event that fails the function performed by the SSC. For one LCO conditions, the LAR did not provide enough description for NRC staff to conclude that the PRA modeling will be sufficient for each proposed LCO Condition.

Footnote 9 to LAR Table E1-1 regarding the surrogate modeling for TS LCO 3.4.9.B ("One required group of pressurizer heaters inoperable") states that the impact for this LCO is determined by increasing the likelihood of a plant trip due to degraded pressure control by a factor of 10. Both the LAR and the LAR Supplement dated July 13, 2021, further clarify that the pressurizer heaters do not perform significant accident mitigation function, are not credited for accident mitigation in the safety analyses, are not required for mitigation of steam generator tube rupture, and therefore do not have a quantifiable impact on CDF or LERF. However, neither the LAR nor LAR supplement provide justification that increasing the likelihood of a plant trip is a reasonable surrogate or that increasing this likelihood by a factor of 10 is conservative for determining the impact on CDF and LERF from implementing a RICT. Address the following:

a) Provide justification that increasing the likelihood of a plant trip is a reasonable surrogate for determining the RICT for this LCO.

The pressurizer and the electrical heaters maintain a liquid-to-vapor interface to permit RCS pressure control during normal operations and in response to anticipated design basis transients. The heaters are used to maintain RCS subcooling during a natural circulation cooldown, and the unavailability of the heaters will extend the time to reach entry conditions for the shutdown cooling system. The unavailability of the heaters may complicate steady-state RCS pressure control and may slightly increase the potential of an unplanned reactor trip during significant plant transients. This is modeled as INIT-T1(general transient).

Pressurizer sprays and heaters are required for normal Mode 1 to 3 operations. For normal operation, the control group of pressurizer heaters is controlled proportionally to maintain the pressurizer operating pressure. If the control signal (pressure) falls significantly below the heater proportional band, all pressurizer heaters are turned on.

In the deterministic accident analysis, non-safety equipment such as pressurizer sprays, heaters, and the PORVs are assumed to operate only if such operation results in more severe accident consequences. The PORVs are assumed to be operated manually in the mitigation of a steam generator tube rupture. For SGTR, pressurizer heaters are not credited in the thermohydraulic (T/H) assessment as it is not impactful.

One heater bank in operation is sufficient to overcome pressurizer heat losses. During volume out surges which cause pressure decreases, flashing of saturated water in the pressurizer and generation of steam by electrical heater operation maintains reactor coolant pressure. Heaters are divided into four groups: Control (C) and Backup (A, B, D). The pressurizer minimum nominal heater capacity of ≥ 150 kw per group for two groups is based on engineering judgment and estimates that the control group heaters (400 kw) operate at about 50% during steady state operation. Therefore, 300 kw should be adequate to maintain the pressurizer near operating temperatures when accounting for pressurizer heat losses.

The unavailability of one required group of pressurizer heaters would not have any significant impact on plant transient response (beyond the potential to lead to plant trip) so there is no quantifiable impact to CDF or LERF. While mitigation of a SGTR is enhanced by the availability of pressurizer heaters, ECA-3.3A/B provides for mitigation of a SGTR without pressurizer heaters, if necessary.

Degraded pressurizer heater capability is supplemented by the availability of the remaining heaters for plant pressure control, and the availability of plant procedures which provide plant shutdown and cooldown guidance with pressurizer heaters, If the available heaters are sufficient to maintain RCS pressure control, normal plant operations can continue.

In summary, when a single bank of pressurizer heaters is unavailable, the initiating event, reactor trip (T1), is a more significant contributor to risk than SGTR. There is no credit for the heaters in the T/H for SGTR because it is not impactful, meaning small impact to the contribution of cooldown. And the LCO is only for one group of heaters - no loss of function. For SGTR conditions where all pressurizer heaters are potentially unavailable proceduralized guidance is provided.

b) Provide justification that increasing the likelihood of a plant trip by a factor of 10 provides a conservative estimate of the RICT for this LCO.

The current model of record mean value for the basic event INIT-T1 (reactor/Turbine Trip) which is being used as a surrogate when a Pressurizer Heater Bank is removed from service is 5.77E-01 events per year with a variance of 3.26E-02. These values are based on the data in the 2010 update of NUREG/CR-6928 and Bayesian updated with plant specific operation history (2 events over 5.02 years).

Based on the information above, the use of a factor of 10 (5.77 events per year) provides a conservative estimate for the RICT program. Pressurizer heater control leading to a plant trip is only a contributor to the INIT-T1 frequency, but this assumes; (1) that it is the sole contributor, and (2) that the loss of one heater bank can have an order of magnitude impact on the trip frequency, leading to multiple plant trips predicted due to this single cause within one year. The plant would not operate in that way and could not realistically result in five plant trips within one year due to this single cause because of existing programs to prevent such recurrence.

The impact for internal events of the 10 factor is a CDF of ~ 1.4E-06 and, in particular,confirms that the results do not exceed acceptance criteria. Note that the 95th percentile of the reactor trip frequency, which is 9.03E-01, itself would be sufficient to bound the case and could support a factor of 2 multiplier.

QUESTION 12 - Performance Monitoring (APLA)

Key Principle 5 of RG 1.177, Revision 1, pertains to performance monitoring. The RG states:

The licensee should consider implementation and performance monitoring strategies formulated to ensure (1) that no adverse safety degradation occurs because of the changes to the TS and (2) that the engineering evaluation conducted to examine the impact of the proposed changes continues to reflect the actual reliability and availability of TS equipment that has been evaluated. This will ensure that the conclusions that have been drawn from the evaluation remain valid. [...]

Similarly, RG 1.174, Revision 3 provides guidance of implementation and monitoring program for any risk-informed licensing basis changes:

The licensee should propose monitoring programs that adequately track the performance of equipment that, when degraded, can affect the conclusions of the licensee's engineering evaluation and integrated decision-making that support the change to the licensing basis. The program should be capable of trending equipment performance after a change has been implemented to demonstrate that performance is consistent with the assumptions in the traditional engineering and probabilistic analyses conducted to justify the change. [...] The program should be structured such that, (1) SSCs are monitored commensurate with their safety importance [...], (2) feedback of information and corrective actions is timely, and (3)

degradation in SSC performance is detected and corrected before plant safety can be compromised. [...]

LAR Attachment 1, Section 2.3 states that the application of a RICT will be evaluated using the guidance provided in NEI 06-09, Revision 0-A, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines."The LAR further states:

> ...the NEI 06-09, Revision 0 methodology satisfies the five key safety principles specified in Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk- Informed Decision-making: Technical Specifications," dated August 1998 (ADAMS Accession No. ML003740176), relative to the risk impact due to the application of a RICT.

The LAR did not provide sufficient information to explain how the RICT Program satisfies the fifth key safety principle of RG 1.177 and RG 1.174, specifically with respect to the ability of the monitoring program to adequately track the performance of equipment in a timely fashion, so that if degraded, its degraded performance will be considered in the licensee's RICT evaluations.

Therefore, provide a description of the performance monitoring strategies proposed for the RICT program and justify how the program meets key principle 5 of RG 1.177 and RG 1.174. Include description and justification on:

a) Whether and how SSCs are monitored commensurate with their safety importance

See the response under item c).

b) The timeliness of the feedback of information and corrective actions

See the response under item c).

c) How degradation in SSC performance is detected and corrected before plant safety can be compromised

NEI 06-09 states that "The NRC staff anticipates that the use of extended CTs within an RMTS program is unlikely to be a routine practice since licensees already accomplish planned maintenance activities within the existing TS CTs. Although the RMTS are permitted to be applied to planned maintenance activities, other requirements, such as the 10CFR50.65 performance monitoring, and regulatory oversight of equipment performance, are disincentives to a licensee to incur significant additional unavailability of plant equipment, even when allowed by an RMTS program. This provides a further control on the use of the RMTS which could result in a significant increase in equipment unavailability and the commensurate risk."

For the purpose of tracking the performance of equipment that, when degraded, can affect the conclusions of the licensee's engineering evaluation and integrated decision-making that support the change to the licensing basis, the RICT program relies on various plant programs including Corrective Action Program (STA-422), Equipment Reliability program (STA-748), Maintenance Rule (STA-744) program and the Mitigating System Performance Index (MSPI). Each of these programs monitors and trends equipment performance.

Maintenance Rule (MR) is currently based on NUMARC 93-01 and uses a set of performance metrics. The monitoring of these kinds of metrics will continue if CPNPP goes to an alternate MR program. The current set of programs used at CPNPP considers and monitors significant components affecting ALL hazards associated with the RICT program, fire, high winds, internal flood, etc. The programs are established with risk information as input to ensure program actions are commensurate with safety importance of SSCs:

- Equipment Reliability Programs address safety importance through classification of critical components, based in part on risk information
- Risk metrics are used in expert panel deliberations to identify risk importance for system functions and set appropriate goals in Maintenance Rule
- Reliability and unavailability of safety important systems is quantitatively evaluated on a periodic basis for MSPI
- Timeliness of corrective actions and effectiveness of program feedback are evaluated in periodic assessments

The programs are established to ensure a focus on safety importance, to anticipate adverse trends and to implement timely actions that prevent degraded performance.The Maintenance Rule performance monitoring provisions and Mitigating System Performance Index thresholds assist in tracking the performance of equipment and correcting poor performance before plant safety can be compromised.

These programs ensure the assumptions and analysis used to support the PRA model and the LAR are maintained.

Equipment Reliability Program:

Equipment Reliability Programs are in place to ensure safe, reliable, and efficient operation of all plant equipment that impacts safety and generation. The Equipment Reliability Program supports a process for intolerance of unexpected critical equipment failures.

The equipment reliability process represents the integration and coordination of a broad range of equipment reliability activities into one process for plant personnel to evaluate important station equipment, develop and implement long-term equipment health plans, monitor equipment performance, and condition, and make continuing adjustments to preventive maintenance tasks and frequencies based on equipment operating experience. This process includes activities associated with, preventive maintenance, Maintenance Rule, surveillance and post work testing, life cycle management (LCM) planning, and equipment performance and condition monitoring.

Performance monitoring is used to establish performance criteria and monitoring parameters for important system functions and critical components. Performance monitoring provides one of the main bases for predicting failures and implementing corrective actions. If a performance trend is noted or anticipated for a critical component it is documented in the Corrective Action Program in a timely manner to ensure attention is given to addressing the issue prior to a failure.

If a performance criterion and/or monitoring parameter is exceeded the CorrectiveAction Process is utilized for resolution. Specific guidance on System and Performance Monitoring is contained in CPNPP procedure STI-748.01 System Monitoring and Health Reporting.

Maintenance Rule:

The purpose of the Maintenance Rule program is to assess maintenance activity effectiveness and impact on safe, reliable plant performance as a basis for making necessary improvements. As part of the process, goals are established for use when monitoring progress of the corrective actions taken to bring about necessary improvements in maintenance program effectiveness. Performance is monitored against the goal(s) and corrective actions assessed for effectiveness in a manner that provides documentation and a means of recognizing performance trends so progress toward satisfactory performance can be tracked. If a goal is not met or becomes unachievable, then an Issue Report is initiated to have the responsible organization determine why and identify corrective actions including determining if goals need

to be modified.

Engineering trends and assess plant, system, train and component level performance criteria data and:

- Recommend actions which will result in improvements to performance
- Identify trends along with recommended actions to prevent exceeding performance criteria

In addition to monitoring system performance through performance criteria, Engineering trends or monitors system and equipment performance through the System Health process to identify and address potential precursors to performance problems.

Work Control and responsible work organizations should consider reliability, availability and other performance criteria when making work scheduling decisions that affect plant, system, train or component performance.

A Maintenance Effectiveness Assessment is performed by Engineering approximately once every refueling cycle, but not to exceed 24 months.

As part of the Corrective Action Process (STA-422), the Management Review Committee (MRC) confirms that the corrective action plan will correct the identified causes. In addition, the MRC reviews for station execution/timeliness of the corrective action plan. Individual Department Managers are responsible for overseeing timely and effective analysis, investigation, and resolution of issues.

<u>Mitigating System Performance Index</u>

The reactor oversight process includes requirements for reporting performance indicator data and a process for developing supporting calculations. The key reference for MSPI requirements and direct inputs to the index is NEI 99-02 and associated requirements.

The purpose of the Reactor Oversight Program (ROP) Mitigating System Performance Index (MSPI) is to monitor the performance of selected systems based on their ability to perform risk-significant functions as defined by NEI 99-02. It is comprised of three elements – system unavailability, system unreliability and system component performance limits. The index is used to determine the cumulative significance of failures and unavailability over the monitored time period.

a) How it is ensured that the PRA used in the RICT program continues to reflect the actual reliability and availability of TS equipment.

Enclosure 10 of the LAR provides a description of the implementing programs and procedures regarding the plant staff responsibilities for the RICT Program, including training of plant personnel, and specifically discusses the decision process for RMA implementation during extended Completion Times (CT). Enclosure 7 of the LAR describes the administrative controls and procedural processes applicable to configuration control of the PRA model used to support the Risk-Informed Completion Time (RICT) Program, which will be in place to ensure that these models reflect the as-built, as-operated plant.

These Configuration Controls are established to assure the integrity of the RICT calculations and to ensure the underlying PRA models appropriately reflect the as-built, as-operated plant.

Plant changes, including physical modifications and procedure revisions, will be identified and reviewed prior to implementation to determine if they could impact the PRA models per CPNPP procedures STA-762 and STI-762.02 [Drafts]. The configuration control program will ensure these plant changes are incorporated into the PRA models as appropriate. The process

will include discovered conditions associated with the PRA models, which will be addressed by the site's Corrective Action Program.

The PRA configuration control process delineates the responsibilities and guidelines for updating the full power internal events, internal flood, and fire PRA models, and includes both periodic and unscheduled PRA model updates.

The process includes provisions for monitoring potential impact areas affecting the technical elements of the PRA models (e.g., due to plant changes, plant/industry operational experience, or errors or limitations identified in the model), assessing the individual and cumulative risk impact of unincorporated changes, and controlling the model and necessary computer files, including those associated with the Real Time Risk model.

To ensure the PRA model and PhoenixRM reflect the as-built, as-operated plant, the PRA model and PhoenixRM should be updated every 48 months. The periodicity of the update is addressed in more detail in the response to the NRC Audit question 13a.

Maintenance Rule monitoring of actual reliability and availability of TS equipment, along with the specific assessment of cumulative risk impact described above, serve as the Implementation and Monitoring Program for the RICT Program (LAR Enclosure 11). The integrity of PhoenixRM, the PRA models and the PhoenixRM models will be maintained in a Configuration-Controlled environment. CPNPP procedure STI-762.02 contains the specific instructions.

Should a plant change or a discovered condition be identified that has a significant impact to the RICT Program calculations as defined by the above procedures, an unscheduled update of the PRA model will be implemented. Otherwise, the PRA model change is incorporated into a subsequent periodic model update. Such pending changes are considered when evaluating other changes until they are fully implemented into the PRA models.

License Amendment Request docketed change is found in Enclosure 11, Section 2.0 that has been revised to explicitly state that the performance metrics required by NEI 06-09 will continue to be collected and reviewed, regardless of the implemented Maintenance Rule program at CPNPP. In addition, it has been clarified that significant components affecting all hazards are monitored.

QUESTION 13 – Cumulative Risk Calculation Frequency (APLA)

The NRC SE to NEI 06-09, Revision 0, specifies that a periodic assessment of the risk incurred due to the extension of CTs is required. This is an evaluation of the calculated change in risk after implementation of a RMTS program to assure that the guidance of RG 1.174 for small risk changes [e.g., delta CDF (1E-5 per year) and delta LERF (1E-6 per year)] are met. NEI 06-09 specifies that the cumulative risk assessment "shall be conducted every refueling cycle on a periodicity not to exceed 24 months." This guidance is clear in that the cumulative risk is to be calculated after each refueling cycle and for each unit for multi-unit plants.

Section 2.0 of LAR Enclosure 11 states that the calculation of cumulative risk impact will be conducted "at least once every 48 months as part of the periodic review and update of the PRA models." This periodicity is inconsistent with the guidance in NEI 06-09 and does not appear to meet the guidance of RG 1.174, Revision 3. Address the following with regards to this concern:

a) Provide justification that the periodicity of once every 48 months is in accordance with NEI 06-09. In the response specifically address how this periodicity provides assurance that the RG 1.174, Revision 3, risk guidelines are met.

Cumulative risk from the use of the RICT program will be continuously tracked for each of the two CPNPP units for a rolling 12-month period for comparison against the RG 1.174 risk guidelines. As a further check, additional reviews, as described in Enclosure 11, are performed during the periodic model update.

b) Explain how cumulative risk will be calculated for each of the Comanche Peak units.

Cumulative risk for each unit, incurred through the use of the Extended Completion Times, is tracked as it is incurred through the use of the PhoenixRM Real Time Risk Monitor. The cumulative risk is maintained as a rolling 12-month total for comparison against the RG 1.174 risk guidelines.

QUESTION 14 – Open Phase Condition (APLA)

Section C.1.4 of RG 1.200 states the base (e.g., Model of Record) PRA is to represent the as-built, as-operated plant to the extent needed to support the application. The licensee is to have a process that identifies updated plant information that necessitate changes to the base PRA model.

In response to the January 30, 2012, Open Phase Condition (OPC) event at the Byron Generating Station, the NRC issued Bulletin 2012-01.[1] As part of the initial Voluntary Industry Initiative (VII) for mitigation of the potential for the occurrence of an OPC in electrical switchyards[2], licensees have made the addition of an Open Phase Isolation System (OPIS). Asper SRM-SECY-16-0068[3], the NRC staff was directed to ensure that licensees have appropriately implemented OPIS and that licensing bases have been updated accordingly.

Inspections of OPIS by NRC staff are currently underway. From the revised voluntary initiative[4] and resulting industry guidance in NEI 19-02[5] on estimating OPC and OPIS risk, it is understood that the risk impact of an OPC can vary widely dependent on electrical switchyard configuration and design. In light of these observations, provide the following information:

a) Discuss Comanche Peak's evaluation of the risk impact associated with OPC events including the likelihood of OPC initiating plant trips and the impact of those trips on PRA-modeled SSCs. Also, explain whether an OPIS has been installed at Comanche Peak and if it has been installed, then discuss its functionality and any operator actions needed to operate the system or needed in response to the system.

Evaluation EV-TR-2019-006419-6 (Evaluation Log #310) includes a general description of the OPEN PHASE PROTECTION (OPP) SYSTEM installed on each of CPNPP's four Startup Transformers, details the expected plant response to an OPC and documents the plant specific risk evaluation. A plant modification installed a dual channel OPP system at each transformer to monitor for the condition and prompt an operator response. The function of the OPP, as described in the system specification, is to detect the condition, actuate protective features, and alarm remotely when open circuit faults on offsite power sources occur under unloaded and loaded transformer operating conditions. For CPNPP, an OPC does not immediately cause a plant initiating event. OPC frequency and probability estimates were obtained from the available published estimates (NEI 19-02). These values were judged to be applicable; using a plant capacity factor of 0.92, an OPC Frequency = 7.5 events in 15 calendar years = 7.5 / (0.92 *1500 reactor-years) = 5.43E-03 per reactor-year was applied as representative for the purpose of evaluating the OPC impacts associated with the CPNPP plant response. Because the system is implemented as Alarm Only, OPC initiating plant trips have the same SSC consequences as an interruption of AC power with OPC effects limited to the direct bus the transformer serves. Operator actions are established to detect or determine an OPC condition exists and restore 6.9kV safeguards bus balanced voltage, by first, opening

supply breakers and second, ensuring transfer of at least one safeguards bus. An operator recovery action provides for manual start of equipment that is running or demanded, if the equipment were to trip when running or demanded during an OPC. One startup transformer has the OPP system installed but is non-functional. Plans are in progress to remove the transformer from service and repair the OPP system during the first quarter of 2022.

b) Clarify whether any installed OPIS equipment and associated operator actions are credited in the PRAs that support this application. If OPIS equipment and associated operator actions are credited, then provide the following information:

    i. Describe the OPIS equipment and associated actions that are credited in the PRA models.

    ii. Describe the impact that this treatment, if any, has on key assumptions and sources of uncertainty for the categorization process.

    iii. Discuss human reliability analysis (HRA) methods and assumptions used for crediting OPIS alarm manual response.

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1 U.S. NRC Bulletin 2012-01, , "Design Vulnerability in Electric Power System" (ADAMS Accession No. ML12074A115).

2 Anthony R. Pietrangelo to Mark A. Satorius, Ltr re: "Industry Initiative on Open Phase Condition - Functioning of Important-to-Safety Structures, Systems and Components (SSCs)", dated October 9, 2013 (ADAMS Accession No. L13333A147).

3 U.S. NRC SRM-SECY-16-0068, "Interim Enforcement Policy For Open Phase Conditions In Electric Power Systems For Operating Reactors," dated March 9, 2017 (ADAMS Accession No. ML17068A297).

4 Doug True to Ho Nieh, Ltr re: "Industry Initiative on Open Phase Condition,Revision 3", dated June 6, 2019 (ADAMS Accession No. ML19163A176)

5 Nuclear Energy Institute (NEI) 19-02, "Guidance for Assessing Open Phase Condition Implementation Using Risk Insights", Revision 0, April 2019 (ADAMSAccession No. ML19122A321).

    iv. Discuss how OPC related scenarios are modeled for non-internal event scenarios such as fire, seismic, flooding, high winds, tornado, and other external events.

    v. Regarding inadvertent OPIS actuation:

        1. Explain whether scenarios regarding inadvertent actuation of the OPIS, if applicable, are included in the RTR model that supports the RICT calculations.

        2. If inadvertent OPIS actuation scenarios are not included in the PRA models, then provide justification that the exclusion of this inadvertent actuation does not impact the RICT calculations.

The PRA model used to support this application did not credit the OPIS system or associated operator actions. The potential for an OPC event and OPIS modification evaluation are identified for reference in model maintenance documentation.

c) If OPC and OPIS are not included in the application PRA models (whether OPIS equipment is installed or not), then provide justification the exclusion of this failure mode and mitigating system does not impact the RICT calculations.

Exclusion of this failure mode and mitigating system from the PRA Model does not impact the RICT calculations. The plant is assumed to be in normal electrical configuration, with more than one transmission feeder aligned to the switchyard. Time spent in unusual configurations which would propagate a phase imbalance via an OPC in the transmission system is assumed to be small. An OPC event is similar in nature to plant/grid centered LOOP modeled in the

internal events PRA; the loss of power from an OPC condition is bounded by these initiators for frequency and impact to station startup transformers. Safeguard Class 1E AC 6.9kV buses (1EA1, 1EA2) power frontline safety systems (required after a transient or initiating event) and as they are mitigating systems in standby mode, a loss of their power source will not result in a plant transient. The loss of a 1E AC 6.9kV bus will lead to an orderly plant shutdown as required by technical specifications and does not meet the criteria to be considered an initiating event. The OPC contribution to CDF is far below the maximum CDF contribution of <1 E-6/yr. This limiting value has a maximum ICDP impact <1E-7/yr (1E-6/yr * 30 days/365 days/yr) such that the OPC impact is much less than 1 % of the permissible ICDP in the bounding time and this minimal contribution is not significant to the decision in computing a RICT.

Exclusion of the OPIS system or associated operator actions from the PRA model is not a key source of uncertainty for CPNPP. However, to ensure that the conclusion of the Open Phase Condition assessment remain valid, this modeling choice is being added to the CPNPP initiating events and electric power notebooks such that this choice will be reviewed and assessed as the model is revised.

d) As an alternative to Part (c), propose a mechanism to ensure that OPC- related scenarios are incorporated into the application PRA models prior toimplementing the RICT program.

Not applicable.

QUESTION 15 – Update of Fire PRA with Internal Event Facts and Observations(F&O) Resolutions (APLB)

RG 1.200, Revision 3 provides guidance for addressing PRA acceptability. RG 1.200, Revision 3, describes a peer review process using the ASME/ANS PRA standard as one acceptable approach for determining the technical acceptability of the PRA. The primary results of peer review are the F&Os recorded by the peer review team and the subsequent resolution of these F&Os. A process to close finding-level F&Os is documented in Appendix X titled "NEI 05-04/07-12/12-06 Appendix X: Close-out of Facts and Observations (F&Os)," dated February 21, 2017(ADAMS Package Accession No. ML17086A431), to the Nuclear Energy Institute (NEI) guidance documents NEI 05-04, NEI 07-12, and NEI 12- 13, which was accepted by the NRC in a letter dated May 3, 2017 (ADAMS Accession No. ML17079A427). LAR Enclosure 2, Section 3 states that an Independent Assessment was performed in 2019 to close out internal events PRA F&Os after the model was updated to resolve F&Os from the 2011 full-scope peer review. LAR Enclosure 2, Section 4 states that the last full-scope peer review of the fire PRA was performed in 2016 which is before the internal events PRA F&O closure review in 2019. The LAR does not indicate when the modeling updates to the internal events PRA to resolve F&Os occurred and whether applicable modeling updates were also performed for the fire PRA. Given that internal events PRA provides the modeling foundation for the fire PRA, it is not clear to NRC staff whether F&O resolutions made to the internal events PRA to close F&Os that could impact the fire PRA were incorporated into the fire PRA. Therefore, address the following:

a) Confirm that all internal events PRA modeling updates performed to resolve F&Os that could impact fire risk were incorporated into the fire PRA.

Appendix A of CN-RAM-13-031 Revision 3 references PWROG-18060-P which documents the closure of Internal Events F&Os. The internal events F&O closures were reviewed, and there are no outstanding exceptions or deficiencies that would adversely impact the fire PRA PRM.

b) If it cannot be confirmed in response to part (a) above that all internal events modeling

updates performed to resolve F&Os that could impact fire risk were incorporated into the fire PRA, then propose a mechanism that ensures that all internal events modeling updates performed to resolve F&Os that could impact fire risk are incorporated into the fire PRA prior to implementation of the RICT program.Alternatively, justify that all the internal events modeling updates performed to resolve F&Os have an inconsequential impact on the RICT calculations.

Based on the conclusion documented in part (a), there is no impact on the RICT calculations.

QUESTION 16 – Deviations from NRC Endorsed Guidance as Source of Modeling Uncertainty (APLB)

RG 1.200 states "NRC reviewers, [will] focus their review on key assumptions and areas identified by peer reviewers as being of concern and relevant to the application." The relatively extensive and detailed reviews of fire PRAs undertaken in support of LARs to transition to NFPA-805 determined that implementation of some of the complex fire PRA methods often used non-conservative and over-simplified assumptions to apply the method to specific plant configurations. Some of these issues were not always identified in F&Os by the peer review teams but are considered potential key assumptions by the NRC staff because using more defensible and less simplified assumptions could substantively affect the fire risk and fire risk profile of the plant. The NRC staff evaluates the acceptability of the PRA for each new risk-informed application and as discussed in RG 1.174, recognizes that the acceptable technical adequacy of risk analyses necessary to support regulatory decision-making may vary with the relative weight given to the risk assessment element of the decision-making process.

The NRC staff notes that the calculated results of the PRA are used directly to calculate a RICT which subsequently determines how long SSCs (both individual SSCs and multiple, unrelated SSCs) controlled by TSs can remain inoperable. Therefore, the PRA results are given a very high weight in a TSTF-505 application and the NRC staff requests additional information on the following issues that have been previously identified as potentially key fire PRA assumptions.

<u>Use of Unacceptable Methods</u>

a) The LAR provides the history of the fire PRA peer review but does not discuss methods used in the fire PRA. Methods may have been used in the fire PRA that deviate from guidance in NUREG/CR-6850, "EPRI/NRC-RES Fire PRA Methodology for Nuclear Power Facilities," (ADAMS Accession Nos. ML052580075, ML052580118, and ML103090242), or other acceptable guidance (e.g., frequently asked questions (FAQs),NUREGs, or interim guidance documents).

   i. Identify methods used in the fire PRA that deviate from guidance in NUREG/CR-6850 or other acceptable guidance.

Only approved methodologies were utilized in the development of the Fire PRA.

   ii. If such deviations exist, then justify their use in the fire PRA and impact on the RICT.

Not applicable, no deviations exist.

   iii. As an alternative to part (ii) above, add an implementation item to replace those methods with a method acceptable to NRC prior to the implementation of the RICT Program. Include a description of the replacement method along with justification that it is consistent with NRC accepted guidance.

Not applicable, no deviations exist.

<u>Reduced Transient Heat Release Rates (HRRs)</u>

b) The key factors used to justify using transient fire reduced HRRs below those prescribed in NUREG/CR-6850 are discussed in the June 21, 2012, letter from Joseph Giitter, U.S. Nuclear Regulatory Commission, to Biff Bradley, NEI, "Recent Fire PRA Methods Review Panel Decisions and EPRI 1022993, Evaluation of Peak Heat Release Rates in Electrical Cabinet Fires," (ADAMS Accession No. ML12172A406).

If any reduced transient HRRs below the bounding 98 percent HRR of 317 kW from NUREG/CR-6850 were used, discuss the key factors used to justify the reduced HRRs. Include in this discussion:

i. Identification of the fire areas where a reduced transient fire HRR is credited and what reduced HRR value was applied.

ii. A description for each location where a reduced HRR is credited, and a description of the administrative controls that justify the reduced HRR including how location-specific attributes and considerations are addressed. Include a discussion of the required controls for ignition sources in these locations and the types and quantities of combustible materials needed to perform maintenance. Also, include discussion of the personnel traffic that would be expected through each location.

iii. The results of a review of records related to compliance with the transient combustible and hot work controls.

All transients in the Comanche Peak Fire PRA utilized the bounding 98th percentile HRR of 317 KW from NUREG/CR-6850 (See Section 4.3.8.7 and Section 4.3.8.8 of CN-RAM-13-034 Revision 3). There are no locations utilizing a reduced transient fire HRR.

<u>Treatment of Sensitive Electronics</u>

c) FAQ 13-0004, "Clarifications on Treatment of Sensitive Electronics" (ADAMS Accession No. ML13322A085) provides supplemental guidance for application of the damage criteria provided in Sections 8.5.1.2 and H.2 of NUREG/CR-6850, Volume 2, for solid-state and sensitive electronics.

i. Describe the treatment of sensitive electronics for the fire PRA and explain whether it is consistent with the guidance in FAQ 13-0004, including the caveats about configurations that can invalidate the approach (i.e., sensitive electronics mounted on the surface of cabinets and the presence of louver or vents).

NUREG/CR-6850 (Page 8-10) radiant heat flux damage threshold of 3 kW/m2 and a temperature damage threshold of 65°C is used for sensitive electronics and FAQ 13-0004 was followed (Section 4.3.6.3 of CN-RAM-13-034). The Fire PRA treated sensitive electronics consistent with FAQ 13-0004 as documented in the paragraph under Table 4-7 of CN-RAM-13-034 "FAQ 13-0004 is used to determine if damage occurs in these cabinets (Reference 49). If sensitive electronic equipment is mounted inside a control panel (cabinet) such that the walls, top, front and back doors shield the component from the radiant energy of an exposure fire, the equipment may be considered qualified up to the heat flux damage threshold for thermoset cables. This criterion only applies to the heat flux generated by fires external to the cabinet: it does not apply to immersion of the sensitive electronics in the hot upper gas layer. The temperature threshold of 65°C for hot upper gas layer scenarios containing sensitive equipment was used. If the upper gas layer exceeds the sensitive electronics' 65°C failure temperature and descends to the elevation where the sensitive electronics are located, then the sensitive electronics will be considered failed."

ii. If the approach cannot be justified to be consistent with FAQ 13-0004, then justify that the treatment of sensitive electronics has no consequential impact on the RICT calculations.

Not applicable, approach consistent with FAQ 13-0004.

iii. As an alternative to part (ii) above, add an implementation item to replace the current approach with an acceptable approach prior to the implementation of the RICT Program. Include a description of the replacement method along with justification that it is consistent with NRC accepted guidance.

Not applicable, approach consistent with FAQ 13-0004.

Minimum Joint Human Error Probability

d) NUREG-1921, "EPRI/NRC-RES Fire Human Reliability Analysis Guidelines-Final Report," (ADAMS Accession No. ML12216A104), discusses the need to consider a minimum value for the joint probability of multiple HFEs in HRAs.

NUREG-1921 refers to Table 2-1 of NUREG-1792, "Good Practices for Implementing Human Reliability Analysis (HRA)," (ADAMS Accession No. ML051160213), which recommends that joint HEP values should not be below 1E-5. Table 4-4 of EPRI 1021081, "Establishing Minimum Acceptable Values for Probabilities of Human Failure Events," provides a lower limiting value of 1E-6 for sequences with a very low level of dependence. Therefore, the guidance in NUREG-1921 allows for assigning joint HEPs that are less than 1E-5, but only through assigning proper levels of dependency.

The LAR does not provide this information and does not explain what minimum joint HEP value is currently assumed in the fire PRA. Also, even if the assumed minimum joint HEP values are shown to have no impact on the current fire PRA risk estimates, it is not clear to the NRC staff how it will be ensured that the impact remains minimal for future PRA model revisions. In light of these observations:

i. Explain what minimum joint HEP value was assumed in the fire PRA.

Section 4.3.3 of CN-RAM-13-036 Revision 4 states, "Additionally, a minimum HEP of 1E-06 was applied to all combinations in order to capture any non-conservative assessments made by the dependency analysis tool."

ii. If a minimum joint HEP value less than 1E-05 was used in the fire PRA, then provide a description of the sensitivity study that was performed and the quantitative results that justify that the minimum joint HEP value has an inconsequential impact on the RICT application.

Minimum joint probability less than 1E-05 was used in the fire PRA. A sensitivity study was performed to update to a minimum joint probability of 1E-05. This sensitivity provides reasonable assurance that a small change in CDF/LERF (less than 1% CDF and LERF) does not have significant impact on the RICT calculated timings.

PhoenixRM RICT Model (Fire ONLY)				
	DepMin of **1E-05**	DepMin of **1E-06**	Delta	Delta (%)
CDF	9.27E-05	9.27E-05	0.00E+00	**0.00%**
LERF	8.85E-06	8.82E-06	3.00E-08	**0.34%**
PhoenixRM RICT Model (All Hazards)				
	DepMin of **1E-05**	DepMin of **1E-06**	Delta	Delta (%)
CDF	9.53E-05	9.52E-05	1.00E-07	**0.11%**
LERF	8.95E-06	8.93E-06	2.00E-08	**0.22%**

iii. If, in response part (b), if it cannot be justified that the minimum joint HEP value has no impact on the application, then provide the following:

Confirm that each joint HEP value used in the fire PRA below 1.0E-5 includes its own justification that demonstrates the inapplicability of the NUREG-1792 lower value guideline (i.e., using such criteria as the dependency factors identified in NUREG-1921 to assess level of dependence). Provide an estimate of the number of these joint HEP values below 1.0E-5,discuss the range of values, and provide at least two different examples where this justification is applied.

1. If joint HEP values used in the fire PRA below 1E-05 cannot bejustified, add an implementation item to set these joint HEPs to1E-05 in the fire PRA prior to the implementation of the RICT Program.

The minimum joint HEP has no impact on the application based on the sensitivity results shared under Part d.ii.

Obstructed plume model

e) NUREG-2178, "Refining And Characterizing Heat Release Rates From Electrical Enclosures During Fire (RACHELLE-FIRE), Volume 1, "Peak Heat Release Rates and Effect of Obstructed Plume," dated April 2016 (ADAMS Accession No. ML16110A140), contains refined peak HRRs, compared to those presented in NUREG/CR-6850, and guidance on modeling the effect of plume obstruction. Additionally, NUREG-2178 provides guidance that indicates that the obstructed plume model is not applicable to cabinets in which the fire is assumed to be located at elevations of less than one-half of the cabinet.

i. If obstructed plume modeling was used, then indicate whether the base of the fire was assumed to be located at an elevation of less than one-half of the cabinet.

NUREG-2178 guidance on obstructed plume was used for selected cabinets identified in Attachment 2 of CN-RAM-13-034 Revision 3. The modeled fire elevation is also documented in Attachment 2 of CN-RAM-13-034 Revision 3. The base of the fire was always modeled at an elevation greater than one-half of the cabinet height (supported by CN-RAM-13-034 Revision 3 Attachment 7 - Detailed Fire Modeling Walkdown Data).

ii. Justify any modeling in which the base of an obstructed plume is located at less than one-half of the cabinet's height.

Not applicable, base of fire was modeled at greater than one-half of cabinet's height.

iii. As an alternative to part (ii) above, add an implementation item to remove credit for the obstructed plume model in the fire PRA prior to the implementation of the RICT program.

Not applicable, see response to e.ii.

Systems not Credited in the Fire PRA

f) CN-RAM-13-038, "Qualitative Screening, Quantitative Screening, Quantification, and Uncertainty Analysis for CPNPP Fire PRA," on the portal states: "If the location of equipment and cables is not known, then the equipment and its cables are assumed failed." As expected, the results of the sensitivity study in Section 5.5.1.1 assuming these equipment never fail show a significant decrease in fire CDF and LERF.

However, the NRC staff notes that some conservative PRA modeling could have a nonconservative impact on the RICT calculations. If an SSC is part of a system not credited in the fire PRA or it is supported by a system that is assumed to always fail, then the risk increases due to taking that SSC out of service is masked. Therefore, address the following:

i. Identify the systems or components that are assumed to be always failed in the fire PRA, or are not included in the fire PRA, due to lack of cable tracing or other reasons.

The following systems or components are always failed in the Fire PRA: Main Feedwater (MFW), Circulating water, Cooling to RCP Seals, Non-safety power, Condenser Vacuum (result from Non-safety power), Anything downstream of MSIVs due to non-safety power being always failed.

ii. Justify that this assumption has an inconsequential impact on the RICT calculations.

The Fire PRA notebook (Section 5.5.1.1 of CN-RAM-13-038 Revision 3) documents the maximum impact of the always failed list on the Fire PRA results.

The always-failed list is comprised of non-safety systems. Discrediting them for fire risk is considered conservative and, while the impact of a RICT that involves these components in some way may not show in the quantitative results, it is known to be conservative because it is already unavailable. The way that this can influence the RICT calculation is by limiting the results, reducing the AOT where it might otherwise be less restricting if the components were not assumed failed. In the most limiting case, a RICT would only impact these always-failed components. In that case, the baseline results represent the assessed AOT (RICT) because otherwise, with those components not assumed failed, the baseline risk would be lower, and then would increase to the current baseline, at most, when affecting those components.

A sensitivity case was done to show the potential impact of the modeling choice to assume equipment whose cable routing was unknown in the FIRE PRA was assumed to always be failed. The current RICT model was revised to remove the logic from the fire portion of the RICT integrated model that fails these components for any fire scenario. First the list of components whose cable routing was not known was compared to the list of components that are part of the extended LCOs associated with the CPNPP RICT submittal. A few components were identified as being part of both list and are listed in the table below. The RICT for each of these components were calculated using the Phoenix RM-RICT software with both the baseline RICT fault tree and the modified fault tree. The results of those cases show (below) that the limiting time calculated for each case is the 30-day backstop. An additional case was run removing a CCP from service. This case was chosen as there are several CCW components, associated with non-safeguards loop of CCW identified as being on both lists discussed previously. As these valves are important to the RICT program in support of Thermal Barrier Cooling (one method to provide cooling to the RCPS) with the CCPs also providing cooling for the RCP seal (seal injection), the impact of the modeling choice on this LCO was investigated. The results also show not significant impact on the calculated RICT

time. This sensitivity provides reasonable assurance that a small change in CDF/LERF (~3 ½% CDF/less than 1% LERF) does not have significant impact on the RICT calculated timings.

Always Fails in RICT				
Component	**Tag**	**Description**	**LCO**	**Function in FPRA**
1-K639-B	1-K639-B	SSPS SLAVE RELAY/SI	3.3.2.C	Supports STM Dump Open function
1-K639-A	1-K639-A	SSPS SLAVE RELAY/SI	3.3.2.C	Supports STM Dump Open function
1-HV-4696	1-HV-4696	MOTOR-OPERATED VALVE 1-HV-4696	3.6.3.A	Impacts Non-SFGD CCW supply to TBC
1-HV-4708	1-HV-4708	MOTOR-OPERATED VALVE 1-HV-4708	3.6.3.A	Impacts Non-SFGD CCW supply to TBC
1-HV-4709	1-HV-4709	MOTOR-OPERATED VALVE 1-HV-4709	3.6.3.A	Impacts Non-SFGD CCW supply to TBC

Always Fails in RICT			
Component	**Base line RICT**	**Modified RICT**	**Notes**
1-K639-B	30 days	30 days	Back-stop is limiting item
1-K639-A	30 days	30 days	Back-stop is limiting item
1-HV-4696	30 days	30 days	Back-stop is limiting item
1-HV-4708	30 days	30 days	Back-stop is limiting item
1-HV-4709	30 days	30 days	Back-stop is limiting item
Charging pump OOS was looked at as the flow control valves above affect TBC, CCPs provide alternate RCP Seal cooling			
TBX-CSAPCH-01	30 days	30 days	Back-stop is limiting item

iii. If, in response to part (ii) above, it cannot be determined that the cited assumption has an inconsequential impact on the estimated RICTs, then identify what programmatic changes will be considered to compensate for this uncertainty and the basis for their consideration (e.g., identification of additional RMAs).

See f) ii.

Well-Sealed Motor Control Center (MCC) cabinets

g) Guidance in FAQ 08-0042 from Supplement 1 of NUREG/CR-6850 applies to electrical cabinets below 440V. With respect to Bin 15 as discussed in Chapter 6, it clarifies the meaning of "robustly or well-sealed." Thus, for cabinets of 440V or less fires from well-sealed cabinets do not propagate outside the cabinet.

For cabinets of 440V and higher, the original guidance in Chapter 6 remains and requires that Bin 15 panels which house circuit voltages of 440V or greater are counted because an arcing fault could compromise panel integrity (an arcing fault could burn through the panel sides, but this should not be confused with the high energy arcing fault type fires)." Fire PRA FAQ 14- 0009, "Treatment of Well- Sealed MCC Electrical Panels Greater than 440V" (ADAMS Accession No. ML15119A176) provides the technique for evaluating fire damage from MCC cabinets having a voltage greater than 440V. Therefore, propagation of fire outside the ignition source panel must be evaluated for all MCC cabinets that house circuits of 440V or greater.

i. Describe how fire propagation outside of well-sealed MCC cabinets greater than 440V is evaluated.

Per FAQ 14-0009, a factor of 0.23 was used to represent the fraction of fires that breach a well-sealed MCC cabinet operating at 440V or greater (FE). The factor is applied to the fire damage states with propagation (damage sets) outside the well-sealed MCC as documented in CN-RAM-13-034 Section 4.3.9.10.

ii. If well-sealed cabinets less than 440V are included in the Bin 15 count of ignition sources, provide justification for using this approach as this is contrary to the guidance.

All motor control centers modeled in the Fire PRA are 440V or greater therefore guidance in FAQ 08-0042 is not applicable.

Transient Fire Influencing Factors

h) NUREG/CR-6850 Section 6 and FAQ 12-0064 "Hot Work/Transient Fire Frequency Influence Factors" (ADAMS Accession No. ML12346A488) describe the process for assigning influence factors for hot work and transient fires. Provide the following regarding application of this guidance:

i. Indicate whether the methodology used to calculate hot work and transient fire frequencies applies influencing factors using NUREG/CR-6850 guidance or FAQ12-0064 guidance.

NUREG/CR-6850 Section 6 methodology was followed for assigning hot work / transient fire frequency influence factors (Section 4.3.3 of CN-RAM-13-032 Revision 3).

ii. Indicate whether administrative controls are used to reduce transient fire frequency, and if so, describe and justify these controls.

Administrative controls were not used to assign weighting factors. The factors were developed for each fire compartment based on a survey of four knowledgeable CPNPP personnel, including a fire protection system engineer, fire protection program engineer, fire protection supervisor, and an operations unit supervisor.

iii. Indicate whether Comanche Peak has any combustible control violations and discuss the treatment of these violations for the assignment of transient fire frequency influence factors. For those cases where Comanche Peak has violations and have assigned an influence factor of 1 (Low) or less, indicate the value of the influence factors assigned and provide justification.

During the development of the Fire PRA, reviews of fire performance related Condition Reports were reviewed. In conjunction with plant walkdowns, surveys and interviews, this information was used to support the judgements made in the Fire PRA development. These judgements were reviewed during the subsequent Peer Reviews and were not required to be modified. Fire-related Corrective Actions involving process changes are programmatically flagged for review by the PRA staff for potential impact on the PRA models. There have been no substantive Condition Reports or Corrective Actions since the Fire PRA model was completed.

Comanche Peak has had fire impairment and transient combustible condition reports, but no fire impairment or transient combustible issues have been significant enough that a change to the fire PRA was required. Normally if a fire impairment is inadequate it is remedied shortly after being identified. Transient combustibles that are not properly tagged are normally removed or properly tagged when found to be inadequate. When fire protection suppression or alarm system deficiencies are identified a compensatory action is normally implemented until the system is restored.

iv. If an influencing factor of "0" to Maintenance, Occupancy, or Storage, or Hot Work

for any fire physical analysis units (PAUs) has been assigned, then provide justification.

A weighting factor of "0" was not assigned to maintenance, occupancy or storage (hot work was not a factor in NUREG/CR-6850 methodology).

v. If a weighting factor of "50" was not used in any fire PAU, provide a sensitivity study that assigns weighting factors of "50" per the guidance in FAQ 12-0064.

Weighting factor of "50" was used in five locations for maintenance.

i) Fire Scenario Treatment of the Main Control Board

Traditionally, the cabinets on the front face of the Main Control Board (MCB) have been referred to as the MCB for purposes of fire PRA. Appendix L of NUREG/CR-6850, provides a refined approach for developing and evaluating those fire scenarios. Fire PRA FAQ 14-0008, "Main Control Board Treatment," dated July 22, 2014 (ADAMS Accession No. ML14190B307), clarifies the definition of the MCB and effectively provides guidance for when to include the cabinets on the back side of the MCB as part of the MCB for fire PRA. It is important to distinguish between MCB and non-MCB cabinets because misinterpretation of the configuration of these cabinets can lead to incomplete or incorrect fire scenario development. This FAQ also provides several alternatives to NUREG/CR-6850 for using Appendix L to treat partitions in a MCB enclosure. Therefore, address the following:

i. Briefly describe the main control room MCB configuration and use the guidance in FAQ 14-0008 to determine whether cabinets on the rear side of the MCB are a part of the MCB.

CN-RAM-13-032 Revision 3 states, "The MCB is defined as the collection of control panels inside the MCR from which operators control the plant on a day-to-day basis. This typically includes the front face of the "horseshoe" and the main control consoles.The horseshoe has a count equal to 1; individual MCB sections are not counted. Backpanels are not counted in this bin. Reference Appendix L of NUREG/CR-6850 and Chapter 5 of EPRI 1019259 (References 2 and 26)." FAQ 14-0008 was not applicable and not used.

ii. If the cabinets on the rear side of the MCB are part of a single integral MCB enclosure using the definition in FAQ 14-0008, then confirm that guidance in FAQ 14-0008 was used to develop fire scenarios in the MCB and determine the frequency of those scenarios.

The MCB did not include any rear panels in Bin 4 MCB counting as there are no rear panels so they are not part of a single integral MCB. Electrical cabinets in the MCR outside of the MCB were counted with Bin 15 Electrical Cabinets. See Figure 5-1 of CN-RAM-13-035 Revision 3 for MCR general layout.

iii. If the cabinets on the rear side of the MCB are part of a single integral MCB enclosure and the guidance in FAQ 14-0008 was not used to develop fire scenarios involving the MCB, then provide a description of hoe the fire scenarios for the backside cabinets are developed and an explanation of how the treatment aligns with NRC accepted guidance.

Not applicable; the treatment aligns with NRC accepted guidance and the MCR layout.

iv. If in response to parts (i and ii) above, the current treatment of the MCB and those cabinets on the rear side of the MCB cannot be justified using NRC accepted guidance, then justify that the treatment has no impact on the RICT calculations.

Not applicable, see responses to parts (i and ii).

PRA Treatment of Fire Dependencies Between Units 1 and 2

j) Many plants have Unit 1 and 2 adjoined and thus have common areas. For these plants, the risk contribution from fires originating in one unit must be addressed for impacts to the other unit given the physical proximity of the other unit and common areas. Therefore, address the following if Units 1 and 2 have common areas and shared systems.

   i. Explain how the risk contribution of fires originating in one unit is addressed for the other unit given impacts due to the physical proximity of equipment and cables in one unit to equipment and cables in the other unit. Include identification of locations where fire in one unit can affect components in the other unit and explain how the risk contributions of such scenarios are allocated in the LAR.

Comanche Peak is a dual-unit plant with shared auxiliary and electrical/control buildings, as well as the service water intake structure. Select Unit 1 equipment required for safe shutdown is able to cross-tie to its sister equipment in Unit 2 (and vice-versa) to provide alternate cooling capabilities. These cross-ties are credited in the plant response model. All shared locations of the plant are modeled and analyzed for impact on each unit and included in the discussion of results.

   ii. Explain how the contributions of fires in common areas are addressed, including the risk contribution of fires that can impact components in both units.

Shared locations are documented in results in CN-RAM-13-038 Revision 3 with allocations being quantified for impact on either unit. The FRANX mapping includes impacted targets regardless of unit association.

Additionally, it should be noted that a fire in one unit is not assumed to result in an automatic reactor trip in the other unit, based on the plant design and the fire response procedures. However, if a fire in the control room requires control room evacuation then a trip of both units is completed prior to exiting.

License Amendment Request docketed change is found in Enclosure 2, that has been revised to:

- **State that only approved methodologies were used in the development of the Fire PRA**
- **All transients in the Comanche Peak Fire PRA utilized the bounding 98th percentile Heat Release Rate (HRR) of 317 KW from NUREG/CR-6850. There are no locations utilizing a reduced transient fire HRR.**
- **Any sensitive electronics exposed to the fire or the radiant energy were treated consistent with FAQ 13-0004.**
- **A minimum HEP of 1.0E-06 was applied to all combinations in order to capture any non-conservative assessments made by the dependency analysis tool.**
- **State that because of the plant design and the fire response procedures, fire in one unit is not assumed to result in an automatic reactor trip in the other unit.**
- **Provide a summary of the assumed Main Control Room abandonment procedures, including tripping of both units prior to the evacuation.**

QUESTION 17 – Determination of Seismic CDF and LERF "Penalty"(APLC)

Section 2.3.1, Item 7, of NEI 06-09, Revision 0-A, states that the "impact of other external events risk shall be addressed in the RMTS program," and explains that one method to do this

is by "a reasonable bounding analysis and applying it along with the internal events risk contribution in calculating the configuration risk and the associated RICT." The NRC staff's SE for NEI 06-09 states that "[w]here PRA models are not available, conservative or bounding analyses may be performed to quantify the risk impact and support the calculation of the RICT."

LAR Enclosure 4, Section 3 presents the details of an approach for determining the seismic "penalty." The calculated seismic CDF (SCDF) was then adjusted using the Comanche Peak Plant Availability Factor of 0.94. Given that the plant is operating during implementation of RICTs, adjusting the SCDF and seismic LERF (SLERF) by the plant availability factor does not appear to be appropriate. Furthermore, this adjustment is inconsistent with the process to translate the baseline PRA model for use in the configuration risk model (i.e., RTR model) wherein the plant availability factor is set to 1.0 (see LAR Enclosure 8 Section 2).

a) Provide justification for adjusting the bounding SCDF and SLERF estimates by the plant availability factor. If justification cannot be provided, provide updated bounding SCDF and SLERF values to be used in the RICT calculations.

The initiating event frequencies used in the Comanche Peak PRA Model explicitly include the plant availability factor (PAF). When the seismic penalty was developed, this same approach was used to generate a frequency (i.e., a frequency that explicitly includes the plant availability factor). When converting the baseline PRA model into a Configuration Risk (or real-time risk) model, logic was added at the top of the model to include or exclude the PAF from the calculation. This is done by multiplying the CDF or LERF results by a value of 1/PAF (~1.06).

b) Provide the justification that the plant baseline risk is not impacted by seismic events. If the justification cannot be provided, adjust the baseline SCDF and SLERF for both units.

The two tables are consistent although the nomenclature is recognizably confusing.The results reported in Table 1 of LTR-RAM-20-45 indicate the seismic CDF/LERF values and then the delta from the case without seismic CDF/LERF. Table E4-1 of Enclosure 4 reports explicitly the seismic contribution to the "base case" (referring to the base case from internal events) and then the delta. While the nomenclature is confusing, the numerical values are consistent, and the RICT model always includes the seismic penalty in the calculations. To summarize, the baseline risk includes the penalties for seismic and high wind impacts.

Because of the scope of the changes from a) and b) above this second supplement to the license amendment request has been reviewed by the Comanche Peak Station Operations Review Committee (SORC) prior to submittal.

Table E4-1 of Enclosure 4 to the LAR provides seismic bounding analysis results and shows baseline SCDF and SLERF are 0 per year for both units. It is unclear why calculated SCDF and SLERF are not considered as the baseline risk for the RICT program. There is no justification provided for this selection in the LAR. Table 1 of LTR- RAM-20-45 "Seismic Hazard Analysis to Support Comanche Peak RICT LAR," provided by the licensee on the portal indicates that SCDF and seismic delta CDF are the same, and SLERF and delta SLERF are the same. It appears that these two tables are not consistent.

c) Explain the inconsistency between the values in Table E4-1 of Enclosure 4 to the LAR and Table 1 of LTR-RAM-20-45, and explain which values are being used for your analysis.

See Item b)

License Amendment Request docketed change is found in Enclosure 4, Table E4-1 and

supporting text that have been revised to include the information in response a) and clarify the interpretation of the table per response b).

QUESTION 18 – Determination of the High Winds CDF and LERF "Penalty" (APLC)

Section 2.3.1, Item 7, of NEI 06-09, Revision 0-A, states that the "impact of other external events risk shall be addressed in the RMTS program," and explains that one method to do this is by "performing a reasonable bounding analysis and applying it along with the internal events risk contribution in calculating the configuration risk and the associated RICT." The NRC staff's SE for NEI 06-09 (ADAMS Accession No. ML071200238) states that "[w]here PRA models are not available, conservative or bounding analyses may be performed to quantify the risk impact and support the calculation of the RICT."

a) Discuss whether the high wind CCDP and CLERP are obtained by quantifying Comanche Peak internal events PRA model, or high winds PRA model. If it is by high winds PRA model, discuss the model and its acceptability.

Enclosure 4 to the LAR (ML21131A233) describes how the CCDP and CLERP values were calculated. Page 7 of 22 - Section 1. High Winds Analysis within that enclosure states "The CPNPP High Winds PRA model was used to calculate the conditional core damage probability (CCDP) and Conditional Large Early Release Probability (CLERP) by quantifying the model while assuming the following:" This sentence is incorrect. It should say "The CPNPP Internal Events PRA model was used to estimate the conditional core damage probability (CCDP) and Conditional Large Early Release Probability (CLERP) due to high wind events by quantifying the model while assuming the following..." Page 8 of 22 of Enclosure 4 to ML21131A233, under the heading "Internal Events Model Sequence Development" describes the process that was used to quantify CCDP and CLERP values; the internal events PRA model was quantified to develop these values.

b) The LAR does not explain how the mean hazard frequencies were developed for each of the 10 tornado wind speed intervals and for each of the 10 straight wind speed intervals. Address the following:

   i. Provide the mean hazard frequencies used in the analysis.

The mean hazard frequencies associated with the 10 tornado wind speed intervals and 10 straight wind speed intervals are listed in the table below (tornado intervals designated with prefix T and straight wind intervals designated with prefix S):

Table 1: Wind Speed Interval Frequencies

Interval designator	Wind speed lower bound (mph)	Wind speed upper bound (mph)	Interval frequency (yr^{-1})
T11	73	84	7.43E-04
T12	85	97	6.28E-04
T13	98	111	5.27E-04
T21	112	125	3.59E-04
T22	126	140	3.49E-04
T23	141	156	2.46E-04
T31	157	176	1.08E-04
T32	177	205	3.00E-05
T4	206	259	3.25E-06
T5	260	318	5.36E-08
S11	73	84	1.48E-01
S12	85	97	3.56E-02
S13	98	111	7.28E-03
S21	112	125	1.28E-03
S22	126	140	2.35E-04
S23	141	156	3.80E-05
S31	157	176	5.70E-06
S32	177	205	5.26E-07
S4	206	259	1.57E-08
S5	260	318	2.15E-11

ii. Describe how the mean hazard frequencies were developed and justify the source(s) of the wind data used to develop the frequencies. Specifically address how the frequencies are applicable to the Comanche Peak site and how these have been updated since the Comanche Peak Individual Examination of External Events (IPEEE).

Prior to calculating tornado and straight wind hazard frequencies, the analysis in CN-RAM-20-002 considers all wind hazards. The applicable wind hazards for CPNPP are tornadoes, thunderstorms, and extratropical storms. "Special winds" are not applicable to the site based on the applicability region map (Figure 26.5-1) in ASCE 7-16. Hurricanes are screened out of the analysis. According to the CPNPP FSAR, section 2.3.1.2.2, amendment No.108, the average frequency of tropical cyclones that affected Texas for the period 1931 to 1960 is approximately two per year; and of these about one in four were of hurricane force. According to historical hurricane tracks published by National Oceanic and Atmospheric Association (NOAA) which consist of over 150 years of data, a total of 1 hurricane (rated Category 1), 6 tropical storms, and 10 tropical depressions have affected the 65-nautical mile radius around the CPNPP site (as of June 2020 when CN-RAM-20-002 was published). Based on the strength of a hurricane and how it dissipated rapidly once the storm commences an overland trajectory, distance minimizes the influence that a hurricane would have upon the site. The CPNPP site is located approximately 250 miles (402 km) from the Gulf of Mexico, and

according to the 2009 ASME/ANS PRA Standard, hurricane risk analysis is not required farther inland than "up to a few hundred kilometers or so from the coastline." On this basis and in consideration of the hurricane history described above, hurricanes as a specific phenomenon can be screened out of the CPNPP high winds bounding penalty analysis.

The steps in developing the tornado hazard frequencies include the following:

- Identify data sources
- Obtain data applicable to the site and make adjustments to account for known uncertainties
- Calculate the occurrence frequency of a tornado of a particular magnitude
- Calculate the exceedance frequency of a particular windspeed (i.e., link tornado magnitudes to associated wind speeds) and calculate the interval frequency for the desired quantification intervals.

The data source for tornado events is the Storm Prediction Center (SPC) tornado database maintained by NOAA. This database is recommended by EPRI 3002003107, "High Wind Risk Assessment Guidelines," an industry guidance document used when developing the wind hazard frequencies. As a benchmark, the SPC tornado database was also used in SRNL-STI-2013-00664, "Probabilistic Hazard Assessment for Tornadoes, Straight-line Wind, and Extreme Precipitation at the Savannah River Site." A reasonable alternative to the SPC database is a very similar tornado database maintained by the National Climatic Data Center (NCDC), a separate division within NOAA. Both databases are compiled from the NWS Storm Data publication, but the SPC database was easier to work with as the entire database can be downloaded in a single .csv file.

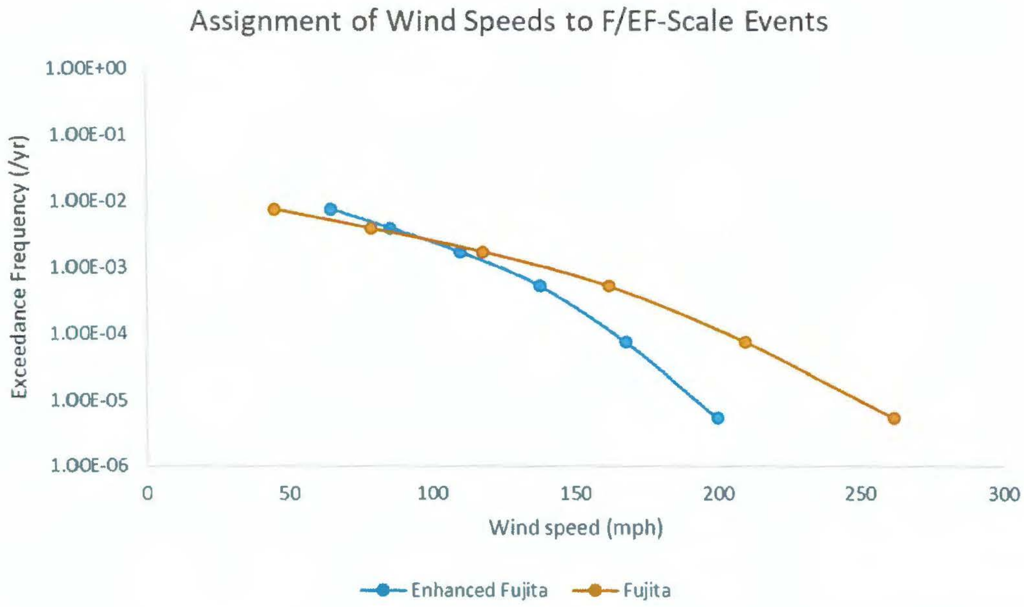
To make the data applicable to the site, tornado records were selected with a starting or ending coordinate within 125 miles of the site. Other radii (as well as the 2-degree latitude-longitude "box" method) for selecting tornado records were examined in a sensitivity study (in CN-RAM-20-002) and a radial area of 125 miles was judged to provide an adequate balance of representing the site while providing enough data to reduce uncertainties. The resulting tornado records were then adjusted to account for the following known uncertainties: mis-classification of intensity, unreported and unclassified tornadoes, and variation of wind speed within the impact area. These account for each of the elements in Note 1 to supporting requirement WHA-A1 of ASME/ANS RA-Sa-2009; that Note was clarified to be mandatory in Revision 2 to Regulatory Guide 1.200.

Annual tornado occurrence frequency is calculated following the methods suggested in Revision 2 of NUREG/CR-4461, using the finite-structure strike probability for a rectangular structure with characteristic length of 8,474 feet. This represents the probability that a tornado intersects any portion of the "site," rather than one particular structure on the site. To determine this value, a radius of 2,500 feet was drawn from several important structures on site, including the reactor buildings, switchyard, and diesel generators; a rectangle with a diagonal of 8,474 feet bounds such an area. The radius of 2,500 feet ensures that the impact from tornado missiles as well as direct wind effects is captured.

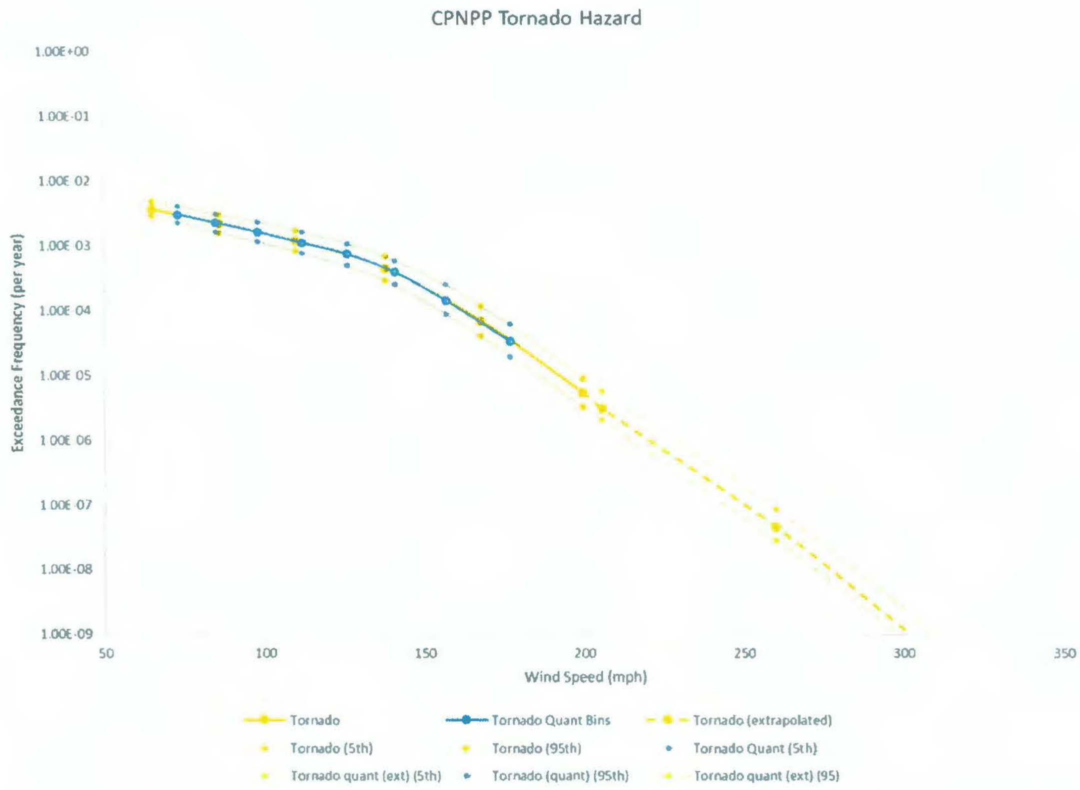
All tornado records, regardless of the scale they were classified under, are used to calculate the annual tornado occurrence frequencies. Tornado intensity classifications are based on the damage observed after the fact along the tornado path; they are not directly based on tornado wind speed measurement. The damage caused by an F1 tornado meets the same classification criteria as the damage caused by an EF1 tornado; the difference between the two scales is a shift in what experts estimate as the wind speeds responsible for that damage. Since the method calculates occurrence frequency of tornadoes of a particular magnitude and

subsequently maps those tornado magnitudes to wind speeds, it is appropriate to use all tornado records (regardless of the scale they were classified under) when calculating the tornado occurrence frequency.

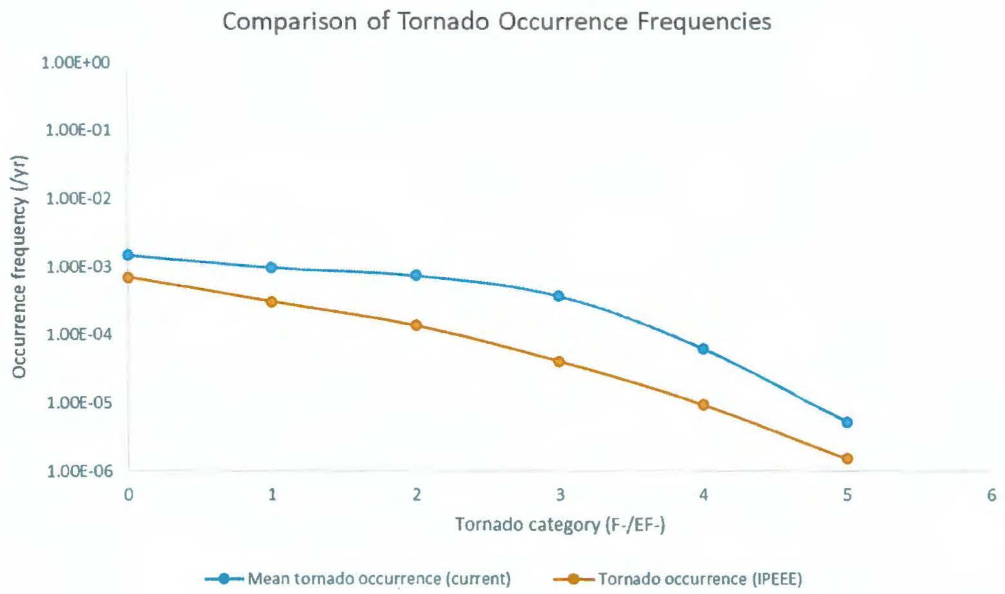
Exceedance frequencies for wind speeds due to tornadoes were developed by linking the occurrence frequency of tornado magnitudes to wind speeds. As shown in the figure below, using the wind speeds from the Enhanced Fujita (EF)-scale results in higher (i.e., more conservative) exceedance frequencies for wind speeds below approximately 100 mph, and results in lower (i.e., more optimistic) exceedance frequencies for wind speeds above approximately 100 mph (relative to using the Fujita (F)-scale).



The EF-scale is the currently accepted estimate for the wind speeds responsible for the damage observed in each tornado category, as evidenced by its use by NOAA. In addition, low wind speed tornado events have typically contributed more of the total risk in recent HWPRAs. For these reasons it was chosen to use the EF-scale to assign wind speeds to the tornado categories. The exceedance frequencies thus developed are plotted as a function of wind speed. A second data series is created to represent exceedance frequencies of the wind speeds associated with the quantification bins (which do not align one-to-one with the lower bounds of the wind speed ranges of the EF-scale). The exceedance frequencies for the quantification bin wind speeds were estimated graphically by aligning the curve representing the exceedance frequencies developed from the EF-scale wind speed lower bounds to the second data series representing the quantification bin wind speeds (as shown in the figure below).



As a basis for comparison, the figure below plots the tornado event occurrence frequencies developed for the bounding penalty assessment against the tornado event occurrence frequencies developed in the CPNPP Individual Plant Examination of External Events (IPEEE) documented in the series titled "Reinhold Aerial" in Table 3-2 of CPNPP document ER-EA-004, which is assumed to be the closest match to the finite structure strike frequency developed in this document. Note that the figure below presents occurrence frequencies (rather than exceedance frequencies as discussed elsewhere in this document) because the IPEEE values are stated on that basis. The current assessment results in a higher tornado occurrence frequency than the IPEEE.



The steps in developing the straight wind hazard frequencies include the following:

1. Identify data sources
2. Obtain peak 3-second gust wind speed data applicable to the site and make adjustments to account for anemometer height and terrain effects
3. Separate thunderstorm and non-thunderstorm data (because they are separate phenomena their hazard frequencies should be calculated independently; steps 4 through 6 performed for both thunderstorm and non-thunderstorm data)
4. Combine the data from the chosen stations to obtain a larger data pool
5. Identify the maximum wind speed for each year on record
6. Calculate the exceedance frequency by fitting the maximum wind speeds to a Type I extreme value distribution
7. Sum the thunderstorm and non-thunderstorm exceedance frequencies to determine the "straight wind" exceedance frequency

The Global Historical Climate Network – Daily Surface Data Hourly Global dataset (NCEI DSI 9101_01) contains detailed daily observational climate data for thousands of locations worldwide. This database was queried to provide data appropriate for CPNPP. A list of all surface weather observation stations in the states of Texas and Oklahoma was obtained from the Federal Aviation Administration search tool. Then, each 4-digit station ID was entered into the station history search tool of NOAA's Historical Observing Metadata Repository to identify the latitude and longitude of the station. The distance from each station to CPNPP is calculated, and the list of stations is sorted from closest to furthest from CPNPP. Next, starting with the closest station, each station is investigated to determine whether data elements WSFG and WT03 (peak 3-second wind gust and thunder indicator, respectively, each part of the GHCN-D dataset) are present at that station and for how long. Stations with at least 30 years of WSFG data that also contain the WT03 data element are retained, and the search is finished when the retained stations comprise at least 100 years of cumulative data.

Only including data from stations with at least 30 years of WSFG data is an assumption; using

data from sites with a shorter period of record may lead to under-estimating the wind speed exceedance frequency by not capturing extreme wind gusts. DOE-STD-1020-2012 includes the statement "at least ten continuous years of annual extreme wind speed records shall be recorded. However, if longer periods of record exist, the entire period may be used." There are several surface weather observation stations within a reasonable distance of the site that meet the 30-year criteria and are representative of the site (following adjustments for terrain and anemometer location); therefore, it was not necessary to include data from surface weather observation stations with shorter periods of record.

The table below describes the adjustments that were made to the straight winds data to ensure it is representative of the CPNPP site.

Table 1: Straight Winds Data Corrections

Parameter being corrected	Applicability	How the correction is applied
Anemometer Height	Determine if anemometer height was not equal to 10 m at any point during the period when the data is used. If it is, identify the height during that period.	Use Equation 1 (shown below) for height correction based on Tamura and Kareen (2013) as recommended by EPRI 3002003107. Use z_0 values for each station based on engineering judgment of terrain roughness based on review of satellite images.
Terrain Profile for Station	Review satellite images showing terrain surrounding the site, then use engineering judgment with conservative bias to select an appropriate factor.	Applied when selecting z_0 value for anemometer height correction and applied when weighting stations for superstation approach (a lower weight is assigned to stations where the terrain is different from the CPNPP site).
Anemometer Averaging Period	NOAA Historical Observing Metadata Repository lists averaging period for stations and the time period each are applicable.	Peak 3-second gust wind speed observations are assumed to be the most appropriate to represent maximum wind speed. For all of the stations selected, the anemometer during the period when data element WSFG is available is identified as cup-style, 5-second. For time periods when data element WSF5 is available, the wind speed must be converted to a 3-second gust. Therefore, all wind speed data is multiplied by the averaging period conversion factor.
Storm cause (t-storm or ET-storm)	Data ordered from NOAA included present weather indicator for thunder (WT03).	If thunder indicator is true for a data point, it is associated with a thunderstorm. Otherwise, it is associated with an extratropical storm.
Outlier Investigation	Raw WSFG data were sorted largest to smallest, and the top 20 peaks were investigated by reviewing the Storm Data publication for the month and year in which the data point occurred. If the storm data publication has no record of a storm affecting the corresponding part of Texas	For any data that are to be removed as a suspected outlier, the following are recorded: station, date, wind speed, and justification for removing. Then, the data point is excluded from the extreme value analysis. The outliers for each station for

	on the date associated with the peak, it is considered to be an outlier. If the peak is from before 1959, it is assumed valid since Storm Data publication is not available prior to that date.	thunderstorm and extratropical storms are recorded.
Distance from site for "Superstation" Approach	If all data are from a homogeneous wind climatological region, weighting is not need and additional stations simply increase the period of record. In total there are 167 years of data from which peaks are used even though the data covers a period from 1953 - 2020.	An assessment of data homogeneity was performed which justified <u>not</u> performing any weighting. A sensitivity study showed that using data from a single station results in more conservative wind speed exceedance frequency values (compared to the superstation approach) for non-thunderstorm winds at all wind speeds and for thunderstorm winds at wind speeds greater than approximately 160 mph. This is expected because, when using data from a single station, there are fewer observations from which to estimate exceedance frequency of wind gusts. However, given that the data are from a homogeneous region, it is acceptable to pool the data, and thus, the superstation approach will be used.
Storm Independence	Winds are separated by type prior to performing this correction. A time interval is chosen to identify peaks from separate storms, and this value is larger for extratropical storms than for thunderstorms. If two peak values are not separated by at least this time interval, they are considered to be from the same storm. If multiple data points are determined to be from the same storm, only the highest one is taken.	This correction is <u>not</u> applied given that an epochal approach is used where a maximum value from each year of data is used (i.e., two peaks from the same storm would not be used anyway since only one can represent the maximum for that year).

$$V(10) = V(z) * \frac{\ln\left(\frac{10}{0.03}\right)}{\ln\left(\frac{z}{z_0}\right)}$$ Equation 1

Where:

z	=	Height of the initial observation above ground (m)
z_0	=	Roughness length (m)
$V(10)$	=	Wind velocity at a height of 10 m
$V(z)$	=	Wind velocity at height z

The CPNPP IPEEE did not quantify frequencies associated with straight winds hazards; therefore, no comparison is possible for the straight winds hazard.

iii. Discuss uncertainties associated with the development of these frequencies and their potential impact on the RICT application.

See the discussion in Table 2 below. The uncertainties and assumptions associated with high winds hazard frequencies are characterized in Section 4.4 of CN-RAM-20-002 as provided in the original submittal.

Table 2: Disposition of Key Assumptions and Sources of Uncertainty

ID	Summary of High Winds Assumption/Uncertainty	Part of Model Affected	Generic Impact on Risk Applications	Evaluation of RICT Impact
1	Site meteorological tower data does not include peak gust measurements for wind. Without peak gust data at the site, other data near the site must be utilized. Therefore, there is uncertainty in how well the regional data represents the site wind climatology.	Straight wind initiating event frequencies.	The selected modeling approach is consistent with EPRI 3002003107. One alternative approach might be to select different nearby anemometers (from airports other than the ones chosen in the baseline model). However, the data corrections applied (described above) attempt to correct regional data to better apply to the site, so it is expected that any differences would be minimal.	This approach follows EPRI 3002003107 and industry practice, which is in essence, a consensus process. In addition, the alternative approach is expected to result in minimal change. Therefore, no additional sensitivities are required.
2	Extrapolation of straight wind hazards to very low exceedance frequencies represents a substantial uncertainty because the wind speeds being predicted are well beyond any observed data. Mean hazard frequencies are used in the final calculation.	Straight wind initiating event frequencies.	The selected modeling approach is consistent with EPRI 3002003107.	The impact with respect to these applications would be to potentially produce uniform shifts in the straight wind hazard frequencies, which is unlikely to have a significant impact on equipment importance measures or relative risk insights.

ID	Summary of High Winds Assumption/Uncertainty	Part of Model Affected	Generic Impact on Risk Applications	Evaluation of RICT Impact
3	SSCs located outside, or located inside a building vulnerable to high winds, are assumed to fail for the bounding penalty approach. This is conservative because failure of the building may not always result in failure of all of the equipment inside, or equipment located outside may survive smaller or less-intense wind events.	Equipment credited to mitigate high wind events.	This is a conservative assumption that is made based on the uncertainty related to the damage that may occur to credited equipment and is consistent with EPRI 3002003107.	The uncertainty/assumption represents a generally conservative bias in the penalty assessment and removing the identified conservative bias would only serve to improve acceptability with respect to the acceptance guidelines. This criterion is consistent with the guidance in Section 3.1.1 of EPRI 1016737, "Treatment of Parameter and Modeling Uncertainty for Probabilistic Risk Assessments." Additionally, this approach follows EPRI 3002003107 and industry practice, which is in essence, a consensus process.
4	It is assumed that offsite power recovery is not possible for high wind events.	Electric power support for ECCS equipment credited for mitigation of high wind events.	This is a conservative assumption. A sensitivity study was performed to characterize the impact of this assumption in LTR-RAM-20-99.	Existing sensitivity studies adequately characterize this source of uncertainty. The impact with respect to these applications would be to potentially change overall LOOP contribution, which would not alter the current insights from the model.

ID	Summary of High Winds Assumption/Uncertainty	Part of Model Affected	Generic Impact on Risk Applications	Evaluation of RICT Impact
5	Tornado records are selected from a symmetric area centered on the plant. A more uniform tornado occurrence rate might be achieved if a contiguous, non-symmetric area was used. That is, some locations within the 125-mile radius used to select tornado records may have a slightly different tornado occurrence rate than others due to topographic features or local weather patterns.	Tornado initiating event frequencies.	The alternative modeling approach (selecting from a non-symmetric area) could conceivably result in more tornado records over approximately the same area, which would result in a greater tornado occurrence rate. The approach implemented is a consensus approach to tornado record selection and is consistent with NUREG/CR-4461, which is referenced in the note to SR WHA-A1 of the PRA Standard as an example of a state-of-the-art methodology for tornado hazard analysis. Sensitivity studies for tornado record selection area were performed in in CN-RAM-20-002 and justify the area chosen.	This approach follows industry guidance, which is in essence, a consensus process. Existing sensitivity studies adequately characterize this source of uncertainty. The impact with respect to these applications would be to either uniformly increase or uniformly decrease the tornado initiating event frequencies, thus impacting risk metrics in a somewhat uniform way (i.e., little to no impact on relative risk insights). Therefore, no additional sensitivities are required.

ID	Summary of High Winds Assumption/Uncertainty	Part of Model Affected	Generic Impact on Risk Applications	Evaluation of RICT Impact
6	Tornado data is not corrected to account for the change in reporting of path width that occurred in 1994. Prior to this date, the reported path width was the mean; after this date, the reported path width was the maximum.	Tornado initiating event frequencies.	This is consistent with EPRI 3002003107, which states that this is a conservative approach since the maximum wind speed is only present in part of the tornado path.	The uncertainty/assumption represents a generally conservative bias in the PRA model, and removing the identified conservative bias would only serve to improve acceptability with respect to the acceptance guidelines. This criterion is consistent with the guidance in Section 3.1.1 of EPRI 1016737. Additionally, this approach follows EPRI 3002003107 and industry practice, which is in essence, a consensus process. Therefore, no additional sensitivities are required.

ID	Summary of High Winds Assumption/Uncertainty	Part of Model Affected	Generic Impact on Risk Applications	Evaluation of RICT Impact
7	Tornado data is corrected to account for an observed under-reporting of F0 tornadoes prior to 1988. The number of tornadoes is increased by a factor of approximately 3.4, which is the factor by which the average count of F0 tornadoes in the contiguous US from 1989-2018 is greater the average from 1950-1988. This factor is applied to tornado records prior to 1989. This approach redistributes the exceedance frequency among the various tornado bins as a result of changing the intensity distribution vector by adding new EF0 records. In other words, the frequencies of EF0 and EF1 tornadoes increase, and the frequencies of other tornadoes decrease.	Tornado initiating event frequencies.	This is consistent EPRI 3002003107. An alternative would be to exclude data prior to 1988, which would adversely impact the limited statistics and introduce more uncertainty through state of knowledge.	This approach follows EPRI guidance and industry practice, which is in essence, a consensus process. Therefore, no additional sensitivities are required.

ID	Summary of High Winds Assumption/Uncertainty	Part of Model Affected	Generic Impact on Risk Applications	Evaluation of RICT Impact
8	The method of assigning wind speed values to the F-/EF-scales represents a substantial uncertainty. See the discussion in the response to question 18.b.ii.	Binning of tornado exceedance frequencies.	The selected modeling approach is consistent with EPRI 3002003107 and is deemed as an acceptable industry practice; essentially a consensus model or process, and no further characterization is required. There is also no practical alternative (i.e., cannot quantify in 1-mph increments).	This approach follows EPRI guidance and industry practice, which is in essence, a consensus process. This criterion is consistent with Section 3.3.2 of RG 1.200 Revision 2. Therefore, no additional sensitivity studies are required. Existing sensitivity studies adequately characterize this source of uncertainty. The impact with respect to these applications would be to potentially produce minor shifts in the risk from some tornado categories to others, which is unlikely to have a significant impact on equipment importance measures or relative risk insights.

ID	Summary of High Winds Assumption/Uncertainty	Part of Model Affected	Generic Impact on Risk Applications	Evaluation of RICT Impact
9	It is assumed that straight wind events below 73 mph are addressed in the weather-induced LOOP initiator of the CPNPP internal events PRA model.	High Winds initiating event frequencies.	The weather-induced LOOP initiating event frequency in the internal events model is calculated by examining the number of LOOP events caused by weather (including high winds) in a region surrounding the site. 73 mph was chosen because it represents the lower bound of wind speeds capable of causing equipment damage in excess of a LOOP.	This approach follows EPRI guidance and industry practice, which is in essence, a consensus process. This criterion is consistent with Section 3.3.2 of RG 1.200 Revision 2. Therefore, no additional sensitivity studies are required.

c) Neither the LAR nor LTR-RAM-20-99 on the portal explain the technical basis for the conditional loss of offsite power (LOOP) probabilities developed for each of the 10 tornado wind speed intervals and for each of the 10 straight wind speed intervals using engineering judgement. Address the following:

i. Provide the conditional LOOP probabilities used for each wind speed interval.

The conditional LOOP probabilities for each interval are shown in the table below:

Wind Event Bin	Wind speed LB (mph)	Wind Speed UB (mph)	Conditional LOOP probability
T11	73	84	0.05
T12	85	97	0.10
T13	98	111	0.10
T21	112	125	0.10
T22	126	140	1.00
T23	141	156	1.00
T31	157	176	1.00
T32	177	205	1.00
T4	206	259	1.00
T5	260	318	1.00
S11	73	84	0.05
S12	85	97	0.10
S13	98	111	0.10
S21	112	125	0.10
S22	126	140	1.00
S23	141	156	1.00
S31	157	176	1.00
S32	177	205	1.00
S4	206	259	1.00
S5	260	318	1.00

ii. Provide the basis for each of the probabilities and justify that these probabilities will not result in non-conservative RICTs.

Conditional LOOP probability estimates are based on engineering judgment of the likelihood of different wind-speed conditions causing a LOOP and failure of all SSCs in the plant yard, switchyard and turbine building. It is assumed that any potential non-conservatism in the conditional loss of offsite power (LOOP) probabilities is outweighed by the conservative assumption of no recovery of offsite power. A sensitivity study (described below) was performed to validate this assumption by combining the CCDPs from Sensitivity Study 2 of LTR-RAM-20-99 (LOOP recovery applied via internal events weather-related LOOP offsite power non-recovery factors for wind events below 98 mph) with the more realistic conditional LOOP probabilities developed below.

The offsite power transmission lines can be realistically assumed to be the limiting component capable of causing a LOOP in terms of wind speed required for damage. Realistic fragility values for the offsite power transmission lines can be calculated by modeling the capacity as a log-normally distributed random variable as described in Equation 2, which is an often-used method for calculating fragilities (see for example equation 10-12 of NUREG/CR-2300, Volume 2) and is recommended by EPRI 3002003107.

$$f = \Phi\left(\frac{\ln\left(\frac{v}{v_m}\right) + \beta_u \Phi^{-1}(Q)}{\beta_r}\right) \qquad \text{Equation 2}$$

Where:

f	=	SSC fragility at wind speed v
$\Phi\,(\,)$	=	Standard Gaussian cumulative distribution function
v	=	Wind speed at which fragility is evaluated
v_m	=	Median capacity wind speed
β_r	=	Logarithmic standard deviation of the random variable reflecting inher randomness in the loading and material properties
β_u	=	Logarithmic standard deviation of the random variable reflecting the uncertainty in the calculation of the wind capacity
Q	=	Confidence level

According to the IPEEE tornado risk assessment for CPNPP, the switchyard is "designed to withstand 80 mph wind speeds. Grid power should be assumed to be unavailable following a tornado strike with winds in excess of 80 mph." Accounting for a safety factor of 20% results in a median wind speed capacity, v_m, of 96 mph. Per M.K. Ravindra, "State-of-the-Art and Current Research Activities in Extreme Winds Relating to Design and Evaluation of Nuclear Power Plants," recommended values for β_U and β_R are 0.075 and 0.176 respectively for wind failure modes. To calculate the fragility value for each wind speed interval, the geometric mean[1] of the upper and lower bounds of the wind speed range is used as v in Equation 2. Applying these values in Equation 2 results in the following fragility values:

Interval designator	Geometric mean of wind speed interval ≡ fragility evaluation wind speed (mph)	Mean transmission line wind fragility ≡ conditional LOOP probability for this sensitivity study	Conditional LOOP probability assumed in baseline based on engineering judgment
T11 and S11	78.3	1.43E-01	5.00E-02
T12 and S12	90.8	3.85E-01	1.00E-01
T13 and S13	104.3	6.68E-01	1.00E-01
T21 and S21	118.3	8.63E-01	1.00E-01
T22 and S22	132.8	9.55E-01	1.00E+00
T23 and S23	148.3	9.88E-01	1.00E+00
T31 and S31	166.2	9.98E-01	1.00E+00
T32 and S32	190.5	1.00E+00	1.00E+00
T4 and S4	231.0	1.00E+00	1.00E+00
T5 and S5	287.5	1.00E+00	1.00E+00

The CCDPs used in the quantification of this sensitivity study are developed from the internal events model as described in Section 5.3 of LTR-RAM-20-99 and apply the weather-related LOOP offsite power non-recovery factors for wind events below 98 mph. The results of this sensitivity study for each wind interval are presented in the table below. Overall, this sensitivity

[1] The geometric mean is used as opposed to the arithmetic mean because, per EPRI 3002003107, "the range of the quantity of interest over a discrete bin may be very large. In this situation use of the typical arithmetic mean would bias the bin average to the higher windspeed (that is, the bin maximum). Since events at lower windspeeds are much more frequent than events with higher windspeeds, use of the arithmetic mean would tend to overestimate the average value of the windspeeds applicable to that bin and would produce overly conservative results."

study results in a CDF value of 3.56E-06/yr, which is 13% lower than the baseline value of 4.09E-06/yr. The sensitivity results in a LERF value of 2.03E-07/yr, which is 14% lower than the baseline value of 2.35E-07/yr. Therefore, the conservatism in not applying recovery for the baseline outweighs any potential non-conservatism in the transmission line fragility values. Thus, use of the values assumed in the baseline will not result in non-conservative RICTs.

Wind Event Bin	Mean Hazard frequency (/yr)	Conditional LOOP probability (Sensitivity)	CCDP for sensitivity (italics indicate recovery applied)	Sequence CDF (/yr) (Sensitivity)	CLERP (sensitivity)	Sequence LERF (/yr) (sensitivity)
T11	7.43E-04	1.43E-01	*6.95E-05*	7.39E-09	*3.95E-06*	4.20E-10
T12	6.28E-04	3.85E-01	*6.95E-05*	1.68E-08	*3.95E-06*	9.55E-10
T13	5.27E-04	6.68E-01	*6.95E-05*	2.45E-08	*3.95E-06*	1.39E-09
T21	3.59E-04	8.63E-01	3.14E-04	9.74E-08	1.81E-05	5.60E-09
T22	3.49E-04	9.55E-01	3.14E-04	1.05E-07	1.81E-05	6.02E-09
T23	2.46E-04	9.88E-01	3.14E-04	7.64E-08	1.81E-05	4.39E-09
T31	1.08E-04	9.98E-01	3.14E-04	3.39E-08	1.81E-05	1.95E-09
T32	3.00E-05	1.00E+00	3.14E-04	9.43E-09	1.81E-05	5.42E-10
T4	3.25E-06	1.00E+00	3.14E-04	1.02E-09	1.81E-05	5.87E-11
T5	5.36E-08	1.00E+00	3.14E-04	1.68E-11	1.81E-05	9.68E-13
S11	1.48E-01	1.43E-01	*6.95E-05*	1.47E-06	*3.95E-06*	8.36E-08
S12	3.56E-02	3.85E-01	*6.95E-05*	9.53E-07	*3.95E-06*	5.41E-08
S13	7.28E-03	6.68E-01	*6.95E-05*	3.38E-07	*3.95E-06*	1.92E-08
S21	1.28E-03	8.63E-01	3.14E-04	3.47E-07	1.81E-05	2.00E-08
S22	2.35E-04	9.55E-01	3.14E-04	7.05E-08	1.81E-05	4.06E-09
S23	3.80E-05	9.88E-01	3.14E-04	1.18E-08	1.81E-05	6.78E-10
S31	5.70E-06	9.98E-01	3.14E-04	1.79E-09	1.81E-05	1.03E-10
S32	5.26E-07	1.00E+00	3.14E-04	1.65E-10	1.81E-05	9.50E-12
S4	1.57E-08	1.00E+00	3.14E-04	4.93E-12	1.81E-05	2.84E-13
S5	2.15E-11	1.00E+00	3.14E-04	6.76E-15	1.81E-05	3.88E-16

iii. LAR Enclosure 9 Table 1 ID #11 identifies theses probabilities as a key source of uncertainty. The implication of the disposition to this uncertainty item is that the conservative assumption of no LOOP recovery for all windspeed intervals off sets any potential non-conservatism in the probabilities.Provide justification that the conservative assumption of no LOOP recovery for all wind speed intervals outweighs any potential non-conservatisms in the determination of the high winds penalty.

See response to part ii of this question.

iv. LTR-RAM-20-99 on the portal provides the results of a sensitivity analysis assuming the conditional loop probabilities are increased by a factor of 10 for all wind speed intervals, which shows that the high winds CDF and LERF penalties correspondingly increase by a factor of 10. However, it is noted in Table 7-1 of this report that the increased probabilities for several wind speed intervals are greater than 1.0.

1. Provide justification for the use of probabilities greater than 1.0 and that the sensitivity analysis results are realistic.

2. If justification cannot be provided, provide revised results for the sensitivity analysis.

This is an error; the probabilities should not be greater than 1.0. Revision 1 to LTR-RAM-20-99 corrects this error. The correct result for this sensitivity case is 3.80E-05/yr for CDF and 2.19E-06/yr for LERF. LTR-RAM-20-99 is a reference provided during the license amendment request audit found in the Box folder provided.

d) The LAR does not explain why the seven equipment out of service (OOS) conditions identified in Table E4-2 adequately encompass the potential impact of high winds events on the RICT program. Neither the LAR explain how it was determined which basic events in the internal events PRA were deemed to be vulnerable to high wind damage. Address the following:

   i. Provide justification for not including other equipment OOS conditions, and why not including other equipment OOS conditions is not significant to the determination of RICTs.

For Items i and ii, addressed in Section 5.3 of LTR-RAM-20-99: "Reviewing the current CPNPP Risk Monitor calculation (Reference 12), components that were identified as approaching or exceeding the various risk monitor thresholds were chosen for this assessment."

   ii. Discuss whether there are other potential equipment OOS conditions involving equipment from more than just one system being OOS (e.g.,an emergency diesel generator and turbine-drive auxiliary feedwater),and how these multiple OOS conditions are considered in the development of the high winds CDF and LERF penalties.

See part i of this question.

   iii. Explain how it was determined which internal events PRA basic events were deemed vulnerable to high wind damage and included in the determination of the high winds CDF and LERF penalties. In the response, address how dependencies and tornado-missile damage are accounted for in identifying the vulnerable basic events.

Per Section 5.3 of LTR-RAM-20-99, "Basic events selected were those deemed vulnerable to high wind damage based on component location, HWPRA walkdowns and IPEEE evaluation results." Tornado missile damage was considered as a failure mode for identifying vulnerable components during the high winds walkdown. Included were all components located outside or inside buildings which can be exposed to the wind following failure of the building envelope (such as the circulating water building and turbine building).

e) The LAR explains that Table E4-4 of Enclosure 4 provides the high winds penalty to be used in RICT calculations. However, Table E4-4 provides two columns for each SCDF and SLERF, one column titled baseline and one column titled delta risk. Please clarify that SCDF is a typo for high wind (HW) CDF and SLERF is a typo for HW LERF. If not, please explain SCDF and SLERF.

Yes, this is a typographical error. Table E4-4 of this supplement provides CCDP and CLERP values for the high winds bounding penalty assessment, and Table E4-5 of this supplement provides HW CDF and HW LERF values.

f) Footnote 2 to Table 1 in LAR Enclosure 5 states "the baseline high winds CDF and LERF are developed and are representative of a penalty factor. The high winds penalty is procedurally adjusted based on the component(s) to which the RICT is applied." It is

unclear to the NRC staff how the results in Table E4-4 of applied in RICT calculations. Clarify how the information in Table E4-4 is used to apply a high winds penalty in RICT calculations.

Response is found in part g) of this question below.

g) Justify that this application addresses the risk of high wind events in all RICT calculations.

Section 6 of LTR-RAM-20-99 describes the application of the penalty factor on the RICT fault tree. From that section of the document:

"The high wind penalty factors - either for the baseline or for the corresponding OOS case should be applied for all RICT calculations, according to the values presented. The designated OOS cases have higher penalty values applied to account for the impact of reduced redundancy of important PRA functions. The major components OOS should be considered surrogates for the associated modeled PRA functions when affected by a TS action. This means that when any PRA component of either train is OOS, the penalty for the surrogate should be applied for the system. This can be accomplished by mapping basic events for each surrogate within the risk monitor software. Review of specific OOS cases indicated penalty factors could be simplified into grouped penalty values that were bounding for multiple cases. The resulting group penalty factors shown in Table 6-1 for CDF and Table 6-2 for LERF are recommended for configurations where the associated system PRA functions are impacted.

These penalty factors are applied to both units if any of the indicated systems are unavailable.

If any of the designated components are out of service (OOS) in combination with another of these components, the RICT should be based upon the current Technical Specifications (TS), i.e., front stop completion time, unless the specific PRA case is run to determine the appropriate penalty factor for the configuration before entering the RICT."

h) The baseline values for high winds CDF and LERF provided in Table E4-4 are 4.09E-06 per year and 2.35E-07 per year, respectively. The baseline values for high winds CDF and LERF provided in Enclosure 5 Table 1 are 3.85E-06 per year and 2.21E-07 per year, respectively. Explain the differences between these two sets of results and justify the values to be used as penalty factors in the RICT program.

The values in Enclosure 5, Table 1 for high winds CDF and LERF are incorrect, they should match the values in Table E4-5.

i) If any of the responses to the previous questions result in updates to the high winds penalty results, provide the updated penalties.

See the response to 18.b.iv for updated sensitivity study results and see the response to 18.c.ii for a new sensitivity study. The baseline penalty values are unchanged.

The following bullets describe how EPRI 3002003107 was used in developing the high winds hazard frequencies and why its use does not result in non-conservative RICTs. From the public description of the report available on the EPRI website, it "provides a review of previous high winds risk assessments and their application to NPP PRAs; it investigates and proposes a graded approach for performing the major tasks of a high winds PRA; and it recommends areas where further research is needed."

- Followed recommendation to use SPC tornado database. Does not result in non-conservative RICTs because there is no more suitable alternative as discussed previously.

- Followed recommendation to make corrections to straight winds data; see discussion in Table 1 of this document for why these corrections are believed to be appropriate.
- Followed recommendation to use the generalized extreme value distribution for calculating straight wind exceedance frequencies.
- Followed recommendation to use wind gust measurements rather than other wind measurements such as fastest-mile speed. Wind gusts are expected to be bounding relative to other wind measurements and so do not result in non-conservative RICTs.
- Cited as justification for the criterion that weather stations providing straight wind data have at least 30 years of data. This does not result in non-conservative RICTs because the straight winds data are representative of the site following the data corrections discussed in Table 1.

License Amendment Request docketed change is found in Enclosure 4, Section 4.0, High Winds, that has been revised to:

- **Explicitly state that "The CPNPP Internal Events PRA model was used to estimate the conditional core damage probability (CCDP) and Conditional Large Early Release Probability (CLERP) due to high wind events by quantifying the model while assuming the following..."**
- **Provide: 1) summary descriptions of the relevant portions of all referenced documents - enough detail to allow the NRC reviewers to understand the content and methodology (if included) and support their Safety Evaluation conclusions. This includes summaries of relevant EPRI reports and supporting engineering evaluations. 2) Provide additional justification for key judgements or modeling choices made, including those supported by sensitivity studies and identified as (potentially) key assumptions and sources of uncertainty.**
- **Provide an explicit statement that no other components Out of Service would result in more severe penalties than those presented. Also, validate that the LAR text and procedure would preclude use if RICT to two or more risk-significant components (in terms of the HW penalties) were Out of Service.**
- **Update miscellaneous text sections to correct typographical errors.**

QUESTION 19 – Configuration Specific Considerations for External Hazards (APLC)

In Table E4-6 of Enclosure 4 to the LAR, the licensee provided the external hazards screening. In Section 4 of Enclosure 4 to the LAR, the licensee stated that particular plant configurations could impact the decision on whether a particular hazard that screens under the normal plant configuration and concluded that there are no configuration specific considerations related to the screening assessment provided for the normal plant alignment.

a) Confirm that all external hazards can be screened out without any configuration specific considerations.

External hazards screening details are presented in Enclosure 4. Other external hazards were screened based on low frequency of occurrence, or in specific instances by bounding the potential impact on configuration risk. The external hazards screening results identified a few specific hazards for which configuration considerations apply addressed by bounding penalty or by a developed PRA. Configuration-specific conditions were considered as part of the screening process, but none were found to be required.

b) Discuss how the configuration specific considerations are systematically evaluated and documented for the external hazards that may impact on the RICT program.

The majority of hazards screened out on the initial screening for reasons that preclude the need for configuration specific evaluation. The initial screening justifications include conditions for which impacts are within the design basis, the event mean frequency and consequences can be bounded by analyzed events, elimination for cases where it is physically impossible for the hazards to occur, or the event develops slowly allowing adequate time to eliminate or mitigate the threat. Progressive screening was applied to confirm results from initial screening for a number of hazards and specifically to evaluate the aircraft impact hazard. For the latter, the resulting probability of an aircraft crashing into the CPNPP site was 1.91E-07 per year. For a CCDP assumed as 1.0, the hazard due to aircraft crashes was thus screened based on CDF <1.0E-06 independent of plant configuration. Hazards of internal flood and fire have not been screened but the impact on the RICT program is assessed with the respective hazard PRAs.

Similarly, Seismic and high wind hazards were not screened but risk penalty values have been developed to account for the impact on the RICT program.

License Amendment Request docketed change is found in Enclosure 4, Section 1.0, that has been revised to state that configuration specific conditions were considered, but none were found to be required.

QUESTION 20 – Shared Electrical Equipment (EEEB)

Please identify any electrical equipment that is shared between the units and clarify whether that shared equipment is modeled in PRA.

Control Room HVAC

Comanche Peak Units 1 and 2 share a common Control Room which shares the Control Room Air Conditioning System (CRACS) and Control Room Emergency Filtration System (CREFS). See Figure 1, Control Room Ventilation.

The CRACS Air Conditioning Units, Emergency Pressurization Units, Emergency Filtration Units, Emergency Pressurization Unit Fans, Emergency Filtration Unit Fans (CREFS), Control Room Exhaust Fans, Kitchen and Toilet Exhaust fans, Pneumatic Dampers, Motorized Dampers, and Makeup Air Supply Fans are powered from two separate and independent electrical sources Train "A" and Train "B" of Class 1E, AC and DC buses. Each of the AC buses can be powered from either of two offsite independent sources of from onsite standby power source (diesel generator) assigned to that bus.

Primary Plant Ventilation System (PPVS)

The primary function of the PPVS is to provide a suitable environment for personnel and equipment during normal plant operation by controlling ambient temperatures, humidity and airborne activity levels. This system also maintains a slightly negative pressure.

The PPVS supply consists of a supply plenum and eight fan coil units supplying outside conditioned air to Auxiliary, Fuel, and both Safeguards Buildings. These fan coil units are powered by common Non-Class 1E 480 VAC which can be aligned to either Unit 1 or 2. During a Design Bases Accident (DBA) all eight fans are de-energized. See Figure 2, Primary Plant Ventilation Supply Equipment.

The PPVS exhaust consists of an exhaust plenum and sixteen fans coil units to cleanup air exhausted from the Auxiliary, Fuel, and both Safeguards Buildings while maintaining a slight negative pressure. These fan coil units are powered by common Class 1E 480 VAC which can be aligned to either Unit 1 or 2. During a DBA twelve of these units are de-energized. The remaining four units are designated as ESF Exhaust filter units and operate to cleanup air exhausted and maintain a slightly negative pressure within the Auxiliary, Fuel, and both Safeguards Buildings. See Figure 3, Primary Plant Ventilation Exhaust Equipment.

Uninterruptable Power Supply (UPS) HVAC System

The UPS HVAC System maintains the ambient temperature in the UPS and Distribution Rooms and the air conditioning (A/C) Equipment Rooms to ensure the operability of the essential electrical power supply equipment located in these areas.

The UPS HVAC System is a common system which serves areas of Units 1 and 2. The rooms cooled by the system are; both UPS HVAC System A/C equipment rooms, Unit 1 Trains A and B UPS and Distribution rooms, and Unit 2 Trains A and B UPS and Distribution rooms. See Figure 4, UPS and Distribution Rooms Cooling System.

The UPS HVAC System consists of:

a. a dedicated Emergency Fan Coil Unit (EFCU) located in each safety-related UPS and Distribution Room, and

b. two electrically independent and redundant A/C trains either of which can support all four safety-related UPS and Distribution rooms. Each A/C train is comprised of an air conditioning unit, interconnecting ductwork, dampers and associated instrumentation.

The rooms cooled by the UPS HVAC System are normally cooled by fan coil units using Safety Chilled Water. The UPS fan coil units are each powered from separate and independent (Unit 1 Train A/B & Unit 2 Train A/B) Unit related 480 VAC Class 1E MCC feeder breakers.

Common Safety Related 480 V Motor Control Centers (MCCs)

CPNPP has multiple “common” 480 V MCCs that may be powered from either Unit. The MCCs not modeled in the PRA model do not supply any components needed to respond to a DBA or SBO. See Attachment 1, Common 480 V Motor Control Centers (MCC).

QUESTION 21 – Potential Electrical Loss of Function (LOF) (EEEB)

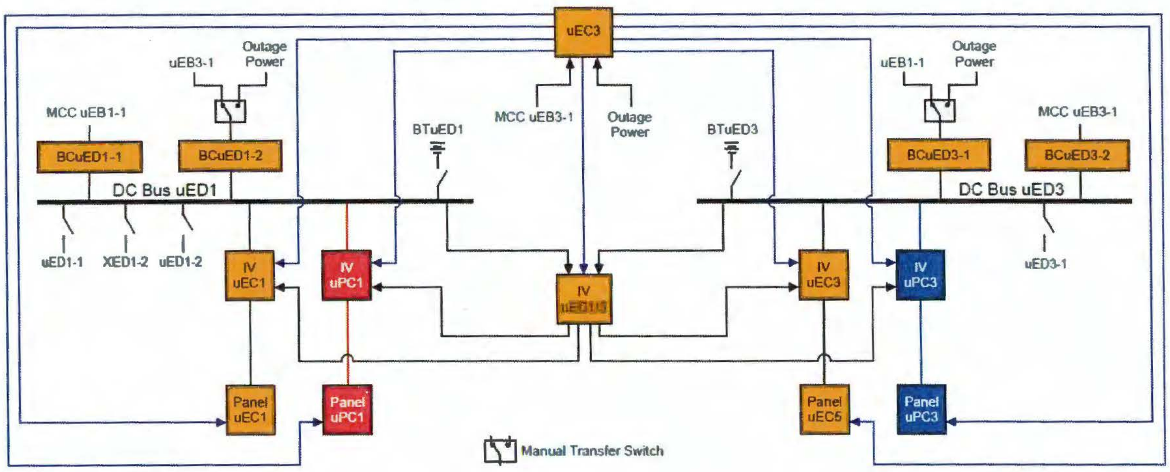
As part of its TSTF-505 review, the NRC staff examines each proposed TS condition for the potential LOF. One method to do that is reviewing the design success criteria (DSC) the licensee provided in the LAR. The DSC is a minimum set of remaining equipment required to perform the safety function. The DSC must demonstrate that the proposed change will not result in a LOF. The staff notes that the following DSC in Table E1-1 of Enclosure 1 of the LAR do not reflect the criteria of DSC and therefore, raise the concern of the potential LOF.

a) TS 3.8.1 Condition F is "One SI sequencer is inoperable." The DSC in Table E1-1 for this TS condition is "See LCO 3.8.1.B." LCO 3.8.1.B is for "One DG is inoperable." Clarify or correct this DSC information in the Table.

License Amendment Request docketed change is found in Enclosure 1, Table E1-1, TS 3.8.1, Condition F, that has been revised to clarify that the other train SI sequencer satisfies the DSC.

b) TS Condition 3.8.4.A is "One or two required battery chargers on one train inoperable." The DSC in Table E1-1 for this TS condition is "One 100% capacity battery for one of two DC trains." TS Condition 3.8.4.A is a TS condition related to battery charger inoperability, but the DSC in Table E1-1 describes the battery. Clarify or correct this DSC information in the Table.

License Amendment Request docketed change is found in Enclosure 1, Table E1-1, TS 3.8.4.A, that has been revised to clarify that one required battery charger for each battery per DC bus in a single DC Train satisfies the DSC. The DSC for TS 3.8.4.B has also been revised for consistency with the revision made to the DSC for TS 3.8.4.A.



Simplified Safeguards 125 VDC diagram

QUESTION 22 – Modeling of Turbine Driven Auxiliary Feedwater (TDAFW) Pump (EEEB)

TS 3.8.1 Conditions A, B, and C have the following Note:

--------------------NOTE--------------------
In MODES 1, 2 and 3, the TDAFW
pump is considered a required
redundant feature.

Clarify whether the TDAFW pump is modeled in the PRA when TS 3.8.1.A/B/C is in RICT.

The TDAFWP is modeled in the PRA and is included in the RICT.

License Amendment Request docketed change is found in Enclosure 1, Table E1-1, TS 3.7.5.B, Comments, that have been revised to include that both MDAFWPs and the TDAFWP are modeled in the PRA.

QUESTION 23 – Batteries (EEEB)

TS 3.8.4.B is "One or two batteries on one train inoperable." In Table E1-1, the DSC for TS 3.8.4.B is "One battery available for one of two DC [direct current] trains." Please clarify the capacity of the battery and the number of DC trains required to safe shutdown of a unit.

License Amendment Request docketed change is found in Enclosure 1, Table E1-1, TS 3.8.4.B, that has been revised to clarify that one battery per DC bus in a single DC Train satisfies the DSC.

QUESTION 24 –Electrical Risk Management Actions (RMAs) (EEEB)

Enclosure 12 of the LAR provides RMA examples for offsite source, diesel generator (DG), and battery charger inoperable. Provide the RMA examples for the alternating current AC and DC distribution systems inoperable.

License Amendment Request docketed change is found in Enclosure 12 that has been revised to include RMA examples for inoperable AC and DC distribution systems.

QUESTION 25 – Loss of Power (LOP) Instrumentation (EICB)

TSTF-505 Revision 2 specifies that "Required Actions associated with Conditions that represent a TS loss of specified safety function are outside the scope of this traveler. " The LOF is a condition that such a specific item cannot perform its function described in the Comanche Peak design basis documents. Further, the existence and operability of a diversity to this item does not exclude this condition from LOF. The equipment needed to meet this function should be listed in LAR, Enclosure 1, Table E1-1, in the "Design Success Criteria" column. TSTF-505 Revision 2 traveler for the Westinghouse Standard Technical Specifications (STS) for TS 3.3.5 assumes the LOP design consists of 3 channels per bus with a logic of 2 out of 3. The Comanche Peak LOP design appears to have several differences from the STS design, including two channels per bus with a 2 out of 2 logic. The NRC staff suggests that the STS is not applicable in this case, and the application of RICT and LOF screening to LCO 3.3.5 needs to be evaluated. Please be prepared to discuss the design of the Comanche Peak LOP system, and the sequence of events of how LOP system is actuated, and scenarios under each LCO 3.3.5 conditions and actions. In particular, please respond to the following questions (all page references are to the LAR supplement submitted July 13, 2021:

a. Please clarify all LOP functions consist of 2 sensing relays (or channels) per bus with a logic of 2 out of 2.

The following information applies to Unit 1;

Condition B Preferred offsite source bus undervoltage - 2 per bus - 2 of 2 coincidence [Train A: Relays 27A-1 ST2-Y and 27A-2 ST2-Y with Setpoint 5185 volts]

[Train B: Relays 27B-1 ST2-Y and 27B-2 ST2-Y with Setpoint 5185 volts]

Condition C Alternate offsite source bus undervoltage - 2 per bus - 2 of 2 coincidence
[Train A: Relays 27A-1 ST1-X and 27A-2 ST1-X with Setpoint 5185 volts]
[Train B: Relays 27B-1 ST1-X and 27B-2 ST1-X with Setpoint 5185 volts]

Condition D 6.9 kV Class 1E bus undervoltage - 2 per bus - 2 of 2 coincidence
[Train A: Relays 27-2A 1EA1 and 27-2B 1EA1 with Setpoint 2022 volts]
[Train B: Relays 27-2A 1EA2 and 27-2B 1EA2 with Setpoint 2022 volts]

Condition D 6.9 kV Class 1E bus degraded voltage - 2 per bus - 2 of 2 coincidence
[Train A: Relays 27-3A 1EA1 and 27-3B 1EA1 with Setpoint 6163.2 volts]
[Train B: Relays 27-3A 1EA2 and 27-3B 1EA2 with Setpoint 6163.2 volts]

Condition E 480 V Class 1E bus low grid undervoltage - 2 per bus - 2 of 2 coincidence
[Train A: Relays 27-A1 1EB1(1EB3) and 27-A2 1EB1 (1EB3) with Setpoint 444 volts]
[Train B: Relays 27-A1 1EB2(1EB4) and 27-A2 1EB2 (1EB4) with Setpoint 444 volts]

Condition E 480 V Class 1E bus degraded voltage - 2 per bus - 2 of 2 coincidence
[Train A: Relays 27-B1 1EB1(1EB3) and 27-B2 1EB1 (1EB3) with Setpoint 442 volts]
[Train B: Relays 27-B1 1EB2(1EB4) and 27-B2 1EB2 (1EB4) with Setpoint 442 volts]

See Figure 5, Safeguards Undervoltage Relaying.

License Amendment Request docketed change is found in Enclosure 1, Section 4.3 that has been revised to include LOP functions.

b. On page 4 of the Executive Summary, in the discussion of Condition 3.3.5.F, last paragraph, "This is only a loss of safety function if all AC sources are declared inoperable." Please explain how many sources and buses on which the LOP is deployed.

Technical Specification OPERABILITY requires either normal or emergency power. The following dialogue provides a Unit 1 example. Each Unit has the same capability.

There are three AC sources to the 6.9 kV safety related buses; 1) Preferred Offsite, 2) Alternate Offsite, and 3) Standby Onsite (DGs). The two buses are 1EA1 (Train A) and 1EA2 (Train B). The preferred offsite source normally provides power through breakers 1EA1-1 and 1EA2-1. If the preferred offsite source is unavailable the alternate offsite source provides power through breakers 1EA1-2 and 1EA2-2. If neither offsite source is available, 1EA1 is power from EDG 1-01 through breaker 1EG1 and 1EA2 is powered from EDG 1-02 through breaker 1EG2. To lose the safety function both offsite sources and both onsite emergency diesel generators would have to be inoperable.

See Figure 6, 6.9 kV/480 VAC Single Line Diagram.

License Amendment Request docketed change is found in Enclosure 1, Section 4.3 that has been revised to include loss of safety function description.

c. On page 9 of the Executive Summary, in the discussion of Condition 3.3.5.E, the first paragraph states in part, "Two channels per bus" is acceptable as each bus must have both channels to initiate the start signal for the DG in Conditions B, C, D, or E. Condition F allows for 1 hour to restore Automatic Actuation Logic and Actuation Relays train(s) whether one or both trains are inoperable." Please clarify what do these sentences mean.

Each DG undervoltage signal in Conditions B, C, D, and E all require a 2 of 2 coincidence to initiate a DG start signal. Both channels must fall below the setpoint to actuate a DG start. Condition A applies to the signals in Conditions B, C, D, and E for failure of a single channel. If a single channel in any of the 2 of 2 coincidence channels fails, placing that input in trip, functionally places the start signal in a 1 of 1 coincidence.

Condition F applies if a single train or if both trains are inoperable. They must be restored within one hour or the associated DG is declared inoperable. At that point LCO 3.8.1, Condition B is entered.

License Amendment Request docketed change is found in Enclosure 1, Section 4.3.3 that has been revised to include a description of the action sequence upon Condition F entry. A note has been added to TS 3.3.5, Condition F, Completion Time stating, "RICT entry is not permitted when a loss of function occurs."

d. On page 9 of the Executive Summary, in the discussion of Condition 3.3.5.E, first paragraph states in part, "If both buses are found to be inoperable per Conditions B, C, D, or E then actions for the inoperable source or bus will be required." Please confirm that Conditions B, C, D or E discuss the number of channels per bus, not the number of buses; and clarify what does the "buses" means in the statement, and how many buses are in a unit?

Conditions B, C, D, and E all require a 2 of 2 coincidence to start the associated DG.

There are two 6.9 kV safety related buses per Unit;

Unit 1 - 1EA1 (Train A) and 1EA2 (Train B)
Unit 2 - 2EA1 (Train A) and 2EA2 (Train B)

There are four 480 V safety related buses per Unit;

Unit 1 - 1EB1 and 1EB3 (Train A) and 1EB2 and 1EB4 (Train B)
Unit 2 - 2EB1 and 2EB3 (Train A) and 2EB2 and 2EB4 (Train B)

License Amendment Request docketed change is found in Enclosure 1, Section 4.3.1 that has been revised to include a description of the safety-related buses. A note has been added to TS 3.3.5, Conditions B, C, D, and E, Completion Time stating, "RICT entry is not permitted when a loss of function occurs."

e. On page 9 of the Executive Summary, in the discussion of Condition 3.3.5.E, first paragraph states in part, "If the transfer fails, or if the Alternate offsite power source is not available, the diesel generators are started to energize the 6.9 kV Class 1E buses." Please clarify this transfer process, and what relays and logics are involved in this process, and the scenarios under one or more relay or logic channels or functions inoperable.

The 6.9 kV AC Distribution system receives power from two startup transformers for the two safety-related class 1E buses (Preferred and Alternate). Emergency Diesel Generators provide

standby emergency power in the event of a loss of offsite power.

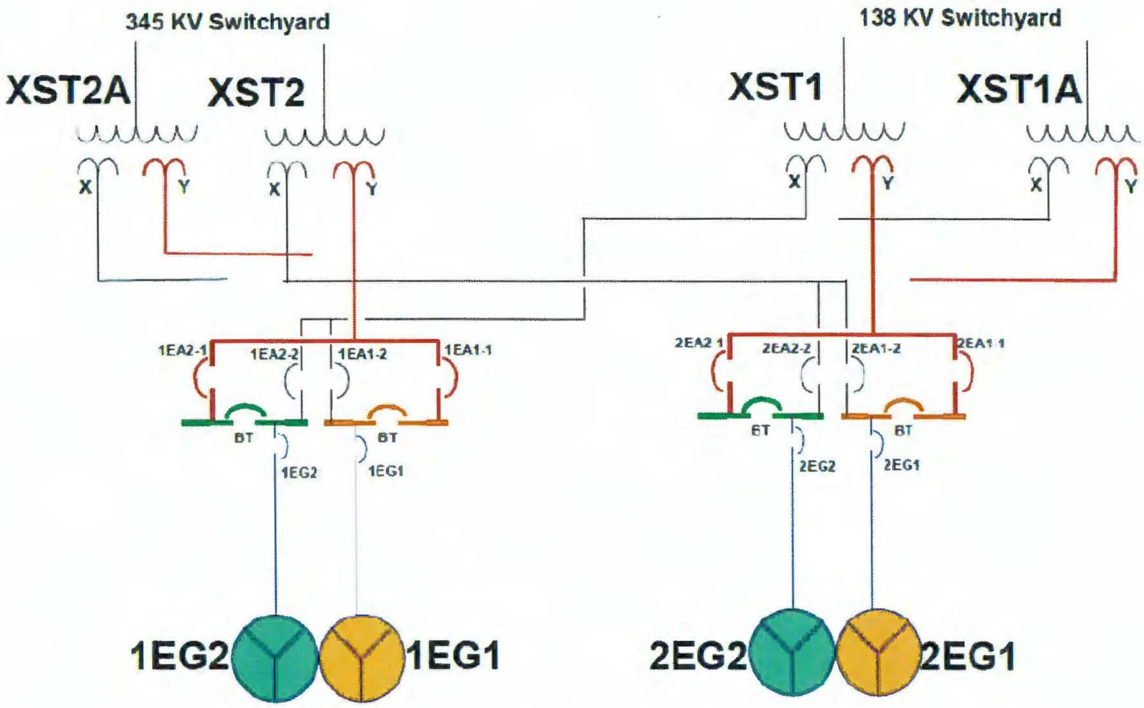
Each class 1E bus can be fed from two independent offsite power sources or the diesel generator (DG) aligned to that bus.

Redundant safety related loads are divided between Trains A and B so that loss of either train (single failure criteria) does not impair fulfillment of the minimum safe shutdown requirements. There are no manual or automatic connections between Class 1E buses and loads of redundant trains.

In the event of a loss of the preferred power source to the 6.9 kV AC Safeguards bus (buses), a transfer to the alternate source will be initiated in addition to bus load shedding (slow transfer). If the transfer to the alternate source is successful, the respective DG will NOT start, and loads will be sequenced on to the bus powered by the alternate power supply. If the transfer to the alternate source is not successful, the respective DG will receive a start signal (1.0 second time delay following loss of power) and loads will be sequenced on to the bus supplied by the diesel. See attached document titled Attachment 2, Safety Related Bus Undervoltage. Also see simplified 6.9 kV buses diagram below.

License Amendment Request docketed change is found in Enclosure 1, Section 4.3.1 that has been revised to include the bus transfer scheme.

6.9 KV SAFEGUARDS BUSES



f. On page 7 of Attachment 1, in the discussion of Condition 3.3.5.C, the first paragraph states, "The requirements of TS 3.3.5, Action B.1 currently allow for 1 hour to restore one channel per bus to OPERABLE status. This will result in at least one operable sensing relay per bus. The 1 hour Completion Time should allow ample time to repair most failures and takes into account the low probability of an event requiring a loss of power (LOP) start occurring during this interval." If ACTION 3.3.5.B.1 enters the RICT, this interval will be extended from 1 hour to

potentially 30 days. Please clarify the basis for 30 days when the justification for the variation is for 1 hour.

The justification for the potential of a 30 day Completion Time comes from the RICT based on internal events, internal flooding, and internal fire PRA model calculations with seismic and high winds CDF and LERF penalties. Actual RICT values are calculated using the existing plant configuration and the current PRA model which represents the as-built and as-operated plant. Conditions C, D, and E provide a diversity of inputs that provide multiple undervoltage DG start signals.

License Amendment Request docketed change is found in Enclosure 1, Table E1-2, where Note 4 has been added to include RICT use justification. Enclosure 1, Table E1-3 has also been updated with this information.

g. On page 7 of Attachment 1, in the discussion of Condition 3.3.5.C, the second paragraph states in part, "If the Preferred offsite power source is lost, the 6.9 kV Class 1E buses are automatically energized from the Alternate offsite power source." Please confirm which LOP functions are required to complete this transfer.

The following will use Unit 1, 6.9 kV bus 1EA1:

When the Preferred source voltage lowers to the setpoint (5185 V) as sensed by relays 27A-1/ST2-Y and 27A-2/ST2-Y, feeder breaker 1EA1-1 opens. Voltage will continue to lower until relays 27-2A 1EA1 and 27-2B 1EA1 reach the setpoint (2022 V) and initiating the following actions;

1. All motor breakers on bus 1EA1 are tripped open on undervoltage.
2. A 1 second timer for emergency DG start is energized.
3. A permissive to allow closure of Alternate source feeder breaker 1EA1-2 is energized. Incoming voltage, as sensed by relays 27A-1/ST1-X and 27A-2/ST1-X must be above setpoint (5185 V) for the permissive.
4. Alternate source feeder breaker will close providing;
   a. Relays 27-2A 1EA1 and 27-2B 1EA1 are actuated.
   b. Incoming voltage as sensed by relays 27A-1/ST1-X and 27A-2/ST1-X is above setpoint (5185 V).
   c. Preferred source feeder breaker 1EA1-1 and emergency DG feeder breaker 1EG1 are open.

Relays 27A-1/ST2-Y and 27A-2/ST2-Y are used for Condition B, Preferred offsite source

Relays 27A-1/ST1-X and 27A-2/ST1-X are used for Condition C, Alternate offsite source

Relays 27-2A 1EA1 and 27-2B 1EA1 are used for Condition D, 6.9 kV bus undervoltage

See Figure 5, Safeguards Undervoltage Relaying.

License Amendment Request docketed change is found in Enclosure 1, Section 4.3.3 that has been revised to include LOP channels in the transfer to the Alternate offsite power source scheme.

h. On page 7 of Attachment 1, in the discussion of Condition 3.3.5.C, the second paragraph states in part, "If the transfer fails, or if the Alternate offsite power source is not available, the diesel generators are started to energize the 6.9kV

Class 1 E buses." Please clarify how operators know whether this transfer fails, or the Alternate offsite power source is not available.

There are multiple annunciators and indications in the main control room to identify the condition. Feeder breakers 1EA1-1, 1EA1-2, and 1EG1 have handswitch position indication. A loss of all offsite power actuates multiple annunciators on the switchyard and electrical plant panels.

1EA1 bus voltage and frequency are displayed on the Main Control Board (MCB). If the DG started its frequency, voltage, megawatts, and kilovars are displayed on the MCB.

Specific annunciators include;

1. ALB-10B window 4.5, 6.9KV/480V ANY 1E SECOND LVL UNDERVOLT
   This alarm is initiated by any 480V 1E bus with voltage ≤ 442.4 volts or any 6.9KV 1E bus with voltage ≤ 6163.2 volts.
2. ALB-10B window 2.6, 6.9KV BUS 1EA1/1EA2 VOLT LOSS
   This alarm is initiated by either bus 1EA1 or bus 1EA2 with voltage ≤ 2022 volts.
3. ALB-10B window 3.6, 6.9KV BUS 1EA1/1EA2 NOT PWRD FROM PREF OFFSITE PWR
   This alarm is initiated when either the Preferred offsite source feeder breakers 1EA1-1 or 1EA2-1 are not closed.

Safety Systems Inoperable Indication (SSII)

1. SSII TRAIN "AA" window 1.5, PREF OFFSITE PWR
   This alarm is initiated by feeder breaker control switch 1EA1-1 in Pull-Out, Relays 27A-1/ST2-Y and 27A-2/ST2-Y undervoltage, or relays 27-3A 1EA1 and 27-3B 1EA1 with feeder breaker 1EA1-1 closed.
2. SSII TRAIN "AA" window 1.6, ALT OFFSITE PWR
   This alarm is initiated by feeder breaker control switch 1EA1-2 in Pull-Out or auxiliary relay 27AX-1/ST1 undervoltage.
3. SSII TRAIN "AA" window 1.7, ALT OFFSITE PWR
   This alarm is initiated by multiple inputs. The inputs affect DG start capability.

License Amendment Request docketed change is found in Enclosure 1, Section 4.3.3 that has been revised to include alarms and indications available to the Control Room operators regarding Preferred offsite power source, Alternate offsite power source, and Emergency power source (Diesel Generators) transfer.

i. On page 7 of Enclosure 1, Section 4.3 in the discussion of Condition 3.3.5.C, the fourth paragraph states in part, "When any of the six Functions described above become inoperable or when one or more Automatic Actuation Logic and Actuation Relays trains become inoperable, within one hour the Function must be restored or ..." Please confirm if this is still the case when RICT is applied?

When the RICT is applied the Completion Time would be the time that is calculated through the RICT program.

License Amendment Request docketed change is found in Enclosure 1, Section 4.3 that has been revised to include use of the RICT in TS 3.3.5, LOP DG Start Instrumentation.

FOR INFORMATION ONLY

A note has been added to the Completion Times for Conditions A, B, C, D, E, and F that states, "RICT entry is not permitted when a loss of function occurs."

j. On page 19 of Enclosure 1, Table E1-1, 3.3.5.A, SSC column, "Sustained undervoltage (SUR)..." This description seems inconsistent with previous descriptions and discussions; in Design Success Criteria column, "One of Two channels...", this seems inconsistent with previous two out of two logic description. Please clarify.

Condition A applies to a one of two channel failures in Conditions B, C, D, and E. The "One of two trains of Automatic Actuation Logic and Actuation Relays" should be deleted from the Design Success Criteria column for Technical Specification 3.3.5, Condition A.

License Amendment Request docketed change is found in Enclosure 1, Table E1-1 that has been revised for TS 3.3.5.A, to clarify that two of two channels of the loss of voltage and undervoltage functions on at least one bus (Train) satisfies the DSC.

k. On page 41 of Enclosure 1, Table E1-3, note 4, second paragraph, "Failure to meet the Completion Time will cause entry into TS 3.8.1 for an inoperable Diesel Generator in accordance with TS 3.3.5, Condition G." Please confirm that entry into TS 3.8.1 could be extended up to 30 days with application of the RICT Program.

The RICT program could provide a Completion Time up to 30 days depending on plant conditions.

The RICT will be applied based on plant conditions and acceptable risk to determine a Completion Time different from the 72 hours. If the RICT allows the change to the Completion Time, then by default the new Completion Time is reasonable and the probability of an event requiring use of the DGs remains low.

License Amendment Request docketed change is found in Enclosure 1, Table E1-3, where Note 4 has been revised to include use of the RICT.

l. On page 49 of Enclosure 1, Table E1-4, Note 1, "The emergency Diesel Generators (DG) have two automatic starts outside of the starts provided in TS LCO 3.3.5, LOP DG Start Instrumentation; Blackout (undervoltage) and Safety Injection (SI). If the SI is the event initiator the SI starts the DG. If a loss of all offsite power (LOOP) is the event initiator the Blackout will start the DG. The starts provided in LCO 3.3.5 are anticipatory to a loss of offsite power. Separate relays provide the starts from LCO 3.3.5 Functions." Please confirm that the 3 initiators for DG to start are SI, LOOP, and station blackout (SBO), and that LOOP and SBO need LOP DG Start Instrumentation to start the DG.

The DGs are emergency started by an SI, LOOP (undervoltage), and SBO (undervoltage). The LOOP and SBO starts come from undervoltage relays in the LOP DG Start Instrumentation.

License Amendment Request docketed change is found in Enclosure 1, Table E1-4, Note 1 has been revised to include initiating signals for a LOOP and SBO.

m. On page 50 of Enclosure 1, Table E1-4, Note 2, "A loss of non-emergency offsite power will likely be accompanied by a loss of safety related offsite power. If that is so the Blackout (undervoltage) will start the DGs. If the Blackout start

malfunctions, then any of the LCO 3.3.5 will start the DGs due to degraded voltage or undervoltage." Please clarify what non-emergency offsite power is.

Unit 1 is used for the example in the following description.

Comanche Peak design is such that the Non-1E 6.9 kV buses (1A1, 1A2, 1A3, 1A4, XA1) are supplied from the 345 kV switchyard through transformer 1ST until 230 MWe Main Generator load during plant startup. At 230 MWe, operators align Non-1E 6.9 kV buses to be supplied from the Unit 1 Auxiliary Transformer 1UT. 1UT taps off of the Main Generator output prior to the Main Generator output breakers which tie into the 345 kV switchyard. During plant shutdown, when the reactor is tripped the Main Generator output breakers trip open causing the feeder breakers from 1UT to open and closure of the feeder breakers from 1ST.

License Amendment Request docketed change is found in Enclosure 1, Table E1-4, Note 2 has been revised to include a description of non-emergency offsite power source.

Attachment 2 to the license amendment request has been revised for TS 3.3.5, Conditions A, B, C, D, E, and F. This revision adds a note to the Completion Time for each condition as follows, "RICT entry is not permitted when a loss of function occurs."

QUESTION 26 – RICT Program (STSB)

The proposed administrative controls for the RICT Program in TS 5.5.23 paragraph "e" of Attachment 2 of the LAR were based on Section 2.2.2 of the model SE for TSTF-505 Revision 2. In its supplemental information request dated June 22, 2021 (ADAMS Accession No. ML21166A338), the NRC staff recommended that paragraph "e" be based on TSTF-505 Revision 2, which is inconsistent with the model SE for TSTF-505 Revision 2. In its response to the supplemental information request, the license changed paragraph "e" as requested. Upon further review, the NRC staff recognizes that the model SE for TSTF-505 Rev. 2 contains improved phrasing for the administrative controls for the RICT Program in TS 5.5.23 paragraph "e", namely the phrasing "this program" instead of "this amendment". In lieu of the phrase "this license amendment," discuss whether the phrases "Amendment # xxx" or, as discussed in the TSTF-505 model SE, "this program" would provide more clarity for this paragraph.

Comanche Peak would prefer to use "this program" vice "this amendment." "This program" will always be in the administrative section and won't require changing due to program revision. "This amendment" ties the program to the specific amendment that implements the RICT.

License Amendment Request docketed change is found in Attachment 2 to the license amendment request has been revised to replace "This amendment" with "This program."

QUESTION 27 – Power Operated Relief Valve (PORV) Design Success Criteria (STSB)

Table E1-1 of Enclosure 1 of the LAR supplement includes descriptions of the design success criteria (DSC) for TS to be included in the RICT program. The DSC are the minimum set of remaining required equipment that can achieve the TS safety function while in the specified TS Condition. Please discuss/clarify the following multi-part DSCs and whether they represent a minimum set:

a. 3.4.11.B (One PORV inoperable and not capable of being manually cycled): One PORV OPERABLE, One PORV with two CCPs [centrifugal charging pumps], OR Two PORVs with one CCP AND one SI [safety injection] pump.

b. 3.4.11.C (One block valve inoperable): One PORV and associated block valve OPERABLE, One PORV and associated block valve with two CCPs, OR Two PORVs and associated block valves with one CCP AND one SI pump.

From CPNPP Technical Specification Bases;

By maintaining two PORVs and their associated block valves OPERABLE, the single failure criterion is satisfied. An OPERABLE block valve may be either open or closed and energized with the capability to be opened, since the required safety function is accomplished by manual operation. Although typically open to allow PORV operation, the block valves may be OPERABLE while closed to isolate the flow path of an inoperable PORV that is capable of being manually cycled (e.g., as in the case of excessive PORV leakage). Similarly, isolation of an OPERABLE PORV does not render the PORV or the block valve inoperable provided the relief function remains available with manual action.

If one PORV is inoperable and not capable of being manually cycled, it must be either restored, or isolated by closing the associated block valve and removing the power to the associated block valve. The Completion Times of 1 hour are reasonable, based on challenges to the PORVs during this time period, and provide the operator adequate time to correct the situation. If the inoperable valve cannot be restored to OPERABLE status, it must be isolated within the specified time. Because there is at least one PORV that remains OPERABLE, an additional 72 hours is provided to restore the inoperable PORV to OPERABLE status.

If one block valve is inoperable, then it is necessary to either restore the block valve to OPERABLE status within the Completion Time of 1 hour or place the associated PORV in manual control. The prime importance for the capability to close the block valve is to isolate a stuck open PORV. Therefore, if the block valve cannot be restored to OPERABLE status within 1 hour, the Required Action is to place the PORV in manual control to preclude its automatic opening for an overpressure event and to avoid the potential for a stuck open PORV at a time that the block valve is inoperable.

Because at least one PORV remains OPERABLE, the operator is permitted a Completion Time of 72 hours to restore the inoperable block valve to OPERABLE status. The time allowed to restore the block valve is based upon the Completion Time for restoring an inoperable PORV in Condition B, since the PORVs may not be capable of mitigating an event if the inoperable block valve is not fully open. If the block valve is restored within the Completion Time of 72 hours, the power will be restored and the PORV restored to OPERABLE status.

The RICT will be applied based on plant conditions and acceptable risk to determine a Completion Time different from the 72 hours for an inoperable PORV or an inoperable PORV Block Valve. If the RICT allows the change to the Completion Time, then by default the new Completion Time is reasonable and the probability of an event requiring use of the PORVs remains low.

License Amendment Request docketed change is found in Enclosure 1, Table E1-1 that has been revised to clarify the function and DSC for TS 3.4.11.B. Table E1-1 has also been revised for TS 3.4.11.C, DSC to be consistent with the change made to the DSC for TS 3.4.11.B.

QUESTION 28 – Atmospheric Relief Valve (ARV) Design Success Criteria (STSB)

Table E1-1 of Enclosure 1 of the LAR supplement includes descriptions of the DSC for TS to be included in the RICT program. The DSC are the minimum set of remaining required equipment that can achieve the TS safety function while in the specified TS Condition. According to its DSC, TS 3.7.4.C includes a loss of function condition.

In the LAR Supplement Executive Summary, the response to NRC ARII 5 on "3.7.4.C Three or more required ARV lines inoperable," states that "The RICT would only change the Completion Time based on risk analysis, not introduce a loss of safety function." However, since a RICT is not allowed under a loss of safety function, please discuss why this loss of function variation, summarized in the TS description/DSC combination below, should be allowed in the RICT Program.

- TS 3.7.4.C (Three or more required ARV lines inoperable): One of four SG [steam generator] ARVs and CST [condensate storage tank] cooling water supply.

From CPNPP Technical Specification Bases;

With three or more ARV lines inoperable, action must be taken to restore at least two ARV line to OPERABLE status. This will result in at least two OPERABLE ARVs. Since the block valve can be closed to isolate an ARV, some repairs may be possible with the unit at power. The 24 hour Completion Time is reasonable to repair inoperable ARV lines, based on the availability of the Steam Dump System and MSSVs, and the low probability of an event occurring during this period that would require the ARV lines.

The RICT will be applied based on plant conditions and acceptable risk to determine a Completion Time different from the 24 hours. If the RICT allows the change to the Completion Time, then by default the new Completion Time is reasonable and the probability of an event requiring use of the ARVs remains low.

License Amendment Request docketed change is found in Attachment 2 to the license amendment request that has been revised to include the following note in TS 3.7.4.C, Completion Time, "RICT entry is not permitted when a loss of function occurs."

<u>Executive Summary Attachments</u>

1. Common 480 V Motor Control Centers (MCC)
2. Safety Related Bus Undervoltage

<u>Executive Summary Figures</u>

1. Control Room Ventilation
2. Primary Plant Ventilation Supply Equipment
3. Primary Plant Ventilation Exhaust Equipment

4. UPS and Distribution Rooms Cooling System
5. Safeguards Undervoltage Relaying
6. 6.9 kV/480 VAC Single Line Diagram

Common 480 V Motor Control Centers (MCC)

Common MCC	Train	Unit 1 Source	Unit 2 Source	Major Loads	Modeled in PRA
XEB1-1	A	1EB1 / 2C	2EB1 / 2C	CR, CNTMT, & PPVS HVAC	Yes
XEB1-2	A	1EB1 / 3C	2EB1 / 3C	CR, CNTMT, & PPVS HVAC	Yes
XEB1-3	A	1EB1 / 5B	2EB1 / 3B	Radwaste Components	No
XEB2-1	B	1EB2 / 2C	2EB2 / 2C	CR, CNTMT, & PPVS HVAC	Yes
XEB2-2	B	1EB2 / 3C	2EB2 / 3C	CR, CNTMT, & PPVS HVAC	Yes
XEB3-1	A	1EB3 / 11C	2EB3 / 11C	Fuel Building support components	No
XEB3-2	A	1EB3 / 7C	2EB3 / 7C	CR, CNTMT, & PPVS HVAC	Yes
XEB3-3	A	1EB3-3 / 2E	2EB3-3 / 2M	SWIS support components	No
XEB4-1	B	1EB4 / 11C	2EB4 / 11C	Fuel Building support components	No
XEB4-1A	B	XEB4-1 / 2FR	Note 1	Radwaste Components	No
XEB4-2	B	1EB4 / 7C	2EB4 / 7C	CR, CNTMT, & PPVS HVAC	Yes
XEB4-3	B	1EB4-3 / 2E	2EB4-3 / 2M	SWIS support components	No
XB1-1	NA	1B1 / 3B	2B1 / 3B	Turbine & Demin water support	Yes
XB2-1	NA	1B2 / 3B	2B2 / 3B	Turbine & Demin water support	Yes
XB3-1	NA	1B3 / 9D	2B3 / 9D	Electrical Control Bldg support	Yes
XB4-1	NA	1B4 / 9D	2B4 / 9D	Electrical Control Bldg support	Yes

Note 1: Alignment to Unit 2 is through the source aligned to MCC XEB4-1.

The table below lists all common MCCs (location/tag number starting with CPX) in Maximo (work management software) and if they are modeled in the RICT PRA.

Common MCC's		
Component Number	**Component Description**	**Modeled in PRA**
CPX-EPMCEB-01	480 VAC MOTOR CONTROL CENTER XEB1-2	YES
CPX-EPMCEB-02	480 VAC MOTOR CONTROL CENTER XEB2-2	YES
CPX-EPMCEB-03	480 VAC MOTOR CONTROL CENTER XEB3-2	YES
CPX-EPMCEB-04	480 VAC MOTOR CONTROL CENTER XEB4-2	YES
CPX-EPMCEB-05	480 VAC MOTOR CONTROL CENTER XEB3-3	NO
CPX-EPMCEB-06	480 VAC MOTOR CONTROL CENTER XEB4-3	NO
CPX-EPMCEB-07	480 VAC MOTOR CONTROL CENTER XEB1-1	YES
CPX-EPMCEB-08	480 VAC MOTOR CONTROL CENTER XEB2-1	YES
CPX-EPMCNB-01	480 VAC MOTOR CONTROL CENTER XEB1-3	NO
CPX-EPMCNB-03	480 VAC MOTOR CONTROL CENTER XEB3-1	NO
CPX-EPMCNB-04	480 VAC MOTOR CONTROL CENTER XEB4-1	NO
CPX-EPMCNB-05	480 VAC MOTOR CONTROL CENTER XB1-1	**YES**
CPX-EPMCNB-06	480 VAC MOTOR CONTROL CENTER XB2-1	**YES**
CPX-EPMCNB-07	480 VAC MOTOR CONTROL CENTER XB1-3	NO
CPX-EPMCNB-08	480 VAC MOTOR CONTROL CENTER XB2-3	NO
CPX-EPMCNB-09	480 VAC MOTOR CONTROL CENTER XB1-2	NO
CPX-EPMCNB-10	480 VAC MOTOR CONTROL CENTER XB3-1	**YES**
CPX-EPMCNB-11	480 VAC MOTOR CONTROL CENTER XB4-1	**YES**
CPX-EPMCNB-12	480 VAC MOTOR CONTROL CENTER XB3-2	NO
CPX-EPMCNB-13	480 VAC MOTOR CONTROL CENTER XB2-2	NO
CPX-EPMCNB-14	480 VAC MOTOR CONTROL CENTER XB3-3	NO
CPX-EPMCNB-15	480 VAC MOTOR CONTROL CENTER XB3-4	NO
CPX-EPMCNB-16	480 VAC MOTOR CONTROL CENTER XB4-4	NO
CPX-EPMCNB-18	480 VAC MOTOR CONTROL CENTER XB4-3	NO
CPX-EPMCNB-20	480 VAC MOTOR CONTROL CENTER XB1-4	NO
CPX-EPMCNB-21	480 VAC MOTOR CONTROL CENTER XB7-3	NO
CPX-EPMCNB-22	480 VAC MOTOR CONTROL CENTER XB3-5	NO
CPX-EPMCNB-23	480 VAC MOTOR CONTROL CENTER XB1-6	YES
CPX-EPMCNB-24	480 VAC MOTOR CONTROL CENTER XB1-6A	NO
CPX-EPMCNB-25	480 VAC MOTOR CONTROL CENTER XB6-1	NO
CPX-EPMCNB-50	480 VAC MOTOR CONTROL CENTER XB1-1A	NO
CPX-EPMCNB-51	480 VAC MOTOR CONTROL CENTER XB1-1B (SPARED)	NO
CPX-EPMCNB-52	480 VAC MOTOR CONTROL CENTER XEB4-1A	NO
CPX-EPMCNB-53	480 VAC MOTOR CONTROL CENTER XB38-1	NO
CPX-EPMCNB-54	480 VAC MOTOR CONTROL CENTER XB1-7	NO

Common MCC's		
Component Number	Component Description	Modeled in PRA
CPX-EPMCNB-55	480 VAC MOTOR CONTROL CENTER XB7-1	NO
CPX-EPMCNB-56	480 VAC MOTOR CONTROL CENTER XB7-2	NO
CPX-EPMCNB-57	480 VAC MOTOR CONTROL CENTER XB1-8	NO

Safety Related Bus Undervoltage

The 6.9 kV and 480 V AC class 1E buses have an extensive undervoltage protection scheme. It includes relaying which provides automatic load shedding, power supply shifting, and alarms dependent upon the severity and the item elapsed with an undervoltage condition.

The 138Kv and 345 kV sources are monitored for adequate voltage level by two 27 (undervoltage) relays, connected via potential transformers. The drop out of these relays is set at 135 kV and 339 kV and will reset at least one percent higher than the drop out setpoint. A time delay of 40 seconds is provided to allow the system voltage to stabilize from remote disturbances. These relays alarm on the common Switchyard Panel in the control room to alert the operator of an undervoltage condition.

Each 6.9 kV safeguards bus has four sets of undervoltage relays:

- Motor trip or bus undervoltage relays (27-2A & 27-2B)
- 6.9 kV sources bus undervoltage and motor protection [(27A-1/ST2-Y & 27A-2/ST2-Y) i.e. 1EA1]
- Second level (degraded) voltage relays (27-3A & 27-3B)
- Sequencing of emergency loads (Automatic Actuation Logic) 27-1A, 27-1B, 27-1C & 27-1D relays

Motor trip relays 27-2A and 27-2B verify a bus undervoltage condition and are set to drop out when bus voltage is low enough to be energized by the alternate source and not result in damage to the equipment. Setpoint for these is set at 2022 volts.

A time delay of 0.5 seconds allows overcurrent conditions to be cleared from the bus by overcurrent protection prior to performing two functions;

- Trip all 6.9 kV motors and alarm to indicate a loss of bus voltage
- Permissive to close the alternate source breaker (1EA1-2). Breaker will close if alternate source has sufficient voltage

Also, the 27-2A and 27-2B relay contacts initiate the DG start TDPU relay. After 1.0 second this relay picks up and starts the DG associated with the bus, if bus voltage has not returned. This would be an Emergency Start of the DG.

6.9 kV preferred source availability undervoltage relays 27A-1/ST2-Y and 27A-2/ST2-Y detect the loss of the preferred power source and deenergizes a relay which opens the preferred breaker and initiates an auto transfer to the alternate power source. The relays are set to drop out below the minimum voltage expected on the bus during motor starting conditions. These relays:

- Trip incoming supply after a time delay of 0.3 seconds to allow a three phase fault condition to be cleared by overcurrent protection.

- Permit the alternate source breaker to close by verifying incoming voltage is acceptable (> 85%) as sensed by 6.9 kV alternate source availability relay.

- Alternate breaker closes if bus undervoltage relays 27-2A and 27-2B are actuated, the alternate source incoming voltage is acceptable, and breakers 1EA1-1 and 1EG1 are open.

Safety Related Bus Second Level Undervoltage

The basic purpose of this equipment is to protect the entire AC system (everything connected to the 6.9 kV system) from sustained voltage degradation to ensure continued operability of the safety related systems. Specifically, all class 1E motors are protected from potential damage due to low voltage. The system monitors the voltage on the 6.9 kV 1E switchgear and on the 1E 480 volt switchgear. If the voltage on either bus drops to some predetermined level and remains there long enough, the preferred breaker will open, and the alternate breaker will close. If this is not successful in restoring adequate voltage within 2 seconds, the alternate breaker opens, and the power source swaps to the DG.

Second level (degraded) undervoltage relays are set so that a minimum of 90% of the rated motor voltage is maintained at all motor terminals during steady state conditions and a minimum of 80% rated voltage during motor starts for all plant conditions.

Class 1E 6.9 kV Buses

Using 1EA1 as an example, the 6.9 kV degraded undervoltage relays (27-3A & 27-3B) are set to trip at 6163.2 volts. Below 6163.2 volts the voltage relays drop out, energizing the timers. If the condition exists for 7.5 seconds with an SI signal present or if the condition persists for 46 seconds without the SI signal the preferred source breaker, 1EA1-1, trips.

If voltage has been restored above the RESET voltage (nominally 2% above the drop out) prior to the 1.9 seconds by the Slow Transfer to the alternate source, the sequence will terminate. If not, a second timer (27-3Z) energizes after either 7.5 or 46 seconds with or without the SI signal respectively. After 1.9 seconds it will trip the alternate source breaker 1EA1-2 if the bus voltage is not re-established. This will force the DG start and transfer to the DG.

In addition to the above primary function, the auxiliary relays perform several other functions:

- Safety Injection Trip – if the voltage drops below 6163.2 volts at time "0 seconds" and a safety injection is initiated anytime in the first 8 seconds, then the trip cycle is initiated at time 8 seconds. If a safety injection is initiated during the interval from 7.5 seconds to 46 seconds, the trip cycle occurs immediately.

- Safety System Inoperable Indication (SSII) - If the 6.9 kV switchgear is being supplied from its preferred source and bus voltage drops to 6163.2 volts, thus dropping out undervoltage relays, a "Loss of Preferred Offsite Power" indication will occur at the associated train SSII panel in the Control Room.

- Operation – Turning the control board hand switch for the preferred or alternate supply breakers on the 6.9 kV switchgear will momentarily bypass the second level

UV trip signal, allowing closure of these breakers following a second level UV trip that isn't picked up by the DG.

- A contact is placed in the 6.9 kV and the 480 V supply breaker to each 480 V switchgear in the second level UV trip circuit. This allows deliberate deenergization of a 480 V switchgear without triggering a second level UV trip.
- Undervoltage relays (27-1A through D) dropout, providing an input to the Blackout Sequencer (BOS). When the bus is reenergized, these relays also reenergize. After a 2 second time delay, the BOS starts. The dropout of these relays is set below the minimum expected voltage under any load sequencing when the diesel generator is the only source.

<u>Class 1E 480 V Buses</u>

Each 480 volt safeguards bus has an overvoltage and three sets of undervoltage relays:

- Overvoltage 59 relay to alarm
- Motor trip undervoltage 27-1 & 27-2 relays (336 volts)
- Second level degraded undervoltage 27-B1 & 27-B2 relays (442.4 volts)
- Low grid undervoltage 27-A1 & 27-A2 relays (444 volts)

The overvoltage condition annunciates in the Control Room when voltage is approximately 106% of rated after a 5 second time delay allowed for transient overvoltage conditions.

<u>Motor Trip Undervoltage Relays</u>

These relays (27-1 and 27-2) detect the loss of the power source and are set to drop out below the minimum voltage expected on motor starting in either the 480 volt or 6.9 kV buses (442.4 volts). A time delay of 0.5 seconds (relays 27X-1 & 27X-2) allows 3 phase fault conditions to be cleared prior to tripping all motor loads off the bus.

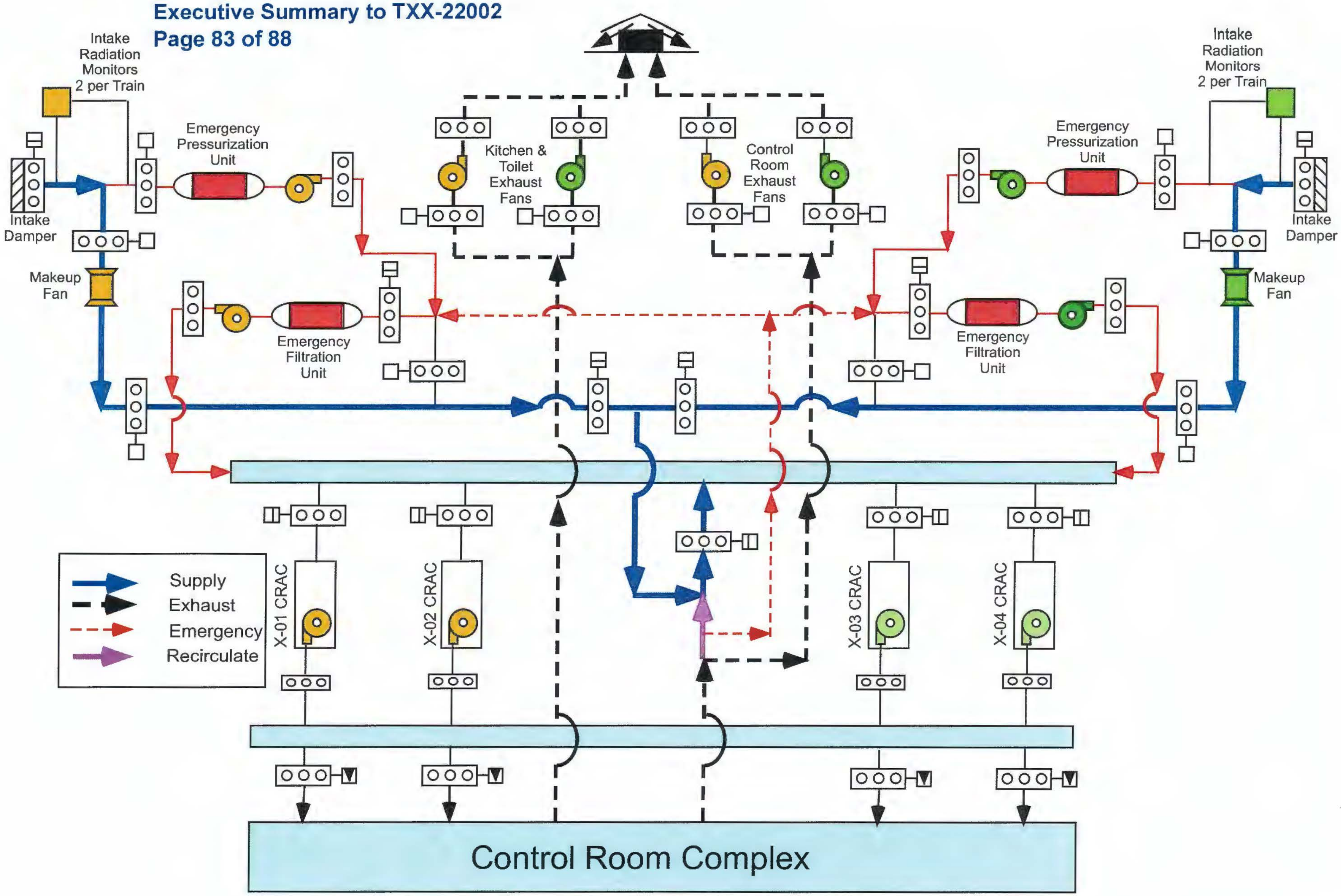
<u>Second Level (Degraded) Undervoltage Relays</u>

These consist of two relays 27B-1 &27B-2 that are set to drop out so that a minimum of 90% of the rated motor voltage is maintained at all 480 V motor terminals during steady state and a minimum of 80% rated voltage is available during the large motor starts (442.4 volts). These relays close contacts in series with the Second Level Undervoltage Auxiliary Relay (27-BX). This auxiliary relay will actuate the same relays which provide the 2nd level undervoltage response for the 6.9 kV buses.

<u>Low Grid Undervoltage Relays</u>

The low grid undervoltage relays 27A-1 & 27A-2 ensure the availability of the 138Kv and 345Kv sources to at least 135Kv and 340Kv respectively during LOCA conditions. They are set to trip at 444 volts. During a LOCA, starting of the components on the 6.9 kV bus can depress the 480 V system lower than the normal worst case loading conditions. To ensure adequate voltage during large motor starts on LOCA conditions, 3 functions are performed after a 54 second time delay (via relay 27AX):

- Alarm to alert operator.
- Trip preferred source during SI only (via 27AX-1).
- Trip alternate source (via 27-3Z) if it fails to restore proper voltage after 1.9 seconds during SI only. Without SI the relay only annunciates.



Control Room Ventilation

Figure 1

FOR INFORMATION ONLY

PRIMARY PLANT VENTILATION SUPPLY EQUIPMENT

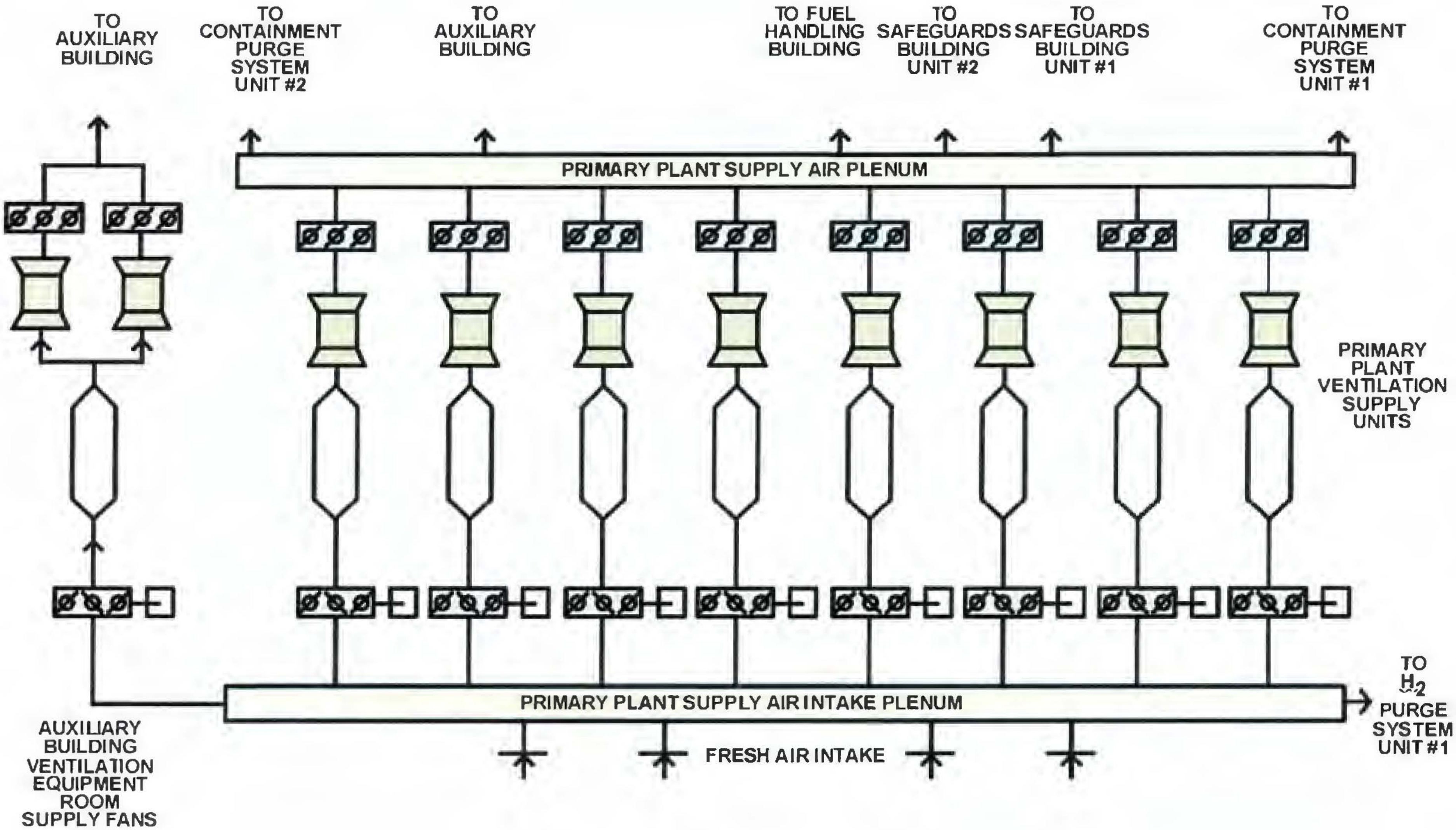


Figure 2

FOR INFORMATION ONLY

PRIMARY PLANT VENTILATION EXHAUST EQUIPMENT

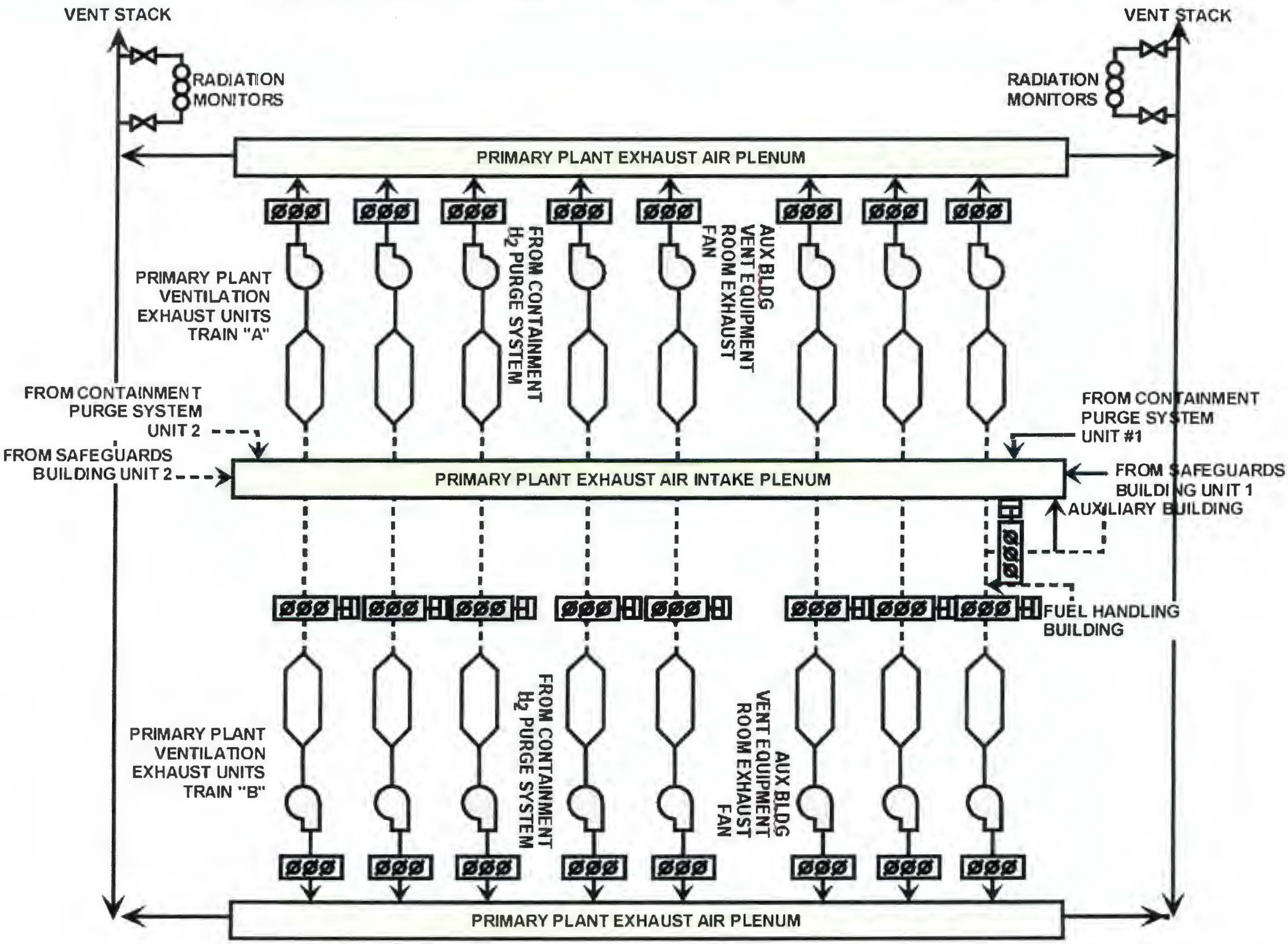


Figure 3

FOR INFORMATION ONLY

UPS & DISTRIBUTION ROOMS COOLING SYSTEM

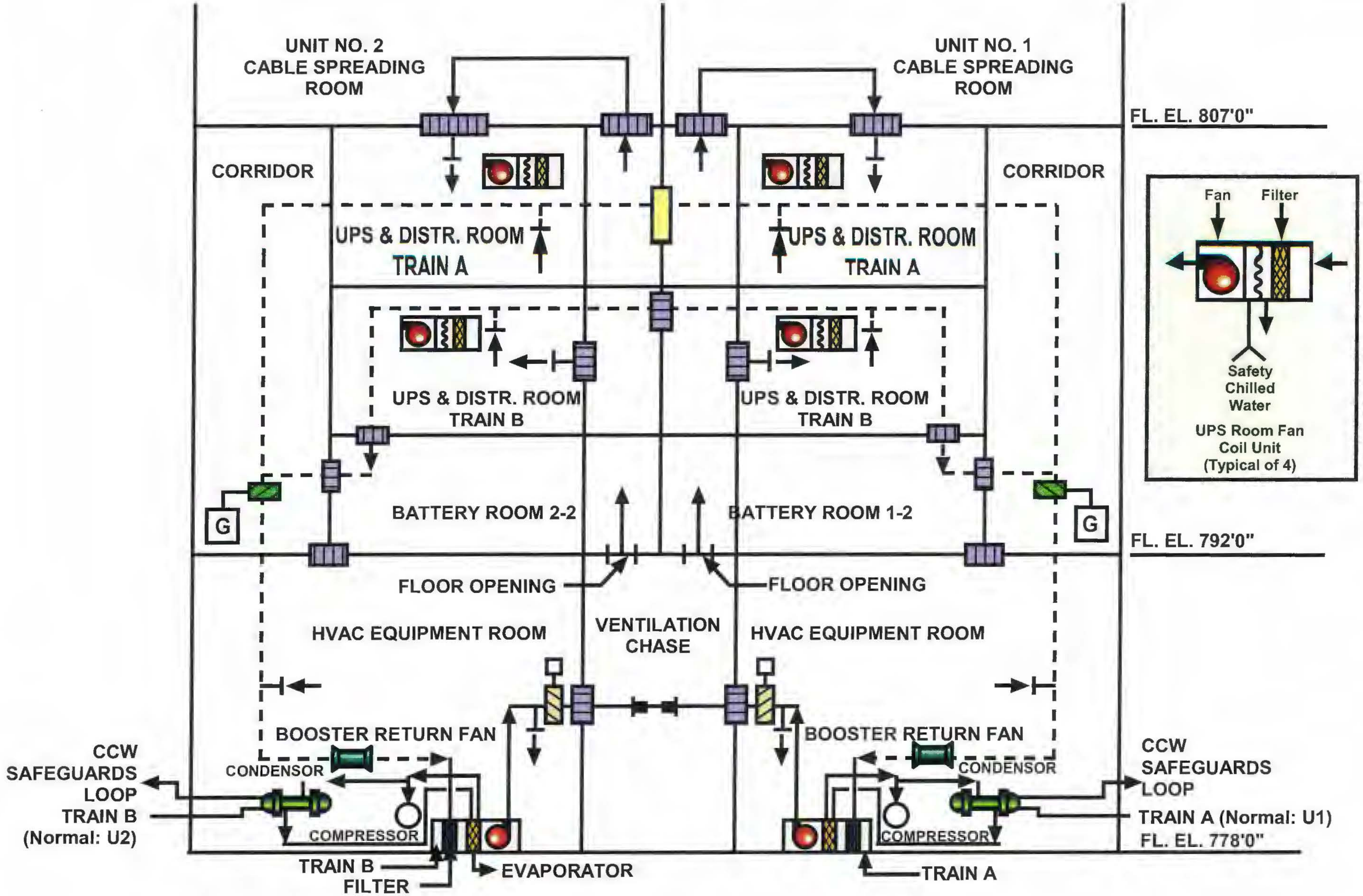
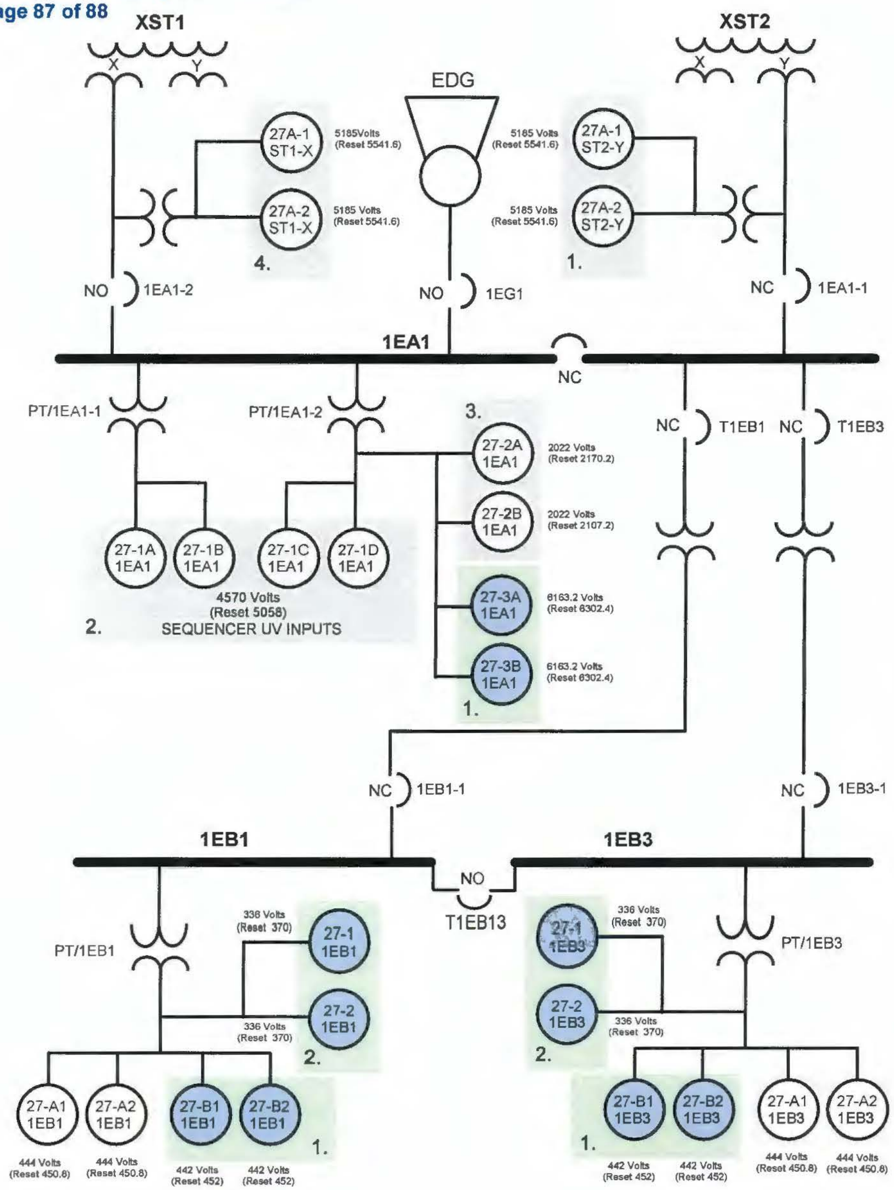


Figure 4

FOR INFORMATION ONLY



1st Level Undervoltage Relays

2nd Level Undervoltage Relays

Explanation for 1st Level Undervoltage:

1. As voltage begins decreasing relays 27A-1 ST2-Y and 27A-2 ST2-Y actuate (2/2 coincidence) causing 1EA1-1 to open.
2. As voltage continues to decrease the Sequencer Relays actuate (3/4 coincidence) generating the Operator and Automatic Lockouts (OL & AL). If only a 2/4 coincidence then OL and AL will not actuate however sequencer will fire to load equipment onto the bus.
3. As voltage continues to decrease the 27-2A 1EA1 and 27-2B 1EA1 relays actuate (2/2 coincidence) causing the following to occur:
   a) All motor breakers are tripped on undervoltage
   b) A 1 sec timer for starting the EDG is energized
   c) Permissive to allow 1EA1-2 to close is energized
4. If the incoming voltage sensed by the 27A-1 ST1-X and 27A-2 ST1-X relays is above setpoint (1/2 coincidence) then a permissive to allow 1EA1-2 to close is energized.
5. 1EA1-2 closes if the following permissives are met:
   a) Relays 27-2A 1EA1 and 27-2B 1EA1 are actuated
   b) The incoming voltage sensed by the 27A-1 ST1-X and 27A-2 ST1-X relays is adequate (2/2 coincidence).
   c) Breakers 1EA1-1 and 1EG1 are open
6. Once breaker 1EA1-2 closes and voltage is returned to normal then the following occurs as voltage increases:
   a) Relay 27-2A 1EA1 or 27-2B 1EA1 reset the EDG 1 sec auto start timer
   b) BOS sequencer fires and begins loading the bus
   c) Operator lockouts (OL) are removed upon completion sequencer timing

NOTES:

In this scenario the EDG does not start because the alternate feeder breaker (1EA1-2) should close before the 1 second timer fires.

In the event 1EA1-2 does not close within 1 sec then the EDG will start and be ready to load w/in 10 secs. Once the EDG is ready to load then 1EG1 will close (as long as 1EA1-1 and 1EA1-2 are open) re-energizing the bus at which point the BOS sequencer fires reloading the bus.

Explanation for 2nd Level Undervoltage:

1. When bus voltage reaches the setpoint for relays:
   - 27-B1 1EB1 and 27-B2 1EB1 (2/2 coincidence)
   - 27-3A 1EA1 and 27-3B 1EA1 (2/2 coincidence)
   - 27-B1 1EB3 and 27-B2 1EB3 (2/2 coincidence)

   the following occurs:
   a) A 46 sec timer is actuated, if voltage does not return to reset value at the end of the 46 secs then 1EA1-1 is tripped open.
   b) At this point the 1st Level Undervoltage sequence is actuated.
   c) If voltage is not returned to reset value 1.9 secs after 1EA1-1 is opened then 1EA1-2 is tripped open
   d) In the event a SI occurs then a 7.5 sec timer is inserted into the circuit causing the normal feeder breaker to trip open sooner. The 1.9 sec timer is unaffected.
   - The above relays all respond the same they just have different setpoints so it's just a matter which relays actuate first.
2. Relays 27-1 1EB1 and 27-2 1EB1 are provided to trip selected loads on the train related 480VAC bus and MCCs. (2/2 coincidence). Relays 27-1 1EB3 and 27-2 1EB3 on 1EB3 are identical.

Remaining Relays:

1. Relays 27-A1 1EB1 and 27-A2 1EB1 (2/2 coincidence) and 27-A1 1EB3 and 27-A2 1EB3 (2/2 coincidence) provide low voltage alarms unless a SI has occurred in which case they become 2nd level undervoltage relays and respond as described above except the time is preset for 54 secs not 7.5 secs (See 1.d above).

Safeguards Undervoltage Relaying
INFO ONLY
Figure 5

FOR INFORMATION ONLY

Capable of Being Transferred to Plant Support Power:

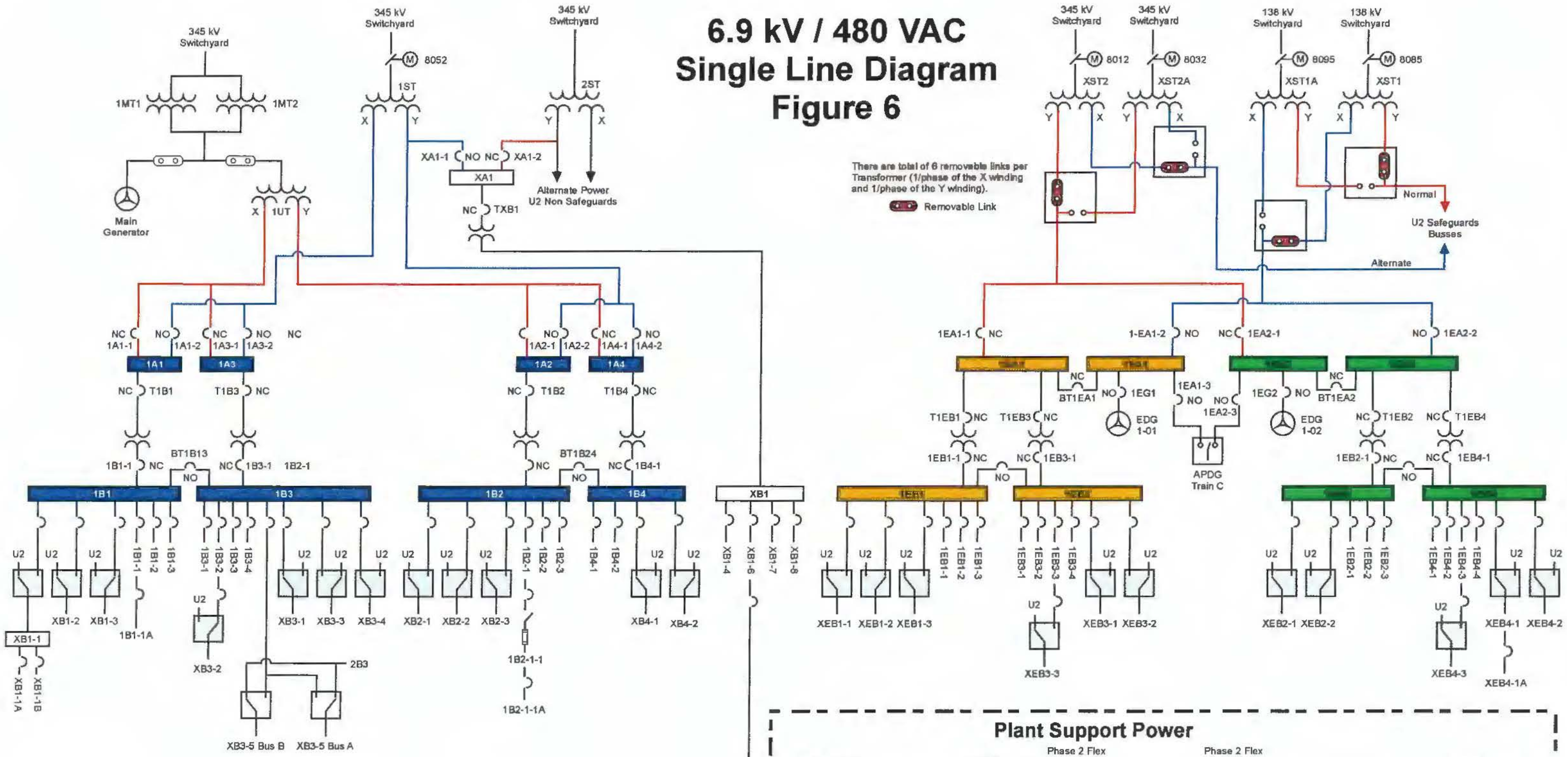
Unit 1 Train A Powered:
- BC1ED1-2
- BC1ED3-1
- Battery Room Exh Fan 8
- Transformer T1EC3
- SFGDs BLDG Lighting
- 1HT-3A
- X-RE-5895A, CR North Intake Rad Monitor
- PAL Hydraulic Pump
- Transformer TXEC1
- Essential Lighting Transformer
- Lighting Transformer S4
- Transformer XFS1

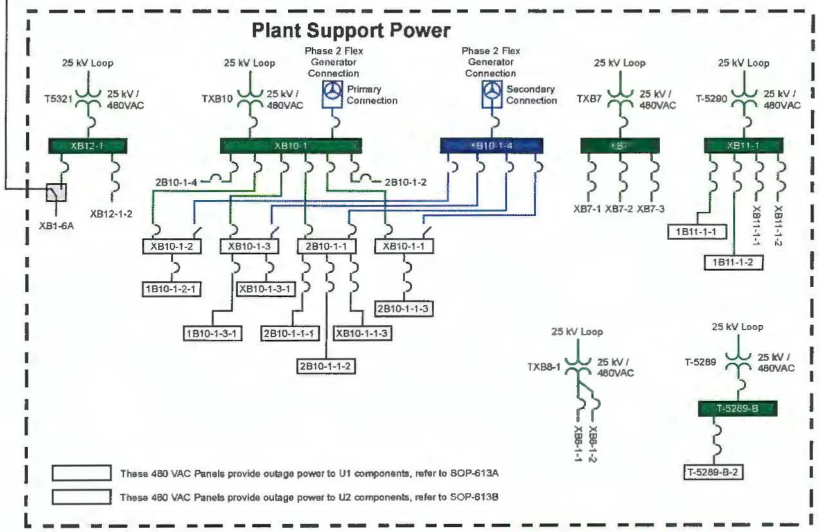
Unit 1 Train B Powered:
- BC1ED2-2
- BC1ED4-1
- BC1D4
- Battery Room EXH Fan 10
- T1EC4
- SFGDs BLDG Lighting
- 1-RE-5502/03/66 U1 CNTMT PIG Rad Monitor
- X-RE-5896B, CR North Intake Rad Monitor
- Transformer TXEC2
- Transformer XFS2
- Transformer XFS4

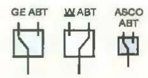
Unit 2 Train A Powered:
- BC2ED1-2
- BC2ED3-1
- Battery Room EXH Fan 8
- Transformer T2EC3
- SFGDs BLDG Lighting
- 2HT-3
- 2-RE-5502/03/66 U2 CNTMT PIG Rad Monitor
- PAL Hydraulic Pump

Unit 2 Train B Powered:
- BC2ED2-2
- BC2ED4-1
- BC2D4
- Battery Room EXH Fan 10
- Transformer T2EC4
- SFGDs BLDG Lighting

6.9 kV / 480 VAC Single Line Diagram Figure 6







General Info:
- SOP-603A/B Provides instructions for operations of 6.9 kV Switchgear
- SOP-604A/B Provides instructions for operation of 480 VAC Switchgear and MCCs
- SOP-613A/B Provides instructions for aligning Plant Equipment to/from Outage Power (25 kV Loop)
- When one Class 1E component is aligned to Plant Support Power, only that component is considered inoperable.

ABT Information:
- The dual power supplies to an ABT are interlocked to preclude supplying power to one MCC OR distribution panel from both units simultaneously.
- Automatic Bus Transfer (ABT) Units are "Normal Seeking" (the selected "preferred" power source) and "Power Seeking."
- IF BOTH power supplies phase voltages are > 90% of nominal, THEN an ABT will "seek" to shift to the power supply selected as the "preferred"
- IF any "preferred" power phase voltage drops to 70% of nominal, for a set time delay, THEN the ABT will automatically shift to the "alternate" power source.
- IF the "preferred" power phase voltages rises to 90% of nominal or more, THEN, after a time delay, the ABT will automatically shift back to the "preferred" (Normal) source. IF the "preferred" source is restored and the "alternate" source is lost during the timing period, THEN the ABT will transfer to the "preferred" instantaneously.
- The "preferred" power source for an ABT is determined by the position of the Power Supply Selector Switch (2SS switch), and the ABT will shift as described above when the Operational Mode Selector Switch (1SS switch) is in AUTO. For Westinghouse ABTs, the Control Power switch (1SSZ) must also be ON.
- The time delayed shifting of an ABT, either direction, is adjustable in a range from 0.2 seconds to 3 minutes.

Blackout Load Shedding (Only applicable if the EDG is supplying the bus):
- MCCs uEB1-2, uEB1-3, uEB2-2 and uEB2-3 are load shed when a Blackout occurs on the associated train
- The supply breakers to common MCCs XEB1-3, XEB3-1, XEB4-1 open when a blackout occurs on the train supplying power. The ABTs should shift to supply power from the opposite unit.
- The Bus Tie Breakers for MCCs XEB3-3 and XEB4-3 open when initially powered from the affected train

FOR INFORMATION ONLY

ATTACHMENT 1
License Amendment Request

Comanche Peak Nuclear Power Plant, Units 1 and 2
NRC Docket Nos. 50-445 and 50-446

Revise Technical Specifications to Adopt Risk-Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b"

Description and Assessment of the Proposed Changes

Table of Contents

1.0 DESCRIPTION

In accordance with CFR 50.90, "Application for amendment of license, construction permit, or early site permit," Vistra Operations Company LLC (Vistra OpCo) requests an amendment to Facility Operating License Nos. NPF-87 and NPF-89 for Comanche Peak Nuclear Power Plant, Units 1 and 2, (CPNPP).

The proposed amendment would modify the Technical Specification (TS) requirements related to Completion Times (CTs) for Required Actions to provide the option to calculate a longer, risk-informed CT (RICT). A new program, the Risk-Informed Completion Time (RICT) Program, is added to TS Section 5.0, "Administrative Controls."

The methodology for using the RICT Program is described in NEI 06-09-A, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0, which was approved by the NRC on May 17, 2007. Adherence to NEI 06-09-A is required by the RICT Program.

The proposed amendment is consistent with TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b." However, only those Required Actions described in Attachment 4 and Enclosure 1, as reflected in the proposed TS mark-ups provided in Attachment 2, are proposed to be changed, because some of the modified Required Actions in TSTF-505 are not applicable to CPNPP, and there are some plant-specific Required Actions not included in TSTF-505 that are included in this proposed amendment.

The proposed amendment also removes the following three one-time only amendments;

1. License Amendment 170: COMANCHE PEAK NUCLEAR POWER PLANT, UNIT NOS. 1 AND 2 - ISSUANCE OF AMENDMENTS RE: REVISION TO TECHNICAL SPECIFICATION 3.8.4, "DC SOURCES-OPERATING," CONDITION B (EXIGENT CIRCUMSTANCES) (EPID: L-2018-LLA-0238) (ML18267A384)
2. License Amendment 175: COMANCHE PEAK NUCLEAR POWER PLANT, UNIT NOS. 1 AND 2 - ISSUANCE OF AMENDMENT NOS. 175 AND 175 REGARDING ONE-TIME REVISION TO TECHNICAL SPECIFICATION 3.7.19, “SAFETY CHILLED WATER” (EPID L-2020-LLA-0137) (ML20223A349)
3. License Amendment 178: COMANCHE PEAK NUCLEAR POWER PLANT, UNIT NOS. 1 AND 2 - ISSUANCE OF AMENDMENT NOS. 178 AND 178 REGARDING ONE-TIME REVISION TO TECHNICAL SPECIFICATIONS 3.7.8, “STATION SERVICE WATER SYSTEM (SSWS),” AND 3.8.1, “AC SOURCES – OPERATING” (EPID L-2020-LLA-0250) (ML21015A212)

The proposed amendment also establishes ***default*** Conditions in TS 3.3.1, Reactor Trip System (RTS) Instrumentation and TS 3.3.2, Engineered Safety Feature Actuation System (ESFAS) Instrumentation. While preparing this proposed amendment it became clear that establishing the ***default*** Conditions will bring the CPNPP Technical Specifications more in alignment with NUREG-1431, Standard Technical Specifications — Westinghouse Plants and the Technical Specification Writer’s Guide.

The following ***default*** Conditions are proposed;

1. TS 3.3.1, Condition N: This Condition establishes the Required Action to ***Reduce THERMAL POWER to < P-7 with a 6 hour Completion Time*** when the Required Action and associated Completion Time of Condition M is not met.
2. TS 3.3.1, Condition Q: This Condition establishes the Required Action to ***Reduce THERMAL POWER to < P-9 with a 4 hour Completion Time*** when the Required Action and associated Completion Time of Condition O or P is not met.
3. TS 3.3.1, Condition W: This Condition establishes the Required Action to ***Be in MODE 3 with a 6 hour Completion Time*** when the Required Action and associated Completion Time of Condition B, D, E, R, S, T, or V is not met.
4. TS 3.3.1, Condition X: This Condition establishes the Required Action to ***Be in MODE 2 with a 6 hour Completion Time*** when the Required Action and associated Completion Time of Condition U is not met.
5. TS 3.3.2, Condition M: This Condition establishes the Required Action to ***Be in MODE 3 with a 6 hour Completion Time <u>AND</u> Be in MODE 5 with a 36 Completion Time*** when the Required Action and associated Completion Time of Condition B, C, or K is not met.
6. TS 3.3.2, Condition N: This Condition establishes the Required Action to ***Be in MODE 3 with a 6 hour Completion Time <u>AND</u> Be in MODE 4 with a 12 Completion Time*** when the Required Action and associated Completion Time of Condition D, E, F, G, or L is not met.
7. TS 3.3.2, Condition O: This Condition establishes the Required Action to ***Be in MODE 3 with a 6 hour Completion*** when the Required Action and associated Completion Time of Condition H, I, or J is not met.

The TS mark-ups in Attachment 2 include proposed changes due to implementation of TSTF-505, Revision 2, the removal of the one-time license amendments and the addition of the ***default*** Conditions in TS 3.3.1 and TS 3.3.2. These ***default*** conditions are consistent with TSTF-505, Revision 2.

This amendment request also corrects a typographical error in TS 3.3.5, Required Action D.2. A.C. is changed to AC. This correction is shown in revised Attachment 2.

The TS Bases mark-ups in Attachment 3 are provided "for information only." These proposed changes include changes due to implementation of TSTF-505, Revision 2, the removal of the one-time license amendments and the addition of the ***default*** Conditions in TS 3.3.1 and TS 3.3.2.

2.0 ASSESSMENT

2.1 Applicability of Published Safety Evaluation

Vistra OpCo has reviewed TSTF-505, Revision 2 (ADAMS Accession No. ML18183A493), and the model safety evaluation dated November 21, 2018 (ADAMS Accession No. ML18267A259). This review included the information provided to support TSTF-505 and the safety evaluation for NEI 06-09-A (ADAMS Accession No. ML12286A322 (part of ADAMS Package Accession No. ML122860402)). As described in the subsequent

paragraphs, Vistra OpCo has concluded that the technical basis is applicable to CPNPP and support incorporation of this amendment in the CPNPP TS.

2.2 Verifications and Regulatory Commitments

In accordance with Section 4.0, Limitations and Conditions, of the safety evaluation for NEI 06-09-A, the following is provided:

1. Enclosure 1 identifies each of the TS Required Actions to which the RICT Program will apply, with a comparison of the TS functions to the functions modeled in the probabilistic risk assessment (PRA) of the structures, systems and components (SSCs) subject to those actions.

2. Enclosure 2 provides a discussion of the results of peer reviews and self-assessments conducted for the plant-specific PRA models which support the RICT Program, as required by Regulatory Guide (RG) 1.200, Section 4.2.

3. Enclosure 3 is not applicable since each PRA model used for the RICT Program is addressed using a standard endorsed by the Nuclear Regulatory Commission.

4. Enclosure 4 provides appropriate justification for excluding sources of risk not addressed by the PRA models.

5. Enclosure 5 provides the plant-specific baseline core damage frequency (CDF) and large early release frequency (LERF) to confirm that the potential risk increases allowed under the RICT Program are acceptable.

6. Enclosure 6 is not applicable since the RICT Program is not being applied to shutdown models.

7. Enclosure 7 provides a discussion of the licensee's programs and procedures that assure the PRA models that support the RICT Program are maintained consistent with the as-built, as-operated plant.

8. Enclosure 8 provides a description of how the baseline PRA model, which calculates average annual risk, is evaluated and modified to assess real time configuration risk, and describes the scope of, and quality controls applied to the real-time model.

9. Enclosure 9 provides a discussion of how the key assumptions and sources of uncertainty in the PRA models were identified, and how their impact on the RICT Program was assessed and dispositioned.

10. Enclosure 10 provides a description of the implementing programs and procedures regarding the plant staff responsibilities for the RICT Program implementation, including risk management action (RMA) implementation.

11. Enclosure 11 provides a description of the monitoring program as described in NEI 06-09-A, Section 2.3.2, Step 7.

12. Enclosure 12 provides a description of the process to identify and provide RMAs, including examples.

2.3 Optional Changes and Variations

Vistra OpCo is proposing the following variations from the TS changes described in TSTF-505, Revision 2, or the applicable parts of the NRC's model safety evaluation dated November 21, 2018. These options were recognized as acceptable variations in TSTF-505 and the NRC's model safety evaluation.

Note that, in several instances, the CPNPP TS use different numbering and titles than the Standard Technical Specifications (STS) on which TSTF-505 was based. These differences are administrative and do not affect the applicability of TSTF-505 to the CPNPP TS. Only TS changes consistent with the CPNPP design and TS are included. Attachment 4 provides specific information.

Attachment 4 is a cross-reference that provides a comparison between the NUREG-1431, "Standard Technical Specifications Westinghouse Plants," Required Actions included in TSTF-505 and the CPNPP Actions included in this license amendment request. The attachment includes a summary description of the referenced Required Actions, which is provided for information purposes only and is not intended to be a verbatim description of the Required Actions. The cross-reference in Attachment 4 identifies the following:

1. CPNPP Actions that have identical numbers to the corresponding NUREG-1431 Required Actions are not deviations from TSTF-505, except for administrative deviations (if any) such as formatting. These deviations are administrative with no impact on the NRC's model safety evaluation dated November 21, 2018.

2. CPNPP Actions that have different numbering than the NUREG-1431 Required Actions are an administrative deviation from TSTF-505 with no impact on the NRC's model safety evaluation dated November 21, 2018.

3. For NUREG-1431 Required Actions that are not contained in the CPNPP TS, the corresponding TSTF-505 mark-ups for the Required Actions are not applicable to CPNPP. This is an administrative deviation from TSTF-505 with no impact on the NRC's model safety evaluation dated November 21, 2018.

4. Existing CPNPP Actions that have new numbers because of additional Actions added to the TS consistent with TSTF-505 are administrative deviations from TSTF-505 with no impact on the NRC's model safety evaluation dated November 21, 2018.

5. The model application provided in TSTF-505, Revision 2, includes an attachment for typed, camera-ready (revised) TS pages reflecting the proposed changes. CPNPP is not including such an attachment due to the number of TS pages included in this submittal that have the potential to be affected by other unrelated license amendment requests and the straightforward nature of the proposed changes. Providing only mark-ups of the proposed TS changes satisfies the requirements of 10 CFR 50.90, "Application for amendment of license, construction permit, or early site permit," in that the mark-ups fully describe the changes desired. This is an administrative deviation from TSTF-505 with no impact on the NRC's model safety evaluation dated

November 21, 2018. Because of this deviation, the contents and numbering of the attachments for this amendment request differ from the attachments specified in the model application in TSTF-505, Revision 2.

6. As stated in TSTF-505, Revision 2, it is necessary to adopt TSTF-439, "Eliminate Second Completion Times Limiting Time from Discovery of Failure to Meet an LCO," in order to adopt TSTF-505 for those Required Actions that are affected by both travelers. On December 19, 2006, (ADAMS Accession No. ML070580149) Vistra OpCo submitted a license amendment request (LAR) for CPNPP to adopt TSTF-439. This LAR impacts the following TS.

    - TS 3.7.5, Auxiliary Feedwater System
    - TS 3.8.1, AC Sources-Operating
    - TS 3.8.9, Distribution Systems-Operating

There are several plant-specific LCOs and associated Actions for which CPNPP are proposing to apply the RICT Program that are variations from TSTF-505 as identified in Attachment 4 with additional justification provided below:

- 3.3.5.B.1 – Two channels per bus for the Preferred offsite source bus undervoltage function inoperable.

  The requirements of TS 3.3.5, Action B.1 currently allow for 1 hour to restore one channel per bus to OPERABLE status. This will result in at least one operable sensing relay per bus. The 1 hour Completion Time should allow ample time to repair most failures and takes into account the low probability of an event requiring a loss of power (LOP) start occurring during this interval.

  Each unit has a designated Preferred offsite power source and a designated Alternate offsite power source. The Preferred offsite power source normally energizes the 6.9kV Class 1E buses. If the Preferred offsite power source is lost, the 6.9kV Class 1E buses are automatically energized from the Alternate offsite power source. If the transfer fails, or if the Alternate offsite power source is not available, the diesel generators are started to energize the 6.9kV Class 1E buses.

  For each unit, the undervoltage protection system, leading to the start of the diesel generators (DG) on loss of offsite power (LOOP), consists of the following functional groups: Preferred offsite source undervoltage, alternate offsite source undervoltage, 6.9kV Class 1E buses loss of voltage, 480V Class 1E buses low grid undervoltage, 6.9kV Class 1E buses degraded voltage, and 480V Class 1E buses degraded voltage. Each of these groups consists of two sensing relays per bus that provide input to two-out-of-two logic. In general, sensing relays for each train feed a network of logic and actuation relays for their respective trains. The start instrumentation requires that two channels per bus of the loss of voltage and degraded voltage Functions shall be operable. Two trains of Automatic Actuation Logic and Actuation Relays shall also be Operable. The required channels of LOOP DG start instrumentation, in conjunction with the ESF systems powered from the DGs, provide unit protection in the event of any of the analyzed accidents in which a loss of offsite power is assumed.

Application of a RICT for this Action will not adversely affect the ability of the LOOP DG start instrumentation or the Engineered Safety Features Systems to perform their intended safety function.

- 3.3.5.C.1 – Two channels per bus for the Alternate offsite source bus undervoltage function inoperable.

  The requirements of TS 3.3.5, Action C.1 currently allow for 1 hour to restore one channel per bus to OPERABLE status. This will result in at least one operable sensing relay per bus. The 1 hour Completion Time should allow ample time to repair most failures and takes into account the low probability of an event requiring an LOP start occurring during this interval.

  Each unit has a designated Preferred offsite power source and a designated Alternate offsite power source. The Preferred offsite power source normally energizes the 6.9kV Class 1E buses. If the Preferred offsite power source is lost, the 6.9kV Class 1E buses are automatically energized from the Alternate offsite power source. If the transfer fails, or if the Alternate offsite power source is not available, the diesel generators are started to energize the 6.9kV Class 1E buses.

  For each unit, the undervoltage protection system, leading to the start of the diesel generators on loss of offsite power, consists of the following functional groups: Preferred offsite source undervoltage, alternate offsite source undervoltage, 6.9kV Class 1E buses loss of voltage, 480V Class 1E buses low grid undervoltage, 6.9kV Class 1E buses degraded voltage, and 480V Class 1E buses degraded voltage. Each of these groups consists of two sensing relays per bus that provide input to two-out-of-two logic. In general, sensing relays for each train feed a network of logic and actuation relays for their respective trains. The start instrumentation requires that two channels per bus of the loss of voltage and degraded voltage Functions shall be operable. Two trains of Automatic Actuation Logic and Actuation Relays shall also be Operable. The required channels of LOOP DG start instrumentation, in conjunction with the ESF systems powered from the DGs, provide unit protection in the event of any of the analyzed accidents in which a loss of offsite power is assumed.

  Application of a RICT for this Action will not adversely affect the ability of the LOOP DG start instrumentation or the Engineered Safety Features Systems to perform their intended safety function.

- 3.3.5.D.1 – Two channels per bus for the 6.9 kV buss loss of voltage function inoperable.

  The requirements of TS 3.3.5, Action D.1 currently allow for 1 hour to restore one channel per bus to OPERABLE status. This will result in at least one operable sensing relay per bus. The 1 hour Completion Time should allow ample time to repair most failures and considers the low probability of an event requiring an LOP start occurring during this interval.

Each unit has a designated Preferred offsite power source and a designated Alternate offsite power source. The Preferred offsite power source normally energizes the 6.9kV Class 1E buses. If the Preferred offsite power source is lost, the 6.9kV Class 1E buses are automatically energized from the Alternate offsite power source. If the transfer fails, or if the Alternate offsite power source is not available, the diesel generators are started to energize the 6.9kV Class 1E buses.

For each unit, the undervoltage protection system, leading to the start of the diesel generators on loss of offsite power, consists of the following functional groups: Preferred offsite source undervoltage, alternate offsite source undervoltage, 6.9kV Class 1E buses loss of voltage, 480V Class 1E buses low grid undervoltage, 6.9kV Class 1E buses degraded voltage, and 480V Class 1E buses degraded voltage. Each of these groups consists of two sensing relays per bus that provide input to two-out-of-two logic. In general, sensing relays for each train feed a network of logic and actuation relays for their respective trains. The start instrumentation requires that two channels per bus of the loss of voltage and degraded voltage Functions shall be operable. Two trains of Automatic Actuation Logic and Actuation Relays shall also be Operable. The required channels of LOOP DG start instrumentation, in conjunction with the ESF systems powered from the DGs, provide unit protection in the event of any of the analyzed accidents in which a loss of offsite power is assumed.

Application of a RICT for this Action will not adversely affect the ability of the LOOP DG start instrumentation or the Engineered Safety Features Systems to perform their intended safety function.

- 3.3.5.E.1 – Two channels per bus for one or more degraded voltage or low grid undervoltage function inoperable.

The requirements of TS 3.3.5, Action E.1 currently allow for 1 hour to restore one channel per bus to OPERABLE status. This will result in at least one operable sensing relay per bus. The 1 hour Completion Time should allow ample time to repair most failures and takes into account the low probability of an event requiring an LOP start occurring during this interval.

Each unit has a designated Preferred offsite power source and a designated Alternate offsite power source. The Preferred offsite power source normally energizes the 6.9kV Class 1E buses. If the Preferred offsite power source is lost, the 6.9kV Class 1E buses are automatically energized from the Alternate offsite power source. If the transfer fails, or if the Alternate offsite power source is not available, the diesel generators are started to energize the 6.9kV Class 1E buses.

For each unit, the undervoltage protection system, leading to the start of the diesel generators on loss of offsite power, consists of the following functional groups: Preferred offsite source undervoltage, alternate offsite source undervoltage, 6.9kV Class 1E buses loss of voltage, 480V Class 1E buses low grid undervoltage, 6.9kV Class 1E buses degraded voltage, and 480V Class 1E buses degraded voltage. Each of these groups consists of two sensing relays per bus that provide input to two-out-of-two logic. In general, sensing relays for each train feed a network of logic and

actuation relays for their respective trains. The start instrumentation requires that two channels per bus of the loss of voltage and degraded voltage Functions shall be operable. Two trains of Automatic Actuation Logic and Actuation Relays shall also be Operable. The required channels of LOOP DG start instrumentation, in conjunction with the ESF systems powered from the DGs, provide unit protection in the event of any of the analyzed accidents in which a loss of offsite power is assumed.

Application of a RICT for this Action will not adversely affect the ability of the LOOP DG start instrumentation or the Engineered Safety Features Systems to perform their intended safety function.

- 3.3.5.F.1 – One or more Automatic Actuation Logic and Actuation Relays trains inoperable.

The requirements of TS 3.3.5, Action F.1 currently allow for 1 hour to restore one train to OPERABLE status. This will result in at least one operable Automatic Logic and Actuation Relays train operable. The 1 hour Completion Time should allow ample time to repair most failures and takes into account the low probability of an event requiring an LOP start occurring during this interval.

Each unit has a designated Preferred offsite power source and a designated Alternate offsite power source. The Preferred offsite power source normally energizes the 6.9kV Class 1E buses. If the Preferred offsite power source is lost, the 6.9kV Class 1E buses are automatically energized from the Alternate offsite power source. If the transfer fails, or if the Alternate offsite power source is not available, the diesel generators are started to energize the 6.9kV Class 1E buses.

For each unit, the undervoltage protection system, leading to the start of the diesel generators (DG) on loss of offsite power (LOOP), consists of the following functional groups: Preferred offsite source undervoltage, alternate offsite source undervoltage, 6.9kV Class 1E buses loss of voltage, 480V Class 1E buses low grid undervoltage, 6.9kV Class 1E buses degraded voltage, and 480V Class 1E buses degraded voltage. Each of these groups consists of two sensing relays per bus that provide input to two-out-of-two logic. In general, sensing relays for each train feed a network of logic and actuation relays for their respective trains. The start instrumentation requires that two channels per bus of the loss of voltage and degraded voltage Functions shall be operable. Two trains of Automatic Actuation Logic and Actuation Relays shall also be Operable. The required channels of LOOP DG start instrumentation, in conjunction with the ESF systems powered from the DGs, provide unit protection in the event of any of the analyzed accidents in which a loss of offsite power is assumed.

Application of a RICT for this Action will not adversely affect the ability of the LOOP DG start instrumentation or the Engineered Safety Features Systems to perform their intended safety function.

- 3.5.2.A.1 – One train inoperable because of the inoperability of a centrifugal charging pump.

  The requirements of TS 3.5.2, Action A.1 currently allow for 7 days to restore the centrifugal charging pump to operable status. With one centrifugal charging pump inoperable the Emergency Core Cooling System (ECCS) is still capable of providing 100% capacity. The 7 day completion time is based on a risk-informed assessment to manage the risk associated with the equipment in accordance with the Configuration Risk Management Program and is responsible for the repair of a centrifugal charging pump.

  The ECCS consists of three separate subsystems: centrifugal charging (high head), safety injection (intermediate head), and residual heat removal (low head). Each of the three subsystems consists of two 100% capacity trains that are interconnected and redundant such that either train is capable of supplying 100% of the flow required to mitigate accident consequences. The interconnecting and redundant subsystem design provides the operators with the ability to utilize components from opposite trains to achieve the required 100% flow.

  Application of a RICT for this Action will not adversely affect the ability of the ECCS to perform their intended safety function.

- 3.7.4.C.1 – Steam Generator Atmospheric Relief Valves (ARVs); Three or more required ARV lines inoperable.

  The requirements of TS 3.7.4, Action C.1 currently allow 24 hours to restore at least two ARV lines to OPERABLE status. This will result in at least two OPERABLE ARVs. Since the block valve can be closed to isolate an ARV, some repairs may be possible with the unit at power. The 24-hour Completion Time is reasonable to repair inoperable ARV lines, based on the availability of the Steam Dump System and Main Steam Safety Valves (MSSVs), and the low probability of an event occurring during this period that would require the ARV lines.

  The ARVs provide a method for cooling the unit to residual heat removal (RHR) entry conditions should the preferred heat sink via the Steam Dump System to the condenser not be available. This is done in conjunction with the Auxiliary Feedwater System providing cooling water from the condensate storage tank (CST).

  The design basis of the ARVs for the minimum relief capacity is established by the capability to cool the unit to RHR entry conditions and the capability to mitigate a steam generator tube rupture (SGTR). The design basis for the maximum relief capacity is established by the 10 CFR 100 limits for SGTR and the capacity of the MSSVs assumed in the accident analyses. The design rate of 50°F per hour is applicable for a natural circulation cooldown using two steam generators, each with one ARV. The unit can be cooled to RHR entry conditions with only one steam generator and one ARV, utilizing the cooling water supply available in the CST.

Application of a RICT for this Action will not adversely affect the ability of the Steam Generator ARVs to perform their intended safety function.

- 3.7.8.B.1 – Station Service Water System, One SSWS train inoperable

The requirements of TS 3.7.8, Action B.1 currently allow 72 hours to restore the SSWS train to operable status. In this condition, the remaining OPERABLE SSWS is adequate to provide a heat sink for the removal of process and operating heat from safety related components.

The SSWS consists of two separate, 100% capacity, safety related, cooling water trains. Each train consists of one 100% capacity pump, piping, valving, and instrumentation. The pumps and valves are remote and manually aligned to be operable in the unlikely event of a loss of coolant accident (LOCA). The pumps aligned to their respective loops are automatically started upon receipt of a safety injection signal. An automatic valve in the discharge of each pump is interlocked to open on a pump start. An automatic valve in the SSWS cooling water flow path for each emergency diesel generator automatically opens on a diesel generator start. All other valves are manual valves operated locally. The SSWS also is the backup water supply to the Auxiliary Feedwater System.

In the event of a total Loss of Station Service Water (LOSSW) event in one unit at Comanche Peak, backup cooling capability is available via a cross-connect between the two units. An OPERABLE pump is manually realigned, and flow balanced to provide cooling to essential heat loads to one or both units as required. The OPERABILITY of the unit cross-connect along with a Station Service Water pump in the shutdown unit ensures the availability of sufficient redundant cooling capacity for the operating unit. The Limiting Condition of Operation will ensure a significant risk reduction as indicated by the analyses of a Loss of Station Service Water System event. The surveillance requirements ensure the short and long-term OPERABILITY of the Station Service Water System and cross-connect between the two units.

The Station Service Water System cross-connect between the two units consists of appropriate piping and cross-connect valves connecting the discharge of the Station Service Water pumps of the two units. By aligning the cross-connect flow paths, additional redundant cooling capacity from one unit is available to the Station Service Water System of the other unit.

The principal safety related function of the SSWS is the removal of decay heat from the reactor via the CCW System. The design basis of the SSWS is for one SSWS train, in conjunction with the CCW System and a 100% capacity containment cooling system, to remove core decay heat following a design basis LOCA.

An SSW Pump on the opposite unit is OPERABLE as back-up in the event of a LOSSW if it is capable of providing required flow rates. An emergency diesel generator power source is not required because loss of offsite power is not assumed coincident with a LOSSW event.

A cross-connect valve is OPERABLE if it can be cycled or is locked open. A valve that cannot be demonstrated OPERABLE by cycling is considered inoperable until the valve is surveilled in the locked open position. However, at least one cross-connect valve between units is required to be maintained closed in accordance with GDC-5 unless required for flushing or due to total loss of Station Service Water pumps for either unit.

If no SSW pump on the opposite unit or its associated cross-connects are operable, the overall reliability is degraded since a back-up in the event of a Loss of Station Service Water System (LOSSWS) event may not be capable of performing the function. The 7 day completion time is based on the low probability of a LOSSWS during this time period.

Application of a RICT for this Action will not adversely affect the ability of the Station Service Water System to perform its safety function.

- 3.7.19.A.1 – Safety Chilled Water; One safety chilled water train inoperable

  The requirements of TS 3.7.19, Action A.1 currently allow 72 hours to restore the safety chilled water train to OPERABLE status. In this condition, the remaining OPERABLE Safety Chilled Water System train is adequate to perform the heat removal function for its associated essential equipment.

  However, the overall reliability is reduced because a single failure in the OPERABLE Safety Chilled Water System train could result in loss of the Safety Chilled Water System function. The 72-hour Completion Time is based on the redundant capabilities afforded by the OPERABLE train, and the low probability of a DBA occurring during this time.

  The design basis of the Safety Chilled Water System is to support emergency fan coil units (EFCUs) that maintain air temperatures as required in selected rooms containing safety-related equipment during normal operation and during and after a design basis accident (with or without a loss of offsite power) or a blackout (loss of offsite power, LOOP). The system is designed to provide chilled water to maintain the ambient air temperature within the design limits of the essential equipment served by the system.

  The Safety Chilled Water System for each unit consists of two separate and completely redundant safety trains. Each train consists of one packaged centrifugal chiller, one centrifugal chilled water recirculation pump, interconnecting piping, valves, controls, and instrumentation. There are no automatic valves in the system. Additionally, the two trains share a common chilled water surge (expansion) tank, partitioned in the middle into two separate compartments to provide complete separation of the two trains, that function to ensure sufficient net positive suction head is available.

  Application of a RICT for this Action will not adversely affect the ability of the Safety Chilled Water system to perform its intended safety function.

Vistra OpCo has determined that the application of a RICT for these CPNPP plant specific LCOs is consistent with TSTF-505, Revision 2, and with the NRC's model safety evaluation dated November 21, 2018. Application of a RICT for these plant specific LCOs will be controlled under the RICT Program. The RICT Program provides the necessary administrative controls to permit extension of Completion Times and thereby delay reactor shutdown or remedial actions if risk is assessed and managed within specified limits and programmatic requirements. The specified safety function or performance levels of TS required structures, systems or components (SSCs) are unchanged, and the remedial actions, including the requirement to shut down the reactor, are also unchanged; only the Action completion times are extended by the RICT Program.

Application of a RICT is evaluated using the methodology and probabilistic risk guidelines contained in NEI 06-09-A, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0, which was approved by the NRC on May 17, 2007 (ADAMS Accession No. ML071200238). The NEI 06-09-A, Revision 0 methodology includes a requirement to perform a quantitative assessment of the potential impact of the application of a RICT on risk, to reassess risk due to plant configuration changes, and to implement compensatory measures and risk management actions (RMAs) to maintain the risk below acceptable regulatory risk thresholds. In addition, the NEI 06-09-A, Revision 0 methodology satisfies the five key safety principles specified in Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decision making: Technical Specifications," dated August 1998 (ADAMS Accession No. ML003740176), relative to the risk impact due to the application of a RICT.

Therefore, the proposed application of a RICT in the CPNPP plant specific Actions is consistent with TSTF-505, Revision 2, and with the NRC's model safety evaluation dated November 21, 2018.

Vistra OpCo has reviewed these changes and determined that they do not affect the applicability of TSTF-505, Revision 2, to the CPNPP TS.

3.0 REGULATORY ANALYSIS

3.1 No Significant Hazards Consideration Determination

Vistra OpCo has evaluated the proposed changes to the TS using the criteria in 10 CFR 50.92 and has determined that the proposed changes do not involve a significant hazards consideration.

Comanche Peak Nuclear Power Plant, Units 1 and 2, request adoption of an approved change to the standard technical specifications (STS) and plant-specific technical specifications (TS), to modify the TS requirements related to Completion Times for Required Actions to provide the option to calculate a longer, risk-informed Completion Time. The allowance is described in a new program in Section 5.0, "Administrative Controls," entitled the "Risk-Informed Completion Time Program."

As required by 10 CFR 50.91(a), an analysis of the issue of no significant hazards consideration is presented below:

1. Do the proposed changes involve a significant increase in the probability or consequences of an accident previously evaluated?

Response: No.

The proposed changes permit the extension of Completion Times provided the associated risk is assessed and managed in accordance with the NRC approved Risk-Informed Completion Time Program, removes historical information, and establishes default Conditions in TS 3.3.1 and TS 3.3.2. The proposed changes do not involve a significant increase in the probability of an accident previously evaluated because the changes involve no change to the plant or its modes of operation. The proposed changes do not increase the consequences of an accident because the design-basis mitigation function of the affected systems is not changed and the consequences of an accident during the extended Completion Time are no different from those during the existing Completion Time.

Therefore, the proposed changes do not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Do the proposed changes create the possibility of a new or different kind of accident from any accident previously evaluated?

Response: No.

The proposed changes do not change the design, configuration, or method of operation of the plant. The proposed changes do not involve a physical alteration of the plant (no new or different kind of equipment will be installed).

Therefore, the proposed changes do not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Do the proposed changes involve a significant reduction in a margin of safety?

Response: No.

The proposed change permits the extension of Completion Times provided risk is assessed and managed in accordance with the NRC approved Risk-Informed Completion Time Program, removes historical information, and establishes default Conditions in TS 3.3.1 and TS 3.3.2. The proposed change implements a risk-informed configuration management program to assure that adequate margins of safety are maintained. Application of these new specifications and the configuration management program considers cumulative effects of multiple systems or components being out of service and does so more effectively than the current TS.

Therefore, the proposed change does not involve a significant reduction in a margin of safety.

Based on the above, Vistra OpCo, concludes that the proposed changes present no significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

3.2 Conclusions

In conclusion, based on the considerations discussed above, (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

4.0 ENVIRONMENTAL CONSIDERATION

Vistra OpCo has reviewed the environmental evaluation included in the model safety evaluation published on November 21, 2018 as part of the Notice of Availability. Vistra OpCo has concluded that the NRC staff findings presented in that evaluation are applicable to CPNPP Units 1 and 2, NPF-87 and NPF-89.

The proposed change would change a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, or would change an inspection or surveillance requirement. However, the proposed change does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluents that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed change meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9).

Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed changes.

5.0 REFERENCES

1. Topical Report NEI 06-09, Revision 0-A, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines" (ADAMS Accession No. ML12286A322 (part of ADAMS Package Accession No. ML122860402)).
2. NUREG-0800, Standard Review Plan 19.1, "Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," Revision 3, May 2012.
3. NUREG-0800, Standard Review Plan 19.2, "Review of Risk Information Used to Support Permanent Plant-Specific Changes to the Licensing Basis: General Guidance," Revision 0, November 2002.
4. NUREG-0800, Standard Review Plan 16.1, "Risk-Informed Decisionmaking: Technical Specifications," Revision 1, March 2007.
5. Regulatory Guide 1.174, Revision 2, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," May 2011, Accession No. ML10091006.
6. Regulatory Guide 1.177, Revision 1, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," May 2011, Accession No. ML100910008.
7. Regulatory Guide 1.200, Revision 2, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," March 2009, Accession No. ML090410014.

Attachment 2

License Amendment Request

Comanche Peak Nuclear Power Plant, Units 1 and 2
NRC Docket Nos. 50-445 and 50-446

Revise Technical Specifications to Adopt Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times – RITSTF Initiative 4b"

<u>Proposed Technical Specification pages (markup)</u>

EXAMPLES

EXAMPLE 1.3-6 (continued)

If after entry into Condition B, Required Action A.1 or A.2 is met, Condition B is exited and operation may then continue in Condition A.

EXAMPLE 1.3-7

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One subsystem inoperable.	A.1 Verify affected subsystem isolated.	1 hour AND Once per 8 hours thereafter
	AND	
	A.2 Restore subsystem to OPERABLE status.	72 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours
	AND	
	B.2 Be in MODE 5.	36 hours

Required Action A.1 has two Completion Times. The 1 hour Completion Time begins at the time the Condition is entered and each "Once per 8 hours thereafter" interval begins upon performance of Required Action A.1.

If after Condition A is entered, Required Action A.1 is not met within either the initial 1 hour or any subsequent 8 hour interval from the previous performance (plus the extension allowed by SR 3.0.2), Condition B is entered. The Completion Time clock for Condition A does not stop after Condition B is entered, but continues from the time Condition A was initially entered. If Required Action A.1 is met after Condition B is entered, Condition B is exited and operation may continue in accordance with Condition A, provided the Completion Time for Required Action A.2 has not expired.

$\boxed{\text{EXAMPLE 1.3-8 INSERT}}$

IMMEDIATE COMPLETION TIME

When "Immediately" is used as a Completion Time, the Required Action should be pursued without delay and in a controlled manner

3.3 INSTRUMENTATION

3.3.1 Reactor Trip System (RTS) Instrumentation

LCO 3.3.1 The RTS instrumentation for each Function in Table 3.3.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.1-1

ACTIONS

-----------------------------NOTE-----------------------------
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one or more required channels or trains inoperable.	A.1 Enter the Condition referenced in Table 3.3.1-1 for the channel(s) or train(s).	Immediately
B. One Manual Reactor Trip channel inoperable.	B.1 Restore channel to OPERABLE status. ~~OR~~ ~~B.2 Be in MODE 3.~~	48 hours RICT INSERT ~~54 hours~~

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One Power Range Neutron Flux - High channel inoperable.	----------NOTE---------- One channel may be bypassed for up to 12 hours for surveillance testing and setpoint adjustment. ------------------------	
	D.1.1 ----------NOTE---------- Only required to be performed when the Power Range Neutron Flux input to QPTR is inoperable. ------------------------ Perform SR 3.2.4.2.	12 hours from discovery of THERMAL POWER > 75% RTP AND Once per 12 hours thereafter
	AND D.1.2 Place channel in trip.	72 hours
	~~OR~~	RICT INSERT
	~~D.2 Be in MODE 3~~	~~78 hours~~

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. One channel inoperable.	------------------------NOTE------------------------ One channel may be bypassed for up to 12 hours for surveillance testing. --	
	E.1 Place channel in trip.	72 hours
	~~OR~~	← RICT INSERT
	~~E.2 Be in MODE 3.~~	~~78 hours~~
F. One Intermediate Range Neutron Flux channel inoperable.	F.1 Reduce THERMAL POWER to < P-6.	24 hours
	OR	
	F.2 Increase THERMAL POWER to > P-10.	24 hours
G. Two Intermediate Range Neutron Flux channels inoperable.	G.1 ------------------NOTE------------------------ Limited boron concentration changes associated with RCS inventory control or limited plant temperature changes are allowed. -- Suspend operations involving positive reactivity additions.	Immediately
	AND	
	G.2 Reduce THERMAL POWER to < P-6.	2 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
M. One channel inoperable.	------------------------NOTE------------------------ One channel may be bypassed for up to 12 hours for surveillance testing. --	
	M.1 Place channel in trip.	72 hours
	~~OR~~	RICT INSERT
	~~M.2 Reduce THERMAL POWER to < P-7.~~	~~78 hours~~
N. ~~Not used.~~ INSERT TS 3.3.1 Condition N		
O. One Low Fluid Oil pressure Turbine Trip channel inoperable.	------------------------NOTE------------------------ One channel may be bypassed for up to 12 hours for surveillance testing. --	
	O.1 Place channel in trip.	72 hours
	~~OR~~	RICT INSERT
	~~O.2 Reduce THERMAL POWER to < P-9.~~	~~76 hours~~
P. One or more Turbine Stop Valve Closure Turbine Trip channel(s) inoperable.	P.1 Place channel(s) in trip.	72 hours
	~~OR~~	RICT INSERT
INSERT TS 3.3.1 Condition Q	~~P.2 Reduce THERMAL POWER to < P-9.~~	~~76 hours~~

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
~~Q.~~ One train inoperable. R	------------------------NOTE------------------------ One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. --	
	R.1 ~~Q.1~~ Restore train to OPERABLE status.	24 hours
	~~OR~~	RICT INSERT
	~~Q.2 Be in MODE 3.~~	~~30 hours~~
~~R.~~ One RTB train inoperable. S	------------------------NOTE------------------------ One train may be bypassed for up to 4 hours for surveillance testing or maintenance, provided the other train is OPERABLE. --	
	S.1 ~~R.1~~ Restore train to OPERABLE status.	24 hours
	~~OR~~	RICT INSERT
	~~R.2 Be in MODE 3.~~	~~30 hours~~
~~S.~~ One or more required channel(s) inoperable. T	T.1 ~~S.1~~ Verify interlock is in required state for existing unit conditions.	1 hour
	~~OR~~	
	~~S.2 Be in MODE 3.~~	~~7 hours~~

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
U ~~T.~~ One or more required channel(s) inoperable.	U.1 ~~T.1~~ Verify interlock is in required state for existing unit conditions. ~~OR~~ ~~T.2 Be in MODE 2.~~	1 hour ~~7 hours~~
V ~~U.~~ One trip mechanism inoperable for one RTB.	V.1 ~~U.1~~ Restore ~~inoperable~~ trip mechanism to OPERABLE status. ~~OR~~ ~~U.2 Be in MODE 3.~~	48 hours RICT INSERT ~~54 hours~~
W ~~V.~~ Not used. INSERT TS 3.3.1 Condition W		
X INSERT TS 3.3.1 Condition X		

SURVEILLANCE REQUIREMENTS

-----NOTE-----
Refer to Table 3.3.1-1 to determine which SRs apply for each RTS Function.

SURVEILLANCE		FREQUENCY
SR 3.3.1.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program.

Table 3.3.1-1 (page 4 of 6)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE(a)
16. Turbine Trip					
a. Low Fluid Oil Pressure	1(j)	3	O	SR 3.3.1.10 SR 3.3.1.15	≥ 46.6 psig
b. Turbine Stop Valve Closure	1(j)	4	P	SR 3.3.1.10 SR 3.3.1.15	≥ 1% open
17. Safety Injection (SI) Input from Engineered Safety Feature Actuation System (ESFAS)	1,2	2 trains	$\boxed{R} \rightarrow$ ~~Q~~	SR 3.3.1.14	NA
18. Reactor Trip System Interlocks					
a. Intermediate Range Neutron Flux, P-6	2(e)	2	$\boxed{T} \rightarrow$ ~~S~~	SR 3.3.1.11 SR 3.3.1.13	≥ 6E-11 amp
b. Low Power Reactor Trips Block, P-7	1	1 per train	$\boxed{U} \rightarrow$ ~~T~~	SR 3.3.1.5	NA
c. Power Range Neutron Flux, P-8	1	4	$\boxed{U} \rightarrow$ ~~T~~	SR 3.3.1.11 SR 3.3.1.13	≤ 50.7% RTP
d. Power Range Neutron Flux, P-9	1	4	$\boxed{U} \rightarrow$ ~~T~~	SR 3.3.1.11 SR 3.3.1.13	≤ 52.7% RTP
e. Power Range Neutron Flux, P-10	1,2	4	$\boxed{T} \rightarrow$ ~~S~~	SR 3.3.1.11 SR 3.3.1.13	≥ 7.3% RTP and ≤ 12.7% RTP
f. Turbine First Stage Pressure, P-13	1	2	$\boxed{U} \rightarrow$ ~~T~~	SR 3.3.1.10 SR 3.3.1.13	≤ 12.7% turbine power
19. Reactor Trip Breakers(RTBs)(k)	1,2	2 trains	$\boxed{S} \rightarrow$ ~~R~~	SR 3.3.1.4	NA
	3(b), 4(b), 5(b)	2 trains	C	SR 3.3.1.4	NA

(a) The Allowable Value defines the limiting safety system setting except for Trip Functions 2a, 2b, 6, 7, and 14 (the Nominal Trip Setpoint defines the limiting safety system setting for these Trip Functions). See the Bases for the Nominal Trip Setpoints.
(b) With Rod Contol System capable of rod withdrawal or one or more rods not fully inserted.
(e) Below the P-6 (Intermediate Range Neutron Flux) interlock.
(j) Above the P-9 (Power Range Neutron Flux) interlock.
(k) Including any reactor trip bypass breakers that are racked in and closed for bypassing an RTB.

Table 3.3.1-1 (page 5 of 6)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[a]
20. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms[k]	1,2	1 each per RTB	V ~~U~~	SR 3.3.1.4	NA
	3[b], 4[b], 5[b]	1 each per RTB	C	SR 3.3.1.4	NA
21. Automatic Trip Logic	1,2	2 trains	R ~~Q~~	SR 3.3.1.5	NA
	3[b], 4[b], 5[b]	2 trains	C	SR 3.3.1.5	NA

(a) The Allowable Value defines the limiting safety system setting except for Trip Functions 2a, 2b, 6, 7, and 14 (the Nominal Trip Setpoint defines the limiting safety system setting for these Trip Functions). See the Bases for the Nominal Trip Setpoints.
(b) With Rod Contol System capable of rod withdrawal or one or more rods not fully inserted.
(k) Including any reactor trip bypass breakers that are racked in and closed for bypassing an RTB.

3.3 INSTRUMENTATION

3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

LCO 3.3.2 The ESFAS instrumentation for each Function in Table 3.3.2-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.2-1

ACTIONS

-----NOTE-----
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one or more required channels or trains inoperable.	A.1 Enter the Condition referenced in Table 3.3.2-1 for the channel(s) or train(s).	Immediately
B. One channel or train inoperable.	B.1 Restore channel or train to OPERABLE status.	48 hours
	~~OR~~	RICT INSERT
	~~B.2.1 Be in MODE 3.~~	~~54 hours~~
	~~AND~~	
	~~B.2.2 Be in MODE 5.~~	~~84 hours~~

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One train inoperable.	------------------------NOTE------------------------ One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. --	
	C.1 Restore train to OPERABLE status.	24 hours
	~~OR~~	RICT INSERT
	~~C.2.1 Be in MODE 3.~~	~~30 hours~~
	~~AND~~	
	~~C.2.2 Be in MODE 5.~~	~~60 hours~~
D. One channel inoperable.	------------------------NOTE------------------------ One channel may be bypassed for up to 12 hours for surveillance testing. --	
	D.1 Place channel in trip.	72 hours
	~~OR~~	RICT INSERT
	~~D.2.1 Be in MODE 3.~~	~~78 hours~~
	~~AND~~	
	~~D.2.2 Be in MODE 4.~~	~~84 hours~~

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. One Containment Pressure channel inoperable.	------------NOTE------------ One channel may be bypassed for up to 12 hours for surveillance testing. ----------------------------	
	E.1 Place channel in bypass.	72 hours
	~~OR~~	
	~~E.2.1 Be in MODE 3.~~	~~78 hours~~
	~~AND~~	
	~~E.2.2 Be in MODE 4.~~	~~84 hours~~
F. One channel or train inoperable.	F.1 Restore channel or train to OPERABLE status.	48 hours
	~~OR~~	RICT INSERT
	~~F.2.1 Be in MODE 3.~~	~~54 hours~~
	~~AND~~	
	~~F.2.2 Be in MODE 4.~~	~~60 hours~~

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
G. One train inoperable.	---NOTE--- One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. ---	
	G.1 Restore train to OPERABLE status.	24 hours
	~~OR~~	RICT INSERT
	~~G.2.1 Be in MODE 3.~~	~~30 hours~~
	~~AND~~	
	~~G.2.2 Be in MODE 4.~~	~~36 hours~~
H. One train inoperable.	---NOTE--- One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. ---	
	H.1 Restore train to OPERABLE status.	24 hours
	~~OR~~	RICT INSERT
	~~H.2 Be in MODE 3.~~	~~30 hours~~

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
I. One channel inoperable.	---------------------NOTE--------------------- One channel may be bypassed for up to 12 hours for surveillance testing. --	
	I.1 Place channel in trip.	72 hours
	~~OR~~	RICT INSERT
	~~I.2 Be in MODE 3.~~	~~78 hours~~
J. One Main Feedwater Pump trip channel inoperable.	J.1 Place channel in trip.	6 hours
	~~OR~~	RICT INSERT
	~~J.2 Be in MODE 3.~~	~~12 hours~~
K. One channel inoperable.	---------------------NOTE--------------------- One channel may be bypassed for up to 12 hours for surveillance testing. --	
	K.1 Place channel in bypass.	72 hours
	~~OR~~	
	~~K.2.1 Be in MODE 3.~~	~~78 hours~~
	~~AND~~	
	~~K.2.2 Be in MODE 5.~~	~~108 hours~~

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
L. One or more ~~required~~ channel~~(s)~~ inoperable.	L.1 Verify interlock is in required state for existing unit condition.	1 hour
	~~OR~~	
	~~L.2.1 Be in MODE 3.~~	~~7 hours~~
INSERT TS 3.3.2 Conditions M, N, and O	~~AND~~	
	~~L.2.2 Be in MODE 4.~~	~~13 hours~~

SURVEILLANCE REQUIREMENTS

-----NOTE-----
Refer to Table 3.3.2-1 to determine which SRs apply for each ESFAS Function.

SURVEILLANCE		FREQUENCY
SR 3.3.2.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.2.2	Perform ACTUATION LOGIC TEST.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.2.3	Not Used.	

3.3 INSTRUMENTATION

3.3.5 Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

LCO 3.3.5 The Loss of Power Diesel Generator Start Instrumentation for each Function in Table 3.3.5-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

-----------------------NOTE-----------------------
Not applicable for 6.9 kV Preferred Offsite Source Undervoltage function when associated source breaker is open.

ACTIONS

-----------------------NOTE-----------------------
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. -------NOTE-------- Not applicable to Automatic Actuation Logic and Actuation Relays Function -------------------- One or more Functions with one channel per bus inoperable.	A.1 Place channel in trip.	6 hours ------NOTE------- RICT entry is not permitted when a loss of function occurs. ----------------- <u>OR</u> In accordance with the Risk Informed Completion Time Program.

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Two channels per bus for the Preferred offsite source bus undervoltage function inoperable.	B.1 Restore one channel per bus to OPERABLE status.	1 hour ------ NOTE ------- RICT entry is not permitted when a loss of function occurs. ------------------ <u>OR</u> In accordance with the Risk Informed Completion Time Program.
	<u>OR</u>	
	B.2.1 Declare the Preferred offsite source inoperable.	1 hour
	<u>AND</u>	
	B.2.2 Open associated Preferred offsite source bus breaker.	6 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Two channels per bus for the Alternate offsite source bus undervoltage function inoperable.	C.1 Restore one channel per bus to OPERABLE status.	1 hour ------ NOTE ------- RICT entry is not permitted when a loss of function occurs. ------------------ <u>OR</u> In accordance with the Risk Informed Completion Time Program.
	<u>OR</u>	
	C.2.1 Declare the Alternate offsite source inoperable.	1 hour
	<u>AND</u>	
	C.2.2 Open associated Alternate offsite source bus breaker.	6 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Two channels per bus for the 6.9 kV bus loss of voltage function inoperable.	D.1 Restore one channel per bus to OPERABLE status.	1 hour ------ NOTE ------- RICT entry is not permitted when a loss of function occurs. ------------------ OR In accordance with the Risk Informed Completion Time Program.
	OR	
	D.2 Declare the affected AC emergency buses inoperable.	1 hour

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. Two channels per bus for one or more degraded voltage or low grid undervoltage function inoperable.	E.1 Restore one channel per bus to OPERABLE status.	1 hour ------ NOTE ------- RICT entry is not permitted when a loss of function occurs. ------------------ <u>OR</u> In accordance with the Risk Informed Completion Time Program.
	<u>OR</u>	
	E.2.1 Declare both offsite power source buses inoperable.	1 hour
	<u>AND</u>	
	E.2.2 Open offsite power source breakers to the associated buses.	6 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. One or more Automatic Actuation Logic and Actuation Relays trains inoperable.	F.1 Restore train(s) to OPERABLE status.	1 hour ------ NOTE ------- RICT entry is not permitted when a loss of function occurs. ------------------ OR In accordance with the Risk Informed Completion Time Program.
G. Required Action and associated Completion Time not met.	G.1 Enter applicable Condition(s) and Required Action(s) for the associated DG made inoperable by LOP DG start instrumentation.	Immediately

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.9 Pressurizer

LCO 3.4.9 The pressurizer shall be OPERABLE with:

a. Pressurizer water level ≤ 92%; and

b. Two groups of pressurizer heaters OPERABLE with the capacity of each group ≥ 150 kW.

APPLICABILITY: MODES 1, 2, and 3

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Pressurizer water level not within limit.	A.1 Be in MODE 3.	6 hours
	AND	
	A.2 Fully insert all rods.	6 hours
	AND	
	A.3 Place Rod Control System in a condition incapable of rod withdrawal.	6 hours
	AND	
	A.4 Be in MODE 4.	12 hours
B. One required group of pressurizer heaters inoperable.	B.1 Restore required group of pressurizer heaters to OPERABLE status.	72 hours RICT INSERT

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.11 Pressurizer Power Operated Relief Valves (PORVs)

LCO 3.4.11 Each PORV and associated block valve shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3

ACTIONS

---NOTE---
Separate Condition entry is allowed for each PORV.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more PORVs inoperable and capable of being manually cycled.	A.1 Close and maintain power to associated block valve.	1 hour
B. One PORV inoperable and not capable of being manually cycled.	B.1 Close associated block valve.	1 hour
	AND	
	B.2 Remove power from associated block valve.	1 hour
	AND	
	B.3 Restore PORV to OPERABLE status.	72 hours RICT INSERT

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One block valve inoperable.	----------NOTE---------- Required Actions do not apply when block valve is inoperable solely as a result of complying with Required Actions B.2 or E.2. ---------------------------------	
	C.1 Place associated PORV in manual control.	1 hour
	AND	
	C.2 Restore block valve to OPERABLE status.	72 hours RICT INSERT
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1 Be in MODE 3.	6 hours
	AND	
	D.2 Be in MODE 4	12 hours
E. Two PORVs inoperable and not capable of being manually cycled.	E.1 Close associated block valves.	1 hour
	AND	
	E.2 Remove power from associated block valves.	1 hour
	AND	
	E.3 Be in MODE 3	6 hours
	AND	
	E.4 Be in MODE 4	12 hours

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.2 ECCS -- Operating

LCO 3.5.2 Two ECCS trains shall be OPERABLE.

--NOTES--

1. In MODE 3, both safety injection (SI) pump flow paths may be isolated by closing the isolation valves for up to 2 hours to perform pressure isolation valve testing per SR 3.4.14.1.

2. Operation in MODE 3 with ECCS pumps made incapable of injecting, pursuant to LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," is allowed for up to 4 hours or until the temperature of all RCS cold legs exceeds 375°F, whichever comes first.

APPLICABILITY: MODES 1, 2, and 3

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One train inoperable because of the inoperability of a centrifugal charging pump.	A.1 Restore pump to OPERABLE status.	7 days ← RICT INSERT

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or more trains inoperable for reasons other than one inoperable centrifugal charging pump. AND At least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train available.	B.1 Restore train(s) to OPERABLE status.	72 hours RICT INSERT
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.2.1	Verify the following valves are in the listed position with power to the valve operator removed. Number / Position / Function 8802 A&B / Closed / SI Pump to Hot Legs 8809 A&B / Open / RHR to Cold Legs 8835 / Open / SI Pump to Cold Legs 8840 / Closed / RHR to Hot Legs 8806 / Open / SI Pump Suction from RWST 8813 / Open / SI Pump Miniflow Valve	In accordance with the Surveillance Frequency Control Program.

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One or more containment air locks inoperable for reasons other than Condition A or B.	C.1 Initiate action to evaluate overall containment leakage rate per LCO 3.6.1. AND C.2 Verify a door is closed in the affected air lock. AND C.3 Restore air lock to OPERABLE status.	Immediately 1 hour 24 hours RICT INSERT
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 5.	6 hours 36 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. --------------NOTE-------------- Only applicable to penetration flow paths with two containment isolation valves. -------------------------------------	A.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.	4 hours RICT INSERT
One or more penetration flow paths with one containment isolation valve inoperable except for containment purge, hydrogen purge or containment pressure relief valve leakage not within limit.	<u>AND</u>	
	A.2 -------------------NOTES------------------ 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed or otherwise secured may be verified by administrative means. --	
	Verify the affected penetration flow path is isolated.	Once per 31 days for following isolation isolation devices outside containment <u>AND</u> Prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days for isolation devices inside containment

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. ---------------NOTE------------- Only applicable to penetration flow paths with only one containment isolation valve and a closed system. ------------------------------------- One or more penetration flow paths with one containment isolation valve inoperable.	C.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange. AND C.2 -------------------NOTES------------------- 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed or otherwise secured may be verified by administrative means. --- Verify the affected penetration flow path is isolated.	72 hours RICT INSERT Once per 31 days following isolation
D. One or more penetration flow paths with one or more containment purge, hydrogen purge or containment pressure relief valves not within leakage limits.	D.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange. AND	24 hours

3.6 CONTAINMENT SYSTEMS

3.6.6 Containment Spray System

LCO 3.6.6 Two containment spray trains shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One containment spray train inoperable.	A.1 Restore containment spray train to OPERABLE status.	72 hours RICT INSERT
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 84 hours
C. Two containment spray trains inoperable.	C.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.6.1	Verify each containment spray manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position.	In accordance with the Surveillance Frequency Control Program.

3.7 PLANT SYSTEMS

3.7.2 Main Steam Isolation Valves (MSIVs)

LCO 3.7.2 Four MSIVs shall be OPERABLE.

APPLICABILITY: MODE 1,
MODES 2 and 3 except when all MSIVs are closed and deactivated.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One MSIV inoperable in MODE 1.	A.1 Restore MSIV to OPERABLE status.	8 hours RICT INSERT
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 2.	6 hours
C. --------------NOTE-------------- Separate Condition entry is allowed for each MSIV. ----------------------------------- One or more MSIV inoperable in MODE 2 or 3.	C.1 Close MSIV. AND C.2 Verify MSIV is closed.	8 hours Once per 7 days
D. Required Action and associated Completion Time of Condition C not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 4.	6 hours 12 hours

3.7 PLANT SYSTEMS

3.7.4 Steam Generator Atmospheric Relief Valves (ARVs)

LCO 3.7.4 Four ARV lines shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required ARV line inoperable.	A.1 Restore required ARV line to OPERABLE status.	7 days RICT INSERT
B. Two required ARV lines inoperable.	B.1 Restore at least one ARV line to OPERABLE status.	72 hours RICT INSERT
C. Three or more required ARV lines inoperable.	C.1 Restore at least two ARV lines to OPERABLE status.	24 hours --------- NOTE ------- RICT entry is not permitted when a loss of function occurs. --------------------- RICT INSERT
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 4	6 hours 12 hours

3.7 PLANT SYSTEMS

3.7.5 Auxiliary Feedwater (AFW) System

LCO 3.7.5 Three AFW trains shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3

ACTIONS

---NOTE---
LCO 3.0.4.b is not applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One steam supply to turbine driven AFW pump inoperable.	A.1 Restore steam supply to OPERABLE status.	7 days RICT INSERT
B. One AFW train inoperable for reasons other than Condition A.	B.1 Restore AFW train to OPERABLE status.	72 hours RICT INSERT

3.7 PLANT SYSTEMS

3.7.7 Component Cooling Water (CCW) System

LCO 3.7.7 Two CCW trains shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One CCW train inoperable.	---NOTE--- Enter applicable Conditions and Required Actions of LCO 3.4.6, "RCS Loops - MODE 4," for residual heat removal loops made inoperable by CCW. A.1 Restore CCW train to OPERABLE status.	 72 hours RICT INSERT
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

3.7 PLANT SYSTEMS

3.7.8 Station Service Water System (SSWS)

LCO 3.7.8 Two SSWS trains and a SSW Pump on the opposite unit with its associated cross-connects shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required SSW Pump on the opposite unit or its associated cross-connects inoperable.	A.1 Restore a SSW Pump on the opposite unit to OPERABLE status.	7 days RICT INSERT
	AND	
	A.2 Restore associated cross-connects to OPERABLE status.	7 days RICT INSERT

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One SSWS train inoperable.	--------------------NOTES------------------- 1. Enter applicable Conditions and Required Actions of LCO 3.8.1, "AC Sources -- Operating," for emergency diesel generator made inoperable by SSWS. 2. Enter applicable Conditions and Required Actions of LCO 3.4.6, "RCS Loops -- MODE 4," for residual heat removal loops made inoperable by SSWS. ---	
	B.1 ~~NOTE~~ ~~Required Action B.1 is not applicable to Unit 2 during replacement of the SSWS Pump 2-02 (Train B) during Unit 2 Cycle 19.~~ Restore SSWS train to OPERABLE status.	72 hours
	~~OR~~	RICT INSERT

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
~~B. (continued)~~	~~B.2 NOTE Required Action B.2 is applicable on a one-time basis to replace SSWS Pump 2-02 (Train B) during Unit 2 Cycle 19. If Unit 2, Train A SSWS becomes inoperable, immediately enter LCO 3.0.3. Regulatory Commitment 5966825 (Attachment 1 to TXX-20086) will be implemented during the 8 day COMPLETION TIME.~~ ~~Restore SSWS train to OPERABLE status.~~	~~8 days~~
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 5.	6 hours 36 hours

3.7 PLANT SYSTEMS

3.7.19 Safety Chilled Water

LCO 3.7.19 Two safety chilled water trains shall be OPERABLE

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One safety chilled water train inoperable.	A.1 Restore safety chilled water train to OPERABLE status. ~~OR~~ ~~A.2 NOTE~~ ~~Required Action A.2 is applicable on a one time basis to replace Safety Chiller 2-06 (Train B) compressor during Unit 2 Cycle 19. If Train A safety chilled water becomes inoperable, immediately enter LCO 3.0.3. Regulatory Commitment 5900444 (Attachment 2 to TXX-20056) will be implemented during the 7 day COMPLETION TIME.~~ ~~Restore safety chilled water train to OPERABLE status.~~	72 hours RICT INSERT ~~7 days~~
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

ACTIONS

--NOTE--
LCO 3.0.4.b is not applicable to DGs.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required offsite circuit inoperable.	A.1 Perform SR 3.8.1.1 for required OPERABLE offsite circuit.	1 hour AND Once per 8 hours thereafter
	AND	
	A.2 -------------------NOTE------------------- In MODES 1, 2 and 3, the TDAFW pump is considered a required redundant feature. -- Declare required feature(s) with no offsite power available inoperable when its redundant required feature(s) is inoperable.	24 hours from discovery of no offsite power to one train concurrent with inoperability of redundant required feature(s)
	AND	
	A.3 Restore required offsite circuit to OPERABLE status.	72 hours RICT INSERT

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Included for information only.

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One DG inoperable.	B.1 Perform SR 3.8.1.1 for the required offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND	
	B.2 --------------------NOTE-------------------- In MODES 1, 2 and 3, the TDAFW pump is considered a required redundant feature. -- Declare required feature(s) supported by the inoperable DG inoperable when its required redundant feature(s) is inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	AND	
	B.3.1 Determine OPERABLE DG(s) is not inoperable due to common cause failure.	24 hours
	OR	
	B.3.2 ------------------NOTE------------------ The SR need not be performed if the DG is already operating and loaded. -- Perform SR 3.8.1.2 for OPERABLE DG(s).	24 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	AND	
	B.4.~~1~~ ~~NOTE~~ ~~Required Action B.4.1 is not applicable to Unit 2 during replacement of the SSWS Pump 2-02 (Train B) during Unit 2 Cycle 19.~~	
	Restore DG to OPERABLE status.	72 hours
	~~OR~~	RICT INSERT
	~~B.4.2~~ ~~NOTE~~ ~~Required Action B.4.2 is applicable on a one time basis to replace SSWS Pump 2-02 (Train B) during Unit 2 Cycle 19. If Unit 2, Train A SSWS becomes inoperable, immediately enter LCO 3.0.3. Regulatory Commitment 5966825 (Attachment 1 to TXX-20086) will be implemented during the 8 day COMPLETION TIME.~~	
	~~Restore DG to OPERABLE status.~~	~~8 days~~

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Two required offsite circuits inoperable.	C.1 --------------------NOTE-------------------- In MODES 1, 2 and 3, the TDAFW pump is considered a required redundant feature. -- Declare required feature(s) inoperable when its redundant required feature(s) is inoperable.	 12 hours from discovery of Condition C concurrent with inoperability of redundant required features
	<u>AND</u>	
	C.2 Restore one required offsite circuit to OPERABLE status.	24 hours RICT INSERT

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One required offsite circuit inoperable. AND One DG inoperable.	----------------------NOTE---------------------- Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems - Operating," when Condition D is entered with no AC power source to any train. --	
	D.1 Restore required offsite circuit to OPERABLE status.	12 hours ← RICT INSERT
	OR	
	D.2 Restore DG to OPERABLE status.	12 hours ← RICT INSERT
E. Two DGs inoperable.	E.1 Restore one DG to OPERABLE status.	2 hours
F. One SI sequencer inoperable.	F.1 ------------------NOTE------------------- One required SI sequencer channel may be bypassed for up to 4 hours for surveillance testing provided the other channel is operable. ---	
	Restore SI sequencer to OPERABLE status.	24 hours ← RICT INSERT
G. Required Action and associated Completion Time of Condition A, B, C, D, E, or F not met.	G.1 Be in MODE 3.	6 hours
	AND	
	G.2 Be in MODE 5.	36 hours

3.8 ELECTRICAL POWER SYSTEMS

3.8.4 DC Sources -- Operating

LCO 3.8.4 The Train A and Train B DC electrical power subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or two required battery chargers on one train inoperable.	A.1 Restore affected battery(ies) terminal voltage to greater than or equal to the minimum established float voltage.	2 hours
	AND	
	A.2 Verify affected battery(ies) float current ≤ 2 amps.	Once per 12 hours
	AND	
	A.3 Restore required battery charger(s) to OPERABLE status.	7 days RICT INSERT

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or two batteries on one train inoperable.	B.1 Restore affected battery(ies) to OPERABLE status. ~~OR~~ ~~B.2 ----------NOTE----------~~ ~~Required Action B.2 is applicable for a one time basis to replace cell 27 in battery BT1ED2 and cell 41 in battery BT1ED4 during Unit 1 Cycle 20 (not at the same time). If the second battery on the same train becomes inoperable, immediately initiate Required Actions D.1 and D.2. Regulatory Commitment 5644411 (Attachment 2 to TXX-18064) will be implemented during the 18 hour Completion Time.~~ ~~-----------------------------~~ ~~Restore affected battery to OPERABLE status.~~	2 hours RICT INSERT ~~18 hours~~
C. One DC electrical power subsystem inoperable for reasons other than Condition A or B.	C.1 Restore DC electrical power subsystem to OPERABLE status.	2 hours RICT INSERT
D. Required Action and Associated Completion Time not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 5.	6 hours 36 hours

3.8 ELECTRICAL POWER SYSTEMS

3.8.7 Inverters -- Operating

LCO 3.8.7 The required Train A and Train B inverters shall be OPERABLE.

-----NOTE-----
Inverters may be disconnected from one DC bus for ≤ 24 hours to perform an equalizing charge on their associated common battery, provided:

a. The associated AC vital bus(es) are energized; and

b. All other AC vital buses are energized from their associated OPERABLE inverters.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required inverter inoperable.	A.1 -----NOTE----- Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems - Operating" with any vital bus de-energized. ----- Restore inverter to OPERABLE status.	24 hours RICT INSERT

3.8 ELECTRICAL POWER SYSTEMS

3.8.9 Distribution Systems -- Operating

LCO 3.8.9 Train A and Train B AC, DC, and AC vital bus electrical power distribution subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One AC electrical power distribution subsystem inoperable.	A.1 Restore AC electrical power distribution subsystem to OPERABLE status.	8 hours RICT INSERT
B. One AC vital bus subsystem inoperable.	B.1 Restore AC vital bus subsystem to OPERABLE status.	2 hours RICT INSERT
C. One DC electrical power distribution subsystem inoperable.	C.1 Restore DC electrical power distribution subsystem to OPERABLE status.	2 hours RICT INSERT
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3. <u>AND</u> D.2 Be in MODE 5.	6 hours 36 hours
E. Two trains with inoperable distribution subsystems that result in a loss of safety function.	E.1 Enter LCO 3.0.3.	Immediately

5.5 Programs and Manuals

5.5.22 Spent Fuel Storage Rack Neutron Absorber Monitoring Program (continued)

In order to ensure the reliability of the Neutron Poison material, a monitoring program is required to routinely confirm that the assumptions utilized in the criticality analysis remain valid and bounding. The Neutron Absorber Monitoring Program is established to monitor the integrity of neutron absorber test coupons periodically as described below.

A test coupon "tree" shall be maintained in each SFP. Each coupon tree originally contained 8 neutron absorber surveillance coupons. Detailed measurements were taken on each of these 16 coupons prior to installation, including weight, length, width, thickness at several measurement locations, and B-10 content (g/cm^2). These coupons shall be maintained in the SFP to ensure they are exposed to the same environmental conditions as the neutron absorbers installed in the Region I storage cells, until they are removed for analysis.

One test coupon from each SFP shall be periodically removed and analyzed for potential degradation, per the following schedule. The schedule is established to ensure adequate coupons are available for the planned life of the storage racks.

Year	Coupon Number	Year	Coupon Number
2013	1	2028	5
2015	2	2033	6
2018	3	2043	7
2023	4	2053	8

Further evaluation of the absorber materials, including an investigation into the degradation and potential impacts on the Criticality Safety Analysis, is required if:

- A decrease of more than 5% in B-10 content from the initial value is observed in any test coupon as determined by neutron attenuation.
- An increase in thickness at any point is greater than 25% of the initial thickness at that point.

INSERT SECTION 5.5.23

CPNPP TS INSERTS

EXAMPLE 1.3-8 INSERT

Example 1.3-8

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One subsystem inoperable.	A.1 Restore subsystem to OPERABLE status.	7 days OR In accordance with the Risk Informed Completion Time Program
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

When a subsystem is declared inoperable, Condition A is entered. The 7 day Completion Time may be applied as discussed in Example 1.3-2. However, the licensee may elect to apply the Risk Informed Completion Time Program which permits calculation of a Risk Informed Completion Time (RICT) that may be used to complete the Required Action beyond the 7 day Completion Time. The RICT cannot exceed 30 days. After the 7 day Completion Time has expired, the subsystem must be restored to OPERABLE status within the RICT or Condition B must also be entered.

The Risk Informed Completion Time Program requires recalculation of the RICT to reflect changing plant conditions. For planned changes, the revised RICT must be determined prior to implementation of the change in configuration. For emergent conditions, the revised RICT must be determined within the time limits of the Required Action Completion Time (i.e., not the RICT) or 12 hours after the plant configuration change, whichever is less.

If the 7 day Completion Time clock of Condition A has expired and subsequent changes in plant condition result in exiting the applicability of the Risk Informed Completion Time Program without restoring the inoperable subsystem to OPERABLE status, Condition B is also entered and the Completion Time clocks for Required Actions B.1 and B.2 start.

If the RICT expires or is recalculated to be less than the elapsed time since the Condition was entered and the inoperable subsystem has not been restored to OPERABLE status, Condition B is also entered and the Completion Time clocks for Required Actions B.1 and B.2 start. If the inoperable subsystems are restored to OPERABLE status after Condition B is entered, Conditions A is exited, and therefore, the Required Actions of Condition B may be terminated.

CPNPP TS INSERT

RICT INSERT

OR

In accordance with the Risk Informed Completion Time Program.

INSERT TS 3.3.1 Condition N

N. Required Action and associated Completion Time of Condition M not met.	N.1 Reduce THERMAL POWER to < P-7	6 hours

INSERT TS 3.3.1 Condition Q

Q. Required Action and associated Completion Time of Condition O or P not met.	Q.1 Reduce THERMAL POWER to < P-9	4 hours

INSERT TS 3.3.1 Condition W

W. Required Action and associated Completion Time of Condition B, D, E, R, S, T or V not met.	W.1 Be in MODE 3.	6 hours

INSERT TS 3.3.1 Condition X

X. Required Action and associated Completion Time of Condition U not met.	X.1 Be in MODE 2.	6 hours

INSERT TS 3.3.2 Condition M

M. Required Action and associated Completion Time of Conditions B, C, or K not met.	M.1 Be in MODE 3	6 hours
	AND	
	M.2 Be in MODE 5	36 hours

INSERT TS 3.3.2 Condition N

N. Required Action and associated Completion Time of Conditions D, E, F, G, or L not met.	N.1 Be in MODE 3	6 hours
	AND	
	N.2 Be in MODE 4	12 hours

INSERT TS 3.3.2 Condition O

O. Required Action and associated Completion Time of Conditions H, I, or J not met.	O.1 Be in MODE 3	6 hours

SECTION 5.5.23 INSERT REVISED

5.5.23 Risk Informed Completion Time Program

This program provides controls to calculate a Risk Informed Completion Time (RICT) and must be implemented in accordance with NEI 06-09-A, Revision 0, "Risk-Managed Technical Specifications (RMTS) Guidelines." The program shall include the following:

a. The RICT may not exceed 30 days;

b. A RICT may only be utilized in MODE 1 and 2;

c. When a RICT is being used, any change to the plant configuration, as defined in NEI 06-09-A, Appendix A, must be considered for the effect on the RICT.

    1. For planned changes, the revised RICT must be determined prior to implementation of the change in configuration.

    2. For emergent conditions, the revised RICT must be determined within the time limits of the Required Action Completion Time (i.e., not the RICT) or 12 hours after the plant configuration change, whichever is less.

    3. Revising the RICT is not required If the plant configuration change would lower plant risk and would result in a longer RICT.

d. For emergent conditions, if the extent of condition evaluation for inoperable structures, systems, or components (SSCs) is not complete prior to exceeding the Completion Time, the RICT shall account for the increased possibility of common cause failure (CCF) by either:

    1. Numerically accounting for the increased possibility of CCF in the RICT calculation; or

    2. Risk Management Actions (RMAs) not already credited in the RICT calculation shall be implemented that support redundant or diverse SSCs that perform the function(s) of the inoperable SSCs, and, if practicable, reduce the frequency of initiating events that challenge the function(s) performed by the inoperable SSCs.

e. The risk assessment approaches and methods shall be acceptable to the NRC. The plant PRA shall be based on the as-built, as-operated, and maintained plant; and reflect the operating experience at the plant, as specified in Regulatory Guide 1.200, Revision 2. Methods to assess the risk from extending the Completion Times must be PRA methods used to support this program, or other methods approved by the NRC for generic use; and any change in the PRA methods to assess risk that are outside these approval boundaries require prior NRC approval.

Attachment 3

License Amendment Request

Comanche Peak Nuclear Power Plant, Units 1 and 2
NRC Docket Nos. 50-445 and 50-446

Revise Technical Specifications to Adopt Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times – RITSTF Initiative 4b"

Proposed Technical Specification Bases pages (For Information Only – markup)

BASES

ACTIONS (continued)

B.1 ~~and B.2~~

RICT BASES INSERT 1

Condition B applies to the Manual Reactor Trip in MODE 1 or 2. This action addresses the train orientation of the SSPS for this Function. With one channel inoperable, the inoperable channel must be restored to OPERABLE status within 48 hours. In this Condition, the remaining OPERABLE channel is adequate to perform the safety function.

The Completion Time of 48 hours is reasonable considering that there are two automatic actuation trains and another manual initiation channel OPERABLE, and the low probability of an event occurring during this interval.

If the Manual Reactor Trip Function cannot be restored to OPERABLE status within the allowed 48 hour Completion Time, the unit must be brought to a MODE in which the requirement does not apply in accordance with Condition W. ~~To achieve this status, the unit must be brought to at least MODE 3 within 6 additional hours (54 hours total time). The 6 additional hours to reach MODE 3 are reasonable, based on operating experience, to reach MODE 3 from full power operation in an orderly manner and without challenging unit systems.~~ With the unit in MODE 3, Condition C is entered if the Manual Reactor trip function has not been restored and the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

C.1, C.2.1 and C.2.2

Condition C applies to the following reactor trip Functions in MODE 3, 4, or 5 with the Rod Control System capable of rod withdrawal or one or more rods not fully inserted:

- Manual Reactor Trip;
- RTBs;
- RTB Undervoltage and Shunt Trip Mechanisms; and
- Automatic Trip Logic.

This action addresses the train orientation of the SSPS for these Functions. With one channel or train inoperable, the inoperable channel or train must be restored to OPERABLE status within 48 hours. If the affected Function(s) cannot be restored to OPERABLE status within the allowed 48 hour

(continued)

ACTIONS

C.1, C.2.1 and C.2.2 (continued)

Completion Time, the unit must be placed in a MODE in which the requirement does not apply. To achieve this status, action must be initiated within the same 48 hours to fully insert all rods and the Rod Control System be rendered incapable of rod withdrawal within the next hour (e.g., by de-energizing all CRDMs, by opening the RTBs, or de-energizing the motor generator (MG) sets). The additional hour provides sufficient time to accomplish the action in an orderly manner. In this condition, these Functions are no longer required.

The Completion Time is reasonable considering that in this Condition, the remaining OPERABLE train is adequate to perform the safety function, and given the low probability of an event occurring during this interval.

Condition C is modified by a Note stating that while the LCO is not met in MODE 5 making the Rod Control System capable of rod withdrawal is not permitted for Functions 19, 20, or 21. This Note specifies an exception to LCO 3.0.4 and avoids placing the plant in a condition where control rods can be withdrawn while the reactor trip system is degraded.

D.1.1 and D.1.2

Condition D applies to the Power Range Neutron Flux-High Function.

With one of the NIS power range detectors inoperable, 1/4 of the radial power distribution monitoring capability is lost. Therefore, SR 3.2.4.2 must be performed (Required Action D.1.1) within 12 hours of THERMAL POWER exceeding 75% RTP and once per 12 hours thereafter. If reactor power decreases to ≤ 75% RTP, the measurement of both Completion Times for Required Action D.1.1 stops and SR 3.2.4.2 is no longer required. Completion Time tracking recommences upon reactor power exceeding 75% RTP. Calculating QPTR every 12 hours compensates for the lost monitoring capability due to the inoperable NIS power range channel and allows continued plant operation at power levels > 75% RTP. At power levels ≤ 75% RTP, operation of the core with radial power distributions beyond the design limits, at a power level where DNB conditions may exist, is prevented.

Required Action D.1.1 has been modified by a Note which only requires SR 3.2.4.2 to be performed if the Power Range Neutron Flux input QPTR becomes inoperable. Failure of a component in the Power Range Neutron Flux Channel which renders the High Flux Trip Function inoperable may not

(continued)

ACTIONS

D.1.1 and D.1.2(continued)

affect the capability to monitor QPTR. As such, determining QPTR using the movable incore detectors or an OPERABLE PDMS once per 12 hours may not be necessary.

The NIS power range detectors provide input to the CRD System and, therefore, have a two-out-of-four trip logic. A known inoperable channel must be placed in the tripped condition. This results in a partial trip condition requiring only one-out-of-three logic for actuation. The 72 hours allowed to place the inoperable channel in the tripped condition is justified in WCAP-14333-P-A (Ref. 11). RICT BASES INSERT 2

As an alternative to the above Actions, the plant must be placed in a MODE where this Function is no longer required OPERABLE. Seventy-eight (78) hours are allowed to place the plant in MODE 3. The 78-hour Completion Time includes 72 hours for channel corrective maintenance, and an additional 6 hours for the MODE reduction in accordance with Condition W. ~~This is a reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems. If Required Actions cannot be completed within their allowed Completion Times, LCO 3.0.3 must be entered.~~

The Required Actions are modified by a Note that allows placing one channel in bypass for 12 hours while performing routine surveillance testing, and setpoint adjustments when a setpoint reduction is required by other Technical Specifications. The 12 hour time limit is justified in Reference 11.

E.1 ~~and E.2~~

Condition E applies to the following reactor trip Functions:

- Power Range Neutron Flux-Low;
- Overtemperature N-16;
- Overpower N-16;
- Power Range Neutron Flux-High Positive Rate;
- Pressurizer Pressure-High; and
- SG Water Level-Low Low.

(continued)

ACTIONS

E.1 ~~and E.2~~ (continued)

A known inoperable channel must be placed in the tripped condition within 72 hours. Placing the channel in the tripped condition results in a partial trip condition requiring only one-out-of-two logic for actuation of the two-out-of-three trips and one-out-of-three logic for actuation of the two-out-of-four trips. The 72 hours allowed to place the inoperable channel in the tripped condition is justified in Reference 11.

If the operable channel cannot be placed in the trip condition within the specified Completion Time, the unit must be placed in a MODE where these Functions are not required OPERABLE. An additional 6 hours is allowed to place the unit in MODE 3 in accordance with Condition W. ~~Six hours is a reasonable time, based on operating experience, to place the unit in MODE 3 from full power in an orderly manner and without challenging unit systems.~~

The Required Actions have been modified by a Note that allows placing one channel in bypass for up to 12 hours while performing routine surveillance testing. The 12 hour time limit is justified in References 8 and 11.

F.1 and F.2

Condition F applies to the Intermediate Range Neutron Flux trip when THERMAL POWER is above the P-6 setpoint and below the P-10 setpoint and one channel is inoperable. Above the P-6 setpoint and below the P-10 setpoint, the NIS intermediate range detector performs the monitoring Functions. If THERMAL POWER is greater than the P-6 setpoint but less than the P-10 setpoint, 24 hours is allowed to reduce THERMAL POWER below the P-6 setpoint or increase to THERMAL POWER above the P-10 setpoint. The NIS Intermediate Range Neutron Flux channels must be OPERABLE when the power level is above the capability of the source range, P-6, and below the capability of the power range, P-10. If THERMAL POWER is greater than the P-10 setpoint, the NIS power range detectors perform the monitoring and protection functions and the intermediate range is not required. The Completion Times allow for a slow and controlled power adjustment above P-10 or below P-6 and take into account the redundant capability afforded by the redundant OPERABLE channel, the overlap of the Power Range detectors, and the low probability of its failure during this period. This action does not require the inoperable channel to be tripped because the Function uses one-out-of-two logic. Tripping one channel would trip the reactor. Thus, the Required Actions specified in this Condition are only applicable when channel failure does not result in reactor trip.

(continued)

BASES

ACTIONS

K.1, K.2.1 and K.2.2 (continued)

reactivity (i.e., temperature or boron concentration fluctuations associated with RCS inventory or chemistry management or temperature control) are permitted provided the ADM limits specified in the COLR are met and the initial and critical boron concentration assumptions in FSAR Section 15 are satisfied.

L.1

Not Used.

M.1 ~~and M.2~~

Condition M applies to the following reactor trip Functions:

- Pressurizer Pressure-Low;
- Pressurizer Water Level-High;
- Reactor Coolant Flow-Low;
- Undervoltage RCPs; and
- Underfrequency RCPs.

RICT BASES INSERT 1

With one channel inoperable, the inoperable channel must be placed in the tripped condition within 72 hours. For the Pressurizer Pressure-Low, Pressurizer Water Level-High, Undervotage RCPs, and Underfrequency RCPs trip Functions, placing the channel in the tripped condition when above the P-7 setpoint results in a partial trip condition requiring only one additional channel to initiate a reactor trip. For the Reactor Coolant Flow - Low trip Function, placing the channel in the tripped condition when above the P-8 setpoint results in a partial trip condition requiring only one additional channel in the same loop to initiate a reactor trip. Two tripped channels in two RCS loops are required to initiate a reactor trip when below the P-8 setpoint and above the P-7 setpoint. These Functions do not have to be OPERABLE below the P-7 setpoint because there are no loss of flow trips below the P-7 setpoint. There is insufficient heat production to generate DNB conditions below the P-7 setpoint. The 72 hours allowed to place the channel in the tripped condition is justified in Reference 11. An additional 6 hours is allowed to reduce THERMAL POWER to below P-7 in accordance with Condition N, if the inoperable channel cannot be restored to OPERABLE status or placed in trip within the specified Completion Time.

(continued)

BASES

ACTIONS

M.1 ~~and M.2~~ (continued)

Allowance of this time interval takes into consideration the redundant capability provided by the remaining redundant OPERABLE channel, and the low probability of occurrence of an event during this period that may require the protection afforded by the Functions associated with Condition M.

The Required Actions are modified by a Note that allows placing one channel in bypass for up to 12 hours while performing routine surveillance testing. The 12 hour time limit is justified in References 8 and 11.

N.1

~~Not Used.~~ INSERT BASES 3.3.1 N.1

O.1 ~~and O.2~~

RICT BASES INSERT 1

Condition O applies to Turbine Trip on Low Fluid Oil Pressure. With one channel inoperable, the inoperable channel must be placed in the trip condition within 72 hours. If placed in the tripped condition, this results in a partial trip condition requiring only one additional channel to initiate a reactor trip. If the channel cannot be restored to OPERABLE status or placed in the trip condition, then power must be reduced below the P-9 setpoint within the next 4 hours in accordance with Condition Q. The 72 hours allowed to place the inoperable channel in the tripped condition and the 4 hours allowed for reducing power are justified in Reference 11.

The Required Actions are modified by a Note that allows placing one channel in bypass for up to 12 hours while performing routine surveillance testing. The 12 hour time limit is justified in Reference 11.

P.1 ~~and P.2~~

RICT BASES INSERT 1

Condition P applies to Turbine Trip on Turbine Stop Valve Closure. With one or more channels inoperable, the inoperable channel(s) must be placed in the trip condition within 72 hours. If placed in the tripped condition, this results in a partial trip condition. For the Turbine Trip on Turbine Stop Valve Closure function, four of four channels are required to initiate a reactor trip; hence, more than one channel may be placed in trip. If the channels cannot be restored to OPERABLE status or placed in the trip condition, then power must be reduced below the P-9 setpoint within the next 4 hours in accordance with Condition Q. The 72 hours allowed to place the inoperable channels in the tripped condition and the 4 hours allowed for reducing power are justified in Reference 11.

INSERT BASES 3.3.1.Q.1

(continued)

BASES

ACTIONS (continued)

R ~~Q~~.1 ~~and Q.2~~ R

Condition ~~Q~~ applies to the SI Input from ESFAS reactor trip and the RTS Automatic Trip Logic in MODES 1 and 2. These actions address the train orientation of the RTS for these Functions. With one train inoperable, 24 hours are allowed to restore the train to OPERABLE status ~~(Required Action Q.1)~~ or the unit must be placed in MODE 3 within the next 6 hours in accordance with Condition W. ~~The Completion Time of 24 hours (Required Action Q.1) is reasonable considering that in this Condition, the remaining OPERABLE train is adequate to perform the safety function and given the low probability of an event during this interval. The~~ 24 hours allowed to restore the inoperable train to OPERABLE status is ~~justified in~~ Reference 11. ~~The Completion Time of 6 hours (Required Action Q.2) is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems.~~

RICT BASES INSERT 2

The Required Actions have been modified by a Note that allows bypassing one train up to 4 hours for surveillance testing, provided the other train is OPERABLE.

Consistent with the requirement in Reference 11 to include Tier 2 insights into the decision-making process before taking equipment out of service, restrictions on concurrent removal of certain equipment when a logic train is inoperable for maintenance are included (note that these restrictions do not apply when a logic train is being tested under the 4-hour bypass Note of Condition R). Entry into Condition R is not a typical, pre-planned evolution during power operation, other than for surveillance testing. Since Condition R is typically entered due to equipment failure, it follows that some of the following restrictions may not be met at the time of Condition R entry. If this situation were to occur during the 24-hour Completion Time of Required Action R.1, the Configuration Risk Management Program will assess the emergent condition and direct activities to restore the inoperable logic train and exit Condition R or fully implement these restrictions or perform a plant shutdown, as appropriate from a risk management perspective. The following restrictions will be observed:

- To preserve ATWS mitigation capability, activities that degrade the availability of the auxiliary feedwater system, RCS pressure relief system (pressurizer PORVs and safety valves), AMSAC, or turbine trip should not be scheduled when a logic train is inoperable for maintenance.

(continued)

ACTIONS

~~Q~~R.1 ~~and Q.2~~ (continued)

- To preserve LOCA mitigation capability, one complete ECCS train that can be actuated automatically must be maintained when a logic train is inoperable for maintenance.

- To preserve reactor trip and safeguards actuation capability, activities that cause master relays or slave relays in the available train to be unavailable and activities that cause analog channels to be unavailable should not be scheduled when a logic train is inoperable for maintenance.

- Activities on electrical systems (e.g., AC and DC power) and cooling systems (e.g., station service water and component cooling water) that support the systems or functions listed in the first three bullets should not be scheduled when a logic train is inoperable for maintenance. That is, one complete train of a function that supports a complete train of a function noted above must be available.

~~R~~S.1 ~~and R.2~~

RICT BASES INSERT 2

Condition ~~R~~ S applies to the RTBs in MODES 1 and 2. These actions address the train orientation of the RTS for the RTBs. With one train inoperable, 24 hours are allowed for train corrective maintenance to restore the train to OPERABLE status or the unit must be placed in MODE 3 within the next 6 hours in accordance with Condition W. The 24 hour Completion Time is justified in Reference 12. ~~The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems.~~ Placing the unit in MODE 3 results in Condition C entry if one RTB train is inoperable.

The Required Actions have been modified by a Note. The Note allows one channel to be bypassed for up to 4 hours for surveillance testing or maintenance provided the other channel is OPERABLE. The 4 hour time limit is justified in reference 11.

Consistent with the requirement in Reference 12 to include Tier 2 insights into the decision-making process before taking equipment out of service, restrictions on concurrent removal of certain equipment when a RTB train is inoperable for maintenance are included (note that these restrictions do not apply when a RTB train is being tested under the 4-hour bypass Note for TS 3.3.1 Condition S). Entry into Condition S is not a typical, pre-planned evolution during power operation, other than for surveillance testing. Since Condition S is typically entered due to equipment failure, it follows that some of the following Tier 2 restrictions may not be met at the time of Condition S

(continued)

ACTIONS

~~R~~.1 ~~and R.2~~ (continued)

S

entry. If this situation were to occur during the 24-hour Completion Time of Required Action S.1, the Configuration Risk Management Program will assess the emergent condition and direct activities to restore the inoperable RTB train and exit Condition S or fully implement these restrictions or perform a plant shutdown, as appropriate from a risk management perspective. The following restrictions will be put in place:

- The probability of failing to trip the reactor on demand will increase when a RTB is removed from service, therefore, systems designed for mitigating an ATWS event should be maintained available. RCS pressure relief (pressurizer PORVs and safeties), auxiliary feedwater flow (for RCS heat removal), AMSAC, and turbine trip are important to alternate ATWS mitigation. Therefore, activities that degrade the availability of the auxiliary feedwater system, RCS pressure relief system (pressurizer PORVs and safety valves), AMSAC, or turbine trip should be scheduled when a RTB train is inoperable for maintenance.

- Due to the increased dependence on the available reactor trip train when one logic train or one RTB train is inoperable for maintenance, activities that degrade other components of the RTS, including master relays or slave relays, and activities that cause analog channels to be unavailable, should not be scheduled when a logic train or RTB is inoperable for maintenance.

- Activities on electrical systems (e.g., AC and DC power) and cooling systems (e.g., station service water and component cooling water) that support the systems or functions listed in the first two bullets should not be scheduled when a RTB train is inoperable for maintenance. That is, one complete train of a function that supports a complete train of a function noted above must be available.

T

~~S~~.1 and ~~S~~.2

T T

Condition ~~S~~ applies to the P-6 and P-10 interlocks. With one or more required channel(s) inoperable, the associated interlock must be verified to be in its required state for the existing unit condition within 1 hour or the unit must be placed in MODE 3 within the next 6 hours in accordance with Condition W. Verifying the interlock status manually, e.g., by observation of the permissive annunciator window, accomplishes the interlock's Function. The Completion Time of 1 hour is based on operating experience and the minimum amount of time allowed for manual operator actions.

(continued)

BASES

ACTIONS

T

~~S~~.1 and ~~S~~.2 (continued)

T

~~The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems. The 1 hour and 6 hour Completion Times are equal to the time allowed by LCO 3.0.3 for shutdown actions in the event of a complete loss of RTS Function.~~

U

~~T~~.1 and ~~T~~.2

U U

Condition ~~T~~ applies to the P-7, P-8, P-9, and P-13 interlocks. With one or more channel(s) inoperable, the associated interlock must be verified to be in its required state for the existing unit condition by observation of the permissive annunciator window within 1 hour or the unit must be placed in MODE 2 within the next 6 hours in accordance with Condition X. These actions are conservative for the case where power level is being raised. Verifying the interlock status manually accomplishes the interlock's Function. The Completion Time of 1 hour is based on operating experience and the minimum amount of time allowed for manual operator actions. ~~The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 2 from full power in an orderly manner and without challenging unit systems.~~

~~U.1 and U.2~~

V V

Condition ~~U~~ applies to the RTB Undervoltage and Shunt Trip Mechanisms, or diverse trip features, in MODES 1 and 2. With one of the diverse trip features inoperable, it must be restored to an OPERABLE status within 48 hours or the unit must be placed in a MODE where the requirement does not apply. This is accomplished by placing the unit in MODE 3 within the next 6 hours in accordance with Condition W. ~~The Completion Time of 6 hours is a reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems.~~

RICT BASES INSERT 2

With the unit in MODE 3, Condition C is entered if the Reactor Trip Breaker trip mechanism has not been restored and the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted. The affected RTB shall not be bypassed while one of the diverse features is inoperable except for the time required to perform maintenance to one of the diverse features as described in Condition ~~R~~.

S V

The Completion Time of 48 hours for Required Action ~~U~~.1 is reasonable considering that in this Condition there is one remaining diverse feature for the affected RTB, and one OPERABLE RTB capable of performing the safety function and given the low probability of an event occurring during this interval.

INSERT BASES 3.3.1 W.1

INSERT BASES 3.3.1 X.1

(continued)

BASES

ACTIONS

A.1 (continued)

Condition A addresses the situation where one or more channels or trains for one or more Functions are inoperable at the same time. The Required Action is to refer to Table 3.3.2-1 and to take the Required Actions for the protection functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

B.1~~, B.2.1 and B.2.2~~

Condition B applies to manual initiation of:

- SI;
- Containment Spray;
- Phase A Isolation; and
- Phase B Isolation.

RICT BASES INSERT 2

This action addresses the train orientation of the SSPS for the functions listed above. If a channel or train is inoperable, 48 hours is allowed to return it to an OPERABLE status. Note that for containment spray and Phase B isolation, failure of one or both channels in one train renders the train inoperable. Condition B, therefore, encompasses both situations. The specified Completion Time is reasonable considering that there are two automatic actuation trains and another manual initiation train OPERABLE for each Function, and the low probability of an event occurring during this interval. If the train cannot be restored to OPERABLE status, the unit must be placed in a MODE in which the LCO does not apply. This is done by placing the unit in at least MODE 3 within an additional 6 hours and in MODE 5 within an additional 30 hours in accordance with Condition M. ~~The allowable Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.~~

C.1~~, C.2.1 and C.2.2~~

Condition C applies to the automatic actuation logic and actuation relays for the following functions:

- SI;
- Containment Spray;

(continued)

ACTIONS

C.1~~, C.2.1 and C.2.2~~ (continued)

- Phase A Isolation;
- Phase B Isolation; and
- Semi-Automatic Switchover to Containment Sump.

RICT BASES INSERT 2

This action addresses the train orientation of the SSPS and the master and slave relays. If one train is inoperable, 24 hours are allowed to restore the train to OPERABLE status. The 24 hours allowed for restoring the inoperable train to OPERABLE status is justified in Reference 12. The specified Completion Time is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. If the train cannot be restored to OPERABLE status, the unit must be placed in a MODE in which the LCO does not apply. This is done by placing the unit in at least MODE 3 within an additional 6 hours (30 hours total time) and in MODE 5 within an additional 30 hours (60 hours total time) in accordance with Condition M. ~~The Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.~~

The Required Actions are modified by a Note that allows one train to be bypassed for up to 4 hours for surveillance testing, provided the other train is OPERABLE. This allowance is based on the reliability analysis assumption of WCAP-10271-P-A (Ref. 6) that 4 hours is the average time required to perform train surveillance.

Consistent with the requirement in Reference 12 to include Tier 2 insights into the decision-making process before taking equipment out of service, restrictions on concurrent removal of certain equipment when a logic train is inoperable for maintenance are included (note that these restrictions do not apply when a logic train is being tested under the 4 hour bypass Note of Condition C). Entry into Condition C is not a typical, pre-planned evolution during power operation, other than for surveillance testing. Since Condition C is typically entered due to equipment failure, it follows that some of the following restrictions may not be met at the time of Condition C entry. If this situation were to occur during the 24-hour Completion Time of Required Action C.1 ~~C.2~~, the Configuration Risk Management Program will assess the emergent condition and direct activities to restore the inoperable logic train and exit Condition C or fully implement these restriction or perform a plant shutdown, as appropriate from a risk management perspective. The following restrictions will be observed:

(continued)

ACTIONS

C.1~~, C.2.1 and C.2.2~~ (continued)

- To preserve ATWS mitigation capability, activities that degrade the availability of the auxiliary feedwater system, RCS pressure relief system (pressurizer PORVs and safety valves), AMSAC, or turbine trip should not be scheduled when a logic train is inoperable for maintenance.
- To preserve LOCA mitigation capability, one complete ECCS train that can be actuated automatically must be maintained when a logic train is inoperable for maintenance.
- To preserve reactor trip and safeguards actuation capability, activities that cause master relays or slave relays in the available train to be unavailable and activities that cause analog channels to be unavailable should not be scheduled when a logic train is inoperable for maintenance.
- Activities on electrical systems (e.g., AC and DC power) and cooling systems (e.g., station service water and component cooling water) that support the systems or functions listed in the first three bullets should not be scheduled when a logic train is inoperable for maintenance. That is, one complete train of a function that supports a complete train of a function noted above must be available.

D.1~~, D.2.1, and D.2.2~~

Condition D applies to:

- Containment Pressure-High 1;
- Pressurizer Pressure-Low;
- Steam Line Pressure-Low;
- Containment Pressure-High 2;
- Steam Line Pressure - Negative Rate-High; and
- SG Water Level-Low Low.

RICT BASES INSERT 2

If one channel is inoperable, 72 hours are allowed to restore the channel to OPERABLE status or to place it in the tripped condition. Generally this Condition applies to functions that operate on two-out-of-three logic. Therefore, failure of one channel places the Function in a two-out-of-two

(continued)

ACTIONS

D.1~~, D.2.1, and D.2.2~~ (continued)

configuration. The inoperable channel must be tripped to place the Function in a one-out-of-two configuration that satisfies redundancy requirements. The 72 hours allowed to restore the channel to OPERABLE status or to place it in the tripped condition is justified in Reference 12.

Failure to restore the inoperable channel to OPERABLE status or place it in the tripped condition within 72 hours requires the unit be placed in MODE 3 within the following 6 hours and MODE 4 within the next 6 hours in accordance with Condition N. In MODE 4, these Functions are no longer required OPERABLE.

The Required Actions are modified by a Note that allows placing one channel in bypass for up to 12 hours while performing routine surveillance testing. The 12 hour time limit is justified in Reference 12.

E.1~~, E.2.1, and E.2.2~~

Condition E applies to:

- Containment Spray Containment Pressure-High 3; and
- Containment Phase B Isolation Containment Pressure-High 3.

None of these signals has input to a control function. Thus, two-out-of-three logic is necessary to meet acceptable protective requirements. However, a two-out-of-three design would require tripping a failed channel. This is undesirable because a single failure would then cause spurious containment spray initiation. Spurious spray actuation is undesirable because of the cleanup problems presented. Therefore, these channels are designed with two-out-of-four logic so that a failed channel may be bypassed rather than tripped. Note that one channel may be bypassed and still satisfy the single failure criterion. Furthermore, with one channel bypassed, a single instrumentation channel failure will not spuriously initiate containment spray.

To avoid the inadvertent actuation of containment spray and Phase B containment isolation, the inoperable channel should not be placed in the tripped condition. Instead it is bypassed. Restoring the channel to OPERABLE status, or placing the inoperable channel in the bypass condition within 72 hours, is sufficient to assure that the Function remains OPERABLE and minimizes the time that the Function may be in a partial trip

(continued)

ACTIONS

E.1~~, E.2.1, and E.2.2~~ (continued)

condition (assuming the inoperable channel has failed high). The completion Time is further justified based on the low probability of an event occurring during this interval. Failure to restore the inoperable channel to OPERABLE status, or place it in the bypassed condition within 72 hours, requires the unit be placed in MODE 3 within the following 6 hours and MODE 4 within the next 6 hours in accordance with Condition N. ~~The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. In MODE 4, these Functions are no longer required OPERABLE.~~

The Required Actions are modified by a Note that allows placing one channel in bypass for up to 12 hours while performing routine surveillance testing. The channel to be tested can be tested in bypass with the inoperable channel also in bypass. The 12 hour time limit is justified in Reference 12.

F.1~~, F.2.1, and F.2.2~~

Condition F applies to:

- Manual Initiation of Steam Line Isolation;
- Loss of Offsite Power; and
- P-4 Interlock.

For the Manual Initiation and the P-4 Interlock Functions, this action addresses the train orientation of the SSPS. For the Loss of Offsite Power Function, this action recognizes the lack of manual trip provision for a failed channel. If a train or channel is inoperable, 48 hours is allowed to return it to OPERABLE status~~.~~ RICT BASES INSERT 2 The specified Completion Time is reasonable considering the nature of these Functions, the available redundancy, and the low probability of an event occurring during this interval. If the Function cannot be returned to OPERABLE status, the unit must be placed in MODE 3 within the next 6 hours and MODE 4 within the following 6 hours in accordance with Condition N. ~~The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power in an orderly manner and without challenging unit systems. In MODE 4, the unit does not have any analyzed transients or conditions that require the explicit use of the protection functions noted above.~~

(continued)

ACTIONS (continued)

G.1~~, G.2.1 and G.2.2~~

RICT BASES INSERT 2

Condition G applies to the automatic actuation logic and actuation relays for the Steam Line Isolation and AFW actuation Functions.

The action addresses the train orientation of the SSPS and the master and slave relays for these functions. If one train is inoperable, 24 hours are allowed to restore the train to OPERABLE status. The 24 hours allowed for restoring the inoperable train to OPERABLE status is justified in Reference 12. The Completion Time for restoring a train to OPERABLE status is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. If the train cannot be returned to OPERABLE status, the unit must be brought to MODE 3 within the next 6 hours and MODE 4 within the following 6 hours in accordance with Condition N. ~~The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.~~ Placing the unit in MODE 4 removes all requirements for OPERABILITY of the protection channels and actuation functions. In this MODE, the unit does not have analyzed transients or conditions that require the explicit use of the protection functions noted above.

The Required Actions are modified by a Note that allows one train to be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. This allowance is based on the reliability analysis (Ref. 6) assumption that 4 hours is the average time required to perform train surveillance.

Consistent with the requirement in Reference 12 to include Tier 2 insights into the decision-making process before taking equipment out of service, restrictions on concurrent removal of certain equipment when a logic train is inoperable for maintenance are included (note that these restriction do not apply when a logic train is being tested under the 4-hour bypass Note of Condition G). Entry into Condition G is not a typical, pre-planned evolution during power operation, other than for surveillance testing. Since Condition G is typically entered due to equipment failure, it follows that some of the following restrictions may not be met at the time of Condition G entry. If this situation were to occur during the 24-hour Completion Time of Required Action G.1, the Configuration Risk Management Program will assess the emergent condition and direct activities to restore the inoperable logic train and exit Condition G or fully implement these restrictions or perform a plant shutdown, as appropriate from a risk management perspective. The following restrictions will be observed:

(continued)

ACTIONS

G.1~~, G.2.1 and G.2.2~~ (continued)

- To preserve ATWS mitigation capability, activities that degrade the availability of the auxiliary feedwater system, RCS pressure relief system (pressurizer PORVs and safety valves), AMSAC, or turbine trip should not be scheduled when a log train is inoperable for maintenance.

- To preserve LOCA mitigation capability, one complete ECCS train that can be actuated automatically must be maintained when a logic train is inoperable for maintenance.

- To preserve reactor trip and safeguards actuation capability, activities that cause master relays or slave relays in the available train to be unavailable and activities that cause analog channels to be unavailable should not be scheduled when a logic train is inoperable for maintenance.

- Activities on electrical systems (e.g., AC and DC power) and cooling systems (e.g., station service water and component cooling water) that support the systems or functions listed in the first three bullets should not be scheduled when a logic train is inoperable for maintenance. That is, one complete train of a function that supports a complete train of a function noted above must be available.

H.1 ~~and H.2~~

RICT BASES INSERT 2

Condition H applies to the automatic actuation logic and actuation relays for the Turbine Trip and Feedwater Isolation Function.

This action addresses the train orientation of the actuation logic for this Function. If one train is inoperable, 24 hours are allowed to restore the train to OPERABLE status or the unit must be placed in MODE 3 within the following 6 hours in accordance with Condition O. The 24 hours allowed for restoring the inoperable train to OPERABLE status is justified in Reference 12. The Completion Time for restoring a train to OPERABLE status is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. ~~The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems.~~ These Functions are no longer required in MODE 3. Placing the unit in MODE 3 removes all requirements for OPERABILITY of the protection channels and actuation functions. In this MODE, the unit does not have analyzed transients or conditions that require the explicit use of the protection functions noted above.

(continued)

BASES

ACTIONS

H.1 ~~and H.2~~ (continued)

The Required Actions are modified by a Note that allows one train to be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. This allowance is based on the reliability analysis (Ref. 6) assumption that 4 hours is the average time required to perform channel surveillance.

I.1 ~~and I.2~~

Condition I applies to:

RICT BASES INSERT 2

- SG Water Level-High High (P-14)

If one channel is inoperable, 72 hours are allowed to restore one channel to OPERABLE status or to place it in the tripped condition. ~~If~~ placed in the tripped condition, the Function is then in a partial trip condition where one-out-of-two or one-out-of-three logic will result in actuation. The 72 hour Completion Time is justified in Reference 12. Failure to restore the inoperable channel to OPERABLE status or place it in the tripped condition within 72 hours requires the unit to be placed in MODE 3 within the following 6 hours in accordance with Condition O. ~~The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems.~~ In MODE 3, these Functions are no longer required OPERABLE.

The Required Actions are modified by a Note that allows placing one channel in bypass for up to 12 hours while performing surveillance testing. The 72 hours allowed to place the inoperable channel in the tripped condition, and the 12 hours allowed for a second channel to be in the bypassed condition for testing, are justified in Reference 12.

J.1 ~~and J.2~~

Condition J applies to the AFW pump start on trip of all MFW pumps.

This action addresses the train orientation of the SSPS for the auto start function of the AFW System on loss of all MFW pumps. The OPERABILITY of the AFW System must be assured by allowing automatic start of the AFW System pumps. If a channel is inoperable, 6 hours are allowed to place it in the tripped condition. If the channel cannot be tripped in 6 hours, 6 additional hours are allowed to place the unit in MODE 3 in accordance with Condition O. ~~The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems.~~

(continued)

BASES

ACTIONS

J.1 ~~and J.2~~ (continued)

In MODE 3, the unit does not have any analyzed transients or conditions that require the explicit use of the protection function noted above.

RICT BASES INSERT 2

K.1, ~~K2.1 and K2.2~~

Condition K applies to:

- RWST Level-Low Low Coincident with Safety Injection.

RWST Level-Low Low Coincident With SI provides semi-automatic actuation of switchover to the containment recirculation sumps. Note that this Function requires the bistables to energize to perform their required action. The failure of up to two channels will not prevent the operation of this Function. However, placing a failed channel in the tripped condition could result in a premature switchover to the sump, prior to the injection of the minimum volume from the RWST. Placing the inoperable channel in bypass results in a two-out-of-three logic configuration, which satisfies the requirement to allow another failure without disabling actuation of the switchover when required. Restoring the channel to OPERABLE status or placing the inoperable channel in the bypass condition within 72 hours is sufficient to ensure that the Function remains OPERABLE, and minimizes the time that the Function may be in a partial trip condition (assuming the inoperable channel has failed high). The 72 hour ~~and 78 hour~~ Completion Times is justified in References 8 and 12. If the channel cannot be returned to OPERABLE status or placed in the bypass condition within 72 hours, the unit must be brought to MODE 3 within the following 6 hours and MODE 5 within the next 30 hours in accordance with Condition M. ~~The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.~~ In MODE 5, the unit does not have any analyzed transients or conditions that require the explicit use of the protection functions noted above.

The Required Actions are modified by a Note that allows placing one channel in bypass for up to 12 hours while performing routine surveillance testing. The channel to be tested can be tested in bypass with the inoperable channel also in bypass. The total of 78 hours to reach MODE 3 and 12 hours for a second channel to be bypassed is acceptable based on the results of References 8 and 12.

L.1, ~~L.2.1 and L.2.2~~

Condition L applies to the P-11 interlock.

(continued)

BASES

ACTIONS

L.1, ~~L.2.1 and L.2.2~~ (continued)

With one or more required channel(s) inoperable, the operator must verify that the interlock is in the required state for the existing unit condition by observation of the permissive annunciator windows. This action manually accomplishes the function of the interlock. Determination must be made within 1 hour. The 1 hour Completion Time is equal to the time allowed by LCO 3.0.3 to initiate shutdown actions in the event of a complete loss of ESFAS function. If the interlock is not in the required state (or placed in the required state) for the existing unit condition, the unit must be placed in MODE 3 within the next 6 hours and MODE 4 within the following 6 hours in accordance with Condition N. ~~The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.~~ Placing the unit in MODE 4 removes all requirements for OPERABILITY of these interlocks.

$\boxed{\text{INSERT BASES 3.3.2 M.1 and M.2 , N.1 and N.2, and O1}}$

SURVEILLANCE REQUIREMENTS

The SRs for each ESFAS Function are identified by the SRs column of Table 3.3.2-1.

A Note has been added to the SR Table to clarify that Table 3.3.2-1 determines which SRs apply to which ESFAS Functions.

Note that each channel of process protection supplies both trains of the ESFAS. When testing channel I, train A and train B must be examined. Similarly, train A and train B must be examined when testing channel II, channel III, and channel IV. The CHANNEL CALIBRATION and COTs are performed in a manner that is consistent with the assumptions used in analytically calculating the required channel accuracies.

SR 3.3.2.1

Performance of the CHANNEL CHECK ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value.

Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

(continued)

BASES

ACTIONS (continued)

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in the LCO. The Completion Time(s) of the inoperable channel(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

RICT BASES INSERT 1

Condition A applies to one or more LOP DG start Functions with one channel per bus inoperable.

If one channel is inoperable, Required Action A.1 requires that channel to be placed in trip within 6 hours. With a channel in trip, the LOP DG start instrumentation channels are configured to provide a one-out-of-one logic to trip the incoming offsite power and initiate the LOP DG start logic.

The specified Completion Time is reasonable considering the Function remains fully OPERABLE on every bus and the low probability of an event occurring during these intervals.

A note has been added to clarify that this Condition is not applicable to the Automatic Actuation Logic and Actuation Relay function. This function is addressed by Condition F.

A note has been added to the Completion Time to clarify that RICT entry is not permitted if there is a loss of function. A loss of function occurs when one channel on each bus is inoperable for Conditions B, C, D, or E. For example, if one channel for the Preferred offsite source bus undervoltage function (Condition B) is inoperable on 6.9 kV bus uEA1 and if one channel for the Preferred offsite source bus undervoltage function is inoperable on 6.9 kV bus uEA2 at the same time, a loss of function would exist. Neither train would initiate a Preferred offsite source bus undervoltage start of either DG. This logic is followed for Functions 2 through 7 in Table 3.3.5-1, Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation.

B.1, B.2.1, and B.2.2

Condition B applies when both loss of voltage channels on the Preferred Offsite Voltage Source bus are inoperable.

Required Action B.1 requires restoring one channel to OPERABLE status. The 1 hour Completion Time should allow ample time to repair most failures and takes into account the low probability of an event requiring an LOP start occurring during this interval.

RICT BASES INSERT 2

(continued)

BASES

ACTIONS (continued) B.1, B.2.1, and B.2.2 (continued)

Alternatively, Required Actions B.2.1 and B.2.2 can be completed. Action B.2.1 requires the Preferred Offsite Voltage Source bus be declared inoperable and the appropriate condition(s) specified in LCO 3.8.1, "AC Sources - Operating," be entered within one hour. This requires that the additional Required Actions associated with an inoperable monitored function (the preferred offsite power source) be taken. The 1 hour completion time allows time to repair at least one channel and takes into account the low probability of an event requiring an LOP start occurring during this interval. Action B.2.2 requires that the Preferred Offsite Voltage

Source Breaker be opened within 6 hours. Opening this breaker separates the preferred offsite power source from the Class 1E system and thereby eliminates the need for any undervoltage monitoring and eliminates any potential impact resulting from having an unmonitored power source connected to the Class 1E distribution system. The 6 hour completion time allows additional time to repair at least one inoperable channel and takes into account the low probability of an event requiring an LOP start occurring during this interval.

A note has been added to the Completion Time to clarify that RICT entry is not permitted if there is a loss of function. A loss of function occurs when the Preferred offsite source bus undervoltage function is inoperable on both uEA1 and uEA2. For example, if both channels for the Preferred offsite source bus undervoltage are inoperable on uEA1 but, both of the Preferred offsite source bus undervoltage channels are OPERABLE on uEA2, then there is no loss of function.

C.1, C.2.1, and C.2.2

Condition C applies when both loss of voltage channels on the Alternate Offsite Voltage Source bus are inoperable.

Required Action C.1 requires restoring one channel to OPERABLE status. The 1 hour Completion Time should allow ample time to repair most failures and takes into account the low probability of an event requiring an LOP start occurring during this interval. RICT BASES INSERT 2

Alternatively, Required Actions C.2.1 and C.2.2 can be completed. Action C.2.1 requires the Alternate Offsite Voltage Source bus be declared inoperable and the appropriate condition(s) specified in LCO 3.8.1, "AC Sources - Operating," be entered within one hour. This requires that the additional Required Actions associated with an inoperable monitored function (the alternate offsite power source) be taken. The 1 hour completion time allows time to repair at least one channel and takes into

(continued)

BASES

ACTIONS (continued) C.1, C.2.1, and C.2.2 (continued)

account the low probability of an event requiring an LOP start occurring during this interval. Action C.2.2 requires that the Alternate Offsite Voltage Source Breaker be opened within 6 hours. Opening this breaker separates the alternate offsite power source from the Class 1E system and thereby eliminates the need for any undervoltage monitoring and eliminates any potential impact resulting from having an unmonitored power source connected to the Class 1E distribution system. The 6 hour completion time allows additional time to repair at least one inoperable channel and takes into account the low probability of an event requiring an LOP start occurring during this interval.

A note has been added to the Completion Time to clarify that RICT entry is not permitted if there is a loss of function. A loss of function occurs when the Alternate offsite source bus undervoltage function is inoperable on both uEA1 and uEA2. For example, if both channels for the Alternate offsite source bus undervoltage are inoperable on uEA1 but, both of the Alternate offsite source bus undervoltage channels are OPERABLE on uEA2, then there is no loss of function.

D.1 and D.2

Condition D applies when both loss of voltage channels on the 6.9 kV safeguards bus are inoperable.

Required Action D.1 requires restoring one channel to OPERABLE status. The 1 hour Completion Time should allow ample time to repair most failures and takes into account the low probability of an event requiring an LOP start occurring during this interval. RICT BASES INSERT 2

Alternatively, Required Actions D.2 can be completed. Action D.2 requires the affected 6.9 kV bus be declared inoperable and the appropriate condition(s) specified in LCO 3.8.9, "Electrical Power Systems, Distribution Systems - Operating," be entered within one hour. This requires that the additional Required Actions associated with an inoperable monitored function (the affected 6.9kV bus) be taken. The 1 hour completion time allows time to repair at least one channel and takes into account the low probability of an event requiring an LOP start occurring during this interval. The affected bus remains available to support required components although automatically powering the bus from the associated diesel generator may not occur on bus undervoltage.

A note has been added to the Completion Time to clarify that RICT entry is not permitted if there is a loss of function. A loss of function occurs when the 6.9 kV Class 1E bus loss of voltage or the 6.9 kV Class 1E bus degraded voltage function is inoperable on both uEA1 and uEA2. For example, if both channels for the 6.9 kV Class 1E bus loss of voltage are inoperable on uEA1 but, both of the 6.9 kV Class 1E bus loss of voltage channels are OPERABLE on uEA2, then there is no loss of function.

(continued)

ACTIONS (continued)

E.1, E.2.1, and E.2.2

Condition E applies when two channels per bus with one or more degraded voltage or low grid undervoltage functions inoperable.

Required Action E.1 requires restoring one channel per bus to OPERABLE status within one hour. The 1 hour Completion Time should allow ample time to repair most failures and takes into account the low probability of an event requiring an LOP start occurring during this interval.

Alternatively, Required Actions E.2.1 and E.2.2 can be completed. Action E.2.1 requires that the offsite power sources be declared inoperable and the appropriate condition(s) specified in LCO 3.8.1, "AC Sources - Operating," be entered within one hour. This requires that the additional Required Actions associated with the inoperable monitored functions (the offsite power sources) be taken. The 1 hour completion time allows time to repair at least one channel and takes into account the low probability of an event requiring an LOP start occurring during this interval. Action E.2.2 requires that the offsite power source breakers be opened within 6 hours. Opening these breakers separates the offsite power sources from the Class 1E system and thereby eliminates the need for any monitoring of degraded voltage or low grid undervoltage for the offsite power sources and eliminates any potential impact resulting from having unmonitored offsite power sources connected to the Class 1E distribution system. The 6 hour completion time allows additional time to repair at least one inoperable channel and takes into account the low probability of an event requiring an LOP start occurring during this interval. RICT BASES INSERT 2

A note has been added to the Completion Time to clarify that RICT entry is not permitted if there is a loss of function. A loss of function occurs when the 480 V Class 1E bus low grid under voltage or the 480 V Class 1E bus degraded voltage function is inoperable on both uEB1 and uEB3 (Train A) and on both uEB2 and uEB4 (Train B). For example, if both channels for the 480 V Class 1E bus low grid under voltage are inoperable on uEB1 and uEB3 (Train A) but, both of the 480 V Class 1E bus low grid under voltage channels are OPERABLE on uEB2 or uEB4, then there is no loss of function.

F.1

Condition F applies when one or more trains of Automatic Actuation Logic and Actuation Relay function are inoperable.

Required Action F.1 requires restoring the inoperable train(s) to OPERABLE status. The 1 hour completion Time allows time to repair failures and takesinto account the low probability of an event requiring LOP DG start occurringduring this interval. RICT BASES INSERT 2

A note has been added to the Completion Time to clarify that RICT entry is not permitted if there is a loss of function. If both trains are inoperable RICT entry is not permitted.

(continued)

BASES

APPLICABILITY (continued)

emergency power supply. In the event of a loss of offsite power, the initial conditions of these MODES give the greatest demand for maintaining the RCS in a hot pressurized condition with loop subcooling for an extended period. For MODE 4, 5, or 6, it is not necessary to control pressure (by heaters) to ensure loop subcooling for heat transfer when the Residual Heat Removal (RHR) System is in service, and therefore, the LCO is not applicable.

ACTIONS

A.1, A.2, A.3 and A.4

Pressurizer water level control malfunctions or other plant evolutions may result in a pressurizer water level above the nominal upper limit, even with the plant at steady state conditions. Normally the plant will trip in this event since the upper limit of this LCO is the same as the Pressurizer Water Level - High Trip.

If the pressurizer water level is not within the limit, action must be taken to bring the plant to a MODE in which the LCO does not apply. To achieve this status, within 6 hours the unit must be brought to MODE 3, with all rods fully inserted and incapable of withdrawal (e.g., de-energize all CRDMs by opening the RTBs or de-energizing the motor generator (MG) sets). Additionally, the unit must be brought to MODE 4 within 12 hours. This takes the unit out of the applicable MODES.

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

B.1

RICT BASES INSERT 1

If one required group of pressurizer heaters is inoperable, restoration is required within 72 hours. The Completion Time of 72 hours is reasonable considering the anticipation that a demand for more than one group of heaters would be unlikely in this period.

C.1 and C.2

If one required group of pressurizer heaters is inoperable and cannot be restored in the allowed Completion Time of Required Action B.1, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable,

(continued)

ACTIONS (continued)

B.1, B.2, and B.3

is required to be closed, but power must be maintained to the associated block valves, since removal of power would render the block valve inoperable. This permits operation of the plant until the next refueling outage (MODE 6) so that maintenance can be performed on the PORVs to eliminate the problem condition.

Quick access to the PORV for pressure control can be made when power remains on the closed block valve. The Completion Time of 1 hour is based on plant operating experience that has shown that minor problems can be corrected or closure accomplished in this time period.If one PORV is inoperable and not capable of being manually cycled, it must be either restored, or isolated by closing the associated block valve and removing the power to the associated block valve. The Completion Times of 1 hour are reasonable, based on challenges to the PORVs during this time period, and provide the operator adequate time to correct the situation. If the inoperable valve cannot be restored to OPERABLE status, it must be isolated within the specified time of 1 hour. Because there is at least one PORV that remains OPERABLE, ~~an~~ additional 72 hours is provided to restore the inoperable PORV to OPERABLE status. RICT BASES INSERT 2 If the PORV cannot be restored within this additional time, the plant must be brought to a MODE in which the LCO does not apply, as required by Condition D.

C.1 and C.2

If one block valve is inoperable, then it is necessary to either restore the block valve to OPERABLE status within the Completion Time of 1 hour or place the associated PORV in manual control. The prime importance for the capability to close the block valve is to isolate a stuck open PORV. Therefore, if the block valve cannot be restored to OPERABLE status within 1 hour, the Required Action is to place the PORV in manual control to preclude its automatic opening for an overpressure event and to avoid the potential for a stuck open PORV at a time that the block valve is inoperable. The Completion Time of 1 hour is reasonable, based on the small potential for challenges to the system during this time period, and provides the operator time to correct the situation. Because at least one PORV remains OPERABLE, the operator is permitted a Completion Time of 72 hours to restore the inoperable block valve to OPERABLE status. RICT BASES INSERT 2 The time allowed to restore the block valve is based upon the Completion Time for restoring an inoperable PORV in Condition B, since the PORVs may not be capable of mitigating an event if the inoperable block valve is not fully open. If the block valve is restored within the Completion Time of 72 hours, the power will be restored and the PORV restored to OPERABLE status. If it cannot be restored within this additional time, the plant must be brought to a MODE in

(continued)

APPLICABILITY (continued)

requirements in the lower MODES. The centrifugal charging pump performance is based on a small break LOCA, which establishes the pump performance curve and has less dependence on power. The SI pump performance requirements are based on a small break LOCA. MODE 2 and MODE 3 requirements are bounded by the MODE 1 analysis.

This LCO is only applicable in MODE 3 and above. Below MODE 3, the SI signal setpoint is manually bypassed by operator control, and system functional requirements are relaxed as described in LCO 3.5.3, "ECCS - Shutdown."

In MODES 5 and 6, plant conditions are such that the probability of an event requiring ECCS injection is extremely low. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level," and LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level."

ACTIONS

A.1

With one centrifugal charging pump (CCP) inoperable, the inoperable CCP must be returned to OPERABLE status within 7 days. The 7 day allowed outage time is based on a risk-informed assessment to manage the risk associated with the equipment in accordance with the Configuration Risk Management Program and is a reasonable time for the repair of a CCP.

RICT BASES INSERT 1

B.1

With one or more trains inoperable, for reasons other than one inoperable centrifugal charging pump, and at least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train available, the inoperable components must be returned to OPERABLE status within 72 hours. The 72 hour Completion Time is based on an NRC reliability evaluation (Ref. 5) and is a reasonable time for repair of many ECCS components.

RICT BASES INSERT 1

100% of the ECCS flow equivalent to a single OPERABLE ECCS train is considered available if the following conditions are met: 1) There must be one fully OPERABLE centrifugal charging pump, one fully OPERABLE safety injection pump and one fully OPERABLE RHR pump with associated heat exchanger at a minimum. 2) The flow paths associated with each pump and heat exchanger for which credit is being taken must be OPERABLE in

(continued)

ACTIONS

B.1, B.2, and B.3 (continued)

Required Action B.3 is modified by a Note that applies to air lock doors located in high radiation areas and allows these doors to be verified locked closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

C.1, C.2, and C.3

With one or more air locks inoperable for reasons other than those described in Condition A or B, Required Action C.1 requires action to be initiated immediately to evaluate previous combined leakage rates using current air lock test results. An evaluation is acceptable, since it is overly conservative to immediately declare the containment inoperable if both doors in an air lock have failed a seal test or if the overall air lock leakage is not within limits. In many instances (e.g., only one seal per door has failed), containment remains OPERABLE, yet only 1 hour (per LCO 3.6.1) would be provided to restore the air lock door to OPERABLE status prior to requiring a plant shutdown. In addition, even with both doors failing the seal test, the overall containment leakage rate can still be within limits.

Required Action C.2 requires that one door in the affected containment air lock must be verified to be closed within the 1 hour Completion Time. This specified time period is consistent with the ACTIONS of LCO 3.6.1, which requires that containment be restored to OPERABLE status within 1 hour.

Additionally, the affected air lock(s) must be restored to OPERABLE status within the 24 hour Completion Time. The specified time period is considered reasonable for restoring an inoperable air lock to OPERABLE status, assuming that at least one door is maintained closed in each affected air lock.

RICT BASES INSERT 1

D.1 and D.2

If the inoperable containment air lock cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

ACTIONS (continued)

In the event the containment isolation valve leakage results in exceeding the overall containment leakage rate acceptance criteria, Note 4 directs entry into the applicable Conditions and Required Actions of LCO 3.6.1.

A.1 and A.2

In the event one containent isolation valve in one or more penetration flow paths is inoperable except for Containment Purge, Hydrogen Purge and Containment Pressure Relief isolation valve leakage not within limit, the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve (this includes power operated valves with power removed), a blind flange, and a check valve with flow through the valve secured. For a penetration flow path isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available one to containment. Required Action A.1 must be completed within 4 hours. The 4 hour Completion Time is reasonable, considering the time required to isolate the penetration and the relative importance of supporting containment OPERABILITY during MODES 1, 2, 3, and 4.

RICT BASES INSERT 1

For affected penetration flow paths that cannot be restored to OPERABLE status within the 4 hour Completion Time and that have been isolated in accordance with Required Action A.1, the affected penetration flow paths must be verified to be isolated on a periodic basis. This is necessary to ensure that containment penetrations required to be isolated following an accident and no longer capable of being automatically isolated will be in the isolation position should an event occur. This Required Action does not require any testing or device manipulation. Rather, it involves verification through a system walkdown (which may include the use of local or remote indicators), that those isolation devices outside containment and capable of being mispositioned are in the correct position. The Completion Time of "once per 31 ~~days~~ days following isolation for isolation devices outside containment" is appropriate considering the fact that the devices are operated under administrative controls and the probability of their misalignment is low. For the isolation devices inside containment, the time period specified as "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the isolation devices and other administrative controls that will ensure that isolation device misalignment is an unlikely possibility.

(continued)

ACTIONS (continued)

C.1 and C.2

RICT BASES INSERT 1

following isolation

With one or more penetration flow paths with one containment isolation valve inoperable, the inoperable valve flow path must be restored to OPERABLE status or the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve (this includes power operated valves with power removed), and a blind flange. A check valve may not be used to isolate the affected penetration flow path. Required Action C.1 must be completed within the 72 hour Completion Time. The specified time period is reasonable considering the relative stability of the closed system (hence, reliability) to act as a penetration isolation boundary and the relative importance of maintaining containment integrity during MODES 1, 2, 3, and 4. In the event the affected penetration flow path is isolated in accordance with Required Action C.1, the affected penetration flow path must be verified to be isolated on a periodic basis. This periodic verification is necessary to assure leak tightness of containment and that containment penetrations requiring isolation following an accident are isolated. The Completion Time of once per 31 days for verifying that each affected penetration flow path is isolated is appropriate because the valves are operated under administrative controls and the probability of their misalignment is low. Condition C is modified by a Note indicating that this Condition is only applicable to those penetration flow paths with only one containment isolation valve and a closed system. The closed system inside containment for GDC-57 penetrations meet the requirements of Reference 3. The closed systems outside containment for GDC-55 and GDC-56 penetrations are in accordance with Reference 2. This Note is necessary since this Condition is written to specifically address those penetration flow paths in a closed system.

There are three types of penetrations to which Condition C applies:

1. All GDC-57 penetrations Main Steam (e.g., MSIVs, MSIV bypasses, SG Blowdowns, N2 supplies, MS Drains, SG Sample Lines) Feedwater (e.g., Feedwater supplies to SGs, AFW supplies to SGs, N2 supplies, Feedwater Bypass Lines, Unit 2 Feedwater Preheater Bypass Lines), CCW Supply and Return From Excess Letdown & R.C. Drain Tank Heat Exchanger, Unit 1 PAL, Airlock Hydraulic System). DBD-ME-013 Attachment 1 lists each such valve with the GDC-57 criterion and gives the valve arrangement sketch and the Flow Diagram reference (e.g., MS and FW items 1 thru 30, 73, 76, 79 and 82; CCW items 111 and 112).

(continued)

BASES

LCO (continued)

OPERABLE flow path capable of taking suction from the RWST upon an ESF actuation signal. Upon indication of the RWST level required for switchover, the suction flowpath must be capable of being manually transferred to the containment sump.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment and an increase in containment pressure and temperature requiring the operation of the containment spray trains.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Thus, the Containment Spray System is not required to be OPERABLE in MODES 5 and 6.

ACTIONS

A.1

With one containment spray train inoperable, the inoperable containment spray train must be restored to OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE spray train is adequate to perform the iodine removal and containment cooling functions. The 72 hour Completion Time takes into account the redundant heat removal capability afforded by the Containment Spray System, reasonable time for repairs, and low probability of a DBA occurring during this period.

RICT BASES INSERT 1

B.1 and B.2

If the inoperable containment spray train cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 84 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems. The extended interval to reach MODE 5 allows additional time for attempting restoration of the containment spray train and is reasonable when considering the driving force for a release of radioactive material from the Reactor Coolant System is reduced in MODE 3.

C.1

With two containment spray trains inoperable, the unit is in a condition outside the accident analysis. Therefore, LCO 3.0.3 must be entered immediately.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

e. The MSIVs are also utilized during other events such as a feedwater line break and LOCA (for containment isolation). These events are less limiting so far as MSIV OPERABILITY is concerned.

The MSIVs satisfy Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

This LCO requires that four MSIVs in the steam lines be OPERABLE. The MSIVs are considered OPERABLE when the isolation times are within limits, and they close on an isolation actuation signal.

This LCO provides assurance that the MSIVs will perform their design safety function to mitigate the consequences of accidents that could result in offsite exposures comparable to the 10 CFR 100 (Ref. 4) limits and the NRC staff approved licensing basis.

APPLICABILITY

The MSIVs must be OPERABLE in MODE 1, and in MODES 2 and 3, except when closed and de-activated, when there is significant mass and energy in the RCS and steam generators. When the MSIVs are closed, they are already performing the safety function.

In MODE 4, normally most of the MSIVs are closed, however, because the steam generator energy is low, an inadvertent steam release in this plant condition does not require the MSIVs to be closed to ensure the effects are within the analyzed envelopes.

In MODE 5 or 6, the steam generators do not contain much energy because their temperature is below the boiling point of water; therefore, the MSIVs are not required for isolation of potential high energy secondary system pipe breaks in these MODES.

ACTIONS

A.1

RICT INSERT 1

With one MSIV inoperable in MODE 1, action must be taken to restore OPERABLE status within 8 hours. Some repairs to the MSIV can be made with the unit hot. The 8 hour Completion Time is reasonable, considering the low probability of an accident occurring during this time period that would require a closure of the MSIVs.

The 8 hour Completion Time is greater than that normally allowed for

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, the ARVs are required to be OPERABLE.

In MODE 4, 5 or 6, an SGTR is not a credible event.

ACTIONS

A.1

RICT BASES INSERT 1

With one required ARV line inoperable, action must be taken to restore OPERABLE status within 7 days. The 7 day Completion Time allows for the redundant capability afforded by the remaining OPERABLE ARV lines, a nonsafety grade backup in the Steam Dump System, and MSSVs.

B.1

With two ARV lines inoperable, action must be taken to restore at least one ARV line to OPERABLE status. This will result in at least three OPERABLE ARVs. Since the block valve can be closed to isolate an ARV, some repairs may be possible with the unit at power. The 72 hour Completion Time is reasonable to repair inoperable ARV lines, based on the availability of the Steam Dump System and MSSVs, and the low probability of an event occurring during this period that would require the ARV lines.

RICT BASES INSERT 2

C.1

With three or more ARV lines inoperable, action must be taken to restore at least two ARV line to OPERABLE status. This will result in at least two OPERABLE ARVs. Since the block valve can be closed to isolate an ARV, some repairs may be possible with the unit at power. The 24 hour Completion Time is reasonable to repair inoperable ARV lines, based on the availability of the Steam Dump System and MSSVs, and the low probability of an event occurring during this period that would require the ARV lines.

RICT BASES INSERT 2

A note has been added to the Completion Time to clarify that RICT entry is not permitted if there is a loss of function. A loss of function occurs when all four ARVs are inoperable.

(continued)

BASES (continued)

ACTIONS

D.1 and D.2

If the ARV lines cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4, within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1

To perform a controlled cooldown of the RCS, the ARVs must be able to be opened remotely and throttled through their full range. This SR ensures that the ARVs are tested through a full control cycle at least once per fuel cycle. Performance of inservice testing or use of an ARV during a unit cooldown may satisfy this requirement. Operating experience has shown that these components usually pass the Surveillance when performed at the Inservice Testing Program Frequency. The Frequency is acceptable from a reliability standpoint.

SR 3.7.4.2

The function of the block valve is to isolate a failed open ARV. Cycling the block valve both closed and open demonstrates its capability to perform this function. Performance of inservice testing or use of the block valve during unit cooldown may satisfy this requirement at least once per fuel cycle. Operating experience has shown that these components usually pass the Surveillance when performed at the Inservice Testing Program Frequency. The Frequency is acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Sections 3.9B, 5A, 9.3 and 10.3.
2. FSAR, Chapter 15.

BASES

LCO (continued)

requires that the two motor driven AFW pumps be OPERABLE in two diverse paths, each supplying AFW to separate steam generators. The turbine driven AFW pump is required to be OPERABLE with redundant steam supplies from each of two main steam lines upstream of the MSIVs, and shall be capable of supplying AFW to any of the steam generators. The piping, valves, instrumentation, and controls in the required flow paths also are required to be OPERABLE.

APPLICABILITY

In MODES 1, 2, and 3, the AFW System is required to be OPERABLE in the event that it is called upon to function when the FW is lost. In addition, the AFW System is required to supply enough makeup water to replace the steam generator secondary inventory lost as the unit cools to MODE 4 conditions.

In MODE 4, the AFW System may be used for heat removal via the steam generators. See the BASES for 3.4.7.

In MODE 5 or 6, the steam generators are not normally used for heat removal, and the AFW System is not required.

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable AFW train. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an AFW train inoperable and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

RICT BASES INSERT 1

If one of the two steam supplies to the turbine driven AFW train is inoperable, action must be taken to restore OPERABLE status within 7 days. The 7 day Completion Time is reasonable, based on the following reasons:

a. The redundant OPERABLE steam supply to the turbine driven AFW pump;

b. The availability of redundant OPERABLE motor driven AFW pumps; and

c. The low probability of an event occurring that requires the inoperable steam supply to the turbine driven AFW pump.

(continued)

BASES

ACTIONS (continued)

B.1

RICT BASES INSERT 1

With one of the required AFW trains (pump or flow path) inoperable in MODE 1, 2, or 3 for reasons other than Condition A, action must be taken to restore OPERABLE status within 72 hours. This Condition includes the loss of two steam supply lines to the turbine driven AFW pump. The 72 hour Completion Time is reasonable, based on redundant capabilities afforded by the AFW System, time needed for repairs, and the low probability of a DBA occurring during this time period.

C.1 and C.2

When Required Action A.1 or B.1 cannot be completed within the required Completion Time, or if two AFW trains are inoperable in MODE 1, 2, or 3, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 18 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

In MODE 4, either the reactor coolant pumps or the RHR loops can be used to provide forced circulation. This is addressed in LCO 3.4.6, "RCS Loops - MODE 4." Although not required, the unit may continue to cool down and initiate RHR.

D.1

If all three AFW trains are inoperable in MODE 1, 2, or 3, the unit is in a seriously degraded condition with no safety related means for conducting a cooldown, and only limited means for conducting a cooldown with nonsafety related equipment. In such a condition, the unit should not be perturbed by any action, including a power change, that might result in a trip. The seriousness of this condition requires that action be started immediately to restore one AFW train to OPERABLE status.

Required Action D.1 is modified by a Note indicating that all required MODE changes or power reductions are suspended until one AFW train is restored to OPERABLE status. In this case, LCO 3.0.3 is not applicable because it could force the unit into a less safe condition.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, 3, and 4, the CCW System is a normally operating system, which must be prepared to perform its post accident safety functions, primarily RCS heat removal, which is achieved by cooling the RHR heat exchanger.

In MODE 5 or 6, the OPERABILITY requirements of the CCW System are determined by the systems it supports.

ACTIONS

A.1

Required Action A.1 is modified by a Note indicating that the applicable Conditions and Required Actions of LCO 3.4.6, "RCS Loops - MODE 4," be entered if an inoperable CCW train results in an inoperable RHR loop. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components.

RICT BASES INSERT 1

If one CCW train is inoperable, action must be taken to restore OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE CCW train is adequate to perform the heat removal function. The 72 hour Completion Time is reasonable, based on the redundant capabilities afforded by the OPERABLE train, and the low probability of a DBA occurring during this period.

B.1 and B.2

If the CCW train cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.7.1

This SR is modified by a Note indicating that the isolation of the CCW flow to individual components may render those components inoperable but does not affect the OPERABILITY of the CCW System.

Verifying the correct alignment for manual, power operated, and automatic valves in the CCW flow path provides assurance that the proper flow paths exist for CCW operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves are verified to be

(continued)

BASES

LCO (continued)

b. The associated piping, valves, and instrumentation and controls required to perform the safety related function are OPERABLE.

A SSW Pump on the opposite unit is OPERABLE as back-up in the event of a LOSSW if it is capable of providing required flow rates. An emergency diesel generator power source is not required because loss of offsite power is not assumed coincident with a LOSSW event.

A cross-connect valve is OPERABLE if it can be cycled or is locked open. A valve that cannot be demonstrated OPERABLE by cycling is considered inoperable until the valve is surveilled in the locked open position. However, at least one cross-connect valve between units is required to be maintained closed in accordance with GDC-5 unless required for flushing or due to total loss of Station Service Water pumps for either unit.

APPLICABILITY

In MODES 1, 2, 3, and 4, the SSWS is a normally operating system that is required to support the OPERABILITY of the equipment serviced by the SSWS and required to be OPERABLE in these MODES.

In MODES 5 and 6, the OPERABILITY requirements of the SSWS are determined by the systems it supports.

ACTIONS

A.1 and A.2

If no SSW pump on the opposite unit or its associated cross-connects are operable, the overall reliability is degraded since a back-up in the event of a Loss of Station Service Water System (LOSSWS) event may not be capable of performing the function. The 7 day completion time is based on the low probability of a LOSSWS during this time period. RICT BASES INSERT 2

B.1 ~~and B.2~~

Required Action~~s~~ B.1 ~~and B.2 are~~ is modified by two Notes. The first Note indicates that the applicable Conditions and Required Actions of LCO 3.8.1, "AC Sources - Operating," should be entered if an inoperable SSWS train results in an inoperable emergency diesel generator. The second Note indicates that the applicable Conditions and Required Actions of LCO 3.4.6, "RCS Loops - MODE 4," should be entered if an inoperable SSWS train results in an inoperable decay heat removal train. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components.

(continued)

BASES

ACTIONS (continued)

B.1 (continued)

RICT BASES INSERT 1

If one SSWS train is inoperable, action must be taken to restore OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE SSWS train is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE SSWS train could result in loss of SSWS function. The 72 hour Completion Time is based on the redundant capabilities afforded by the OPERABLE train, and the low probability of a DBA occurring during this time period.

~~B.2~~

~~The COMPLETION TIME for restoring the inoperable SSWS train to OPERABLE status can be extended to 8 days, on a one time basis for SSWS 2-02 (Train B) pump replacement during Unit 2 Cycle 19. This one time change regains reliability margin for Unit 2, Train B SSWS. The 8 day completion time for action B.2 is based on a deterministic evaluation supplemented with risk insights.~~

C.1 and C.2

If the SSWS train or an SSW Pump on the opposite unit and its associated cross-connects cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.8.1

This SR is modified by a Note indicating that the isolation of the SSWS components or systems may render those components inoperable, but does not affect the OPERABILITY of the SSWS.

Verifying the correct alignment for manual, power operated, and automatic valves in the SSWS flow path provides assurance that the proper flow paths exist for SSWS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since they are verified to be in the correct position prior to being locked, sealed, or secured. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The Safety Chilled Water System is designed to perform its function in response to an SI signal with a single failure of any active component, assuming the loss of offsite power. One train of the Safety Chilled Water System provides 100% of the required cooling for the associated train of EFCUs.

The Safety Chilled Water System satisfies criterion 4 of 10CFR50.36(c)(2)(ii).

LCO

Two Safety Chilled Water System trains are required OPERABLE to provide the required redundancy to ensure that the system functions to remove heat from the EFCUs during and after an accident assuming the worst case single failure occurs coincident with the loss of offsite power.

A Safety Chilled Water System train is considered OPERABLE when the associated chiller, chilled water pump, surge tank, piping, valves, and instrumentation required to perform the safety-related function are OPERABLE.

The isolation of Safety Chilled Water from the EFCUs may render those units inoperable but does not affect the OPERABILITY of the Safety Chilled Water System.

APPLICABILITY

In MODES 1, 2, 3, and 4 the Safety Chilled Water System is a normally operating system, which must be prepared to provide a safety-related cooling function consistent with the OPERABILITY requirements of the essential equipment it supports.

In MODE 5 or 6, the OPERABILITY requirements of the Safety Chilled Water System are determined by the systems it supports.

ACTIONS

A. 1

RICT BASES INSERT 1

If one Safety Chilled Water System train is inoperable, action must be taken to restore the train to OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE Safety Chilled Water System train is adequate to perform the heat removal function for its associated essential equipment.

However, the overall reliability is reduced because a single failure in the

(continued)

ACTIONS

A. 1 (continued)

OPERABLE Safety Chilled Water System train could result in loss of the Safety Chilled Water System function. The 72 hour Completion Time is based on the redundant capabilities afforded by the OPERABLE train, and the low probability of a DBA occurring during this time.

~~A. 2~~

~~The Completion Time for restoring the inoperable safety chilled water train to OPERABLE status can be extended to 7 days, on a one time basis for Safety Chiller 2-06 (Train B) compressor replacement during Unit 2 Cycle 19. This one time change regains reliability margin for Unit 2, Train B safety chilled water. The 7 day Completion Time for action A.2 is based on a deterministic evaluation supplemented with risk insights.~~

B.1 and B.2

If the Safety Chilled Water System train cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.19.1

This SR is modified by a Note indicating that the isolation of safety chilled water flow to individual components may render these components inoperable but does not affect the OPERABILITY of safety chilled water system.

Verifying the correct alignment for manual valves servicing safety-related equipment provides assurance that the proper flow paths exist for Safety Chilled Water System operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since they are verified to be in the correct position prior to being locked, sealed, or secured. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

ACTIONS

A2 (continued)

Twenty-four hours is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

The remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to Train A and Train B of the onsite Class 1E Distribution System. The 24 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 24 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

A.3

RICT BASES INSERT 2

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition A for a period that should not exceed 72 hours. With one offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the unit safety systems. In this Condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System.

The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

~~An OR statement for a temporary Completion Time is added to the Completion Time above (72 hours). The one time, 14 day Completion Time is applicable to XST1 only and expires on March 31, 2017. The 14 day Completion Time applies as part of the plant modification to facilitate connection of either XST1 or XST1A startup transformers to the 1E buses. If during the conduct of the prescribed maintenance outage, should any combination of the remaining OPERABLE AC Sources be determined inoperable, current TS requirements would apply.~~

B.1

To ensure a highly reliable power source remains with an inoperable DG, it is necessary to verify the availability of the offsite circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions and Required Actions must then be entered.

(continued)

ACTIONS (continued) B.3.1 and B.3.2

Required Actions B 3.1 and B 3.2 are only applicable to the affected Unit. Any actions that may apply to an unaffected Unit, or the DGs for the unaffected Unit, would be determined by the Corrective Action Program and the 24 hour COMPLETION TIME for TS 3.8.1, Required Actions B 3.1 and B 3.2 does not apply with respect to the unaffected Unit or its DGs.

Required Action B.3.1 provides an allowance to avoid unnecessary testing of the OPERABLE DG. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG, SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on the other DG, the other DG would be declared inoperable upon discovery and Condition E of LCO 3.8.1 would be entered. Once the failure is repaired, the common cause failure no longer exists, and Required Action B.3.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG, performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of that DG.

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, the applicable plant procedures will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

According to Generic Letter 84-15 (Ref. 7), 24 hours is reasonable to confirm that the OPERABLE DG is not affected by the same problem as the inoperable DG.

During performance of surveillance activities as a requirement for ACTION statements, the air-roll test shall not be performed.

B.4.1

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition B for a period that should not exceed 72 hours.

In Condition B, the remaining OPERABLE DG and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

(continued)

RICT BASES INSERT 2

ACTIONS (continued) B.4.2

The COMPLETION TIME for restoring the inoperable SSWS train to OPERABLE status can be extended to 8 days, on a one time basis for SSWS 2-02 (Train B) pump replacement during Unit 2 Cycle19. This one-time change regains reliability margin for Unit 2, Train B SSWS. The 8 day completion time is based on a deterministic evaluation supplemented with risk insights.

C.1 and C.2

Required Action C.1, which applies when two offsite circuits are inoperable, is intended to provide assurance that an event with a coincident single failure will not result in a complete loss of redundant required safety functions. The Completion Time for this failure of redundant required features is reduced to 12 hours from that allowed for one train without offsite power (Required Action A.2). The rationale for the reduction to 12 hours is that Regulatory Guide 1.93 (Ref. 6) allows a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that two complete safety trains are OPERABLE. When a concurrent redundant required feature failure exists, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate. These features are powered from redundant AC safety trains. This includes the motor driven auxiliary feedwater pumps and the TDAFW pump which must be available for mitigation of a Feedwater line break. Single train systems, other than the turbine driven auxiliary feedwater pump, are not included.

The Completion Time for Required Action C.1 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action the Completion Time only begins on discovery that both:

a. All required offsite circuits are inoperable; and

b. A required feature is inoperable.

If at any time during the existence of Condition C (two offsite circuits inoperable) a required feature becomes inoperable, this Completion Time begins to be tracked.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

RICT BASES INSERT 2

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition C for a period that should not exceed 24 hours. This level of degradation means that the offsite electrical power system does not have the capability to effect a safe shutdown and to mitigate the effects of an accident; however, the onsite AC sources have not been degraded. This level of degradation generally corresponds to a total loss of the immediately accessible offsite power sources.

Because of the normally high availability of the offsite sources, this level of degradation may appear to be more severe than other combinations of two AC sources inoperable that involve one or more DGs inoperable.

However, two factors tend to decrease the severity of this level of degradation:

a. The configuration of the redundant AC electrical power system that remains available is not susceptible to a single bus or switching failure; and

b. The time required to detect and restore an unavailable offsite power source is generally much less than that required to detect and restore an unavailable onsite AC source.

With both of the required offsite circuits inoperable, sufficient onsite AC sources are available to maintain the unit in a safe shutdown condition in the event of a DBA or transient. In fact, a simultaneous loss of offsite AC sources, a LOCA, and a worst case single failure were postulated as a part of the design basis in the safety analysis. Thus, the 24 hour Completion Time provides a period of time to effect restoration of one of the offsite circuits commensurate with the importance of maintaining an AC electrical power system capable of meeting its design criteria.

According to Reference 6, with the available offsite AC sources, two less than required by the LCO, operation may continue for 24 hours. If two offsite sources are restored within 24 hours, unrestricted operation may continue. If only one offsite source is restored within 24 hours, power operation continues in accordance with Condition A.

(continued)

ACTIONS (continued) D.1 and D.2

Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it were inoperable. Therefore, the Required Actions of Condition D are modified by a Note to indicate that when Condition D is entered with no AC source to any train, (for CPSES this requires both offsite sources and DG inoperable) the Conditions and Required Actions for LCO 3.8.9, "Distribution Systems - Operating," must be immediately entered. This allows Condition D to provide requirements for the loss of one offsite circuit and one DG, without regard to whether a train is inoperable. LCO 3.8.9 provides the appropriate restrictions for a inoperable train.

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition D for a period that should not exceed 12 hours.

RICT BASES INSERT 2

In Condition D, individual redundancy is lost in both the offsite electrical power system and the onsite AC electrical power system. Since power system redundancy is provided by two diverse sources of power, however, the reliability of the power systems in this Condition may appear higher than that in Condition C (loss of both required offsite circuits). This difference in reliability is offset by the susceptibility of this power system configuration to a single bus or switching failure. The 12 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

RICT BASES INSERT 2

E.1

With Train A and Train B DGs inoperable, there are no remaining standby AC sources. Thus, with an assumed loss of offsite electrical power, insufficient standby AC sources are available to power the minimum required ESF functions. Since the offsite electrical power system is the only source of AC power for this level of degradation, the risk associated with continued operation for a very short time could be less than that associated with an immediate controlled shutdown (the immediate shutdown could cause grid instability, which could result in a total loss of AC power). Since any inadvertent generator trip could also result in a total loss of offsite AC power, however, the time allowed for continued operation is severely restricted. The intent here is to avoid the risk associated with an immediate controlled shutdown and to minimize the risk associated with this level of degradation.

According to Reference 6, with both DGs inoperable, operation may continue for a period that should not exceed 2 hours.

(continued)

ACTIONS (continued)

F.1

The SI sequencer(s) is an essential support system to both the offsite circuit and the DG associated with a given ESF bus. Furthermore, the sequencer is on the primary success path for most major AC electrically powered safety systems powered from the associated ESF bus. Therefore, loss of an ESF bus sequencer affects every major ESF system in the train. The 24 hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining sequencer OPERABILITY. This time period also ensures that the probability of an accident (requiring sequencer OPERABILITY) occurring during periods when the sequencer is inoperable is minimal.

RICT BASES INSERT 2

This Required Action is modified by a note. The note allows one sequencer channel to be bypassed for surveillance testing provided the other channel is operable. The 4 hours allows sufficient time to perform the required testing. Based on the low probability of an event requiring the sequencer in combination with a failure to the operable sequencer channel during the 4 hours, this period of inoperability for testing is acceptable.

G.1 and G.2

If the inoperable AC electric power sources cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

H.1

Condition H corresponds to a level of degradation in which all redundancy in the AC electrical power supplies has been lost. At this severely degraded level, any further losses in the AC electrical power system will cause a loss of function. Therefore, no additional time is justified for continued operation. The unit is required by LCO 3.0.3 to commence a controlled shutdown.

I.1

A Blackout sequencer is an essential support system to the DG associated with a given ESF bus. The sequencer is required to provide the system response to a loss of or degraded ESF bus voltage signal. Therefore, the loss of the Blackout sequencer causes the associated DG to become inoperable immediately.

(continued)

ACTIONS

A.1, A.2, and A.3 (continued)

return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge characteristic of the battery. Thus there is good assurance of fully recharging the battery within 12 hours, avoiding a premature shutdown with its own attendant risk.

If established battery terminal float voltage cannot be restored to greater than or equal to the minimum established float voltage within 2 hours, and the charger is not operating in the current-limiting mode, a faulty charger is indicated. A faulty charger that is incapable of maintaining established battery terminal float voltage does not provide assurance that it can revert to and operate properly in the current limit mode that is necessary during the recovery period following a battery discharge event that the DC system is designed for.

If the charger is operating in the current limit mode after 2 hours that is an indication that the battery is partially discharged and its capacity margins will be reduced. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated DC system, the amount of the previous discharge, and the recharge characteristic of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within 12 hours (Required Action A.2).

Required Action A.2 requires that the affected battery float current be verified as less than or equal to 2 amps. This indicates that, if the battery had been discharged as the result of the inoperable battery charger, it has now been fully recharged. If at the expiration of the initial 12 hour period the battery float current is not less than or equal to 2 amps, then Condition D is entered as a result of the Required Action and Completion Time not met. At the same time, this indicates there may be additional battery problems. Without adequate assurance that the battery can be recharged within 12 hours, the affected battery must also be declared inoperable and LCO 3.8.4 Condition B entered for the inoperable battery, which is consistent with battery parameter requirements and actions of LCO 3.8.6 (Condition B and F).

Required Action A.3 limits the restoration time for the inoperable required battery charger to 7 days. This action is applicable if an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage has been used (e.g., balance of plant non-Class 1E battery charger). The 7 day completion time reflects a reasonable time to effect restoration of the qualified battery charger to operable status.

RICT BASES INSERT 2

(continued)

ACTIONS (continued)

B.1

Condition B represents one train with one or two batteries inoperable. With one or two batteries inoperable, the affected DC bus(es) are being supplied by their associated OPERABLE battery charger(s). Any event that results in a loss of the AC bus supporting the battery charger(s) will also result in loss of or degraded DC to that train. Recovery of the AC bus, especially if it is due to a loss of offsite power, will be hampered by the fact that many of the components necessary for the recovery (e.g., diesel generator control and field flash, AC load shed and diesel generator output circuit breakers, etc.) likely rely upon DC power being supplied from the batteries. In addition, the energization transients of any DC loads that are beyond the capability of the associated battery charger(s) and normally require the assistance of the batteries will not be able to be brought online. The 2 hour limit allows sufficient time to effect restoration of an inoperable battery given that the majority of the conditions that lead to battery inoperability (e.g., loss of battery charger, battery cell voltage less than 2.07 V, etc.) are identified in Specifications 3.8.4, 3.8.5, and 3.8.6 together with additional specific completion times.

RICT BASES INSERT 2

B.2

The completion time for restoring the inoperable battery to OPERABLE status can be extended to 18 hours, on a one-time basis for batteries BT1ED2 and BT1ED4 during Unit 1 Cycle 20. This one-time change regains margin by allowing replacement of cell number 27 in battery BT1ED2 and cell number 41 in battery BT1ED4 (not at the same time). The 18 hour completion time for action B.2 is based on a deterministic evaluation supplemented by risk insights.

C.1

Condition C represents one train with a loss of ability to respond to an event, and a loss of ability to remain energized during normal operation. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for complete loss of DC power to the affected train. The 2 hour limit is consistent with the allowed time for an inoperable DC distribution system train.

RICT BASES INSERT 2

If one of the required DC electrical power subsystems is inoperable, the other DC electrical power subsystem has the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent worst case single failure could, however, result in the loss of the minimum necessary DC electrical subsystems to mitigate a worst case accident,

(continued)

BASES (continued)

ACTIONS

A.1

With a required inverter inoperable, its associated AC vital bus becomes inoperable until it is re-energized by an operable inverter or the alternate bypass power supply from the Class 1E transformers.

For this reason a Note has been included in Condition A requiring the entry into the Conditions and Required Actions of LCO 3.8.9, "Distribution Systems - Operating." This ensures that the vital bus is re-energized within 2 hours.

Required Action A.1 allows 24 hours to fix the inoperable inverter and return it to service. The 24 hour limit is based upon engineering judgment, taking into consideration the time required to repair an inverter and the additional risk to which the unit is exposed because of the inverter inoperability. This has to be balanced against the risk of an immediate shutdown, along with the potential challenges to safety systems such a shutdown might entail. When the AC vital bus is powered from its Class 1E transformer, it is relying upon non-regulating interruptible AC electrical power sources (offsite and onsite). Because of the potential impact of interrupted power on the Emergency Diesel Generator and the Solid State Safeguards Blackout Sequencer during a postulated Loss of Offsite Power event, these components are considered inoperable when operating on inverter bypass power, and evaluated under the SFDP of Specification 5.5.15. The uninterruptible inverter source to the AC vital buses is the preferred source for powering instrumentation trip setpoint devices.

RICT BASES INSERT 2

B.1 and B.2

If the inoperable devices or components cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and AC vital buses energized from the inverter. The verification of proper voltage output ensures that the required power is available for the instrumentation of the RPS and ESFAS connected to the AC vital buses. The Surveillance Frequency is controlled under the

(continued)

APPLICABILITY (continued)

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and Adequate core cooling is provided, and containment

b. OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

Electrical power distribution subsystem requirements for MODES 5 and 6 are covered in the Bases for LCO 3.8.10, "Distribution Systems - Shutdown."

ACTIONS

A.1

With one or more required AC buses or load centers except AC vital buses, in one train inoperable the remaining AC electrical power distribution subsystem in the other train is capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining power distribution subsystem could result in the minimum required ESF functions not being supported. Therefore, the required AC buses, and load centers, must be restored to OPERABLE status within 8 hours. RICT BASES INSERT 1

Condition A worst scenario is one train without AC power (i.e., no offsite power to the train and the associated DG inoperable). In this Condition, the unit is more vulnerable to a complete loss of AC power. It is, therefore, imperative that the unit operator's attention be focused on minimizing the potential for loss of power to the remaining train by stabilizing the unit, and on restoring power to the affected train. The 8 hour time limit before requiring a unit shutdown in this Condition is acceptable because of:

a. The potential for decreased safety if the unit operator's attention is diverted from the evaluations and actions necessary to restore power to the affected train, to the actions associated with taking the unit to shutdown within this time limit; and

b. The potential for an event in conjunction with a single failure of a redundant component in the train with AC power.

(continued)

ACTIONS (continued)

B.1

With one AC vital bus inoperable the remaining OPERABLE AC vital buses are capable of supporting the minimum safety functions necessary to shut down the unit and maintain it in the safe shutdown condition. Overall reliability is reduced, however, since an additional single failure could result in the minimum required ESF functions not being supported. Therefore, the required AC vital bus must be restored to OPERABLE status within 2 hours by powering the bus from the associated inverter via inverted DC, or alternate bypass power via Class 1E ~~transformers.~~ transformers

RICT BASES INSERT 2

Condition B represents one AC vital bus without non-interruptible inverted DC power. In this situation, the unit is significantly more vulnerable to a complete loss of all non-interruptible power. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for loss of non-interruptible power to the remaining vital buses and restoring power to the affected vital bus subsystems.

This 2 hour limit is more conservative than Completion Times allowed for the vast majority of components that are without adequate vital AC power. Taking exception to LCO 3.0.2 for components without adequate vital AC power, that would have the Required Action Completion Times shorter than 2 hours if declared inoperable, is acceptable because of:

a. The potential for decreased safety by requiring a change in unit conditions (i.e., requiring a shutdown) and not allowing stable operations to continue;

b. The potential for decreased safety by requiring entry into numerous Applicable Conditions and Required Actions for components without adequate vital AC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected train; and

c. The potential for an event in conjunction with a single failure of a redundant component.

The 2 hour Completion Time takes into account the importance to safety of restoring the AC vital bus to OPERABLE status, the redundant capability afforded by the other OPERABLE vital buses, and the low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS (continued)

C.1

With DC bus(es) in one train inoperable the remaining DC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining DC electrical power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required DC buses must be restored to OPERABLE status within 2 hours by powering the bus from the associated battery or charger.

RICT BASES INSERT 2

Condition C represents one or more electrical power distribution subsystems without adequate DC power; potentially both with the battery significantly degraded and the associated charger nonfunctioning for the affected bus(es). In this situation, the unit is significantly more vulnerable to a complete loss of all DC power. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for loss of power to the remaining bus(es) and restoring power to the affected bus(es).

This 2 hour limit is more conservative than Completion Times allowed for the vast majority of components that would be without power. Taking exception to LCO 3.0.2 for components without adequate DC power, which would have Required Action Completion Times shorter than 2 hours, is acceptable because of:

a. The potential for decreased safety by requiring a change in unit conditions (i.e., requiring a shutdown) while allowing stable operations to continue;

b. The potential for decreased safety by requiring entry into numerous applicable Conditions and Required Actions for components without DC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected train; and

c. The potential for an event in conjunction with a single failure of a redundant component.

The 2 hour Completion Time for DC buses is consistent with Regulatory Guide 1.93 (Ref. 3).

(continued)

CPNPP TS BASES INSERTS

RICT BASES INSERT 1

or in accordance with the Risk Informed Completion Time Program

RICT BASES INSERT 2

Alternatively, a completion Time can be determined in accordance with the Risk Informed Completion Time Program.

INSERT BASES 3.3.1 N.1

N.1

If the Required Action and associated Completion Time of Condition M is not met, 6 hours is allowed to reduce THERMAL POWER to below P-7.

INSERT BASES 3.3.1 Q.1

Q.1

If the Required Action and associated Completion Time of Condition O or P is not met, THERMAL POWER must be reduced below the P-9 setpoint within 4 hours. This places the unit in a MODE where the LCO is no longer applicable.

INSERT BASES 3.3.1 W.1

W.1

If the Required Action and associated Completion Time of Condition B, D, E, R, S, T, or V is not met, the unit must be placed in MODE 3 within 6 hours. The Completion Time of 6 hours is a reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems. With the unit in MODE 3, ACTION S would apply to any inoperable RTB, RTB trip mechanism, or to any inoperable Manual Reactor Trip Function if the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

INSERT BASES 3.3.1 X.1

X.1

If the Required Action and associated Completion Time of Condition U is not met, the unit must be placed in MODE 2 within 6 hours. The Completion Time of 6 hours is a reasonable time, based on operating experience to reach MODE 2 from full power in an orderly manner and without challenging unit systems.

INSERT BASES 3.3.2 M.1 and M.2

M.1 and M.2

If the Required Action and associated Completion Time of Condition B, C or K is not met, the unit must be placed in a MODE in which the LCO does not apply. This is accomplished by placing the unit in MODE 3 within 6 hours and MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. In MODE 4, these Functions are no longer required OPERABLE.

INSERT BASES 3.3.2 N.1 and N.2

N.1 and N.2

If the Required Action and associated Completion Time of Condition D, E, F, G or L is not met, the unit must be placed in MODE 3 within 6 hours and MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. In MODE 4, these Functions are no longer required OPERABLE.

INSERT BASES 3.3.2 O.1

O.1

If the Required Action and associated Completion Time of Condition H, I, or J is not met, the unit must be placed in MODE 3 within 6 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems. In MODE 3, these Functions are no longer required OPERABLE.

ATTACHMENT 4
License Amendment Request

Comanche Peak Nuclear Power Plant, Units 1 and 2
NRC Docket Nos. 50-445 and 50-446

Revise Technical Specifications to Adopt Risk-Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b"

Cross-Reference of TSTF-505 and CPNPP Technical Specifications

Tech Spec Description	CPNPP TS	TS-505 TS	Apply RICT?	Comments
Completion Times	**1.3**	**1.3**		
Example 1.3-8	[NEW TS] 1.3-8	[NEW TS] 1.3-8	No	The CPNPP TS do not currently contain this example. Example to be added to CPNPP TS to be consistent with TSTF-505. This is a new definition only (i.e., there is no RICT directly applicable to the TS.)
RTS Instrumentation	**3.3.1**	**3.3.1**		
One Manual Reactor Trip channel inoperable.	3.3.1.B.1	3.3.1.B.1	Yes	TSTF-505 changes are incorporated.
One channel or train inoperable.	3.3.1.C.1	3.3.1.C.1	No	RICT Program is not being applied to shutdown models. Therefore, no changes are proposed to this TS.
One Power Range Neutron Flux - High channel inoperable.	N/A	3.3.1.D.1	No	The CPNPP TS do not contain this TS. Therefore, no changes are proposed to the TS.
One Power Range Neutron Flux - High channel inoperable.	3.3.1.D.1.2	3.3.1.D.2.1	Yes	TSTF-505 changes are incorporated.
One Channel inoperable.	3.3.1.E.1	3.3.1.E.1	Yes	TSTF-505 changes are incorporated.
One Source Range Neutron Flux channel inoperable.	3.3.1.K.1	3.3.1.J.1	No	RICT Program is not being applied to shutdown models. Therefore, no changes are proposed to this TS.
Required Action and associated Completion Time of Condition C or J not met.	N/A	[New] 3.3.1.K.1	No	CPNPP is not proposing changes to the associated TS. Therefore, this TS will not be added.
Required Action and associated Completion Time of Condition C or J not met.	N/A	[New] 3.3.1.K.2	No	CPNPP is not proposing changes to the associated TS. Therefore, this TS will not be added.
One channel inoperable.	3.3.1.M.1	3.3.1.L.1	Yes	TSTF-505 changes are incorporated.
Required Action and associated Completion Time of Condition M not met.	[New TS 3.3.1 N]	[New TS] 3.3.1.M.1	No	The CPNPP TS do not currently contain this TS. This new TS condition will be added consistent with TSTF-505.
One Reactor Coolant Pump Breaker Position (Single Loop) channel inoperable.	N/A	3.3.1.N.1	No	The CPNPP TS do not contain this TS. Therefore, a change is not proposed to the TS.

Tech Spec Description	CPNPP TS	TS-505 TS	Apply RICT?	Comments
Required Action and associated Completion Time of Condition N not met.	N/A	[New] 3.3.1.O.1	No	The CPNPP TS do not contain the associated TS. Therefore, this TS will not be added.
Required Action and associated Completion Time of Condition P not met.	N/A	[New] 3.3.1.Q.1	No	The CPNPP TS do not contain this TS. Therefore, no changes are proposed to the TS.
One Low Fluid Oil Pressure Turbine Trip channel inoperable	3.3.1.O.1	3.3.1.R.1	Yes	TSTF-505 Changes are incorporated. The wording of TSTF-505 varies from CPNPP TS (i.e., TS specifies One Low Fluid Oil Pressure Turbine Trip channel inoperable.)
One or more Turbine Stop Valve Closure Turbine Trip channel(s) inoperable.	3.3.1.P.1	3.3.1.R.1	Yes	TSTF-505 Changes are incorporated. The wording of TSTF-505 varies from CPNPP TS (i.e., TS specifies One or more Turbine Stop Valve Closure Trip channel(s) inoperable.)
Required Action and associated Completion Time of Condition O or P not met.	[New TS 3.3.1 Q]	[New TS] 3.3.1.S.1	No	The CPNPP TS do not currently contain this TS. This new TS condition will be added consistent with TSTF-505.
One train inoperable.	3.3.1.R.1	3.3.1.T.1	Yes	TSTF-505 changes are incorporated.
One RTB train inoperable.	3.3.1.S.1	3.3.1.U.1	Yes	TSTF-505 changes are incorporated.
One trip mechanism inoperable for one RTB.	3.3.1.V.1	3.3.1.Y.1	Yes	TSTF-505 changes are incorporated.
Required Action and associated Completion Time of Condition B, D, E, R, S or V not met.	[New TS 3.3.1 W]	[New TS] 3.3.1.Z.1	No	The CPNPP TS do not currently contain this TS. This new TS condition will be added consistent with TSTF-505 Rev. 2
ESFAS Instrumentation	**3.3.2**	**3.3.2**		
One channel or train inoperable.	3.3.2.B.1	3.3.2.B.1	Yes	TSTF-505 changes are incorporated.
One train inoperable.	3.3.2.C.1	3.3.2.C.1	Yes	TSTF-505 changes are incorporated.
One channel inoperable.	3.3.2.D.1	3.3.2.D.1	Yes	TSTF-505 changes are incorporated.
One channel or train inoperable.	3.3.2.F.1	3.3.2.F.1	Yes	TSTF-505 changes are incorporated.
One train inoperable.	3.3.2.G.1	3.3.2.G.1	Yes	TSTF-505 changes are incorporated.
One train inoperable.	3.3.2.H.1	3.3.2.H.1	Yes	TSTF-505 changes are incorporated.
One train inoperable.	3.3.2.I.1	3.3.2.I.1	Yes	TSTF-505 changes are incorporated.

Tech Spec Description	CPNPP TS	TS-505 TS	Apply RICT?	Comments
One Main Feedwater Pumps trip channel inoperable.	3.3.2.J.1	3.3.2.J.1	Yes	TSTF-505 changes are incorporated.
Required Action and associated Completion Time of Conditions B or C not met.	[New] 3.3.2.M	[New] 3.3.2.M.1	No	The CPNPP TS do not currently contain this TS. This new TS condition will be added consistent with TSTF-505.
Required Action and associated Completion Time of Conditions D, E, F, or G not met.	[New] 3.3.2.N	[New] 3.3.2.N.1	No	The CPNPP TS do not currently contain this TS. This new TS condition will be added consistent with TSTF-505.
Required Action and associated Completion Time of Conditions H, I, or J not met.	[New] 3.3.2 O	[New] 3.3.2.O.1	No	The CPNPP TS do not currently contain this TS. This new TS condition will be added consistent with TSTF-505.
LOP DG Start Instrumentation	**3.3.5**	**3.3.5**		
One or more Functions with one channel per bus inoperable.	3.3.5.A.1	3.3.5.A.1	Yes	TSTF-505 changes are incorporated.
Two channels per bus for the Preferred offsite source bus undervoltage function inoperable.	3.3.5.B.1	3.3.5.B.1	Yes	TSTF-505 changes are incorporated. The wording of TSTF-505 varies from CPNPP TS (i.e., TS specifies the Preferred offsite source bus undervoltage function inoperable; and TSTF-505 refers to one or more Functions inoperable.)
Two channels per bus for the Alternate offsite source bus undervoltage function inoperable.	3.3.5.C.1	3.3.5.B.1	Yes	TSTF-505 changes are incorporated. The wording of TSTF-505 varies from CPNPP TS (i.e., TS specifies the Alternate offsite source bus undervoltage function inoperable; and TSTF-505 refers to one or more Functions inoperable.)
Two channels per bus for the 6.9 kV bus loss of voltage function inoperable	3.3.5.D.1	3.3.5.B.1	Yes	TSTF-505 changes are incorporated. The wording of TSTF-505 varies from CPNPP TS (i.e., TS specifies the 6.9kV buss loss of voltage function inoperable; and TSTF-505 refers to one or more Functions inoperable.) This amendment also corrects a typographical error in REQUIRED ACTION D.2. (A.C. to AC)
Two channels per bus for one or more degraded voltage or low grid undervoltage function inoperable	3.3.5.E.1	3.3.5.B.1	Yes	TSTF-505 changes are incorporated. The wording of TSTF-505 varies from CPNPP TS (i.e., TS specifies the degraded voltage or low grid undervoltage function inoperable; and TSTF-505 refers to one or more Functions inoperable.)

Tech Spec Description	CPNPP TS	TS-505 TS	Apply RICT?	Comments
One or more Automatic Actuation Logic and Actuation Relays trains inoperable.	3.3.5.F.1	3.3.5.B.1	Yes	TSTF-505 changes are incorporated. The wording of TSTF-505 varies from CPNPP TS (i.e., TS specifies the Automatic Actuation Logic and Actuation Relay trains inoperable; and TSTF-505 refers to one or more Functions inoperable.)
Boron Dilution Protection System (BDPS)	**N/A**	**3.3.9**		
One train inoperable.	N/A	3.3.9.A.1	No	The CPNPP TS do not contain this TS. Therefore, no changes are proposed to the TS.
RCS Loops -- Mode 3	**3.4.5**	**3.4.5**		
One required RCS loop inoperable.	3.4.5.A.1	3.4.5.A.1	No	RICT Program is not being applied to shutdown models. Therefore, no changes are proposed to this TS.
One required RCS loop not in operation, with Rod Control System capable of rod withdrawal.	3.4.5.C.1	3.4.5.C.1	No	RICT Program is not being applied to shutdown models. Therefore, no changes are proposed to this TS.
Pressurizer	**3.4.9**	**3.4.9**		
One required group of pressurizer heaters inoperable.	3.4.9.B.1	3.4.9.B.1	Yes	TSTF-505 changes are incorporated.
Pressurizer Power Operated Relief Valves (PORVs)	**3.4.11**	**3.4.11**		
One PORV inoperable and not capable of being manually cycled.	3.4.11.B.3	3.4.11.B.3	Yes	TSTF-505 changes are incorporated.
One block valve inoperable.	3.4.11.C.2	3.4.11.C.2	Yes	TSTF-505 changes are incorporated.
ECCS -- Operating	**3.5.2**	**3.5.2**		
One train inoperable because of the inoperability of a centrifugal charging pump.	3.5.2.A.1	N/A	Yes	TSTF-505 Changes are incorporated. The wording of TSTF-505 varies from CPNPP TS (i.e., TS refers to one train inoperable due to inoperability of a centrifugal charging pump; and TSTF-505 refers to one or more trains and does not specify the cause of inoperability)

Tech Spec Description	CPNPP TS	TS-505 TS	Apply RICT?	Comments
One or more trains inoperable for reasons other than one inoperable centrifugal charging pump. AND At least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train available.	3.5.2.B.1	3.5.2.A.1	Yes	TSTF-505 changes are incorporated. The wording of TSTF-505 varies from CPNPP TS (i.e., TS includes AND At least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train available. TSTF-505 does not include this statement.)
Containment Air Locks	**3.6.2**	**3.6.2**		
One or more containment air locks inoperable for reasons other than Condition A or B.	3.6.2.C.3	3.6.2.C.3	Yes	TSTF-505 changes are incorporated.
Containment Isolation Valves	**3.6.3**	**3.6.3**		
One or more penetration flow paths with one containment isolation valve inoperable except for containment purge, hydrogen purge or containment pressure relief valve leakage not within limit.	3.6.3.A.1	3.6.3.A.1	Yes	TSTF-505 changes are incorporated. The wording of TSTF-505 varies from CPNPP TS (i.e., TSTF-505 states One or more penetration flow paths with one containment isolation valve inoperable [for reasons other than Condition[s] D [and E]].
One or more penetration flow paths with one containment isolation valve inoperable.	3.6.3.C.1	3.6.3.C.1	Yes	TSTF-505 changes are incorporated.
Containment Spray System	**3.6.6**	**3.6.6**		
One containment spray train inoperable.	3.6.6.A.1	3.6.6A.A.1	Yes	TSTF-505 changes are incorporated. CPNPP TS did not contain the second Completion Time for this condition and therefore it was not included in the LAR to adopt TSTF-439.
Main Steam Isolation Valves (MSIVs)	**3.7.2**	**3.7.2**		
One MSIV inoperable in MODE 1.	3.7.2.A.1	3.7.2.A.1	Yes	TSTF-505 changes are incorporated.

Tech Spec Description	CPNPP TS	TS-505 TS	Apply RICT?	Comments
Steam Generator Atmospheric Relief Valves (ARVs)	**3.7.4**	**3.7.4**		
One required ARV line inoperable.	3.7.4.A.1	3.7.4.A.1	Yes	TSTF-505 changes are incorporated. The wording of TSTF-505 varies from CPNPP TS (i.e., TS refers to ARV line and TSTF-505 refers to ADV line.)
Two required ARV lines inoperable.	3.7.4.B.1	3.7.4.B.1	Yes	TSTF-505 changes are incorporated. The wording of TSTF-505 varies from CPNPP TS (i.e., TS refers to ARV line and TSTF-505 refers to ADV line.)
Three or more required ARV lines inoperable.	3.7.4.C.1	N/A	Yes	This is a CPNPP-specific condition with restoration action (i.e., Restore at least two ARV lines to operable status) and a completion time of 24 hours. Vistra OpCo proposes to apply RICT to the existing CPNPP TS 3.7.4, Action C.1.
Auxiliary Feedwater (AFW) System	**3.7.5**	**3.7.5**		
One steam supply to turbine driven AFW pump inoperable.	3.7.5.A.1	3.7.5.A.1	Yes	TSTF-505 changes are incorporated. The wording of TSTF-505 varies from CPNPP TS (i.e., TS does not include <u>OR</u> One turbine driven AFW pump inoperable in Mode 3 for refueling). The second Completion Time for this condition was addressed by Vistra OpCo LAR to Adopt TSTF-439 submitted December 19, 2006. (ADAMS Ascension No. ML073400037).
One AFW train inoperable for reasons other than Condition A.	3.7.5.B.1	3.7.5.B.1	Yes	TSTF-505 changes are incorporated. The wording of TSTF-505 varies from CPNPP TS (i.e., TS refers to One AFW train inoperable for reasons other than Condition A and TSTF-505 refers to One AFW train inoperable in MODE 1, 2, or 3 for reasons other than Condition A). The second Completion Time for this condition was addressed by Vistra OpCo LAR to Adopt TSTF-439 submitted December 19, 2006. (ADAMS Ascension No. ML073400037)
Component Cooling Water (CCW) System	**3.7.7**	**3.7.7**		
One CCW train inoperable.	3.7.7.A.1	3.7.7.A.1	Yes	TSTF-505 changes are incorporated.

Tech Spec Description	CPNPP TS	TS-505 TS	Apply RICT?	Comments
Station Service Water System (SSWS)	**3.7.8**	**3.7.8**		
Required SSW Pump on the opposite unit or its associated cross-connects inoperable.	3.7.8.A.1	3.7.8.A.1	Yes	TSTF-505 Changes are incorporated. The wording of TSTF-505 varies from CPNPP TS (i.e., TS refers to Required SSW Pump on the opposite unit or its associated cross-connects inoperable and TSTF-505 refers to one SWS train inoperable.)
Required SSW Pump on the opposite unit or its associated cross-connects inoperable.	3.7.8.A.2	3.7.8.A.1	Yes	TSTF-505 Changes are incorporated. The wording of TSTF-505 varies from CPNPP TS (i.e., TS refers to Required SSW Pump on the opposite unit or its associated cross-connects inoperable and TSTF-505 refers to one SWS train inoperable.)
One SSWS train inoperable.	3.7.8.B.1	3.7.8.A.1	Yes	TSTF-505 Changes are incorporated. The wording of TSTF-505 varies from CPNPP TS (i.e., TS refers to One SSWS train inoperable and TSTF-505 refers to one SWS train inoperable.)
Safety Chilled Water	**3.7.19**	**N/A**		
One safety chilled water train inoperable.	3.7.19.A.1	N/A	Yes	This is a CPNPP-specific Condition with restoration action (i.e., Restore safety chilled water train to OPERABLE status.) and a completion time of 72 hours. Vistra OpCo proposes to apply a RICT to the existing CPNPP TS 3.7.19, Action A.1.
AC Sources -- Operating	**3.8.1**	**3.8.1**		
One required offsite circuit inoperable.	3.8.1.A.3	3.8.1.A.3	Yes	TSTF-505 changes are incorporated. The second Completion Time for this condition was addressed by Vistra OpCo LAR to Adopt TSTF-439 submitted December 19, 2006. (ADAMS Ascension No. ML073400037)
One DG inoperable.	3.8.1.B.4	3.8.1.B.4	Yes	TSTF-505 changes are incorporated. The second Completion Time for this condition was addressed by Vistra OpCo LAR to Adopt TSTF-439 submitted December 19, 2006. (ADAMS Ascension No. ML073400037)
Two required offsite circuits inoperable.	3.8.1.C.2	3.8.1.C.2	Yes	TSTF-505 changes are incorporated.

Tech Spec Description	CPNPP TS	TS-505 TS	Apply RICT?	Comments
One required offsite circuit inoperable. AND One DG inoperable.	3.8.1.D.1	3.8.1.D.1	Yes	TSTF-505 changes are incorporated.
One required offsite circuit inoperable. AND One DG inoperable.	3.8.1.D.2	3.8.1.D.2	Yes	TSTF-505 changes are incorporated.
One SI sequencer inoperable.	3.8.1.F.1	3.8.1.F.1	Yes	TSTF-505 Changes are incorporated. The wording of TSTF-505 varies from CPNPP TS (i.e., TS refers to One SI sequencer inoperable and TSTF-505 refers to One required automatic load sequencer inoperable.
DC Sources -- Operating	**3.8.4**	**3.8.4**		
One or two required battery chargers on one train inoperable.	3.8.4.A.3	3.8.4.A.3	Yes	TSTF-505 changes are incorporated. The wording of TSTF-505 varies from CPNPP TS (i.e., TS refers to One or two required battery chargers on one train inoperable and TSTF-505 does not use the word "required.")
One or two batteries on one train inoperable.	3.8.4.B.1	3.8.4.B.1	Yes	TSTF-505 changes are incorporated.
One DC electrical power subsystem inoperable for reasons other than Condition A or B.	3.8.4.C.1	3.8.4.C.1	Yes	TSTF-505 changes are incorporated.
Inverters -- Operating	**3.8.7**	**3.8.7**		
One required inverter inoperable.	3.8.7.A.1	3.8.7.A.1	Yes	TSTF-505 changes are incorporated.

Tech Spec Description	CPNPP TS	TS-505 TS	Apply RICT?	Comments
Distribution Systems -- Operating	**3.8.9**	**3.8.9**		
One AC electrical power distribution subsystem inoperable.	3.8.9.A.1	3.8.9.A.1	Yes	TSTF-505 changes are incorporated. The wording of TSTF-505 varies from CPNPP TS (i.e., TS refers to One AC electrical power distribution subsystem inoperable and TSTF-505 refers to one or more AC electrical power distribution subsystems inoperable). The second Completion Time for this condition was addressed by Vistra OpCo LAR to Adopt TSTF-439 submitted December 19, 2006. (ADAMS Ascension No. ML073400037).
One AC vital bus subsystem inoperable.	3.8.9.B.1	3.8.9.B.1	Yes	TSTF-505 changes are incorporated. The wording of TSTF-505 varies from CPNPP TS (i.e., TS refers to One AC vital bus subsystem inoperable and TSTF-505 refers to One or more AC vital buses inoperable). The second Completion Time for this condition was addressed by Vistra OpCo LAR to Adopt TSTF-439 submitted December 19, 2006. (ADAMS Ascension No. ML073400037).
One DC electrical power distribution subsystem inoperable.	3.8.9.C.1	3.8.9.C.1	Yes	TSTF-505 changes are incorporated. The wording of TSTF-505 varies from CPNPP TS (i.e., TS refers to One DC electrical power distribution subsystems inoperable and TSTF-505 refers to One or more DC electrical power distribution subsystems inoperable). The second Completion Time for this condition was addressed by Vistra OpCo LAR to Adopt TSTF-439 submitted December 19, 2006. (ADAMS Ascension No. ML073400037).
Programs and Manuals	**5.5**	**5.5**		
Programs and Manuals	[New TS 5.5.23]	5.5.18	No	The CPNPP TS do not currently contain this program. The new RICT Program will be added to the CPNPP TS 5.5 consistent with TSTF-505.

ENCLOSURE 1

Post License Amendment Request Audit Supplement

Comanche Peak Nuclear Power Plant, Units 1 and 2
NRC Docket Nos. 50-445 and 50-446

Revise Technical Specifications to Adopt Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times – RITSTF Initiative 4b"

List of Required Actions to Corresponding PRA Functions, including Tables and Figures

1.0 Introduction

Section 4.0, "Limitations and Conditions", Item 2 of the NRC Final Safety Evaluation [Ref. 1] for NEI 06-09-A, "Risk-Informed Technical Specifications Initiative 4b, Risk Managed Technical Specifications (RMTS) Guidelines", Revision 0 [Ref. 2], identifies the following needed content:

- The license amendment request (LAR) will provide identification of the TS Limiting Conditions for Operation (LCOs) and action requirements to which the RMTS will apply.
- The LAR will provide a comparison of the TS functions to the PRA modeled functions of the structures, systems, and components (SSCs) subject to those LCO actions.
- The comparison should justify that the scope of the PRA model, including applicable success criteria such as number of SSCs required, flow rate, etc., are consistent with licensing basis assumptions (i.e., 50.46 [Emergency Core Cooling System (ECCS)] flowrates) for each of the TS requirements, or an appropriate disposition or programmatic restriction will be provided.

This enclosure provides confirmation that the Comanche Peak Nuclear Power Plant (CPNPP) PRA models include the necessary scope of SSCs and their functions to address each proposed application of the Risk-Informed Completion Time (RICT) Program to the proposed scope TS LCO Conditions, and provides the information requested for Section 4.0, Item 2 of the NRC Final Safety Evaluation. The scope of the comparison includes each of the TS LCO conditions and associated required actions within the scope of the RICT Program.

2.0 In Scope TS/LCO to Corresponding PRA Functions

Table E1-1, "In Scope TS/LCO Conditions to Corresponding PRA Functions" lists each TS LCO Condition to which the RICT Program is proposed to be applied and documents the following information regarding the TSs with the associated safety analyses, the analogous PRA functions, and the results of the comparison:

- Column "Tech Spec Description": Lists all LCOs and condition statements within the scope of the RICT Program.
- Column "SSCs Covered by TS LCO Condition": Lists SSCs addressed by each action requirement.
- Column "Modeled in PRA?": Indicates whether the SSCs addressed by the TS LCO Condition are included in the PRA.
- Column "Function Covered by TS LCO Condition": Lists a summary of the required functions from the design basis analyses.
- Column "Design Success Criteria": A summary of the success criteria from the design basis analyses.
- Column "PRA Success Criteria": The function success criteria modeled in the PRA.
- Column "Comments": Provides the justification or resolution to address any inconsistencies between the TS and PRA functions regarding the scope of SSCs and the success criteria. Where the PRA scope of SSCs is not consistent with the TS, additional information is provided to describe how the LCO condition can be evaluated using appropriate surrogate events. Differences in the success criteria for TS functions are addressed to demonstrate the PRA criteria provide a realistic estimate of the risk of the TS condition as required by NEI 06-09-A, Revision 0.

The corresponding SSCs for each TS LCO and the associated TS functions are identified and compared to the PRA. This description also includes the design success criteria and the applicable PRA success criteria. Any differences between the scope or success criteria are described in the table. Scope differences are justified by identifying appropriate surrogate events which permit a risk evaluation to be completed using the Configuration Risk Management Program tool for the RICT Program. Differences in success criteria typically arise due to the requirement in the American Society of Mechanical Engineers (ASME)/American Nuclear Society

(ANS) RA-Sa-2009 PRA Standard (hereafter "ASME/ANS PRA Standard") to make PRAs realistic rather than bounding, whereas design basis criteria are necessarily conservative and bounding. The use of realistic success criteria is necessary to conform to capability Category II of the ASME/ANS PRA standard as required by NEI 06-09-A, Revision 0.

3.0 In Scope TS/LCO Conditions RICT Estimate

Table E1-2, "In Scope TS/LCO Conditions RICT Estimate" provides examples of calculated RICT for each individual Condition to which the RICT applies (assuming no other SSCs modeled in the PRA are unavailable). These example calculations demonstrate the scope of the SSCs covered by TSs modeled in the PRA. RICTs were calculated for both units and while the results were generally similar, the most limiting RICT is shown in Table E1-2. Also note that the more limiting of the core damage frequency (CDF) and large early release frequency (LERF) RICT result is shown.

Following implementation of the RICT Program, the actual RICT values will be calculated on a unit-specific basis, using the actual plant configuration and the current revision of the PRA model representing the as-built, as-operated condition of the plant, as required by NEI 06-09-A and the NRC Final Safety Evaluation. The actual RICT values may differ from the RICTs presented in this enclosure.

Table E1-3, "Conditions Requiring Additional Technical Justification," contains a list of Required Actions proposed for inclusion in the RICT Program. Additional technical justification is provided to explain why the Condition would not represent a loss of specified safety function as used in the RICT program.

4.0 Evaluation of Instrumentation and Control Systems

In accordance with TSTF-505, Revision 2, Safety Evaluation "Evaluation of Instrumentation and Control Systems" the following is intended to describe the redundant, diverse, and defense-in-depth attributes of the functions for the Reactor Trip System (RTS) Instrumentation, the Engineered Safety Feature Actuation System (ESFAS) Instrumentation, and the LOP DG Start Instrumentation systems.

For the purposes of this evaluation the following definitions are provided;

<u>Redundancy</u> - Parameters that are used for indication of an unsafe condition have redundant measurement systems. Sufficient redundant measurements are provided to allow a coincident logic scheme so that a spurious measurement on one channel will not cause nor prevent a reactor trip or safeguard feature actuation. (Example: the use of four separate Power Range Channels to monitor Reactor Power.)

One exception to this rule is the source and intermediate range instruments. They have a coincidence in which actuation of protective features occurs on a single input, but these instruments are not in service at power.

The degree of redundancy is the difference between the number of channels monitoring a Function and the number of channels which when tripped will cause a reactor trip, an ESFAS actuation, or a LOP DG start.

Further redundancy is provided by having two trains of protection logic, two trains of SSPS, with either train being capable of initiating a full train of protective functions. The minimum degree of redundancy is the degree of redundancy below which operation is prohibited or otherwise restricted by Technical Specifications.

RTS and ESFAS are each redundant safety systems. No single failure will cause or prevent a reactor trip or ESFAS actuation. Each redundant channel is powered by an independent power

supply, and a loss of power will place the channel output bistable in a trip condition. The three exceptions to this scheme are Containment Spray, RWST Auto Switchover, and permissive P-6.

The instrumentation and control systems provide equipment diversity and functional diversity. Equipment diversity provides different types of instruments to achieve the same Function. Functional diversity uses different variables to achieve a backup Function. For example, a loss of RCS flow is primarily monitored, and the reactor is tripped due to low RCS flow. The undervoltage and underfrequency RCP trips provide diversity to the RCS low flow trip.

This feature and the other listed features meet the "single failure" criteria for RPS, by meeting the IEEE Standard 279 1971's single failure criteria. IEEE 279 1971 requires that any single failure within the protection system not prevent proper protection system action when required.

Redundant channels and trains are electrically isolated and physically separated so that any single failure within a channel or train will not prevent protective action at the system level when required. Channel independence is carried throughout the systems.

<u>Independence</u> - Each channel of measurement and each train of protection is physically and electrically independent. Components of different channels are physically separated, penetrate the containment at different locations, and are supplied by independent electrical power supplies. Independence ensures that a single malfunction or casualty will interrupt only one of the redundant channels or trains. The systems (channels and trains) are also designed such that no single failure will cause a loss of Function.

Physical separation is used to the maximum extent practical to maintain the integrity of redundant protection system instrument channels, providing independence for each channel. There are four separate process protection analog sets. Physical separation of the redundant analog protection channels originates at the process sensors and continues through the field wiring and containment penetrations to the analog protection racks.

<u>Diversity</u> - Several different methods are used to perform similar functions or to indicate the same casualty. For example: Excessive localized fuel element power (KW/FT) protection is provided by both the Power Range Nuclear Instruments and by ion chambers measuring gamma flux in the reactor coolant from Nitrogen 16 decay (N-16 Detectors). Several parameters are also used for protection against a departure from nucleate boiling (DNB) in the Reactor Core.

Certain reactor trips are automatically or manually bypassed at low power when they are not required for safety. For a function to be bypassed, a series of conditions or permissives must be met. The bypass circuit design is such that the bypass is automatically removed whenever the permissive conditions are not met.

<u>Defense-In-Depth (DID)</u> - For this evaluation the seven considerations from Regulatory Guide 1.174, Revision 3, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis" are used to review impact of proposed change on function defense-in-depth philosophy.

1. Preserve a reasonable balance among the layers of defense.
2. Preserve adequate capability of design features without an overreliance on programmatic activities as compensatory measures.
3. Preserve system redundancy, independence, and diversity commensurate with the expected frequency and consequences of challenges to the system, including consideration of uncertainty.
4. Preserve adequate defense against potential CCFs.
5. Maintain multiple fission product barriers.
6. Preserve sufficient defense against human errors.
7. Continue to meet the intent of the plant's design criteria.

DID is enhanced by minimizing the chances for a common mode failure through the use of anticipatory trips such as that provided when the turbine trips above 50% power which initiates a reactor trip signal from the turbine tripping independent of any process signals.

Anticipatory trips function to prevent or minimize the severity of an undesired plant event (transient). The systems also use alarms and actions in a layered approach for DID. For example, Overtemperature N-16 and Overpower N-16 provide reactor trip signals at specified setpoints. The two parameters also provide turbine runbacks at a setpoint below the setpoints of the trips.

Automatic Actuation Logic and Actuation Relays are provided in the Solid State Protection System (SSPS). The SSPS equipment is used for the decision logic processing of outputs from the signal processing equipment bistables. To meet the redundancy requirements, two trains of SSPS, each performing the same functions, are provided. If one train is taken out of service for maintenance or test purposes, the second train will provide ESF actuation for the unit. If both trains are taken out of service or placed in test, a reactor trip will result. Each train is packaged in its own cabinet for physical and electrical separation to satisfy separation and independence requirements.

The SSPS performs the decision logic for most ESF equipment actuation; generates the electrical output signals that initiate the required actuation; and provides the status, permissive, and annunciator output signals to the main control room of the unit.

The bistable outputs from the signal processing equipment are sensed by the SSPS equipment and combined into logic matrices that represent combinations indicative of various transients. If a required logic matrix combination is completed, the system will send actuation signals via master and slave relays to those components whose aggregate Function best serves to alleviate the condition and restore the unit to a safe condition.

The SSPS energizes the master relays appropriate for the condition of the unit. Each master relay then energizes one or more slave relays, which then cause actuation of the end devices.

Each of the analyzed accidents can be detected by one or more ESFAS Functions. One of the ESFAS Functions is the primary actuation signal for that accident. An ESFAS Function may be the primary actuation signal for more than one type of accident. An ESFAS Function may also be a secondary, or backup, actuation signal for one or more other accidents. For example, Pressurizer Pressure-Low is a primary actuation signal for small loss of coolant accidents (LOCAs) and a backup actuation signal for steam line breaks (SLBs) outside containment. Functions such as manual initiation, not specifically credited in the accident safety analysis, are qualitatively credited. These Functions may provide protection for conditions that do not require dynamic transient analysis to demonstrate Function performance. These Functions may also serve as backups to Functions that were credited in the accident analysis.

The LCO generally requires OPERABILITY of four or three channels in each instrumentation function and two channels in each logic and manual initiation function. The two-out-of-three and the two-out-of-four configurations allow one channel to be tripped during maintenance or testing without causing an ESFAS initiation. Two logic or manual initiation channels are required to ensure no single random failure disables the ESFAS. The required channels of ESFAS instrumentation provide unit protection in the event of any of the analyzed accidents.

4.1 3.3.1 Reactor Trip System (RTS) Instrumentation

The RTS initiates a unit shutdown, based on the values of selected unit parameters, to protect against violating the core fuel design limits and Reactor Coolant System (RCS) pressure boundary during anticipated operational occurrences (AOOs) and to assist the Engineered Safety Features (ESF) Systems in mitigating accidents.

The RTS design creates defense-in-depth due to the redundancy of the channels for each Function in Table 3.3.1-1, "Reactor Trip System Instrumentation."

- Each Function has multiple channels.
- Each Function will cause a reactor trip with one-out-of-two (1/2), two-out-of-three (2/3), or two-out-of-four (2/4) coincidence trip signals.
- A bypassed channel does not initiate a trip signal. It reduces the number of total available channels from (1/2) to (1), (2/3) to (2/2), or (2/4) to (2/3) coincidence to trip.
- A channel placed in a tripped condition will provide a tripped input for the applicable Function.
- Manual reactor trip handswitches provide diversity and DID for all automatic reactor trips

See Table E1-5, "Reactor Trip Systems (RTS) Instrumentation Functions" for redundancy discussion.

4.2 3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

The ESFAS initiates necessary safety systems, based on the values of selected unit parameters, to protect against violating core design limits and the Reactor Coolant System (RCS) pressure boundary, and to mitigate accidents.

The ESFAS design creates defense-in-depth due to the redundancy of the channels for each Function in Table 3.3.2-1, "Engineered Safety Feature Actuation System Instrumentation."

- Each Function has multiple channels.
- Each Function will cause an ESFAS actuation with one-out-of-two (1/2), two-out-of-three (2/3), or two-out-of-four (2/4) coincidence trip signals.
- A bypassed channel does not initiate an actuation signal. It reduces the number of total available channels from (1/2) to (1), (2/3) to (2/2), or (2/4) to (2/3) coincidence to actuate.
- A channel placed in a tripped condition will provide a tripped input for the applicable Function.

ESFAS redundant channels and trains are electrically isolated and physically separated so that any single failure within a channel or train will not prevent protective action at the system level when required. Channel independence is carried throughout the system.

No single failure will prevent the ESFAS from generating the proper actuation signal on demand for an engineered safety feature. Failures are either in the safe direction or a redundant channel or train ensures the necessary actuation capability.

See Table E1-6, "Engineered Safety Features Actuation System (ESFAS) Instrumentation Functions" for redundancy discussion.

The following information is from CPNPP Design Bases Document, EE-DBD-021, Reactor Protection and NSSS Related Control Systems, Table 1, "Reactor Protection System Diversity." This augments the information provided in Table E1-4, "Evaluation of Instrumentation and Control Systems." Table E1-4 only covers the accidents from CPNPP FSAR, Chapter 15, "Accident Analysis." The following table includes the accidents analyzed as well as other events that rely on TS Instrumentation systems.

See Table E1-8, "Event Protection and Diverse Functions" for redundancy, independence, diversity, and defense-in-depth Functions discussion.

4.3 3.3.5 Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

The DGs provide a source of emergency power when offsite power is either unavailable or is insufficiently stable to allow safe unit operation. Undervoltage protection will generate an LOP start if a loss of voltage or degraded voltage condition occurs in the 6.9kv bus.

For each unit, the undervoltage protection system, leading to the start of the diesel generators on loss of power, consists of the following functions:

- Preferred offsite source undervoltage,
- Alternate offsite source undervoltage,
- 6.9kV Class 1E buses loss of voltage,
- 480V Class 1E buses low grid undervoltage,
- 6.9 kV Class 1E buses degraded voltage, and
- 480V Class 1E buses degraded voltage.

Each function consists of two sensing relays per bus that provide input to two-out-of-two logic.

The following information applies to Unit 1 (Unit 2 has the same logic with Unit 2 designators);

Condition B Preferred offsite source bus undervoltage - 2 per bus - 2 of 2 coincidence
[Train A: Relays 27A-1 ST2-Y and 27A-2 ST2-Y with Setpoint 5185 volts]
[Train B: Relays 27B-1 ST2-Y and 27B-2 ST2-Y with Setpoint 5185 volts]

Condition C Alternate offsite source bus undervoltage - 2 per bus - 2 of 2 coincidence
[Train A: Relays 27A-1 ST1-X and 27A-2 ST1-X with Setpoint 5185 volts]
[Train B: Relays 27B-1 ST1-X and 27B-2 ST1-X with Setpoint 5185 volts]

Condition D 6.9 kV Class 1E bus undervoltage - 2 per bus - 2 of 2 coincidence
[Train A: Relays 27-2A 1EA1 and 27-2B 1EA1 with Setpoint 2022 volts]
[Train B: Relays 27-2A 1EA2 and 27-2B 1EA2 with Setpoint 2022 volts]

Condition D 6.9 kV Class 1E bus degraded voltage - 2 per bus - 2 of 2 coincidence
[Train A: Relays 27-3A 1EA1 and 27-3B 1EA1 with Setpoint 6163.2 volts]
[Train B: Relays 27-3A 1EA2 and 27-3B 1EA2 with Setpoint 6163.2 volts]

Condition E 480 V Class 1E bus low grid undervoltage - 2 per bus - 2 of 2 coincidence
[Train A: Relays 27-A1 1EB1(1EB3) and 27-A2 1EB1 (1EB3) with Setpoint 444 volts]
[Train B: Relays 27-A1 1EB2(1EB4) and 27-A2 1EB2 (1EB4) with Setpoint 444 volts]

Condition E 480 V Class 1E bus degraded voltage - 2 per bus - 2 of 2 coincidence
[Train A: Relays 27-B1 1EB1(1EB3) and 27-B2 1EB1 (1EB3) with Setpoint 442 volts]
[Train B: Relays 27-B1 1EB2(1EB4) and 27-B2 1EB2 (1EB4) with Setpoint 442 volts]

Please refer to Figure 5, *Safeguards Undervoltage Relaying*, included with Executive Summary to TXX-22002.

The required channels of LOP DG start instrumentation, in conjunction with the ESF systems powered from the DGs, provide unit protection in the event of any of the analyzed accidents, in which a loss of offsite power is assumed.

The LCO for LOP DG start instrumentation requires that two channels per bus of the loss of voltage and degraded voltage Functions shall be OPERABLE in MODES 1, 2, 3, and 4 when the LOP DG start instrumentation supports safety systems associated with the ESFAS. The two-out-of-two logic minimizes the probability of spurious DG starts due to instrument failure while maintaining a robust LOP DG Start system. Two trains of Automatic Actuation Logic and Actuation Relays shall also be OPERABLE in MODES 1, 2, 3 and 4.

Technical Specification OPERABILITY requires either normal or emergency power. The following dialogue provides a Unit 1 example. Each Unit has the same capability.

There are three AC sources to the 6.9 kV safety related buses; 1) Preferred Offsite, 2) Alternate Offsite, and 3) Standby Onsite (DGs). The two buses are 1EA1 (Train A) and 1EA2 (Train B). The

preferred offsite source normally provides power through breakers 1EA1-1 and 1EA2-1. If the preferred offsite source is unavailable the alternate offsite source provides power through breakers 1EA1-2 and 1EA2-2. If neither offsite source is available, 1EA1 is power from EDG 1-01 through breaker 1EG1 and 1EA2 is powered from EDG 1-02 through breaker 1EG2. To lose the safety function both offsite sources and both onsite emergency diesel generators would have to be inoperable.

Please refer to Figure 6, *6.9 kV / 480 VAC Single Line Diagram*, included with Executive Summary to TXX-22002.

The six Functions described above provide redundant signals to start a DG due to undervoltage or degraded voltage on the 6.9 kV buses. This provides defense-in-depth by, preserving adequate capability of design features without an overreliance on programmatic activities as compensatory measures and preserves system redundancy, independence, and diversity commensurate with the expected frequency and consequences of challenges to the system, including consideration of uncertainty. When any of the six Functions described above become inoperable or when one or more Automatic Actuation Logic and Actuation Relays trains become inoperable, within one hour the Function must be restored or entry into LCO 3.8.1, "AC Sources -- Operating" for the applicable Condition is required for offsite power sources or diesel generator. For the Functions that are bus related entry into LCO 3.8.9, "Distribution Systems -- Operating" is entered. The RICT may extend the Completion Times from one hour up to a maximum of 30 days based on internal events, internal flooding, and internal fire PRA model calculations with seismic and high winds CDF and LERF penalties. Actual RICT values are calculated using the existing plant configuration and the current PRA model which represents the as-built and as-operated plant.

The LOP DG Start design creates defense-in-depth due to the redundancy of the channels for each Function in Table 3.3.5-1, "Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation."

- LCO 3.3.5, Conditions A, B, C, D, E, and F have the following NOTE added to their respective Completion Time column;

---NOTE---

RICT entry is not permitted when a loss of function occurs.

This will ensure that multi-layered, redundant inputs are available for LOP DG Start Instrumentation. This prevents entering the RICT if the other train Conditions have been entered. With this new NOTE the intent of NUREG-1431, "Standard Technical Specifications — Westinghouse Plants" is maintained. Please refer to Attachment 2, "Proposed Technical Specification Changes"

See Table E1-7, "Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation Functions" for redundancy discussion.

In summary, CPNPP instrumentation systems as described in TS 3.3, employ input parameters and equipment that provide redundancy, independence, diversity, and a defense-in-depth (DID) philosophy as described in Regulatory Guide 1.174, Revision 4.

1. Preserve a reasonable balance among the layers of defense.

The RTS, ESFAS and LOP DG Start instrumentation systems use multiple layers of defense as they rely on redundant, independent, and diverse means to trip the reactor, actuate ESF components, and provide a LOP DG start. In all cases manual operator action provides a final layer of defense if all automatic actions fail. Plant response to events normally has at least one primary protection input with backups as described in preceding table, Event Protection and Diversity, for RTS and ESFAS. Preceding Table, LOP DG Start Signals indicates that train

redundancy provides independent and diverse layers of defense from a partial loss of Function as given in TS 3.3.5, Conditions A and F. Conditions B, C, D, and E are viewed as providing layers of redundancy by utilizing undervoltage or degraded voltage from diverse signals.

Conditions B, C, D, and E all require a 2 of 2 coincidence to start the associated DG.

There are two 6.9 kV safety related buses per Unit;

Unit 1 - 1EA1 (Train A) and 1EA2 (Train B)

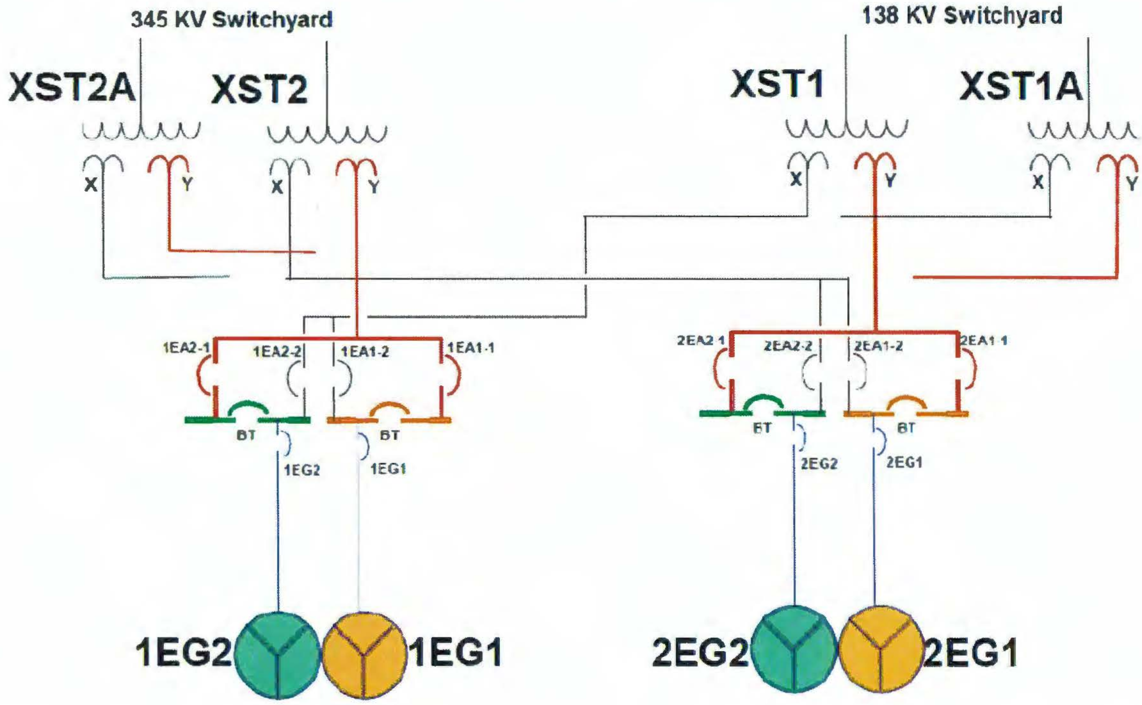
Unit 2 - 2EA1 (Train A) and 2EA2 (Train B)

There are four 480 V safety related buses per Unit;

Unit 1 - 1EB1 and 1EB3 (Train A) and 1EB2 and 1EB4 (Train B)

Unit 2 - 2EB1 and 2EB3 (Train A) and 2EB2 and 2EB4 (Train B)

6.9 KV SAFEGUARDS BUSES



The 6.9 kV AC Distribution system receives power from two startup transformers for the two safety-related class 1E buses (Preferred and Alternate). Emergency Diesel Generators provide standby emergency power in the event of a loss of offsite power.

Each class 1E bus can be fed from two independent offsite power sources or the diesel generator (DG) assigned to that bus.

Redundant safety related loads are divided between Trains A and B so that loss of either train (single failure criteria) does not impair fulfillment of the minimum safe shutdown requirements. There are no manual or automatic connections between Class 1E buses and loads of redundant trains.

In the event of a loss of the preferred power source to the 6.9 kV AC Safeguards bus (buses), a transfer to the alternate source will be initiated in addition to bus load shedding (slow transfer). If

the transfer to the alternate source is successful, the respective DG will NOT start, and loads will be sequenced on to the bus powered by the alternate power supply. If the transfer to the alternate source is not successful, the respective DG will receive a start signal (1.0 second time delay following loss of power) and loads will be sequenced on to the bus supplied by the diesel. See attached document titled *Safety Related Bus Undervoltage*, included with Executive Summary to TXX-22002.

2. Preserve adequate capability of design features without an overreliance on programmatic activities as compensatory measures.

The RTS, ESFAS, and LOP DG Start instrumentation systems only rely on programmatic actions and compensatory measures when no other action is available. For the RTS and ESFAS systems programmatic actions are confined to actions taken to comply with Required Actions in their respective Technical Specifications which are captured in Operations Administrative procedure ODA-308, "LCO Tracking Program." Also, the TS provides actions to take when a Completion Time will not be met. The LOP DG Start Instrumentation confines actions to those required by LCO 3.3.5 which restore the channel or declare associated offsite power source, applicable 6.9 kV buses, or the associated DG inoperable.

3. Preserve system redundancy, independence, and diversity commensurate with the expected frequency and consequences of challenges to the system, including consideration of uncertainty.

For the RTS, a loss of RCS flow/Locked rotor shows the redundancy, independence, and diversity commensurate with a loss of Reactor Coolant flow. Two low flow trip signals are provided; above P-7 (10% power) but below P-8 (48% power) two-out-of-four low flow channels are required to trip the reactor, above P-8 one-out-of-four low flow channels are required to trip the reactor.
A Reactor Coolant Pump (RCP) undervoltage trip is provided which anticipates a loss of RCS flow and is independent from the flow channels. An RCP underfrequency trip is provided which anticipates a loss of RCS flow and is independent from the flow channels and the RCP undervoltage channel. Also, a Pressurizer Pressure high is provided that could trip the reactor during an RCS loss of flow or locked rotor.

For the ESFAS, a Safety Injection (SI) is initiated by the redundant, independent, and diverse inputs commensurate with the accidents that cause a safety injection. An SI can be initiated by one-of-two handswitches on the Main Control Board (MCB). An SI is automatically initiated by a Containment Pressure - High 1, a Pressurizer Pressure Low, or a Steam Line Pressure Low. All of these signals are independent from each other, they are diverse in that monitor and actuate on completely different parameters, and they provide DID as they are layered. Depending on the event; LOCA, SGTR, Main Steam Line fault, or Main Feedwater Line Break each of the independent signals could be the first to respond.

For the LOP DG Start, the inputs are redundant, independent, and diverse. Power to the safety-related 6.9 kV buses is protected by the system design. A single channel cannot cause or prevent a DG start. A single Function failure must be restored or placed in a tripped condition within 6 hours. Automatic Actuation Logic and Actuation Relays trains inoperable must be restored within 1 hour or the associated DG is declared inoperable. In both cases the other redundant train maintains the safety function. The other LOP DG starts are a group of inputs that will start the associated DG under the following conditions;

- Preferred offsite source bus undervoltage
- Alternate offsite source bus undervoltage
- 6.9 kV Class 1E bus undervoltage
- 6.9 kV Class 1E bus degraded voltage
- 480 V Class 1E bus low grid undervoltage

- 480 V Class 1E bus degraded voltage

These channels are independent from each other and are a diverse group of parameters which can cause a DG start. The DID layering begins at the source for 1E power with the two offsite source undervoltage, a second layer adds 6.9 kV 1E bus undervoltage, a third layer provides for 6.9 kV 1E bus degraded voltage, a fourth layer adds the 480 V 1E bus grid undervoltage, and a fifth layer provides for 480 V 1E bus degraded voltage.

Each DG undervoltage signal in Conditions B, C, D, and E all require a 2 of 2 coincidence to initiate a DG start signal. Both channels must fall below the setpoint to actuate a DG start. Condition A applies to the signals in Conditions B, C, D, and E for failure of a single channel. If a single channel in any of the 2 of 2 coincidence channels fails, placing that input in trip, functionally places the start signal in a 1 of 1 coincidence. Condition F applies if a single train or if both trains are inoperable. They must be restored within one hour or the associated DG is declared inoperable. At that point LCO 3.8.1, Condition B is entered.

The following is a description of the sequence of events that occur when a loss of the Preferred offsite power source is lost. The following dialogue will use Unit 1 6.9 kV bus 1EA1:

When the Preferred source voltage lowers to the setpoint (5185 V) as sensed by relays 27A-1/ST2-Y and 27A-2/ST2-Y, feeder breaker 1EA1 1 opens. Voltage will continue to lower until relays 27-2A 1EA1 and 27-2B 1EA1 reach the setpoint (2022 V) and initiating the following actions;

1. All motor breakers on bus 1EA1 are tripped open on undervoltage.

2. A 1 second timer for emergency DG start is energized.

3. A permissive to allow closure of Alternate source feeder breaker 1EA1-2 is energized. Incoming voltage, as sensed by relays 27A-1/ST1-X and 27A-2/ST1-X must be above setpoint (5185 V) for the permissive.

4. Alternate source feeder breaker will close providing;

    a. Relays 27-2A 1EA1 and 27-2B 1EA1 are actuated.

    b. Incoming voltage as sensed by relays 27A-1/ST1-X and 27A-2/ST1-X is above setpoint (5185 V).

    c. Preferred source feeder breaker 1EA1-1 and emergency DG feeder breaker 1EG1 are open.

Relays 27A-1/ST2-Y and 27A-2/ST2-Y are used for Condition B, Preferred offsite source
Relays 27A-1/ST1-X and 27A-2/ST1-X are used for Condition C, Alternate offsite source
Relays 27-2A 1EA1 and 27-2B 1EA1 are used for Condition D, 6.9 kV bus undervoltage

Please refer to Figure 5, *Safeguards Undervoltage Relaying*, included with Executive Summary to TXX-22002.

If the transfer to the Alternate offsite power source fails or if the Alternate offsite power source is not available, the Control Room operators are alerted as follows;

There are multiple annunciators and indications in the main control room to identify the condition. Feeder breakers 1EA1-1, 1EA1-2, and 1EG1 have handswitch position indication. A loss of all

offsite power actuates multiple annunciators on the switchyard and electrical plant panels.

1EA1 bus voltage and frequency are displayed on the Main Control Board (MCB). If the DG started its frequency, voltage, megawatts, and kilovars are displayed on the MCB.

Specific annunciators include;

1. ALB-10B window 4.5, 6.9KV/480V ANY 1E SECOND LVL UNDERVOLT
   This alarm is initiated by any 480V 1E bus with voltage < 442.4 volts or any 6.9KV 1E bus with voltage < 6163.2 volts.

2. ALB-10B window 2.6, 6.9KV BUS 1EA1/1EA2 VOLT LOSS
   This alarm is initiated by either bus 1EA1 or bus 1EA2 with voltage < 2022 volts.

3. ALB-10B window 3.6, 6.9KV BUS 1EA1/1EA2 NOT PWRD FROM PREF OFFSITE PWR
   This alarm is initiated when either the Preferred offsite source feeder breakers 1EA1 1 or 1EA2-1 are not closed.

Safety Systems Inoperable Indication (SSII)

1. SSII TRAIN "AA" window 1.5, PREF OFFSITE PWR
   This alarm is initiated by feeder breaker control switch 1EA1-1 in Pull-Out, Relays 27A-1/ST2-Y and 27A-2/ST2-Y undervoltage, or relays 27-3A 1EA1 and 27-3B 1EA1 with feeder breaker 1EA1-1 closed.

2. SSII TRAIN "AA" window 1.6, ALT OFFSITE PWR
   This alarm is initiated by feeder breaker control switch 1EA1-2 in Pull-Out or auxiliary relay 27AX-1/ST1 undervoltage.

3. SSII TRAIN "AA" window 1.7, ALT OFFSITE PWR
   This alarm is initiated by multiple inputs. The inputs affect DG start capability.

4. Preserve adequate defense against potential CCFs.

Common Cause Failures (CCF) are avoided by the redundancy, independence, diversity, and DID philosophy that are in the plant design. The preceding tables provide primary trip and ESFAS signals for Functions. The tables show how diverse signals are available to support the Function and that the diversity minimizes or eliminates CCFs. System and Function diversity and DID are also shown when the required coincidence changes based on interlocks with the RTS and ESFAS systems. Most CCFs are eliminated by train related Functions. The remaining train can actuate the required signal when needed.

5. Maintain multiple fission product barriers.

The RTS provides trips that are designed to maintain the fuel cladding intact. Specifically, the Power Range Neutron Flux High, Power Range Neutron Flux Rate Positive High, Overtemperature N-16, and Overpower N-16 trips respond to power excursions minimizing the stress to the fuel cladding. These trips act to protect the fuel cladding (fission product barrier).

The Pressurizer Pressure High and the Pressurizer Water Level High in conjunction with the Pressurizer Power Operated Relief Valves (PORV) and Pressurizer Safety Valves to limit the pressure in the RCS. These trips and components act to protect the RCS piping (fission product barrier).

The ESFAS actuations focus on keeping the reactor core cooled and maintaining the Containment

below design temperature and pressure. The three automatic SI actuation signals respond to potential challenges to Containment integrity. Containment Pressure High 1 initiates a safety injection based on rising pressure in the Containment. Pressurizer Pressure Low is an indication that a LOCA is in progress that could challenge Containment integrity. Steam Line Pressure Low is an indication of either a steam line break or a feedwater line break. Either break if inside Containment could challenge Containment integrity.

Containment isolation signals are designed to protect Containment integrity. When a Safety Injection is actuated, Containment Phase A Isolation is actuated to isolate non-essential penetrations. Containment Phase A Isolation actuates a Containment Ventilation Isolation to ensure ventilation into and out of Containment are isolated. Steam Line Isolation is actuated by either Steam Line Pressure Low or Containment Pressure High 2 to close the Main Steam Isolation Valves (MSIV) to further ensure Containment integrity. Containment Pressure High 3 initiates Containment Spray and Containment Phase B Isolation. Containment Spray acts to lower Containment temperature and pressure. Containment Phase B isolation isolates Component Cooling Water (CCW) to the RCPs inside Containment. CCW will not be required in this condition as the RCPs are secured. With Containment isolated and Containment Spray actuated the Containment integrity is maintained (Fission product barrier).

6. Preserve sufficient defense against human errors.

Operator errors are minimized by a multi-layered approach. Most actions taken by operators are given in written procedures that have gone through 10 CFR 50.59 review. Control board and plant labelling minimize errors as they provide a positive component verification prior to operation. The protection system is designed so that a single failure will not cause or prevent an actuation when needed. The test procedures for the protection system ensure the steps taken will not lead to an inadvertent actuation. There is also a "fail-safe" element in the design. For example, most components actuated by the protection system are actuated when an input de-energizes, so a loss of power takes the system to a safe position. There are some exceptions and they are based on positive actions to initiate Containment Spray and switchover of the suctions for ECCS and Containment Spray pumps to the Containment Sumps when RWST level reaches a specific level. These signal energize to actuate. This is a case also where the operator may play a significant role if the automatic actuation fails.

7. Continue to meet the intent of the plant's design criteria.

The plant design criteria are not changed by the license amendment request to adopt TSTF-505, Revision 2. The PRA and design review have not identified any significant safety concern by extending the Completion Times when implemented by the submitted program. Any LCOs that may have challenged the plant's design criteria have not been submitted for inclusion in the RICT program. Particularly, CPNPP has not submitted changes for low MODE conditions.

5.0 Tables

E1-1, "In Scope TS/LCO Conditions to Corresponding PRA Functions"

E1-2, "In Scope TS/LCO Conditions RICT Estimate"

E1-3, "Conditions Requiring Additional Technical Justification"

E1-4, "Evaluation of Instrumentation and Control Systems"

E1-5, "Reactor Trip Systems (RTS) Instrumentation Functions"

E1-6, "Engineered Safety Features Actuation System (ESFAS) Instrumentation Functions"

E1-7, "Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation Functions"

E1-8, "Event Protection and Diverse Functions"

Table E1-1, In Scope TS/LCO Conditions to Corresponding PRA Functions

Tech Spec	Tech Spec Description	SSCs Covered by TS LCO Condition	Modeled in PRA?	Function Covered by TS LCO Condition	Design Success Criteria	PRA Success Criteria	Comments
3.3.1.B	One Manual Reactor Trip channel inoperable	Two Manual Reactor Trip channels	Yes	Reactor Trip Initiation	One of two reactor trip channels	Same	Mapped to modeled components. (Note 4)
3.3.1.D	One Power Range Neutron Flux - High channel inoperable.	Four Power Range Neutron Flux-High channels	Yes	Reactor Trip Initiation	Two of four channels	Same	RTS is modeled in the CPNPP PRA using two generic RX Trip logics, one four channel instrument loop and one three channel instrument loop based on every trip that would generate at least two sets of signals. For the RICT program, if the components were not explicitly modeled, they were mapped to one of the two logics based on the number of channels and their impact on the function. (Notes 1 and 2)

Table E1-1, In Scope TS/LCO Conditions to Corresponding PRA Functions

Tech Spec	Tech Spec Description	SSCs Covered by TS LCO Condition	Modeled in PRA?	Function Covered by TS LCO Condition	Design Success Criteria	PRA Success Criteria	Comments
3.3.1.E	One channel inoperable.	Four Power Range Flux Low channels Four Power Range Neutron Flux Rate High Positive Rate channels Four Overtemperature N-16 channels Four Overpower N-16 channels Four Pressurizer Pressure- High channels Four SG Water Level Low-Low channels	Yes	Reactor Trip Initiation	Two of Four Power Range Flux Low channels Two of Four Power Range Neutron Flux Rate High Positive Rate channels Two of Four Overtemperature N-16 channels Two of Four Overpower N-16 channels Two of Four Pressurizer Pressure- High channels Two of Four SG Water Level Low-Low channels	Same	RTS is modeled in the CPNPP PRA using two generic RX Trip logics, one four channel instrument loop and one three channel instrument loop based on every trip that would generate at least two sets of signals. For the RICT program, if the components were not explicitly modeled, they were mapped to one of the two logics based on the number of channels and their impact on the function. (Notes 1 and 2)

Table E1-1, In Scope TS/LCO Conditions to Corresponding PRA Functions

Tech Spec	Tech Spec Description	SSCs Covered by TS LCO Condition	Modeled in PRA?	Function Covered by TS LCO Condition	Design Success Criteria	PRA Success Criteria	Comments
3.3.1.M	One channel inoperable.	Four Pressurizer Pressure Low channels Three Pressurizer Water Level High channels Three Reactor Coolant Flow Low channels per loop Four Undervoltage RCPs Four Underfrequency RCPs channels	Yes	Reactor Trip Initiation	Two of Four Pressurizer Pressure Low channels Two of Three Pressurizer Water Level Low channels Two of Three Reactor Coolant Flow Low channels per loop Two of Four Undervoltage RCPs Two of Four Underfrequency RCPs channels	Same	RTS is modeled in the CPNPP PRA using two generic RX Trip logics, one four channel instrument loop and one three channel instrument loop based on every trip that would generate at least two sets of signals. For the RICT program, if the components were not explicitly modeled, they were mapped to one of the two logics based on the number of channels and their impact on the function. (Notes 1 and 2)
3.3.1.O	One Low Fluid Oil Pressure Turbine Trip channel inoperable.	Three Low Fluid Oil pressure channels	Yes	Reactor Trip Initiation	Two of Three channels	Same	RTS is modeled in the CPNPP PRA using two generic RX Trip logics, one four channel instrument loop and one three channel instrument loop based on every trip that would generate at least two sets of signals. For the RICT program, if the components were not explicitly modeled, they were mapped to one of the two logics based on the number of channels and their impact on the function.

Table E1-1, In Scope TS/LCO Conditions to Corresponding PRA Functions

Tech Spec	Tech Spec Description	SSCs Covered by TS LCO Condition	Modeled in PRA?	Function Covered by TS LCO Condition	Design Success Criteria	PRA Success Criteria	Comments
3.3.1.P	One or more Turbine Stop Valve Closure Turbine Trip channel(s) inoperable.	Four Turbine Stop Valve Closure channels (One for each valve)	Yes	Reactor Trip Initiation	Four of Four channels	Same	RTS is modeled in the CPNPP PRA using two generic RX Trip logics, one four channel instrument loop and one three channel instrument loop based on every trip that would generate at least two sets of signals. For the RICT program, if the components were not explicitly modeled, they were mapped to one of the two logics based on the number of channels and their impact on the function. (Note 11)
3.3.1.R	One train inoperable.	Two Safety Injection (SI) Input from Engineered Safety Feature Actuation System (ESFAS) trains Two Automatic Trip Logic trains	Yes	Reactor Trip Initiation	One of Two Safety Injection (SI) Input from Engineered Safety Feature Actuation System (ESFAS) trains One of Two Automatic Trip Logic trains	Same	RTS is modeled in the CPNPP PRA using two generic RX Trip logics, one four channel instrument loop and one three channel instrument loop based on every trip that would generate at least two sets of signals. For the RICT program, if the components were not explicitly modeled, they were mapped to one of the two logics based on the number of channels and their impact on the function.
3.3.1.S	One RTB train inoperable.	Two Reactor Trip Breaker (RTB) trains	Yes	Reactor Trip Initiation	One of Two RTBs open	Same	Mapped to modeled components. (Note 3)
3.3.1.V	One trip mechanism inoperable for one RTB.	RTB Undervoltage and Shunt trip mechanisms	Yes	Reactor Trip Initiation	One trip mechanism	Same	Mapped to modeled components. (Note 4)

Table E1-1, In Scope TS/LCO Conditions to Corresponding PRA Functions

Tech Spec	Tech Spec Description	SSCs Covered by TS LCO Condition	Modeled in PRA?	Function Covered by TS LCO Condition	Design Success Criteria	PRA Success Criteria	Comments
3.3.2.B	One channel or train inoperable.	Two Manual Initiation Safety Injection channels Two Manual Initiation Containment Spray channels (per train) Two Manual Initiation Phase A Containment Isolation channels Two Manual Initiation Phase B Containment Isolation channels	Yes	ESF Actuation	One of Two Manual Initiation Safety Injection channels One of Two Manual Initiation Containment Spray channels (per train) One of Two Manual Initiation Phase A Containment Isolation channels One of Two Manual Initiation Phase B Containment Isolation channels	Same	Mapped to modeled components.

Table E1-1, In Scope TS/LCO Conditions to Corresponding PRA Functions

Tech Spec	Tech Spec Description	SSCs Covered by TS LCO Condition	Modeled in PRA?	Function Covered by TS LCO Condition	Design Success Criteria	PRA Success Criteria	Comments
3.3.2.C	One train inoperable.	Two Safety Injection Automatic Actuation Logic and Actuation Relays trains Two Containment Spray Automatic Actuation Logic and Actuation Relays trains Two Phase A Containment Isolation Automatic Actuation Logic and Actuation Relays trains Two Phase B Containment Isolation Automatic Actuation Logic and Actuation Relays trains Two Automatic Switchover to Containment Sump Automatic Actuation Logic and Actuation Relays trains	Yes	ESF Actuation, P- 14: Trips Main Feed Pumps, Trips Main Turbine, Closes Feedwater Isolation and Discharge Valves	One of Two Safety Injection Automatic Actuation Logic and Actuation Relays trains One of Two Containment Spray Automatic Actuation Logic and Actuation Relays trains One of Two Phase A Containment Isolation Automatic Actuation Logic and Actuation Relays trains One of Two Phase B Containment Isolation Automatic Actuation Logic and Actuation Relays trains One of Two Automatic Switchover to Containment Sump Automatic Actuation Logic and Actuation Relays trains	Same	Mapped to modeled components. Surrogates used for certain components (relays) are conservatively mapped based on their effect on the function.

Table E1-1, In Scope TS/LCO Conditions to Corresponding PRA Functions

Tech Spec	Tech Spec Description	SSCs Covered by TS LCO Condition	Modeled in PRA?	Function Covered by TS LCO Condition	Design Success Criteria	PRA Success Criteria	Comments
3.3.2.D	One channel inoperable.	Three Safety Injection Containment Pressure – High 1 channels Four Safety Injection Pressurizer Pressure – Low channels Three (per line) Safety Injection Steam Line Pressure Low channels Three Steam Line Isolation Containment Pressure – High 2 channels Three (per line) Steam Line Isolation Steam Line Pressure Low channels Three (per line) Steam Line Isolation Negative Rate – High channels Four (per SG) Auxiliary Feedwater SG Water Level Low-Low channels	Yes	ESF Actuation	Two of Three Safety Injection Containment Pressure – High 1 channels Two of Four Safety Injection Pressurizer Pressure – Low channels Two of Three (per line) Safety Injection Steam Line Pressure Low channels Two of Three Steam Line Isolation Containment Pressure – High 2 channels Two of Three (per line) Steam Line Isolation Steam Line Pressure Low channels Two of Three (per line) Steam Line Isolation Negative Rate – High channels Two of Four (per SG) Auxiliary Feedwater SG Water Level Low-Low channels	Same	Mapped to modeled components.

Table E1-1, In Scope TS/LCO Conditions to Corresponding PRA Functions

Tech Spec	Tech Spec Description	SSCs Covered by TS LCO Condition	Modeled in PRA?	Function Covered by TS LCO Condition	Design Success Criteria	PRA Success Criteria	Comments
3.3.2.F	One channel or train inoperable.	Two Steam Line Isolation Manual Initiation channels Two Auxiliary Feedwater Loss of Offsite Power channels Two ESFAS Interlocks Reactor Trip channels (P-4)	Yes	ESF Actuation	One of Two Steam Line Isolation Manual Initiation channels One of Two Safety Injection Loss of Offsite Power channels One of Two ESFAS Interlocks Reactor Trip channels	Same	Mapped to modeled components. Surrogates used for certain components (hand switch/relays) are conservatively mapped based on their effect on the function.
3.3.2.G	One train inoperable.	Two Steam Line Isolation Automatic Actuation Logic and Actuation Relays trains Two Auxiliary Feedwater Automatic Actuation Logic and Actuation Relays trains	Yes	ESF Actuation	One of Two Steam Line Isolation Automatic Actuation Logic and Actuation Relays trains One of Two Auxiliary Feedwater Automatic Actuation Logic and Actuation Relays trains	Same	Mapped to modeled components. Surrogates used for certain components (hand switch/relays) are conservatively mapped based on their effect on the function.
3.3.2.H	One train inoperable	Two Turbine Trip and Feedwater Isolation Automatic Actuation Logic and Actuation Relays trains	Yes	ESF Actuation	One of Two Turbine Trip and Feedwater Isolation Automatic Actuation Logic and Actuation Relays trains	Same	Mapped to modeled components. Surrogates used for certain components are conservatively mapped based on their effect on the function.

Table E1-1, In Scope TS/LCO Conditions to Corresponding PRA Functions

Tech Spec	Tech Spec Description	SSCs Covered by TS LCO Condition	Modeled in PRA?	Function Covered by TS LCO Condition	Design Success Criteria	PRA Success Criteria	Comments
3.3.2.I	One channel inoperable.	Three (per SG) Turbine Trip and Feedwater Isolation SG Water Level – High-High (P-14) channels	Yes	ESF Actuation	Two of Three (per SG) Turbine Trip and Feedwater Isolation SG Water Level – High-High (P-14) channels	Same	Mapped to modeled components.
3.3.2.J	One Main Feedwater Pump trip channel inoperable.	All Main Feedwater Pumps trip channels	Yes	ESF Actuation	One of two per AFW pump	Same	Mapped to modeled components. Surrogates used for certain components (switch/relays) are conservatively mapped based on their effect on the function.
3.3.5.A	One or more Functions with one channel per bus inoperable	Sustained undervoltage (SUR), Transient undervoltage (TU) and Loss of voltage (LOV) sensors on safety related 6.9kV buses	Yes	Diesel Generator Start Instrumentation - Loss of Power	Two of Two channels of the loss of voltage and undervoltage Functions on at least one bus (Train)	Same	Mapped to modeled components. Surrogates used for certain components (relays) are conservatively mapped based on their effect on the function.
3.3.5.B	Two channels per bus for the Preferred offsite source bus undervoltage function inoperable.	Two (per bus) preferred offsite source bus undervoltage channels	Yes	Diesel Generator Start Instrumentation - Loss of Power	Two of Two undervoltage channels on each preferred offsite source bus	Same	Surrogates used for components (relays) are conservatively mapped based on their effect on the function. (Notes 5 and 6)
3.3.5.C	Two channels per bus for the Alternate offsite source bus undervoltage function inoperable.	Two (per bus) Alternate offsite source bus undervoltage channels	Yes	Diesel Generator Start Instrumentation - Loss of Power	Two of Two undervoltage channels on each alternate offsite source bus	Same	Surrogates used for components (relays) are conservatively mapped based on their effect on the function. (Notes 5 and 6)

Table E1-1, In Scope TS/LCO Conditions to Corresponding PRA Functions

Tech Spec	Tech Spec Description	SSCs Covered by TS LCO Condition	Modeled in PRA?	Function Covered by TS LCO Condition	Design Success Criteria	PRA Success Criteria	Comments
3.3.5.D	Two channels per bus for the 6.9 kV bus loss of voltage function inoperable	Two (per bus) 6.9 kV Class 1E bus undervoltage channels	Yes	Diesel Generator Start Instrumentation - Loss of Power	Two of Two undervoltage channels on each 6.9 kV Class 1E bus	Same	Mapped to modeled components. (Notes 5 and 6)
3.3.5.E	Two channels per bus for one or more degraded voltage or low grid undervoltage functions inoperable	Two (per bus) 6.9 kV Class 1E Degraded voltage channels Two (per bus) 480 V Class 1E bus degraded voltage channels Two (per bus) 480 V Class 1E bus low grid undervoltage	Yes	Diesel Generator Start Instrumentation - Loss of Power	Two of Two degraded voltage channels on each 6.9 kV Class 1E bus Two of Two degraded voltage channels on each 480 V Class 1E bus Two of Two low grid undervoltage channels on each 480 V Class 1E bus	Same	Surrogates used for certain components (relays) are conservatively mapped based on their effect on the function. (Notes 5 and 6)
3.3.5.F	One or more Automatic Actuation Logic and Actuation Relays trains inoperable.	Two Automatic Actuation Logic and Actuation Relays trains	Yes	Diesel Generator Start Instrumentation - Loss of Power	One of Two Automatic Actuation Logic and Actuation Relays trains	Same	Surrogates used for certain components (relays) are conservatively mapped based on their effect on the function. (Notes 5 and 6)
3.4.9.B	One required group of pressurizer heaters inoperable.	Two groups of pressurizer heaters	No	RCS subcooling	One of two groups of pressurizer heaters with a capacity ≥ 150 kW	PRA does not model PRZ heaters.	Surrogates used for components are mapped based on their effect on the function. For the RICT, the impact has been mapped to an increase in the likelihood of a plant trip due to degraded pressure control. (Note 9)

Table E1-1, In Scope TS/LCO Conditions to Corresponding PRA Functions

Tech Spec	Tech Spec Description	SSCs Covered by TS LCO Condition	Modeled in PRA?	Function Covered by TS LCO Condition	Design Success Criteria	PRA Success Criteria	Comments
3.4.11.B	One PORV inoperable and not capable of being manually cycled.	Two PORVs	Yes	RCS depressurization for SGTR response	One PORV OPERABLE	Same	Mapped to modeled components.
3.4.11.C	One block valve inoperable.	Two PORV block valves	Yes	Isolate associated PORV Open to allow PORV functions in Function 3.4.11.B	One PORV and associated block valve OPERABLE	Same	Mapped to modeled components.
3.5.2.A	One train inoperable because of the inoperability of a centrifugal charging pump.	Two centrifugal charging pumps	Yes	Provide core cooling and negative reactivity to ensure that the reactor core is protected after any of the following accidents: a. Loss of coolant accident (LOCA), coolant leakage greater than the capability of the normal charging system; b. Rod ejection accident; c. Loss of secondary coolant accident, including uncontrolled steam release or loss of feedwater; and d. Steam generator tube rupture (SGTR).	1 of 2 centrifugal charging pumps.	Same	Mapped to modeled components. The centrifugal charging subsystem consists of two redundant, 100% capacity trains. (Note 8)

Table E1-1, In Scope TS/LCO Conditions to Corresponding PRA Functions

Tech Spec	Tech Spec Description	SSCs Covered by TS LCO Condition	Modeled in PRA?	Function Covered by TS LCO Condition	Design Success Criteria	PRA Success Criteria	Comments
3.5.2.B	One or more trains inoperable for reasons other than one inoperable centrifugal charging pump.	Two ECCS trains consisting of, safety injection pump, RHR Pump, RHR heat exchangers	Yes	Provide core cooling and negative reactivity to ensure that the reactor core is protected after any of the following accidents: a. Loss of coolant accident (LOCA), coolant leakage greater than the capability of the normal charging system; b. Rod ejection accident; c. Loss of secondary coolant accident, including uncontrolled steam release or loss of feedwater; and d. Steam generator tube rupture (SGTR).	One of two ECCS trains	Same	Mapped to modeled components. Surrogates used for certain components (pump/valves) are conservatively mapped based on their effect on the function TS 3.5.2 Condition B requires 100% flow equivalent to a single OPERABLE ECCS train is available. (Note 8)
3.6.2.C	One or more containment air locks inoperable for reasons other than Condition A or B.	Containment Airlocks	Not explicitly	Containment integrity	One of two containment air lock doors closed.	Same	Surrogates used for components are conservatively mapped based on their effect on the function. For RICT, the impact for this condition will be assumed that one end of the containment air lock has been verified to be able to perform its function 3.6.2.C.1. The components will therefore be mapped to a surrogate representing a loss of a single CIV for the 24 hour requirement. TS 3.6.2 Condition C Action 1 initiates action to evaluate overall containment leakage rate per LCO 3.6.1.

Table E1-1, In Scope TS/LCO Conditions to Corresponding PRA Functions

Tech Spec	Tech Spec Description	SSCs Covered by TS LCO Condition	Modeled in PRA?	Function Covered by TS LCO Condition	Design Success Criteria	PRA Success Criteria	Comments
3.6.3.A	One or more penetration flow paths with one containment isolation valve inoperable except for containment purge, hydrogen purge or containment pressure relief valve leakage not within limit.	Two active or passive isolation devices on each fluid penetration line	Yes	Containment boundary and minimization of RCS inventory loss	One of two isolation devices per penetration	Same	Mapped to modeled components. Surrogates used for certain components (CIV not explicitly modeled) are conservatively mapped based on their effect on the function.
3.6.3.C	One or more penetration flow paths with one containment isolation valve inoperable.	See LCO Condition 3.6.3.A					
3.6.6.A	One containment spray train inoperable.	Two Containment Spray System trains	Yes	Containment atmosphere cooling	One of two trains	Same	Mapped to modeled components. Surrogates used for certain components (breakers/valves) are conservatively mapped based on their effect on the function The Containment Spray System for each unit consists of two separate and completely redundant safety trains.

Table E1-1, In Scope TS/LCO Conditions to Corresponding PRA Functions

Tech Spec	Tech Spec Description	SSCs Covered by TS LCO Condition	Modeled in PRA?	Function Covered by TS LCO Condition	Design Success Criteria	PRA Success Criteria	Comments
3.7.2.A	One MSIV inoperable in Mode 1	Main Steam Isolation Valves (MSIVs)	Yes	Isolate Main Steam Lines	One MSIV closure per steam generator	Same	Mapped to modeled components. The design of the secondary system precludes the uncontrolled blowdown of more than one steam generator, assuming a single active component failure (e.g., the failure of one MSIV to close on demand.)
3.7.4.A	One required ARV line inoperable	Steam Generator Atmospheric Relief Valves (ARVs)	Yes	Pressure relief and plant cooldown	Two of four SG ARVs	One of four for Transient / SGTR	Mapped to modeled components.
3.7.4.B	Two required ARV lines inoperable.	Steam Generator Atmospheric Relief Valves (ARVs)	Yes	Pressure relief and plant cooldown	Two of four SG ARVs	One of four for Transient / SGTR	Mapped to modeled components.
3.7.4.C	Three or more required ARV lines inoperable.	Steam Generator Atmospheric Relief Valves (ARVs)	Yes	Pressure relief and plant cooldown	One of four SG ARVs	One of four for Transient / SGTR	Mapped to modeled components. (Note 7)
3.7.5.A	One steam supply to the turbine driven AFW pump inoperable	Turbine driven AFW steam supply line valves and flowpath	Yes	Supply steam to turbine driven AFW pump	One of two steam feed lines	Same	Mapped to modeled components. Surrogates used for certain components (CIV valves) are conservatively mapped based on their effect on the function.

Table E1-1, In Scope TS/LCO Conditions to Corresponding PRA Functions

Tech Spec	Tech Spec Description	SSCs Covered by TS LCO Condition	Modeled in PRA?	Function Covered by TS LCO Condition	Design Success Criteria	PRA Success Criteria	Comments
3.7.5.B	One AFW train inoperable for reasons other than Condition A	Three AFW trains (two motor driven pumps and flowpath, one turbine driven pump and flowpath)	Yes	Supply feedwater to steam generators to remove RCS decay heat	One of three AFW trains supplying two SGs	All transients: One of three AFW pumps supplying 1 SG All LOCAs: :One of three AFW pumps supplying 2 SGs SGTR: :One of three AFW pumps supplying 1 SG	Mapped to modeled components. Surrogates used for certain components (CIV valves) are conservatively mapped based on their effect on the function. Both MDAFWPs and the TDAFWP are modeled in the PRA.
3.7.7.A	One CCW train inoperable.	Two CCW trains comprised of a full capacity pump, heat exchanger, piping, valves, and instrumentation	Yes	Heat sink for removing process and operating heat from safety related components	One of two CCW trains	Same	Mapped to modeled components.
3.7.8.A	Required SSW Pump on the opposite unit or its associated cross-connects inoperable.	Two 100% capacity SSW cooling water pumps and associated cross connects on opposite unit	Yes	Heat sink for removal of process and operating heat from safety related components during DBA or transient	One of two opposite unit SSW trains with cross-ties open.	Same	Mapped to modeled components
3.7.8.B	One SSWS train inoperable.	Two 100% capacity SSWS cooling water trains	Yes	Heat sink for removal of process and operating heat from safety related components during DBA or transient	One of two unit SSWS trains	Same	Mapped to modeled components.

Table E1-1, In Scope TS/LCO Conditions to Corresponding PRA Functions

Tech Spec	Tech Spec Description	SSCs Covered by TS LCO Condition	Modeled in PRA?	Function Covered by TS LCO Condition	Design Success Criteria	PRA Success Criteria	Comments
3.7.19.A	One safety chilled water train inoperable.	Two safety chilled water	Yes	Provide water to emergency fan coil units (EFCUs) to maintain ambient air temperature within design limits of the essential equipment in ESF pump rooms	One of two safety chilled water trains	Same	Mapped to modeled components. The Safety Chilled Water System for each unit consists of two separate and completely redundant safety trains.
3.8.1.A	One required offsite circuit inoperable.	Two trains with two qualified circuits between the offsite transmission network and the onsite 1E AC Electrical Power Distribution System.	Yes	Provide power from offsite transmission network to onsite Class 1E buses.	One qualified circuit between the offsite transmission network and the onsite 1E AC Electrical Power Distribution System.	Same	Mapped to modeled components.
3.8.1.B	One DG inoperable.	Two independent DGs per train capable of supplying onsite 1E AC Electrical Power Distribution System	Yes	Provide power to safety related buses when offsite power to them is lost.	1 of 2 DGs per unit	Same	Mapped to modeled components.
3.8.1.C	Two required offsite circuits inoperable.	Two trains with two qualified circuits between the offsite transmission network and the onsite 1E AC Electrical Power Distribution System.	Yes	Provide power from offsite transmission network to onsite Class 1E buses.	1 of 2 DGs per unit when offsite power is unavailable.	Same	Mapped to modeled components.

Table E1-1, In Scope TS/LCO Conditions to Corresponding PRA Functions

Tech Spec	Tech Spec Description	SSCs Covered by TS LCO Condition	Modeled in PRA?	Function Covered by TS LCO Condition	Design Success Criteria	PRA Success Criteria	Comments
3.8.1.D	One required offsite circuit inoperable. AND One DG inoperable.	Two trains with two qualified circuits between the offsite transmission network and the onsite 1E AC Electrical Power Distribution System and Two independent DGs per train capable of supplying onsite 1E AC Electrical Power Distribution System	Yes	Provide power from offsite transmission network to onsite Class 1E buses.	One qualified circuit between the offsite transmission network and the onsite 1E AC Electrical Power Distribution System if offsite power available. One DG per unit if offsite power unavailable.	Same	Mapped to modeled components.
3.8.1.F	One SI sequencer inoperable.	Two SI sequencers	Yes	Sequentially load components on electrical power source during a DBA.	One of two SI sequencers.	Same	Mapped to modeled components.
3.8.4.A	One or two required battery chargers on one train inoperable.	Two 100% capacity chargers per battery	Yes	Ensure availability of required DC power to shut down the reactor and maintain it in a safe condition	One required battery charger for each battery per DC bus in a single DC Train.	Same	Mapped to modeled components. Surrogates used for certain components (inverters) are conservatively mapped based on their effect on the function. (Note 10)
3.8.4.B	One or two batteries on one train inoperable.	Two batteries per train	Yes	Ensure availability of required DC power to shut down the reactor and maintain it in a safe condition	One battery per DC bus in a single DC Train.	Same	Mapped to modeled components. Surrogates used for certain components (inverters) are conservatively mapped based on their effect on the function.

Table E1-1, In Scope TS/LCO Conditions to Corresponding PRA Functions

Tech Spec	Tech Spec Description	SSCs Covered by TS LCO Condition	Modeled in PRA?	Function Covered by TS LCO Condition	Design Success Criteria	PRA Success Criteria	Comments
3.8.4.C	One DC electrical power subsystem inoperable for reasons other than Condition A or B.	Two DC electrical power distribution subsystems	Yes	Ensure availability of required DC power to shut down the reactor and maintain it in a safe condition	One of Two DC trains	Same	Mapped to modeled components. Surrogates used for certain components (inverters) are conservatively mapped based on their effect on the function.
3.8.7.A	One required inverter inoperable.	Four inverters per train.	Yes	Provide AC power to vital buses	One of two inverters supplying AC vital bus electrical power distribution system.	Same	Mapped to modeled components. Surrogates used for certain components (INSTR Panel) are conservatively mapped based on their effect on the function.
3.8.9.A	One AC electrical power distribution subsystem inoperable.	Two AC electrical power distribution subsystems	Yes	Provide power to safety related equipment.	One of two AC electrical power distribution subsystems	Same	Mapped to modeled components.
3.8.9.B	One AC vital bus subsystem inoperable.	Two AC vital bus subsystems	Yes	Provide power to safety related equipment.	One of two AC vital bus distribution subsystems	Same	Mapped to modeled components. Surrogates used for certain components (INSTR Panel) are conservatively mapped based on their effect on the function.
3.8.9.C	One DC electrical power distribution subsystem inoperable.	Two DC electrical power distribution subsystems	Yes	Ensure availability of required DC power to shut down the reactor and maintain it in a safe condition	One of two DC power distribution subsystems	Same	Mapped to modeled components.

Notes:

1. The Reactor Trip System instrumentation is segmented into four distinct but interconnected modules: field transmitters and process sensors, Signal Process Control and Protection System, Solid State Protection System (SSPS), and reactor trip switchgear. Field transmitters provide measurement of the unit parameters to the Signal Process Control and Protection System via separate, redundant channels. The Signal Process Control and Protection System forwards outputs to the SSPS, which consists of two redundant trains, to indicate a reactor trip or actuate Engineering Safety Functions.

Table E1-1, In Scope TS/LCO Conditions to Corresponding PRA Functions

2. Depending on the measured parameter, three or four instrumentation channels are provided to ensure protective action when required and to prevent inadvertent isolation resulting from instrumentation malfunctions. The output trip signal of each instrumentation channel initiates a trip logic. Failure of any one trip logic does not result in an inadvertent trip. Generally, if a parameter is used only for input to the protection circuits, three channels with a two-out-of-three logic are sufficient to provide the required reliability and redundancy. If a parameter is used for input to the SSPS and a control function, four channels with a two-out-of-four logic are sufficient.

3. A trip breaker train consists of all trip breakers associated with a single Reactor Trip System logic train that are racked in, closed, and capable of supplying power to the Rod Control System. Consistent with the requirements in WCAP-15376-P-A to include Tier 2 insights into the decision-making process before taking equipment out of service, restrictions on concurrent removal of certain equipment when a RTB train is inoperable for maintenance are included.

4. Each RTB is equipped with a shunt trip device that is energized to trip the RTB open upon receipt of a manual reactor trip signal, thus providing a redundant and diverse trip mechanism. Two Manual Reactor Trip channels provide the signal from reactor trip switches located in the Main Control Room to the RTBs.

5. Each unit has a designated Preferred offsite power source and a designated Alternate offsite power source. The Preferred offsite power source normally energizes the 6.9kV Class 1E buses. If the Preferred offsite power source is lost, the 6.9kV Class 1E buses are automatically energized from the Alternate offsite power source. If the transfer fails, or if the Alternate offsite power source is not available, the diesel generators are started to energize the 6.9kV Class 1E buses.

6. For each unit, the undervoltage protection system, leading to the start of the diesel generators (DG) on loss of offsite power (LOOP), consists of the following functional groups: Preferred offsite source undervoltage, alternate offsite source undervoltage, 6.9kV Class 1E buses loss of voltage, 480V Class 1E buses low grid undervoltage, 6.9kV Class 1E buses degraded voltage, and 480V Class 1E buses degraded voltage. Each of these groups consists of two sensing relays per bus that provide input to two-out-of-two logic. In general, sensing relays for each train feed a network of logic and actuation relays for their respective trains. The start instrumentation requires that two channels per bus of the loss of voltage and degraded voltage Functions shall be operable. Two trains of Automatic Actuation Logic and Actuation Relays shall also be Operable. The required channels of LOP DG start instrumentation, in conjunction with the ESF systems powered from the DGs, provide unit protection in the event of any of the analyzed accidents in which a loss of offsite power is assumed. A NOTE will be added to LCO 3.3.5 limits the use of the RICT for Conditions B, C, D, or E to only one of these Conditions at any one time.

7. The unit can be cooled to residual heat removal (RHR) entry conditions with only one steam generator and one ARV, utilizing the cooling water supply available in the CST.

8. The ECCS consists of three separate subsystems: centrifugal charging (high head), safety injection (intermediate head), and residual heat removal (low head). Each of the three subsystems consists of two 100% capacity trains that are interconnected and redundant such that either train is capable of supplying 100% of the flow required to mitigate accident consequences.

9. The unavailability of one required group of pressurizer heaters would not have any significant impact on plant transient response so there is no quantifiable impact to CDF or LERF. While mitigation of a SGTR is enhanced by the availability of pressurizer heaters, ECA-3.3A/B provides for mitigation of a SGTR without pressurizer heaters, if necessary.

   Degraded pressurizer heater capability is supplemented by the availability of the remaining heaters for plant pressure control, and the availability of plant procedures which provide plant shutdown and cooldown guidance with pressurizer heaters. If the available heaters are sufficient to maintain RCS pressure control, normal plant operations can continue. For the RICT, the impact has been mapped to an increase in the likelihood

of a plant trip (factor of 10) due to degraded pressure control.

10. With both chargers inoperable on a single train of DC power the battery becomes the source of DC power until at least one changer can be restored to OPERABLE status. TS 3.8.4 also provides that the opposite train will provide the safety function.

11. The turbine stop valve trip is a backup for the turbine low oil pressure trip. The stop valve trip is not required to operate in the presence of a single or more channel failure. With a loss of load, the Pressurizer Pressure High trip and the Pressurizer safety valves protect the core and RCS integrity.

Table E1-2, In Scope TS/LCO Conditions RICT Estimate

Tech Spec	LCO Condition	RICT Estimate[1,2,3]
3.3.1.B	One Manual Reactor Trip channel inoperable.	30 days
3.3.1.D	One Power Range Neutron Flux-High channel inoperable.	30 days
3.3.1.E	One channel inoperable	30 days
3.3.1.M	One channel inoperable.	30 days
3.3.1.O	One Low Fluid Oil Pressure Turbine Trip channel inoperable.	30 days
3.3.1.P	One Turbine Trip channel inoperable.	30 days
3.3.1.R	One or more Turbine Stop Valve Closure Turbine Trip channel(s) inoperable.	30 days
3.3 1 S	One RTB train inoperable.	30 days
3.3.1.V	One trip mechanism inoperable for one RTB.	30 days
3.3.2.B	One channel or train inoperable.	30 days
3.3.2.C	One train inoperable.	30 days
3.3.2.D	One channel inoperable.	30 days
3.3.2.F	One channel or train inoperable.	30 days
3.3.2.G	One train inoperable.	30 days
3.3.2.H	One train inoperable.	30 days
3.3.2.I	One channel inoperable.	30 days
3.3.2.J	One Main Feedwater Pumps trip channel inoperable.	30 days
3.3.5.A	One or more Functions with one channel per bus inoperable.	30 days
3.3.5.B	Two channels per bus for the Preferred offsite source bus undervoltage function inoperable.	30 days[4]
3.3.5.C	Two channels per bus for the Alternate offsite source bus undervoltage function inoperable.	30 days[4]
3.3.5.D	Two channels per bus for the 6.9 kV bus loss of voltage function inoperable.	30 days[4]
3.3.5.E	Two channels per bus for one or more degraded voltage or low grid undervoltage function inoperable.	30 days[4]
3.3.5.F	One or more Automatic Actuation Logic and Actuation Relays trains inoperable.	30 days
3.4.9.B	One required group of pressurizer heaters inoperable.	30 days
3.4.11.B	One PORV inoperable and not capable of being manually cycled.	30 days
3.4.11.C	One block valve inoperable.	26.7 days
3.5.2.A	One train inoperable because of the inoperability of a centrifugal charging pump.	30 days
3.5.2.B	One or more trains inoperable for reasons other than one inoperable centrifugal charging pump. AND At least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train available.	30 days
3.6.2.C	One or more containment air locks inoperable for reasons other than Condition A or B.	30 days
3.6.3.A	One or more penetration flow paths with one containment isolation valve inoperable except for containment purge, hydrogen purge or containment pressure relief valve leakage not within limit.	30 days
3.6.3.C	One or more penetration flow paths with one containment isolation valve inoperable except for containment purge, hydrogen purge or containment pressure relief valve leakage not within limit.	30 days

Table E1-2, In Scope TS/LCO Conditions RICT Estimate

Tech Spec	LCO Condition	RICT Estimate[1,2,3]
3.6.6.A	One containment spray train inoperable.	30 days
3.7.2.A	One MSIV inoperable in MODE 1.	30 days
3.7.4.A	One required ARV line inoperable	30 days
3.7.4.B	Two required ARV lines inoperable.	30 days
3.7.4.C	Three or more required ARV lines inoperable.	30 days
3.7.5.A	One steam supply to turbine driven AFW pump inoperable.	30 days
3.7.5.B	One AFW train inoperable for reasons other than Condition A.	30 days
3.7.7.A	One CCW train inoperable.	27.5 days
3.7.8.A	Required SSW Pump on the opposite unit or its associated cross-connects inoperable.	30 days
3.7.8.B	One SSWS train inoperable.	12.2 days
3.7.19.A	One safety chilled water train inoperable.	24.8 days
3.8.1.A	One required offsite circuit inoperable.	30 days
3.8.1.B	One DG inoperable.	30 days
3.8.1.C	Two required offsite circuits inoperable.	29.9 days
3.8.1.D	One required offsite circuit inoperable. AND One DG inoperable.	28.1 days
3.8.1.F	One SI sequencer inoperable.	30 days
3. 8.4.A	One or two required battery chargers on one train inoperable.	13.4 days
3. 8.4.B	One or two batteries on one train inoperable.	28 days
3. 8.4.C	One DC electrical power subsystem inoperable for reasons other than Condition A or B.	30 days
3. 8.7.A	One required inverter inoperable.	30 days
3. 8. 9.A	One AC electrical power distribution subsystem inoperable.	30.6 hours
3.8.9.B	One AC vital bus subsystem inoperable.	19 hours
3.8.9.C	One DC electrical power distribution subsystem inoperable.	86 hours

Notes:

1. The actual RICT values will be calculated using the existing plant configuration and the current revision of the PRA model representing the as-built, as-operated condition of the plant, as required by NEI 06-09-A, Revision 0-A and the NRC safety evaluation, and may differ from the pre-calculated RICT values presented here.

2. RICTs are based on the internal events, internal flood, and internal fire PRA model calculations with seismic and high winds CDF and LERF penalties. RICTs calculated to be greater than 30 days are capped at 30 days based on NEI 06-09-A, Revision 0-A. RICTs not capped at 30 days are rounded to nearest number of hours.

3. Per NEI 06-09-A, Revision 0-A, for cases where the total CDF or LERF is greater than 1E-03/yr or 1E-04/yr, respectively, the RICT Program will not be entered.

4. 30 day RICT justification when extending the 1 hour Completion Time (Front Stop) - The justification for the potential of a 30 day Completion Time comes from the RICT based on internal events, internal flooding, and internal fire PRA model calculations with seismic and high winds CDF and LERF penalties. Actual RICT values are calculated using the existing plant configuration and the current PRA model which represents the as-built and as-operated plant. Conditions B, C, D, and E provide a diversity of inputs that provide multiple undervoltage DG start signals.

Table E1-2, In Scope TS/LCO Conditions RICT Estimate

2.0 References

1. Letter from Jennifer M. Golder (NRC) to Biff Bradley (NEI), "Final Safety Evaluation for Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09-A, 'Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines,'" dated May 17, 2007 (ADAMS Accession No. ML071200238)

2. Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09-A, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0-A, dated October 12, 2012 (ADAMS Accession No. ML 12286A322)

Table E1-3, Conditions Requiring Additional Technical Justification

TSTF-505 Tech Spec Description	CPNPP TS	TSTF-505 TS	TSTF-505 Required Justification	Justification *
One Power Range Neutron Flux - High channel inoperable.	3.3.1.D.1.2	3.3.1.D.2.1	Licensee must justify that the condition does not represent the inability to perform the safety function assumed in the FSAR given the loss of spacial distribution of the remaining Power Range detectors. The justification can include that the Actions require periodic monitoring of spacial power distribution and imposition of compensatory limits and reduced power.	Notes 1 and 2
One RTB train inoperable.	3.3.1.S.1	3.3.1.U.1	The licensee must include information regarding how the TSTF-411 conditions and limitations will be implemented (or similar conditions if TSTF-411 has not been adopted), including discussion of ATWS Mitigation System Actuation (AMSAC), and why those actions are sufficient, including a discussion of defense in depth.	Note 3
Two channels per bus for the Preferred offsite source bus undervoltage function inoperable.	3.3.5.B.1	3.3.5.B.1	Licensee must justify that two or more channels per bus inoperable is not a condition in which all required trains or subsystems of a TS required system are inoperable or modify the Action to not apply a RICT when all required trains or subsystems are inoperable. [See attached Safeguards UV Operation diagram, Figure E1.1]	Notes 4 and 5

Table E1-3, Conditions Requiring Additional Technical Justification

TSTF-505 Tech Spec Description	CPNPP TS	TSTF-505 TS	TSTF-505 Required Justification	Justification *
Two channels per bus for the Alternate offsite source bus undervoltage function inoperable.	3.3.5.C.1	3.3.5.B.1	Licensee must justify that two or more channels per bus inoperable is not a condition in which all required trains or subsystems of a TS required system are inoperable or modify the Action to not apply a RICT when all required trains or subsystems are inoperable. [See attached Safeguards UV Operation diagram, Figure E1.1]	Notes 4 and 5
Two channels per bus for the 6.9 kV bus loss of voltage function inoperable.	3.3.5.D.1	3.3.5.B.1	Licensee must justify that two or more channels per bus inoperable is not a condition in which all required trains or subsystems of a TS required system are inoperable or modify the Action to not apply a RICT when all required trains or subsystems are inoperable. [See attached Safeguards UV Operation diagram, Figure E1.1]	Notes 4 and 5
Two channels per bus for one or more degraded voltage or low grid undervoltage function inoperable	3.3.5.E.1	3.3.5.B.1	Licensee must justify that two or more channels per bus inoperable is not a condition in which all required trains or subsystems of a TS required system are inoperable or modify the Action to not apply a RICT when all required trains or subsystems are inoperable. [See attached Safeguards UV Operation diagram, Figure E1.1]	Notes 4 and 5

Table E1-3, Conditions Requiring Additional Technical Justification

TSTF-505 Tech Spec Description	CPNPP TS	TSTF-505 TS	TSTF-505 Required Justification	Justification *
One or more Automatic Actuation Logic and Actuation Relays trains inoperable.	3.3.5.F.1	3.3.5.B.1	Licensee must justify that one or more channels per bus inoperable is not a condition in which all required trains or subsystems of a TS required system are inoperable or modify the Action to not apply a RICT when all required trains or subsystems are inoperable.	Notes 4 and 5
One required group of pressurizer heaters inoperable.	3.4.9.B.1	3.4.9.B.1	Pressurizer is typically not modeled in the PRA. Licensee must justify the ability to calculate a RICT for the condition, including how the system is modeled in the PRA, whether all functions of the system are modeled, and, if a surrogate is used, why that modeling is conservative.	Note 6

Table E1-3, Conditions Requiring Additional Technical Justification

TSTF-505 Tech Spec Description	CPNPP TS	TSTF-505 TS	TSTF-505 Required Justification	Justification *
One or more trains inoperable for reasons other than one inoperable centrifugal charging pump. AND At least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train available.	3.5.2.B	3.5.2.A	Licensee must justify that one or more ECCS trains inoperable is not a condition in which all required trains or subsystems of a TS required system are inoperable. Acceptable justification is TS Condition requiring 100% flow equivalent to a single ECCS train.	The Condition acknowledges that individual component failures could affect both trains but 100% flow equivalent to that of a single train is still required.
One or more containment air locks inoperable for reasons other than Condition A or B.	3.6.2.C.3	3.6.2.C.3	Licensee must justify that an inoperable containment air lock is not a condition in which all required trains or subsystems of a TS required system are inoperable. An acceptable argument may be that a note in TS 3.6.2 requires the condition to be assessed in accordance with TS 3.6.1, Containment Integrity, and excessive leakage would require an immediate plant shutdown under that TS.	TS 3.6.2 Condition C Action C.1 initiates action to evaluate the overall containment leakage rate per LCO 3.6.1. While also verifying a door is closed in the affected air lock and restore the air lock to OPERABLE status in 24 hours. If air lock is not restored, be in MODE 3 in 6 hours and MODE 5 in 36 hours.

Table E1-3, Conditions Requiring Additional Technical Justification

TSTF-505 Tech Spec Description	CPNPP TS	TSTF-505 TS	TSTF-505 Required Justification	Justification *
One containment spray train inoperable.	3.6.6.A.1	3.6.6A	Licensee must justify the ability to calculate a RICT for the condition, including how the system is modeled in the PRA, whether all functions of the system are modeled, and, if a surrogate is used, why that modeling is conservative. [See attached Containment Spray One-Line diagram, Figure E1.2]	Note 7
One MSIV inoperable in MODE 1.	3.7.2.A.1	3.7.2.A.1	Licensee must justify that the condition would not prevent performance of the steam line break isolation function assumed in the accident analysis. An acceptable method may be a second MSIV per steam line, another design feature, or an alternate method of preventing blowdown of more than one steam generator.	The design of the secondary system precludes the uncontrolled blowdown of more than one steam generator, assuming a single active component failure (e.g., the failure of one MSIV to close on demand.) This is accomplished by closing the other three MSIVs manually or automatically.
Two required ARV lines inoperable.	3.7.4.B.1	3.7.4.B.1	Licensee must justify that two or more inoperable ADVs is not a condition in which all required trains or subsystems of a TS required system are inoperable or modify the Action to not apply a RICT when all required trains or subsystems are inoperable.	Note 8

Table E1-3, Conditions Requiring Additional Technical Justification

TSTF-505 Tech Spec Description	CPNPP TS	TSTF-505 TS	TSTF-505 Required Justification	Justification *
Three or more required ARV lines inoperable.	3.7.4.C.1	N/A	Licensee must justify that three or more inoperable ADVs is not a condition in which all required trains or subsystems of a TS required system are inoperable or modify the Action to not apply a RICT when all required trains or subsystems are inoperable.	Note 8
One SSWS train inoperable.	3.7.8.B.1	N/A	Licensee must justify that one SSWS train is not a condition in which all required trains or subsystems of a TS required system are inoperable.	Note 9
One safety chilled water train inoperable.	3.7.19.A.1	N/A	Licensee must justify that one safety chilled water train inoperable is not a condition in which all required trains or subsystems of a TS required system are inoperable. [See attached Safety Chilled Water One-Line diagram, Figure E1.3]	The Safety Chilled Water System for each unit consists of two separate and completely redundant safety trains.

Notes:

* Justification for applying the RICT to any Completion Time must recognize a key fundamental for Technical Specification use. Once in a Condition with Required Actions no additional failures are considered. So, when applying the RICT Completion Time extensions, CPNPP will evaluate if the risk to be in the Condition for the extended time is acceptable.

1. The Reactor Trip System (RTS) instrumentation is segmented into four distinct but interconnected modules: field transmitters and process sensors, Signal Process Control and Protection System, Solid State Protection System (SSPS), and reactor trip switchgear. Field transmitters provide measurement of the unit parameters to the Signal Process Control and Protection System via separate, redundant channels. The Signal Process Control and Protection System forwards outputs to the SSPS,

Table E1-3, Conditions Requiring Additional Technical Justification

which consists of two redundant trains, to actuate a Reactor Trip or an Engineered Safety Feature (ESF). This redundancy maintains safety function.

2. Depending on the measured parameter, three or four instrumentation channels are provided to ensure protective action when required and to prevent inadvertent isolation resulting from instrumentation malfunctions. The output trip signal of each instrumentation channel initiates a trip logic. Failure of any one trip logic does not result in an inadvertent trip. Generally, if a parameter is used only for input to the protection circuits, three channels with a two-out-of-three logic are sufficient to provide the required reliability and redundancy. If a parameter is used for input to the SSPS and a control function, four channels with a two-out-of-four logic are sufficient. In both cases, a single failure will neither cause nor prevent the protective safety function actuation. With a failed power range instrument and rated thermal power greater than 75% the Quadrant Power Tilt Ratio must be verified 12 hours after the channel became inoperable and then every 12 hours until the channel is restored to OPERABLE status.

3. A trip breaker train consists of all trip breakers associated with a single Reactor Trip System logic train that are racked in, closed, and capable of supplying power to the Rod Control System. Consistent with the requirement in WCAP-15376-P-A to include Tier 2 insights into the decision-making process before taking equipment out of service, restrictions on concurrent removal of certain equipment when an RTB train is inoperable for maintenance are included. Multiple SSPS outputs provide trip signals to the trip logic which in turn opens the trip breakers. Additionally, CPNPP has ATWS Mitigation System Actuation Circuitry (AMSAC). At CPNPP the ATWS is referred to as the Anticipated Transient Without Trip (ATWT). AMSAC is independent of SSPS. AMSAC actuation will occur if turbine load is greater than 40% and three of four Steam Generator (SG) narrow range levels are less than 10%. There is a built in time delay to allow SSPS time to actuate. The AMSAC output will trip the main turbine, start all Auxiliary Feedwater (AFW) pumps, isolate SG blowdown and sample lines, and close the Condensate Storage Tank (CST) discharge valves. Due to a different main feedwater design on Unit 2, AMSAC also close the Feedwater Split-flow Bypass Valves (FSBVs). The system design is to provide AFW flow to the SGs and conserve feedwater while responding to an ATWT.

   CPNPP adopted TSTF-411 with License Amendment 114 (ML050460331). It can be seen that the CPNPP SSPS which provides protection through actuation of required reactor trips and engineered safety features and the adoption the AMSAC system described above, there is defense-in-depth should the reactor not trip. AMSAC actuation is delayed allowing SSPS the opportunity to trip the reactor and actuate ESF components. If SSPS fails to perform its safety function, AMSAC will actuate to preserve a heat sink, preventing core damage. A manual reactor trip from two different handswitches and a manual turbine trip in the Control Room are available, providing diversity and defense-in-depth.

4. Each unit has a designated Preferred offsite power source and a designated Alternate offsite power source. The Preferred offsite power source normally energizes the 6.9kV Class 1E buses. If the Preferred offsite power source is lost, the 6.9kV

Table E1-3, Conditions Requiring Additional Technical Justification

Class 1E buses are automatically energized from the Alternate offsite power source. If the transfer fails, or if the Alternate offsite power source is not available, the diesel generators are started to energize the 6.9kV Class 1E buses. For Conditions B, C, D, E, and F separate entries are allowed by TS 3.3.5. Currently each of these Conditions call for restoring one channel per bus to OPERABLE status within 1 hour. "Two channels per bus" is acceptable as each bus must have both channels to initiate the start signal for the DG in Conditions B, C, D, or E.

Condition F allows for 1 hour to restore Automatic Actuation Logic and Actuation Relays train(s) whether one or both trains are inoperable. One train is sufficient to start the train-related DG and satisfy the required functionality. If one or both Automatic Actuation Logic and Actuation Relays train(s) are inoperable, then the associated DG(s) are declared inoperable after 1 hour. If both buses are found to be inoperable per Conditions B, C, D, or E, then actions for the inoperable source or bus will be required. In applying the RICT, the 1 hour Completion Times may be extended based on plant configuration and acceptable risk. Failure to meet the Completion Time will cause entry into TS 3.8.1 for an inoperable Diesel Generator in accordance with TS 3.3.5, Condition G.

The RICT program could provide a Completion Time up to 30 days depending on plant conditions.

The RICT will be applied based on plant conditions and acceptable risk to determine a Completion Time different from the 72 hours. If the RICT allows the change to the Completion Time, then by default the new Completion Time is reasonable and the probability of an event requiring use of the DGs remains low.

5. For each unit, the undervoltage protection system, leading to the start of the diesel generators (DG) on loss of offsite power (LOOP), consists of the following functional groups: Preferred offsite source undervoltage, alternate offsite source undervoltage, 6.9kV Class 1E buses loss of voltage, 480V Class 1E buses low grid undervoltage, 6.9kV Class 1E buses degraded voltage, and 480V Class 1E buses degraded voltage. Each of these groups consists of two sensing relays per bus that provide input to two-out-of-two logic. In general, sensing relays for each train feed a network of logic and actuation relays for their respective trains. The start instrumentation requires that two channels per bus of the loss of voltage and degraded voltage Functions shall be operable. Two trains of Automatic Actuation Logic and Actuation Relays shall also be Operable. The required channels of LOP DG start instrumentation, in conjunction with the ESF systems powered from the DGs, provide unit protection in the event of any of the analyzed accidents in which a loss of offsite power is assumed.

6. Safety analyses do not take credit for pressurizer heaters. The initial assumption is that the RCS is at normal pressure. Any RICT application will evaluate the anticipated demand for more than one group of heaters. The current model of record does not explicitly model the pressurizer heater directly, instead, we use a surrogate to represent its function/impact in the RICT model. For the RICT, this is done by increasing the likelihood of a reactor trip by a factor of 10 (conservative modeling). The unavailability of one required group of pressurizer heaters would not have any significant impact on plant transient response

Table E1-3, Conditions Requiring Additional Technical Justification

so there is no quantifiable impact to CDF or LERF. While mitigation of a SGTR is enhanced by the availability of pressurizer heaters, ECA-3.3A/B provides for mitigation of a SGTR without pressurizer heaters, if necessary.

Degraded pressurizer heater capability is supplemented by the availability of the remaining heaters for plant pressure control, and the availability of plant procedures which provide plant shutdown and cooldown guidance with pressurizer heaters. If the available heaters are sufficient to maintain RCS pressure control, normal plant operations can continue. CPNPP design includes one control heater group and three backup heater groups. Only two groups of heaters are required with an output of 150 KW each.

7. The Containment Spray (CT) System for each unit consists of two separate and completely redundant safety trains. Each Containment Spray train has two pumps. The CPNPP model of record / RICT model requires two CT spray pumps per train to meet its success criteria (only one train is required to meet the PRA success criteria). As this is explicitly modeled, when either pump (in a train) is removed from service the function is failed for that train and the RICT will be calculated based on the new configuration. This is a conservative model that does not credit single pump operation in a train.

8. The unit can be cooled to residual heat removal (RHR) entry conditions with only one steam generator and one ARV, utilizing the cooling water supply available in the CST. Currently the Completion Time for one ARV inoperable is 7 days, for two ARVs inoperable is 72 hours, and for three or more ARVs inoperable is 24 hours.

   The design basis of the ARVs for the minimum relief capacity is established by the capability to cool the unit to RHR entry conditions and the capability to mitigate a SGTR, The design basis for the maximum relief capacity is established by the 10CFR100 limits for SGTR and the capacity of the MSSVs assumed in the accident analyses. The design cooldown rate of 50°F per hour is applicable for a natural circulation cooldown using two steam generators, each with one ARV. The unit can be cooled to RHR entry conditions with only one steam generator and one ARV, utilizing the cooling water supply available in the CST.

9. The SSWS consists of two separate, 100% capacity, safety related, cooling water trains. Each train consists of one 100% capacity pump, piping, valving, and instrumentation. The pumps and valves are remote and manually aligned to be operable in the unlikely event of a loss of coolant accident (LOCA). The pumps aligned to their respective loops are automatically started upon receipt of a safety injection signal. An automatic valve in the discharge of each pump is interlocked to open on a pump start. An automatic valve in the SSWS cooling water flow path for each emergency diesel generator automatically opens on a diesel generator start. All other valves are manual valves operated locally. The SSWS also is the backup water supply to the Auxiliary Feedwater System.

   Cross-connections are provided between trains and between units such that any pump can supply any other pump's required flow.

Table E1-4, Evaluation of Instrumentation and Control Systems

Accident		RTS Function	ESFAS Function	LOP DG Start Function	Equipment	ESF Equipment
15.1	INCREASE IN HEAT REMOVED BY THE SECONDARY SYSTEM					
	Feedwater system malfunctions that result in a decrease in feedwater temperature	• Overpower N-16 • Power range high flux • Overtemperature N-16 • Manual				
	Feedwater system malfunctions that result in an increase in feedwater flow	• Power range high flux • High SG level • Manual	• High SG level (P-14) produced FWI & Turbine Trip		• FWIVs	
	Excessive increase in secondary steam flow	• Power range high flux • Overtemperature N-16 • Overpower N-16 • Manual			• PRZR Safety Valves • MSSVs	
	Inadvertent opening of a steam generator relief or safety valve	• Low PRZR Press • Manual • SI signal	• Low PRZR Press • Low MSL Press • Manual		• FWIVs • MSIVs	• AFW System • SI System
	Steam system piping failure	• SI signal • Low PRZR Press • Manual	• Low PRZR Press • Low MSL Press • CNTMT Press High 1 • Manual	(Note 1)	• FWIVs • MSIVs	• AFW System • SI System

Table E1-4, Evaluation of Instrumentation and Control Systems

Accident		RTS Function	ESFAS Function	LOP DG Start Function	Equipment	ESF Equipment
15.2	DECREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM					
	Loss of external electrical load / turbine trip	• High PRZR Press • Overtemperature N-16 • Manual			• PRZR Safety Valves • MSSVs	
	Loss of non-emergency AC power to the station auxiliaries	• Low-Low SG level • Manual	• Low-Low SG level (AFW Initiation)	Note 2	• MSSVs	• AFW System
	Loss of normal feedwater flow	• Low-Low SG level • Manual	• Low-Low SG level		• MSSVs	• AFW System
	Feedwater system pipe break	• Low-Low SG level • High PRZR Press • SI signal • Manual	• CNTMT Press High 1 • Low-Low SG level • Low MSL Press	Note 1	• MSIVs • Feedline isolation • PRZR Safety Valves • MSSVs	• AFW System • SI System
15.3	DECREASE IN REACTOR COOLANT SYSTEM FLOW RATE					
	Partial and complete loss of forced reactor coolant flow	• RCS low flow • RCP undervoltage • RCP underfrequency • Manual			• MSSVs	
	Reactor coolant pump shaft seizure (locked rotor)	• RCS low flow • Manual			• PRZR Safety Valves • MSSVs	

Table E1-4, Evaluation of Instrumentation and Control Systems

Accident		RTS Function	ESFAS Function	LOP DG Start Function	Equipment	ESF Equipment
15.4	REACTIVITY AND POWER DISTRIBUTION ANOMALIES					
	Uncontrolled rod cluster control assembly bank withdrawal from a subcritical or low power startup condition	• Power range high flux (Low setpoint) • Manual				
	Uncontrolled rod cluster control assembly bank withdrawal at power	• Power range high flux • Power range high flux rate • Overtemperature N-16 • Overpower N-16 • High PRZR Press • Manual			• PRZR Safety Valves • MSSVs	
	Rod cluster control assembly misalignment	• Low PRZR Press • Overtemperature N-16 • Manual				
	Chemical and Volume Control System malfunction that results in a decrease in boron concentration in the reactor coolant	• Source range high flux • Power range high flux • Power range high flux (Low setpoint) • Overtemperature N-16 • Manual			• Rod insertion limit alarms • VCT high level • CVCS/RMWS alarms	
	Spectrum of rod cluster control assembly ejection accidents	• Power range high flux • Power range high flux (Low setpoint) • Power range high flux rate • Manual				

Table E1-4, Evaluation of Instrumentation and Control Systems

Accident		RTS Function	ESFAS Function	LOP DG Start Function	Equipment	ESF Equipment
15.5	INCREASE IN REACTOR COOLANT INVENTORY					
	Inadvertent operation of the ECCS during power operation	• Low PRZR Press • Manual • SI signal				• SI System
15.6	DECREASE IN REACTOR COOLANT INVENTORY					
	Inadvertent opening of a pressurizer safety or relief valve	• Low PRZR Press • Overtemperature N-16 • Manual				
	Steam generator tube failure	• Low PRZR Press • Overtemperature N-16 • Manual	• Low PRZR Press • Manual	Note 1	• SSW System • CCW System • MSSVs / ARVs • MSIVs • PORVs	• ECCS • AFW System • MSSVs / ARVs • Emergency Power
	Loss of coolant accidents resulting from the spectrum of postulated piping breaks within the reactor coolant pressure boundary	• RTS	• ESFAS	Note 1	• SSW System • CCW System • MSSVs / ARVs	• ECCS • AFW System • CNTMT Spray • Emergency Power

Notes

1. The emergency Diesel Generators (DG) have two automatic starts outside of the starts provided in TS LCO 3.3.5, LOP DG Start Instrumentation; Blackout (undervoltage) and Safety Injection (SI). If the SI is the event initiator the SI starts the DG. If a loss of all offsite power (LOOP) is the event initiator the Blackout will start the DG. The starts provided in LCO 3.3.5 are anticipatory to a loss of offsite power. Separate relays provide the starts from LCO 3.3.5 Functions. The DGs are emergency started by an SI, LOOP (undervoltage), and SBO (undervoltage). The LOOP and SBO starts come from undervoltage relays in the LOP DG Start Instrumentation.

Table E1-4, Evaluation of Instrumentation and Control Systems

2. A loss of non-emergency offsite power will likely be accompanied by a loss of safety related offsite power. If that is so the Blackout (undervoltage) will start the DGs. If the Blackout start malfunctions, then any of the LCO 3.3.5 will start the DGs due to degraded voltage or undervoltage.

   Unit 1 is used for the example in the following description.

   Comanche Peak design is such that the Non-1E 6.9 kV buses (1A1, 1A2, 1A3, 1A4, and XA1) are supplied from the 345 kV switchyard through transformer 1ST until 230 MWe Main Generator load during plant startup. At 230 MWe, operators align Non-1E 6.9 kV buses to be supplied from the Unit 1 Auxiliary Transformer 1UT. 1UT taps off of the Main Generator output prior to the Main Generator output breakers which tie into the 345 kV switchyard. During plant shutdown, when the reactor is tripped the Main Generator output breakers trip open causing the feeder breakers from 1UT to open and closure of the feeder breakers from 1ST (offsite power source).

ENCLOSURE 2

License Amendment Request

Comanche Peak Nuclear Power Plant, Units 1 and 2

NRC Docket Nos. 50-445 and 50-446

Revise Technical Specifications to Adopt Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times – RITSTF Initiative 4b"

Information Supporting Consistency with Regulatory Guide 1.200

1.0 Introduction

The purpose of this enclosure is to provide information on the technical adequacy of the Comanche Peak Nuclear Power Plant (CPNPP) probabilistic risk assessment (PRA) internal events model (including internal flooding) and the CPNPP Fire PRA model in support of the license amendment requests to adopt TSTF-505 [Ref. 20].

This enclosure provides information supporting the CPNPP evaluation of the technical adequacy of the PRA models supporting the RICT program based on peer reviews and self-assessments against the relevant PRA standards as endorsed in the current applicable revision of RG 1.200, including consideration of staff clarifications of the standards.

Per NEI 06-09-A [Ref. 1], Capability Category II of the standards is applicable; therefore, this enclosure identifies those parts of the PRAs that conform to capability categories lower than Category II and provides a disposition for the RICT application. Consistent with RG 1.200, Section 4.2, this enclosure identifies and provides a discussion of the resolutions of any findings and observations from the peer reviews or self-assessments.

This enclosure addresses the clarifications and qualifications found in RG 1.200 as the peer reviews and self-assessments performed included consideration of the clarifications and qualifications of the current applicable RG 1.200 revision.

The guidance in Appendix X of NEI 05-04 [Ref. 6], "Process for Performing Internal Events PRA Peer Reviews Using the ASME/ANS PRA Standard, Rev 3, November 2009," NEI 07-12 [Ref. 7], "Fire Probabilistic Risk Assessment Peer Review Process Guidelines, Rev 1, June 2010," and NEI 12-13 [Ref. 15], "External Hazards PRA Peer Review Process Guidelines, Rev 0, August 2012," to close PRA peer review findings was used for the CPNPP model as discussed in the remaining subsections of this enclosure.

Furthermore, the NRC published RG 1.200 Rev. 3 [Ref. 13] in December 2020. The peer reviews, self-assessments, and F&O Closures discussed in the Enclosures to this LAR were all performed to RG 1.200 Rev. 2 [Ref. 4]. RG 1.200 Rev. 3 [Ref. 13] updates RG 1.200 Rev. 2 [Ref. 4] in the following manner:

- Endorses NEI 17-07 Revision 2 [Ref. 16], "Performance of PRA Peer Reviews Using the ASME/ANS PRA Standard."
- Endorses, with staff exceptions and clarifications, requirements in ASME/ANS RA-S Case 1 [Ref. 17], "Case for ASME/ANS RA-Sb-2013 Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment of Nuclear Power Plant Applications."
- Endorses the requirements for peer review of Newly Developed Methods (NDMs), process for determining whether a change to a PRA is classified as PRA maintenance or a PRA upgrade, and definitions related to NDMs, PRA maintenance, and PRA upgrade from PWROG-19027-NP, Revision 2 [Ref. 18], "Newly Developed Method Requirements and Peer Review."
- Enhances guidance related to key assumptions and sources of uncertainty
- Provides a glossary of key terms
- Provides a list of hazards to be considered in the development and use of PRA.

The peer reviews, self-assessments, and F&O closures performed on the CPNPP Unit 1 and 2 PRA models were performed to the endorsements stated in RG 1.200 Rev. 2 [Ref. 4]. Given the list of updates above, the CPNPP Units 1 and 2 PRA model is consistent with RG 1.200 Rev. 3 [Ref. 13].

The current internal events PRA model is a combined PRA model that represents both units. The PRA model is built with a common one-top fault tree, including individual basic events for both Unit 1 and Unit 2 components. Differences that impact the PRA logic for the units are reflected in the combined PRA fault tree and are activated by flags to produce unit-specific PRA results.

The current internal flood PRA model maintains two separate FRANX database files for CPNPP U1 and U2 due to unit specific scenarios. When quantifying both internal events and internal flood, the FRANX database files are used to inject the unit specific scenarios into the internal events PRA model, resulting in a fault tree and associated database for U1 and U2.

The fire PRA model is built to integrate with the interval events PRA model. Currently, four FRANX database files are maintained for the Fire PRA (one for each unit, and files for CDF and LERF, respectively) due to limitations of the FRANX software itself.

Topical Report NEI 06-09-A [Ref.1], as clarified by the United States Nuclear Regulatory Commission (NRC)'s final safety evaluation of this report [Ref. 2], defines the technical attributes of a PRA model and its associated Configuration Risk Management Program (CRMP) required to implement this risk-informed application. Meeting these requirements satisfies NRC Regulatory Guide (RG) 1.174 [Ref. 3] requirements for risk-informed plant-specific changes to a plant's licensing basis.

Vistra OpCo employs a multi-faceted approach to establishing and maintaining the technical adequacy and fidelity of PRA models. This approach includes both a proceduralized PRA maintenance and update process and the use of self-assessments and independent peer reviews.

Section 2 of this enclosure describes requirements related to the scope, as well as the technical adequacy of the CPNPP PRA internal events model (including internal flooding). Section 3 describes requirements related to the scope, as well as the technical adequacy of the CPNPP PRA fire PRA model. Section 4 lists references used in the development of this enclosure. Note that this enclosure does not discuss risk impacts of external events. The treatment of high winds, seismic, and other external hazards are discussed in Enclosure 4.

All the PRA models described below have been peer reviewed, and the review and closure of all suggestion and finding-level F&Os from the peer reviews have been independently evaluated to confirm that the associated model changes did not constitute a model upgrade. Expectations regarding preparation of the peer reviews (NEI 05-04 [Ref. 6], Section 4.2) and conduct of the self-assessment by the host utility (NEI 05-04 [Ref. 6], Section 4.3), were addressed prior to conduct of any of the reviews. This included documentation by the host utility of resolution of the prior PRA peer review finding-level F&Os and preparation of the information required for the independent assessment. The documented bases for F&O closure provided by CPNPP included a written assessment whether the resolution constituted PRA maintenance or PRA upgrade.

Digital systems are not included in the CPNPP RICT program LCOs. There are digital systems installed in the plant (e.g., BOP), but they are not credited in the systems that are explicitly modeled in the PRA. There are no risk significant I&C systems at CPNPP. In the higher-level systems, digital controllers are used for the main feedwater pump speed controller and the main generator voltage control. Failure modes for these applications are considered in the PRA as part of the initiating event frequency (i.e., in reactor/turbine trip or the loss of main feedwater initiator).

Shared systems that are credited in the Real Time Risk (RTR) model that supports the RICT calculations are explicitly modeled. The RTR model contains logic (basic events) that represent the portions of systems that are credited. The plant's risk assessment process (as well as the RICT process) requires the inclusion of these shared components when they are removed from service. For RICT assessments, the analyzed unit out of service (OOS) components and the "other unit" modeled/credited OOS components are imported/entered into the RICT configuration risk management (CRM) tool. Once imported, the CRM software calculates the risk associated from the configuration, including the impacts of the shared systems being out of service. The shared systems are credited for limited scenarios. All shared systems credited in the RTR model were validated during the PRA model development process to be used within their design capacities/capabilities. Any impacts to the other unit explicitly disallow credit for cross-tied systems and shared system impacts can be assessed explicitly in the model, impacting whichever unit alignment is being assessed.

Reference 8 through 12 provide additional details of the various Peer Reviews, and associated F&O closures, including the approach taken.

2.0 Scope and Technical Adequacy of CPNPP Internal Events PRA Model (Including Internal Flooding)

The CPNPP internal events PRA model (including internal flooding) is an at-power model (i.e., they directly address plant configurations during plant modes 1 and 2 of reactor operation). The Level 1 and full Level 2 PRA models provide both the Core Damage Frequency (CDF) and the Large Early Release Frequency (LERF) figures of merit.

Topical report NEI 06-09-A [Ref. 1] requires that the PRA be reviewed to the guidance of NRC RG 1.200 [Ref. 4] for a PRA which meets Capability Category (CC) II for the supporting requirements of the ASME/ANS PRA Standard [Ref. 5]. It also requires that deviations from these CCs relative to the Risk-Informed Completion Time (RICT) program be justified and documented, as necessary.

The information provided in this section demonstrates that the CPNPP internal events PRA model (including internal flooding) meets the expectations for PRA scope and technical adequacy as presented in NRC RG 1.200, Revision 2 [Ref. 4].

The ASME/ANS PRA standard [Ref. 5] contains a total of 316 numbered supporting requirements for internal events and internal flooding in nine technical elements. The requirements contained in the configuration control element were assigned 9 numbers to facilitate the peer review. Therefore, the peer review covered a total of 325 supporting requirements. The peer review team determined that seventeen of the SRs were to be not applicable (N/A) to the CPNPP PRA. Of the 308 remaining SRs, 290 SRs, or 94.2%, were rated as SR Met, Capability Category I/II, or greater. Seven (7) SRs were rated as Category I and eleven (11) SRs were not met.

During the review, eighty-one (81) new Facts and Observations (F&Os) were prepared, including 55 suggestions, 21 findings, and four (4) best practices. Many of these F&Os involved documentation issues.

Following the industry peer review, the CPNPP PRA model was revised to address these findings and observations. An independent assessment of the closure of the F&Os generated from peer reviews of the CPNPP internal events and internal flooding PRAs was performed following the guidance of Appendix X of NEI 05-04 [Ref. 6]. This independent assessment concluded that all internal events and internal flooding "finding" level and identified "suggestion" F&Os are considered closed. All applicable supporting requirements are now met at Capability

Category II or better with the exception of two SRs, IFEV-A6, and LE-C11 which are found Met at CC-I. No peer review finding level F&Os were associated with these SRs. Details of the SR assessments and utility responses for IFEV-A6 and LE-C11 are provided below. These assessments are not considered limiting since use of model results would be conservative or non-impactive for the TSTF-505 application.

Regarding LE-C11, the CPNPP Level 2 model follows the guidance of WCAP-16341-P, "Simplified Level 2 Modeling Guidelines," which results in LE-C11 being Met at CC-I. This report provides a common simplified Level 2 methodology for large dry containments that, in conjunction with appropriate plant-specific assessments, would meet the technical adequacy of the ASME PRA Standard CC-II for assessment of the large early release frequency (LERF). This report provides a Level 2 methodology that is consistent with the approach outline in NUREG/CR-6595, Revision 1, but further concentrates on gathering the data necessary to generate models and data to realistically treat sever accident management actions, direct containment heating failures, and thermally-induced steam generator tube ruptures (TI-SGTR). The model includes the capability to compute LERF, as well as later contributions to plant risk. These later contributions can impact risk importance of containment systems and are of importance as input in Level 3 risk assessments. The LERF model specifically: (1) includes capability to model thermally and pressure induced steam generator tube ruptures, and (2) considers operator actions within the scope of Westinghouse and Combustion Engineering Severe Accident Management Guidance. Level 2 aspects of the event tree have been explicitly developed with simplified treatment of basemat melt-through delayed hydrogen combustion, and consideration of long-term containment heat removal. The ASME Standard (LE-C11, CC-I) allow for not crediting equipment beyond containment failure because it is conservative to assume failure of the equipment at that time or the equipment operation is not relevant to LERF. Note that containment equipment (e.g., sprays, isolation valves) is credited prior to containment failure in the PRA; the assumption of failure is only applicable given that the containment has failed. An example scenario is where containment failure does not allow containment pressure to increase to the point that containment sprays will actuate; thus, containment sprays are not available for radioisotope scrubbing. RICT for systems that are unrelated/unaffected by containment failure are not impacted by this conservative assumption. RICT for systems that can be impacted by containment failure (e.g., containment spray) will have the appropriate equipment out of service in the model for all LERF scenarios. Credit is not taken for these systems following containment failure because they are not significant to the LERF results. Note that the example (containment spray) is not required for LERF scenarios, per the referenced WCAP and NUREG. The operation of sprays (containment heat removal) in these guidance documents is modeled to lead to scrubbed (small) and/or late releases (i.e., not LERF), and is not credited following containment failure. Thus, this topic is largely limited to containment isolation, which is not relevant beyond containment failure for defining LERF (i.e., simplified Level 2 model that does not consider source terms in detail) since the containment is already failed.

SR	Assessment
IFEV-A6	R&R-PN-021 [Ref. 19] Section 4.7 indicates that the flood initiating event frequencies were based on the EPRI 1021086 failure data combined with plant-specific piping lengths. No Bayesian updating with plant-specific operating experience or adjustment based on engineering judgment was performed. Assessment: Cat I is MET **Response** During the internal flooding (IF) analysis a search for previous IF events at CPNPP was performed and none were found. A Bayesian update with no specific plant events would incur a non-conservative result; therefore, no Bayesian update was performed as there is no impact to application evaluations. Assessment: Status remains at Cat I

SR	Assessment
LE-C11	No credit was taken for continued operation of equipment after containment failure. RXE-LA-CPX/0-105 Table 6-1 specifically notes that "No credit is taken for operation of the ECCS/CS system after containment failure or for operator actions or other equipment that could be impacted by containment failure because there are none that are significant." It is not clear that this is equivalent to justifying "any credit given" as required for CC II/III. Assessment: Cat I is MET **Response** Since no credit has been taken for continued operation after containment failure, justification cannot be provided. Impact on specific applications will be evaluated as needed. Assessment: Status remains at Cat I

3.0 Scope and Technical Adequacy of CPNPP Fire PRA Model

The CPNPP internal fire PRA model is an at-power model (i.e., it directly addresses plant configurations during plant modes 1 and 2 of reactor operation). The Level 1 and full Level 2 PRA models provide both the Core Damage Frequency (CDF) and the Large Early Release Frequency (LERF) figures of merit.

Topical report NEI 06-09-A [Ref. 1] requires that the PRA be reviewed to the guidance of NRC RG 1.200 [Ref. 4] for a PRA which meets Capability Category (CC) II for the supporting requirements of the ASME/ANS PRA Standard [Ref. 5]. It also requires that deviations from these CCs relative to the Risk-Informed Completion Time (RICT) program be justified and documented, as necessary.

The information provided in this section demonstrates that the CPNPP internal fire PRA model meets the expectations for PRA scope and technical adequacy as presented in NRC RG 1.200, Revision 2 [Ref. 4]. Only approved methodologies were utilized in the development of the CPNPP internal Fire PRA.

The ASME/ANS PRA Standard [Ref. 5] contains a total of 173 numbered supporting requirements for internal fire under 13 technical elements. The requirements contained in the

configuration control element were assigned 9 numbers to facilitate the peer review. Therefore, the peer review covered a total of 182 SRs. Sixteen SRs were judged to be not applicable. Of the remaining 166 SRs, 149 SRs, or 88% were rated as SR Met, Capability Category I/II, or greater. Four (4) SRs were rated as Category I and 17 SRs were not met. From this review, a total of 99 unique F&Os were generated. These included 35 suggestions and 64 finding level F&Os.

Following the industry peer review, all peer review F&Os were addressed by revision of supporting documents. Proceeding the updates, an independent assessment of closure for F&Os was performed following the guidance of Appendix X of NEI 07-12 [Ref. 7]. The results of that review concluded that all outstanding F&Os have been closed and that the Fire PRA meets or exceeds Category II or better for all applicable SRs.

4.0 Additional Model Information

4.1 Modeling of the Reactor Coolant Pump (RCP) Shutdown Seals

CPNPP Units 1 and 2 are four-loop Westinghouse plants and use model 93A reactor coolant pumps (RCPs). The reactor coolant pumps contain 8-inch (nominal diameter) high-temperature O-rings as well as the Westinghouse low-leakage Generation III shutdown seal SHIELD®. Following inclusion of the Generation III SDS SHIELD® into the RCPs, the NRC-approved WOG2000 RCP seal LOCA PRA model was updated to meet the modeling guidance specific for the Generation III SDS SHIELD®, as provided in the NRC approved version of PWROG-14001-P-A [Ref. 14]. The CPNPP Unit 1 and 2 internal events PRA models both credit the Generation III SDS SHIELD®. Since the internal events PRA models are used as the basis (or backbone) for other hazard models, the Generation III SDS SHIELD® is inherently credited in all hazard PRA models for CPNPP Units 1 and 2.

The CPNPP Units 1 and 2 PRA models are consistent with the NRC-approved version of PWROG-14001-P-A [Ref. 14] and addresses all limitations and conditions specified. Two limitations and conditions are discussed in more detail:

<u>PWROG-14001-P-A [Ref. 14] Limitation and Condition #2:</u>

Limitation and Condition #2 of PWROG-14001-P-A [Ref. 14] specifies that for scenarios where the cold leg temperature exceeds 571°F, an analysis must be performed to demonstrate that the SDS remains at a temperature below its maximum qualified limit of 565°F. Industry analyses have shown that the cold leg temperature can exceed 571°F in configurations where there is asymmetric SG cooling. The CPNPP PRA models assume that in these scenarios, the Generation III SDS SHIELD® fails. Additionally consistent with the guidance in [Ref. 14], it is assumed that if one seal fails, all seals are failed. This results in a conservative leakage rate.

<u>PWROG-14001-P-A [Ref. 14] Limitation and Condition #4:</u>

Limitation and Condition #4 of PWROG-14001-P-A [Ref. 14] specifies that licensees with RCP Model 93A installed shall incorporate the SDS Bypass failure mode with failure rates as specified in [Ref. 14], consistent with the ASME/ANS PRA standard. The CPNPP PRA model includes the additional failure mode as a potential failure of the Generation III SDS SHIELD®.

The inclusion of the NRC-approved Generation III SDS SHIELD® PRA Model is considered a PRA maintenance activity. It does not impact the ability of the PRA Model to meet the applicable sections of the ASME/ANS PRA Standard and is implemented within the existing framework of the PRA model. Regardless, The CPNPP Units 1 and 2 PRA models, including the Generation

III SDS SHIELD® PRA model, have been peer reviewed with no Facts & Observations relating to the implementation of the Generation III SDS SHIELD® PRA model.

4.2 Modeling of FLEX (Portable) Equipment and Mitigating Actions in the PRA

The CPNPP PRA models do not credit any FLEX (portable) equipment or mitigating actions.

4.3 Modeling of Heat Release Rates, Sensitive Electronics and Minimum HEPs in the PRA

The CPNPP internal fire PRA utilized the bounding 98th percentile Heat Release Rate (HRR) of 317 KW from NUREG/CR-6850 for all transients. There are no locations utilizing a reduced transient fire HRR.

Any sensitive electronics exposed to the fire or the radiant energy were treated consistent with FAQ 13-0004.

A minimum HEP of 1.0E-06 was applied to all combinations in order to capture any non-conservative assessments made by the dependency analysis tool.

4.4 Modeling of Dual Unit Considerations in the PRA

The CPNPP is a dual-unit plant with shared auxiliary and electrical/control buildings, as well as the service water intake structure. Based on its design and the fire response procedures, fire in one unit is not assumed to result in an automatic reactor trip in the other unit. However, if a fire in the control room requires control room evacuation then a trip of both units is completed prior to exiting.

5.0 References

1. Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09-A, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0-A, October 2012 (ADAMS Accession No. ML12286A322)
2. Letter from Jennifer M. Golder (NRC) to Biff Bradley (NEI), "Final Safety Evaluation for Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09-A, 'Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines,'" dated May 17, 2007 (ADAMS Accession No. ML071200238).
3. Regulatory Guide (RG) 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," Revision 2, May 2011.
4. Regulatory Guide (RG) 1.200, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," Revision 2, March 2009.
5. ASME/ANS RA-Sa-2009, "Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications," Addendum A to RAS-2008, ASME, New York, NY, American Nuclear Society, La Grange Park, Illinois, February 2009.
6. Nuclear Energy Institute (NEI) Topical Report (TR) NEI 05-04, "Process for Performing Internal Events PRA Peer Reviews Using the ASME/ANS PRA Standard," Revision 2, November 2008.

7. Nuclear Energy Institute (NEI) Topical Report (TR) NEI 07-12, "Fire Probabilistic Risk Assessment (FPRA) Peer Review Process Guidelines," Revision 1, June 2010.
8. LTR-RAM-II-11-038, "RG 1.200 PRA Peer Review Against the ASME/ANS PRA Standard Requirements for the Comanche Peak Nuclear Power Plant Probabilistic Risk Assessment," Westinghouse Electric Co.
9. LTR-RAM-15-48, Revision 0, "Review of SRs not Met at Capability Category II and Resolution of Peer Review F&Os from the 2011 Internal Events and Internal Flooding PRA Peer Review for the Comanche Peak Nuclear Power Plant," Westinghouse Electric Co.
10. LTR-RAM-15-71, Revision 0, "Independent Review and Resolution of Inconsistencies in the 2011 Internal Events and Internal Flooding PRA Peer Review Report for the Comanche Peak Nuclear Power Plant," Westinghouse Electric Co.
11. PWROG-15103-P, Revision 0, "Peer Review of the Comanche Peak Internal Fire Probabilistic Risk Assessment," Pressurized Water Reactors Owners Group, June 2016.
12. PWROG-18060-P, Revision 0, "Independent Assessment of Facts & Observations Closures of the Comanche Peak Probabilistic Risk Assessment, "Pressurized Water Reactors Owners Group, January 2019.
13. Regulatory Guide (RG) 1.200, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," Revision 3, December 2020.
14. PWROG-14001-P-A, Revision 1, "PRA Model for the Generation III Westinghouse Shutdown Seal," December 2017.
15. Nuclear Energy Institute (NEI) Topical Report (TR) NEI 12-13, Revision 0, "External Hazards PRA Peer Review Process Guidelines," August 2012.
16. Nuclear Energy Institute (NEI) Topical Report (TR) NEI 17-07, Revision 2, "Performance of PRA Peer Reviews Using the ASME/ANS PRA Standard," Washington, DC, August 2019, (ADAMS Accession No. ML19241A615).
17. ASME/ANS RA-S Case 1, "Case for ASME/ANS RA-Sb-2013 – Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications," November 2017.
18. PWROG-19027-NP, Revision 2, "Newly Developed Method Requirements and Peer Review," PWROG, July 2020.
19. R&R-PN-021, Revision 5, "Internal Flood Analysis," Comanche Peak Nuclear Power Plant, May 2019.
20. Letter from the Technical Specification Task Force (TSTF) to the NRC, "TSTF Comments on Draft Safety Evaluation for Traveler TSTF-505, 'Provide Risk-Informed Extended Completion Times' and Submittal of TSTF-505, Revision 2", dated July 2, 2018 (ADAMS Accession No. ML18183A493).

ENCLOSURE 4

License Amendment Request

Comanche Peak Nuclear Power Plant, Units 1 and 2

NRC Docket Nos. 50-445 and 50-446

Revise Technical Specifications to Adopt Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times – RITSTF Initiative 4b"

Information Supporting Justification of Excluding Sources of Risk Not Addressed by the PRA Models

1.0 Introduction and Scope

Topical Report NEI 06-09-A, Revision 0-A [Ref. 1], as clarified by the Nuclear Regulatory Commission (NRC) final safety evaluation [Ref. 2], requires that the license amendment request (LAR) provide a justification for exclusion of risk sources from the Probabilistic Risk Assessment (PRA) model based on their insignificance to the calculation of configuration risk In addition, conservative or bounding analyses applied to the configuration risk calculation are discussed. This enclosure addresses these requirements by discussing the overall generic methodology used to identify and disposition such risk sources. This enclosure also provides the Comanche Peak Nuclear Power Plant (CPNPP) specific results of the application of the generic methodology and the disposition of impacts on the CPNPP Risk-Informed Completion Time (RICT) application. Section 3 of this enclosure presents the plant-specific bounding analysis of seismic risk to CPNPP. Section 4 of this enclosure presents the plant-specific bounding analysis of high-winds risk to CPNPP. Section 0 of this enclosure presents the justification for excluding analysis of other external hazards from the CPNPP PRA. Other external hazards were screened based on the low frequency of occurrence, or in specific instances by bounding the potential impact on configuration risk. The external hazards screening results identified a few specific hazards for which configuration consideration apply addressed by bounding penalty or by a developed PRA. Configuration-specific conditions were considered as part of the screening process, but none were found to be required.

Topical Report NEI 06-09-A [Ref. 1] does not provide a specific list of hazards to be considered in a RICT program; however, non-mandatory Appendix 6-A in the ASME/ANS PRA Standard [Ref. 3], as well as Regulatory Guide 1.200 Revision 3, Appendix D [Ref. 14], provides a guide for identification of most of the possible external events for a plant site. Additionally, NUREG-1855 [Ref. 4] provides a discussion of hazards that should be evaluated to assess uncertainties in plant PRAs and support the risk-informed decision-making process. This information was reviewed for the CPNPP site and augmented with a review of information on the site region and plant design to identify the set of external events to be considered. The information in the UFSAR regarding the geologic, seismologic, hydrologic, and meteorological characteristic of the site region as well as present and projected industrial activities in the vicinity of the plant were also reviewed for this purpose. No new site-specific and plant-unique external hazards were identified through this review and associated plant visit. The list of hazards in Appendix 6-A of the PRA Standard were considered for CPNPP.

2.0 Technical Approach

The guidance contained in NEI 06-09-A states that all hazards that contribute significantly to incremental risk of a configuration must be quantitatively addressed in the implementation of the RICT program. The following approach focuses on the risk implications of specific external hazards in the determination of risk management action time (RMAT) and RICT for the Technical Specification (TS) Limiting Conditions of Operation (LCO) selected to be part of the RICT program.

Consistent with NUREG-1855 [Ref. 4], external hazards may be addressed by the following:

1. Screening the hazard based on a low frequency of occurrence,
2. Bounding the potential impact and including it in the decision-making, or

3. Developing a PRA model to be used in the RMAT/RICT calculation.

The overall process for addressing external hazards considers two aspects of the external hazard contribution to risk.

- The first is the contribution from the occurrence of beyond design basis conditions, e.g., winds greater than design, seismic events greater than the design-basis earthquake (DBE), etc. These beyond design basis conditions challenge the capability of the SSCs to maintain functionality and support safe shutdown of the plant.
- The second aspect addressed is the challenges caused by external conditions that are within the design basis, but still require some plant response to assure safe shutdown, e.g., high winds or seismic events causing loss of offsite power, etc. While the plant design basis assures that the safety related equipment necessary to respond to these challenges are protected, the occurrence of these conditions nevertheless causes a demand on these systems that presents a risk.

Hazard Screening

The first step in the evaluation of an external hazard is screening based on an estimation of a bounding core damage frequency (CDF) for beyond design basis hazard conditions. An example of this type of screening is reliance on the NRC's 1975 Standard Review Plant (SRP) [Ref. 10], which is acknowledged in the NRC's Individual Plant Examination of External Events (IPEEE) procedural guidance [Ref. 5] as assuring a bounding CDF of less than 1E-6/yr for each hazard. The bounding CDF estimate is often characterized by the likelihood of the site being exposed to conditions that are beyond the design basis limits and an estimate of the bounding conditional core damage probability (CCDP) for those conditions. If the bounding CDF for the hazard can be shown to be less than 1E-6/yr, then beyond design basis challenges from the hazard can be screened out and do not need to be addressed quantitatively in the RICT program. The basis for this is as follows:

- The overall calculation of the RICT is limited to an incremental core damage probability (ICDP) of 1E-5.
- The maximum time interval allowed for this RICT is 30 days.
- If the maximum CDF contribution from a hazard is <1E-6/yr, then the maximum ICDP from the hazards is <1E-7/yr (1E-6/yr * 30 days/365 days/yr).
- Thus, the bounding ICDP contribution from the hazard is shown to be less than 1% of the permissible ICDP in the bounding time for the condition. Such a minimal contribution is not significant to the decision in computing a RICT.

While the direct CDF contribution from beyond design basis hazard conditions can be shown to be non-significant using this approach, some external hazards can cause a plant challenge, even for hazard severities that are less than the design basis limit. These considerations are addressed in Section 3 and 4. The majority of hazards screened out on the initial screening for reasons that preclude the need for configuration specific evaluation.

Hazard Analysis – CDF and LERF

There are two options in cases where the bounding CDF for the external hazard cannot be shown to be less than 1E-6/yr. The first option is to develop a PRA model that explicitly models the challenges created by the hazard and the role of the SSCs included in the RICT program in

mitigating those challenges. The second option for addressing an external hazard is to compute a bounding CDF contribution for the hazard. Similarly, a bounding estimate can be calculated for LERF. The approaches used for seismic and high wind risk are described in Section 0 and 4, respectively.

Risks from Hazard Challenges

Given the selection of an estimated bounding CDF/LERF, the approach considered must assure that the RICT program calculations reflect the change in CDF/LERF caused by the out of service equipment. For CPNPP, as discussed later in this enclosure, the beyond design basis hazards that could not be screened out are the seismic and high wind hazards, and the approach used considers that the change in risk with equipment out of service will not be higher than the bounding seismic or high wind CDF.

The above steps address the direct risks from damage to the facility from external hazards. While the direct CDF contribution from beyond design basis hazards can be shown to be non-significant using these steps without a full PRA, there are risks that may be addressed. These risks are related to the fact that some external hazards can cause a plant challenge even for hazards severities that are less than the design basis limit. For example, high winds, tornadoes, and seismic events below the design basis levels can cause extended loss of offsite power conditions. Additionally, depending on the site, external floods can challenge the availability of normal plant heat removal mechanisms.

The approach taken in this step is to identify the plant challenges caused by the occurrence of the hazard within the design basis and evaluate whether the risks associated with these events are either already considered in the existing PRA model or they are not significant to risk.

Hazards of internal flood and fire have not been screened but the impact on the RICT program is assessed with the respective hazard PRAs.

Similarly, seismic and high wind hazards were not screened but risk penalty values have been developed to account for the impact on the RICT program.

Section 3 of this enclosure provides the analysis for CPNPP with respect to the beyond design basis seismic hazard, and Section 4 provides an analysis for the high winds hazard. Section 0 of this enclosure provides an analysis of the "other" representative external hazards for CPNPP.

3.0 Seismic Bounding Analysis

This section presents the analysis that bounds the potential seismic impact for inclusion in the decision-making process, as a seismic PRA is not available for CPNPP. The process for analyzing an unscreened external hazard without the use of a full PRA involves the following three steps:

1. Estimate bounding CDF
2. Evaluate potential risk increases due to out of service equipment
3. Evaluate bounding LERF contribution

Estimate Bounding CDF

CPNPP was classified as a reduced-scope plant seismic evaluation for the IPEEE and used Seismic Margins Assessment (SMA) approach, as permitted by NRC NUREG-1407 [Ref. 5]. Therefore, an alternative approach is taken to provide an estimate of Seismic Core Damage

Frequency (SCDF) based on the current CPNPP Seismic hazard curve and assuming the seismic capacity of a component whose seismic failure would lead directly to core damage. This approach to estimation of the SCDF uses a plant level High-Confidence of Low Probability of Failure (HCLPF) hazard level with the seismic hazard curve. This is a commonly used approach (see Section A.1 of Ref. 6) to estimate SCDF when a seismic PRA is not available and is consistent with approaches that have been used in other regulatory applications.

Calculation of the SCDF in this manner also requires definition of the median and the uncertainty parameters for seismic capacity. The uncertainty parameter for seismic capacity is represented by composite beta factor (β_c) of 0.4 and the median capacity is represented by a value of 0.3g. This approximation is consistent with the NRC plant level fragility data for CPNPP performed for the GI-199 [Ref. 6, Appendix C, Table C-2].

Using the above inputs, the CPNPP total SCDF is estimated to be 1.93E-06 per reactor year for the IPEEE HCLPF (0.12g peak ground acceleration (PGA)). Note that this SCDF value was adjusted using the CPNPP Plant Availability Factor (PAF) of 0.94. Although the penalty factors for the seismic hazard that were generated considered the CPNPP PAF, when converting the baseline PRA model into a real-time-risk model, logic was added at the top of the model to exclude the PAF from the calculation. This is done by multiplying the CDF or LERF results by a value of 1/PAF (~1.06). This SCDF value will be used as the bounding estimate of SCDF for the TSTF-505 submittal RICT calculations.

The values of mean seismic hazard curves and site response amplification functions are provided in Table A-1a of Ref. 7. The recognized limitations of this approach are that integration of the mean seismic hazard curve and the mean plant-level fragility curve is not equal to the mean SCDF; accordingly, the SCDF estimates produced by the approach are point estimates. The approach does not provide a quantitative estimate of the parametric uncertainty in the SCDF and does not provide any insight into which SSCs are important to seismic risk.

<u>Evaluate Potential Risk Increases Due to Out of Service Equipment</u>

The approach taken in the estimation of the CPNPP SCDF assumes that the SCDF can be based on the likelihood that a single seismic-induced failure leads to core damage. This approach implicitly relies on the assumption that seismic-induced failures of similar equipment show a high degree of correlation (i.e., if one SSC fails, all similar SSCs will also fail). This assumption is conservative, but direct use of this assumption in evaluating the risk increase from out of service equipment could lead to an under estimation of the change in risk. However, if no correlation at all is assumed in the seismic failures, then the seismic risk would be lower than the risk predicted by a model that incorporates a higher level of seismic correlation, but the change in risk using the un-correlated model with a redundant piece of important equipment out of service would be bounded to the level predicted by the correlated model.

If the industry accepted approach of correlation is assumed (e.g., as implicitly assumed in the studies performed in Ref. 6), the conditional core damage frequency given a seismic event will remain unaltered whether equipment within a correlated group is out of service or not. Thus, the risk increase due to out of service equipment cannot be greater than the total SCDF estimated by the bounding method used in Reference 6. That is, for the CPNPP site, the delta SCDF from equipment out of service cannot be greater than 1.93E-06/yr.

To summarize the above considerations:

- The baseline seismic risk in this approach is assumed to be zero (i.e., in order to maximize the calculated incremental risk), whereas there will always be some level of baseline seismic risk for a zero-maintenance plant configuration. Therefore, the incremental seismic risk (configuration seismic risk less the baseline seismic risk) will always be overstated using a seismic penalty based on the total estimated seismic risk.
- The limiting HCLPF approach assumes that a failure of a component with seismic capacity at that HCLPF leads directly to core damage. However, even common failure of a given set of components (e.g., all emergency diesel generators) would not lead directly to core damage. In reality, there are few SSCs whose failure would lead to seismic core damage with any significant frequency of occurrence. Examples would be important structures, or the reactor pressure vessel, etc. Such failures generally involved HCLPFs much higher than the 0.12g value assumed for the bounding calculation.
- In a seismic PRA, seismic impacts to similar components (e.g., all the emergency diesel generators) are typically assumed to be correlated unless there are reasons to justify otherwise. Correlation has the effect of introducing common cause impacts. So, if one train of emergency AC power fails seismically, both trains are modeled to fail given the same seismic event. In general, most seismic impacts would effectively be equivalent to Technical Specification loss of function. The assumption of full correlation is less realistic at low g level; for low magnitude earthquakes, a single train seismic-induced failure is more realistic than a fully correlated failure of both trains. This approach cannot fully capture the added risk increase of a configuration change during a very low magnitude earthquake. On the other hand, the scenarios with very low magnitude seismic events are essentially captured by the internal events risk scenarios. At very low seismic events, the more realistic event is a seismic-induced loss of offsite power (LOOP). If no other seismic failures are experienced, the additional risk resulting from a seismic-induced LOOP can be estimated by simply comparing the initiating event frequency (IEF). The total IEF for a seismic-induced LOOP can be estimated by a simple integration of the plant hazard curve with the generic fragility for LOOP (A_m=0.3g, β_R=0.3, β_U = 0.45) from EPRI guidance [Ref. 9], resulting in a total IEF of 2.84E-06. This is approximately 0.02% of the total IEF of the internal events LOOP [Ref. 8]. On this basis, the potentially underestimated risk is judged to be non-significant.

Given the above, the use of a seismic penalty based on assuming seismic core damage given the limiting plant HCLPF is determined to be appropriate.

Evaluate Bounding Seismic LERF Contribution

Since a Seismic PRA is not available for CPNPP, the Seismic LERF (SLERF) could be calculated using the ratio between LERF and CDF based on information from the Internal Events PRA and/or other external hazard PRAs (e.g., flood, fire). However, plants that performed Seismic PRAs generally observed an estimated ratio between LERF and CDF to be higher than the LERF-to-CDF ratio for internal events due to the unique nature of the seismically-induced failures. Therefore, the estimation of the SLERF from this approach may not be sufficiently conservative in addressing the influence of seismic-induced failures.

Given the above, the seismic LERF for CPNPP was estimated by convolving the plant seismic hazard with the plant limiting HCLPF for core damage and the plant limiting HCLPR for containment integrity. Although it is believed that containment capability is significantly greater

than the value assessed in the IPEEE (0.12g), the IPEEE screening level can be used as a conservative value to estimate the CPNPP SLERF.

Using this approach and the inputs from Section 4.1, the CPNPP total SLERF is estimated to be 9.73E-07 per reactor year. Similar to SCDF, this SLERF value was adjusted using the CPNPP PAF. The ratio between seismic LERF and seismic CDF is therefore estimated at 0.5. This SLERF value will be used as the bounding estimated for SLERF for the TSTF-505 submittal RICT calculations.

Seismic Bounding Analysis Summary

Table E4-1 reports the seismic contribution results. The RICT model always includes the seismic penalty in the calculations. The industry accepted approach of correlation is assumed, the conditional core damage frequency given a seismic event will remain unaltered whether equipment within a correlated group is out of service or not. Thus, the risk increase due to out of service equipment cannot be greater than the total SCDF estimated by the bounding method.

Table E4-1: Seismic Results Summary for CPNPP

Unit	SCDF (/ry)	SLERF (/ry)
Unit 1	1.93E-06	9.73E-07
Unit 2	1.93E-06	9.73E-07

4. High Winds Analysis

This section provides an analysis that bounds the potential high winds risk for CPNPP for inclusion in the decision-making process. The applicable wind hazards for CPNPP are tornadoes, thunderstorms, and extratropical storms. "Special winds" are not applicable to the site based on the applicability region map (Figure 26.5-1) in ASCE 7-16. Hurricanes are screened out of the analysis based on the location of the site and the hurricane history described in the FSAR.

The process for analyzing an unscreened external hazard without the use of a PRA involves the following three steps:

1. Estimate bounding Core Damage Frequency (CDF)
2. Evaluate bounding Large Early Release (LERF)
3. Evaluate risk increases due to out of service equipment (CDF/LERF)

The bounding evaluation is based on the assumed loss of offsite power (LOOP) and the coincident likelihood of having certain systems OOS. The process for calculating the bounding penalty factor for CDF and LERF is developed in this section.

The CPNPP Internal Events PRA model was used to calculate the Conditional Core Damage Probability (CCDP) and Conditional Large Early Release Probability (CLERP) by quantifying the model while assuming the following:

- Conditional LOOP probability estimates are based on engineering judgment of the likelihood of different wind-speed conditions causing a LOOP and failure of all SSCs in the plant yard, switchyard and Turbine Building.
- Applying no LOOP recovery for all wind events, as a conservative assumption since non-recovery events are absent in records reviewed for the CPNPP switchyard and Texas' grid.

The initiating event frequency for each wind interval is developed as detailed in the Comanche Peak High Winds PRA Hazard Analysis [Ref. 12] and summarized below. The interval frequency is calculated for each wind event bin by the wind speed lower and upper bound, mean hazard frequency over a year, and the conditional LOOP probability. CDF/LERF estimates are then obtained from the product of the two items (mean frequency and conditional LOOP) for each wind event bin. All binned frequencies are summed to obtain the CDF and LERF bounding values for high wind events.

<u>High Winds Model Data</u>

- Wind Speed Lower and Upper Bound
  These reflect the wind speed lower and upper bound in miles per hour for each interval designator representing ten (10) for tornado bins and ten (10) straight wind bins.
- Mean Hazard Frequency (/yr)
  The interval frequency is obtained by the development of Table 2-3 of Comanche Peak High Winds PRA Hazard Analysis [Ref. 12]. The method for calculating the mean hazard frequencies is summarized below.

  The data source for tornado events is the Storm Prediction Center (SPC) tornado database maintained by NOAA. All tornado records within 125 miles of the site were selected and then adjusted to account for the following known uncertainties: mis-classification of intensity, unreported and unclassified tornadoes, and variation of wind speed within the impact area. These account for each of the elements in Note 1 to supporting requirement WHA A1 of ASME/ANS RA-Sa-2009; that Note was clarified to be mandatory in Revision 2 to Regulatory Guide 1.200. Annual tornado occurrence frequency is calculated following the methods suggested in Revision 2 of NUREG/CR-4461, using the finite-structure strike probability for an area the size of the site. All tornado records, regardless of the scale they were classified under, are used to calculate the annual tornado occurrence frequencies. Exceedance frequencies for wind speeds due to tornadoes were developed by linking the occurrence frequency of tornado magnitudes to wind speeds based on the Enhanced Fujita scale. The current assessment results in a higher tornado occurrence frequency than the IPEEE.

  The data source for straight wind events is surface weather observation stations from airports near the site. Corrections to the straight winds data are then made for anemometer height, terrain profile, anemometer averaging period, storm cause, and outlier investigations. The straight winds data from the relevant stations are combined to obtain a larger data pool, then the maximum wind speed for each year on record is identified, and an exceedance frequency is calculated by fitting the maximum wind speeds to a Type I extreme value distribution. The "straight wind" exceedance frequency is the sum of the thunderstorm and non-thunderstorm exceedance frequencies.

  The following bullets summarize how the industry guidance document EPRI 3002003107 was used in developing the high winds hazard frequencies. From the public description of the report available on the EPRI website, it "provides a review of previous high winds risk assessments and their application to NPP PRAs; it investigates and proposes a graded approach for performing the major tasks of a high winds PRA; and it recommends areas where further research is needed."

- Followed recommendation to use SPC tornado database.
- Followed recommendation to make corrections to straight winds data for each element described above.
- Followed recommendation to use the generalized extreme value distribution for calculating straight wind exceedance frequencies.
- Followed recommendation to use wind gust measurements rather than other wind measurements such as fastest-mile speed. Wind gusts are expected to be bounding relative to other wind measurements.
- Cited as justification for the criterion that weather stations providing straight wind data have at least 30 years of data. This does not result in non-conservative RICTs because the straight winds data discussed in the EPRI 3002003107.

- Conditional LOOP Probability
The conditional loss of offsite power probability has an estimate assigned based on engineering judgment for the different wind-speed levels.

The mean hazard frequencies associated with the 10 tornado wind speed intervals and 10 straight wind speed intervals are listed in Table E4-2 (tornado intervals designated with prefix T and straight wind intervals designated with prefix S):

Table E4-2: Wind Speed Interval Frequencies

Interval designator	Wind speed lower bound (mph)	Wind speed upper bound (mph)	Interval frequency (yr^{-1})
T11	73	84	7.43E-04
T12	85	97	6.28E-04
T13	98	111	5.27E-04
T21	112	125	3.59E-04
T22	126	140	3.49E-04
T23	141	156	2.46E-04
T31	157	176	1.08E-04
T32	177	205	3.00E-05
T4	206	259	3.25E-06
T5	260	318	5.36E-08
S11	73	84	1.48E-01
S12	85	97	3.56E-02
S13	98	111	7.28E-03

Table E4-2: Wind Speed Interval Frequencies

Interval designator	Wind speed lower bound (mph)	Wind speed upper bound (mph)	Interval frequency (yr^{-1})
S21	112	125	1.28E-03
S22	126	140	2.35E-04
S23	141	156	3.80E-05
S31	157	176	5.70E-06
S32	177	205	5.26E-07
S4	206	259	1.57E-08
S5	260	318	2.15E-11

Key assumptions and sources of uncertainty associated with the wind hazard frequency assessment are described in Table E4-3:

Table E4-3: Disposition of Key Assumptions and Sources of Uncertainty

ID	Summary of High Winds Assumption/Uncertainty	Part of Model Affected	Generic Impact on Risk Applications	Evaluation of RICT Impact
1	Site meteorological tower data does not include peak gust measurements for wind. Without peak gust data at the site, other data near the site must be utilized. Therefore, there is uncertainty in how well the regional data represents the site wind climatology.	Straight wind initiating event frequencies.	The selected modeling approach is consistent with EPRI 3002003107. One alternative approach might be to select different nearby anemometers (from airports other than the ones chosen in the baseline model). However, the data corrections applied (described above) attempt to correct regional data to better apply to the site, so it is expected that any differences would be minimal.	This approach follows EPRI 3002003107 and industry practice, which is in essence, a consensus process. In addition, the alternative approach is expected to result in minimal change. Therefore, no additional sensitivities are required.
2	Extrapolation of straight wind hazards to very low exceedance frequencies represents a substantial uncertainty because the wind speeds being predicted are well beyond any observed data. Mean hazard frequencies are used in the final calculation.	Straight wind initiating event frequencies.	The selected modeling approach is consistent with EPRI 3002003107.	The impact with respect to these applications would be to potentially produce uniform shifts in the straight wind hazard frequencies, which is unlikely to have a significant impact on equipment importance measures or relative risk insights.

Table E4-3: Disposition of Key Assumptions and Sources of Uncertainty				
ID	Summary of High Winds Assumption/Uncertainty	Part of Model Affected	Generic Impact on Risk Applications	Evaluation of RICT Impact
3	SSCs located outside, or located inside a building vulnerable to high winds, are assumed to fail for the bounding penalty approach. This is conservative because failure of the building may not always result in failure of all of the equipment inside, or equipment located outside may survive smaller or less-intense wind events.	Equipment credited to mitigate high wind events.	This is a conservative assumption that is made based on the uncertainty related to the damage that may occur to credited equipment and is consistent with EPRI 3002003107.	The uncertainty/assumption represents a generally conservative bias in the penalty assessment and removing the identified conservative bias would only serve to improve acceptability with respect to the acceptance guidelines. This criterion is consistent with the guidance in Section 3.1.1 of EPRI 1016737, "Treatment of Parameter and Modeling Uncertainty for Probabilistic Risk Assessments." Additionally, this approach follows EPRI 3002003107 and industry practice, which is in essence, a consensus process.
4	It is assumed that offsite power recovery is not possible for high wind events.	Electric power support for ECCS equipment credited for mitigation of high wind events.	This is a conservative assumption. A sensitivity study was performed to characterize the impact of this assumption in LTR-RAM-20-99.	Existing sensitivity studies adequately characterize this source of uncertainty. The impact with respect to these applications would be to potentially change overall LOOP contribution, which would not alter the current insights from the model.

Table E4-3: Disposition of Key Assumptions and Sources of Uncertainty				
ID	Summary of High Winds Assumption/Uncertainty	Part of Model Affected	Generic Impact on Risk Applications	Evaluation of RICT Impact
5	Tornado records are selected from a symmetric area centered on the plant. A more uniform tornado occurrence rate might be achieved if a contiguous, non-symmetric area were used. That is, some locations within the 125-mile radius used to select tornado records may have a slightly different tornado occurrence rate than others due to topographic features or local weather patterns.	Tornado initiating event frequencies.	The alternative modeling approach (selecting from a non-symmetric area) could conceivably result in more tornado records over approximately the same area, which would result in a greater tornado occurrence rate. The approach implemented is a consensus approach to tornado record selection and is consistent with NUREG/CR-4461, which is referenced in the note to SR WHA-A1 of the PRA Standard as an example of a state-of-the-art methodology for tornado hazard analysis. Sensitivity studies for tornado record selection area were performed in in CN-RAM-20-002 and justify the area chosen.	This approach follows industry guidance, which is in essence, a consensus process. Existing sensitivity studies adequately characterize this source of uncertainty. The impact with respect to these applications would be to either uniformly increase or uniformly decrease the tornado initiating event frequencies, thus impacting risk metrics in a somewhat uniform way (i.e., little to no impact on relative risk insights). Therefore, no additional sensitivities are required.

Table E4-3: Disposition of Key Assumptions and Sources of Uncertainty				
ID	**Summary of High Winds Assumption/Uncertainty**	**Part of Model Affected**	**Generic Impact on Risk Applications**	**Evaluation of RICT Impact**
6	Tornado data is not corrected to account for the change in reporting of path width that occurred in 1994. Prior to this date, the reported path width was the mean; after this date, the reported path width was the maximum.	Tornado initiating event frequencies.	This is consistent with EPRI 3002003107, which states that this is a conservative approach since the maximum wind speed is only present in part of the tornado path.	The uncertainty/assumption represents a generally conservative bias in the PRA model, and removing the identified conservative bias would only serve to improve acceptability with respect to the acceptance guidelines. This criterion is consistent with the guidance in Section 3.1.1 of EPRI 1016737. Additionally, this approach follows EPRI 3002003107 and industry practice, which is in essence, a consensus process. Therefore, no additional sensitivities are required.

Table E4-3: Disposition of Key Assumptions and Sources of Uncertainty

ID	Summary of High Winds Assumption/Uncertainty	Part of Model Affected	Generic Impact on Risk Applications	Evaluation of RICT Impact
7	Tornado data is corrected to account for an observed under-reporting of F0 tornadoes prior to 1988. The number of tornadoes is increased by a factor of approximately 3.4, which is the factor by which the average count of F0 tornadoes in the contiguous US from 1989-2018 is greater than the average from 1950-1988. This factor is applied to tornado records prior to 1989. This approach redistributes the exceedance frequency among the various tornado bins as a result of changing the intensity distribution vector by adding new EF0 records. In other words, the frequencies of EF0 and EF1 tornadoes increase, and the frequencies of other tornadoes decrease.	Tornado initiating event frequencies.	This is consistent EPRI 3002003107. An alternative would be to exclude data prior to 1988, which would adversely impact the limited statistics and introduce more uncertainty through state of knowledge.	This approach follows EPRI guidance and industry practice, which is in essence, a consensus process. Therefore, no additional sensitivities are required.

Table E4-3: Disposition of Key Assumptions and Sources of Uncertainty				
ID	**Summary of High Winds Assumption/Uncertainty**	**Part of Model Affected**	**Generic Impact on Risk Applications**	**Evaluation of RICT Impact**
8	The method of assigning wind speed values to the F-/EF-scales represents a substantial uncertainty. See the discussion in the response to question 18.b.ii.	Binning of tornado exceedance frequencies.	The selected modeling approach is consistent with EPRI 3002003107 and is deemed as an acceptable industry practice; essentially a consensus model or process, and no further characterization is required. There is also no practical alternative (i.e., cannot quantify in 1-mph increments).	This approach follows EPRI guidance and industry practice, which is in essence, a consensus process. This criterion is consistent with Section 3.3.2 of RG 1.200 Revision 2. Therefore, no additional sensitivity studies are required. Existing sensitivity studies adequately characterize this source of uncertainty. The impact with respect to these applications would be to potentially produce minor shifts in the risk from some tornado categories to others, which is unlikely to have a significant impact on equipment importance measures or relative risk insights.

Table E4-3: Disposition of Key Assumptions and Sources of Uncertainty				
ID	Summary of High Winds Assumption/Uncertainty	Part of Model Affected	Generic Impact on Risk Applications	Evaluation of RICT Impact
9	It is assumed that straight wind events below 73 mph are addressed in the weather-induced LOOP initiator of the CPNPP internal events PRA model.	High Winds initiating event frequencies.	The weather-induced LOOP initiating event frequency in the internal events model is calculated by examining the number of LOOP events caused by weather (including high winds) in a region surrounding the site. 73 mph was chosen because it represents the lower bound of wind speeds capable of causing equipment damage in excess of a LOOP.	This approach follows EPRI guidance and industry practice, which is in essence, a consensus process. This criterion is consistent with Section 3.3.2 of RG 1.200 Revision 2. Therefore, no additional sensitivity studies are required.

Internal Events Model Sequence Development

In this approach, the sequence conditional core damage probability (CCDP) and conditional large early release probability (CLERP) baselines are obtained by quantifying the CPNPP PRA model by:

- Setting all initiating events to FALSE, except for the weather-centered loss of offsite power initiating event, which is set to 1.0.
- Setting basic events deemed vulnerable to high wind damage based on component location to TRUE.
- Truncation for each CCDP/CLERP case set to E-10.
- Not applying LOOP recovery for wind events.
- Evaluating equipment out of service conditions for:
  - Emergency Diesel Generators (EDGs)
  - Turbine-Driven Auxiliary Feedwater (TDAFW)
  - Station Service Water (SSW)
  - Component Cooling Water (CCW)
  - Motor-Driven Auxiliary Feedwater (MDAFW)
  - Safety Chilled Water Pump (CHS)
  - Centrifugal Charging Pump (CCP)

The results of this evaluation are reflected in Table E4-4.

Table E4-4: High Winds Sequence Development Results

Case	Sequence CCDP	Sequence CLERP
Baseline	3.14E-04	1.81E-05
EDG OOS	6.61E-03	4.47E-04
TD AFW OOS	4.20E-03	2.55E-04
SSW OOS	6.61E-03	4.47E-04
CCW OOS	9.96E-04	4.61E-05
CCP OOS	3.21E-04	1.83E-05
CHS OOS	1.21E-03	4.72E-05
MD AFW OOS	2.15E-03	9.75E-05

No other components being out of service would result in more severe penalties than those presented. The CPNPP RICT procedure precludes the use of RICT if two or more risk-significant components (in terms of the HW penalties) were Out of Service.

Bounding CDF/LERF

The baseline bounding value for CDF and LERF, per wind interval is obtained by the product of the mean hazard frequency per year, the conditional LOOP probability and the sequence of CCDP/CLERP. Additionally, this evaluation provides bounding CDF/LERF values obtained for the more risk significant components for CPNPP; results are calculated and tabulated for these out of service cases in the same manner as for the base case.

High Winds Bounding Analysis Summary

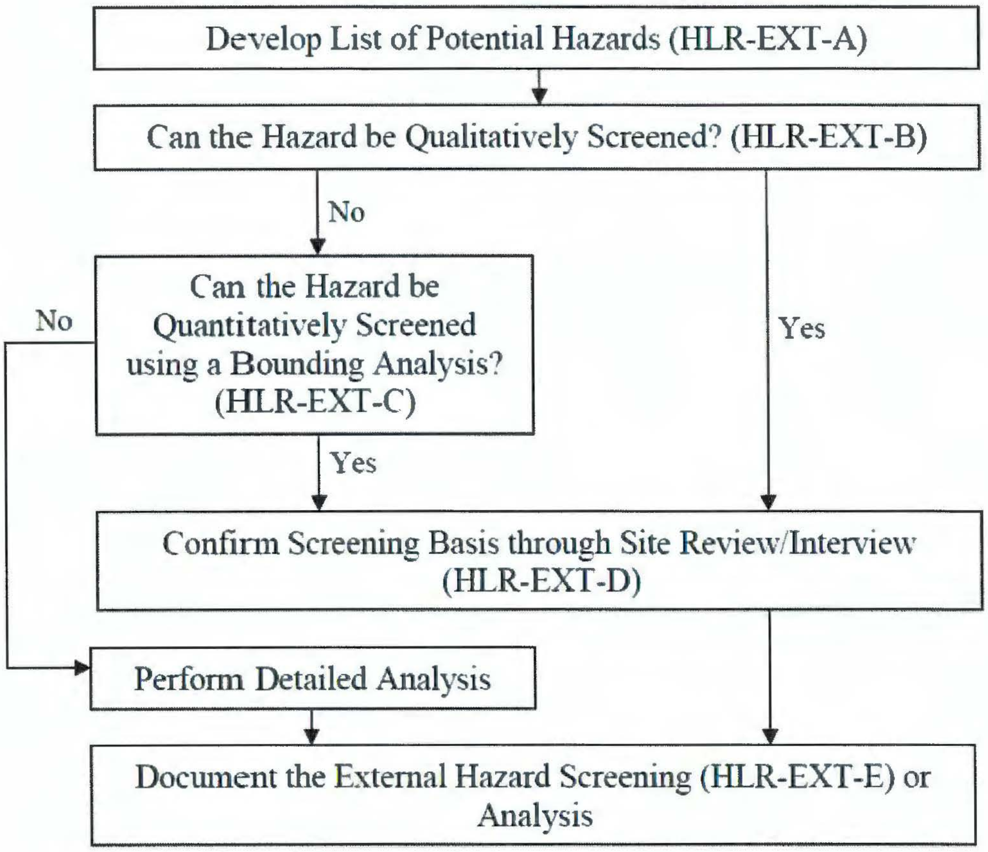
Based on the information presented above, the high winds "penalty" results for CPNPP is provided in Table E4-5 below.

Table E4-5: High Winds Results Summary for CPNPP				
Case	**Baseline HW CDF (/rcry)**	**ΔHWCDF (/rcry)**	**Baseline HWLERF (/rcry)**	**ΔHWLERF (/rcry)**
Unit 1 and 2				
Baseline	4.09E-06	-	2.35E-07	-
EDG OOS		8.20E-05		5.58E-06
TD AFW OOS		5.05E-05		3.08E-06
SSW OOS		8.20E-05		5.58E-06
CCW OOS		8.91E-06		3.65E-07
CCP OOS		9.00E-08		3.00E-09
CHS OOS		1.17E-05		3.80E-07
MD AFW OOS		2.39E-05		1.03E-06

5.0 Evaluation of External Event Challenges and IPEEE Update Results

The purpose of this section is to document the screening for other external hazards at-power for CPNPP. This analysis references design and as-built information from key sources including design and licensing basis documents and PRA Model of Record (MOR) documents. The analysis applies current industry methods and sources as well as plant specific data. The analysis was performed in accordance with the process specified in Part 6, Section 6-2 "Technical Requirements for Screening and Conservative Analysis", of the ASME/ANS RA-S-2009 standard [Ref. 3]. High level requirements (HLR) and the supporting requirements (SR) are established in [Ref. 3] for conducting screening and conservative analysis of "other hazards", defined as those "hazards other than internal events, internal floods, internal fires, and earthquakes." Hazards from internal floods and internal fires are addressed in developed PRA models, but are included by reference in the results summary.

The ASME/ANS PRA Standard [Ref. 3] provides requirements for identifying and screening of the external hazards that may impact the plant. The methodology utilized in this analysis is intended to comply with the requirements in [Ref. 3] as outlined in the process diagram below.



The process begins by identifying all potential external hazards that may affect the site (i.e., all natural and man-made hazards). SRs EXT-A1 and A2 are addressed by reviewing the listed hazards adapted industry sources (e.g., NUREG/CR-2300, NUREG-1407, NUREG-4550, etc.), and then supplement the review with any site-specific and plant-unique hazards. The supplementary review ensures that an unusual type of hazard is not inadvertently omitted. The resulting list includes previously examined hazard information from the CPNPP Final Safety Analysis Report (FSAR and in the CPNPP Individual Plant Examination of External Events reports, which are regarded as plant specific. Applicability of potential hazards is determined through review of site documents and consultation with plant staff.

Screening Criteria

The criteria are applied in a progressive screening process are summarized in Table E4-5. The initial screening is a qualitative evaluation of external hazards based on HLR EXT-B of [Ref. 3]. The initial preliminary screening requirement states that for screening out an external hazard, any one of the five screening criteria (EXT-B1, Criteria 1 through 5, C1-C5) provides an acceptable basis.

SR EXT-B2 of [Ref. 3] provides for second preliminary screening out of external hazards if the design basis for the event meets the criteria in the Standard Review Plan (SRP). If this criterion is met, it is judged that the contribution to CDF is less than 1.00E-06 per reactor-year. This analysis does not base the screening solely on whether the plant is designed to the SRP, but rather examines, in detail, how the plant designed for each hazard. In other words, even when

EXT-B2 is applicable, every hazard that is screened will also apply the criteria of SR EXT-B1 sub-criteria or EXT-C1 of [Ref. 3].

The quantitative screening of external hazards is based on SR EXT-C1, which states that any one of the following three screening criteria provides an acceptable basis for bounding analysis or demonstrably conservative analysis. The CCDP calculations for EXT-C1 (Progressive Screening criteria PS3, PS4) should be estimated considering the initiating events caused by the hazard, and the systems or functions rendered unavailable. Risk (core damage frequency) due to the event scenario can be estimated by the product of the initiating event frequency and the conditional core damage probability.

If this evaluation indicates an acceptable result relative to the specified criteria, then the screening is complete, and no detailed PRA will be necessary. Per Section 6-2.3 of [Ref. 3], "concerning LERF, note that there is an implicit assumption that if an external hazard is screened out using one of the screening criteria [above]... then neither the CDF nor the LERF arising due to that event is of concern." This is a reasonable assumption so long as the hazard being screened does not directly cause a containment bypass event or a containment failure condition.

Table E4-5 : Screening Criterion

Screening Step	**Criterion**	**Source / Comments**
Initial Screening: **EXT-B1**	C1 – Event damage potential is < events for which plant is designed. C2 – Event has lower mean frequency and no worse consequences than other analyzed events. C3 – Event cannot occur close enough to the plant to affect it. C4 – Event is included in the definition of another event.* C5 – Event develops slowly, allowing adequate time to eliminate or mitigate the threat.	NUREG./CR-2300 ASME/ANS Standard RA-SA-2009 *Note criterion C4 is not used to screen. It is used only to include within another event.
Progressive Screening: **EXT-B2** **EXT-C1**	PS1 – Design basis hazard cannot cause a core damage accident. PS2 – Design basis for the event meets the criteria in the NRC 1975 Standard Review Plan (SRP).	NUREG-1407 ASME/ANS Standard RA-Sa-2009

Table E4-5 : Screening Criterion		
Screening Step	**Criterion**	**Source / Comments**
	PS3 – Design basis event mean frequency is < 1E-5/yr and the mean conditional core damage probability is < 0.1. PS4 – Bounding mean CDF is < 1E-6/yr	

Identification of Potential Hazards

Based on review of current plant documents and discussions with plant staff, there are no additional site-specific or plant-unique external hazards identified for CPNPP Units 1 and 2. A search for plant-unique external hazards was performed focusing on industry events, CPNPP hazards analyses, and natural features relevant to the plant location. No additional external hazards were identified. In addition to FSAR and IPEEE references, the following documents of note were reviewed, along with numerous other documents determined to have lesser applicability:

- SOER 07-2, Intake Cooling Water Blockage – applies primarily to ocean and lake plants, fish, and debris entering circulating water intake structures; CPNPP uses water from the Squaw Creek Reservoir and the Safe Shutdown Impoundment (see discussion of Biological events in Table E4-6 for justification that intake blockage is not a concern)
- IER L2-16-9, Revision 1, Risk Management Challenges – none of the example events pertain to CPNPP external hazards. The overall idea that risk is prevalent in new, one-of-a-kind projects has limited applicability for CPNPP such that no new hazards arise under that consideration.
- SOER 02-1, Severe Weather – highlights hurricane and high wind damage incurred at plants worldwide.

To provide additional confidence that all external hazards which could affect the site have been addressed, EPRI report 3002005287 [Ref. 13] was reviewed. This report provides another source for a list of external hazards to be considered in development of the identified potential hazards. The EPRI listed external hazards were reviewed and dispositioned for inclusion as necessary. Results from the reviews addressing SRs EXT-A1 and A2 established the following CPNNP specific list of potential hazards:

- Aircraft Impacts
- Avalanche
- Biological Events
- Coastal Erosion
- Drought
- External Flooding
- Extreme (High) Winds and Tornados
- Fog
- Forest Fire
- Frost

- Hail
- High Summer Temperature
- High Tide
- Hurricane
- Ice Cover
- Industrial or Military Facility Accident
- Internal Flooding
- Landslide
- Lightning
- Low Lake or River Water Level
- Low Winter Temperature
- Meteorite / Satellite Strikes
- Pipeline Accident
- Precipitation, Intense
- Release of Chemicals in Onsite Storage
- River Diversion
- Sandstorm
- Seiche
- Seismic Activity
- Snow
- Soil Shrink-Swell
- Storm Surge
- Toxic Gas
- Transportation Accidents
- Tsunami
- Turbine-Generated Missile
- Volcanic Activity
- Waves

Screening

Table E4-6 provides the results of initial screening reviews for CPNPP specific potential hazards, presented by hazard group. The screening criteria were applied to eliminate all unimportant contributing events and identify the events that should be further examined through progressive screening. For each hazard, the applicable initial and progressive screening criteria, including reference information and a brief discussion, are documented. Selected hazard groups are supplemented with additional detail to support the screening discussion.

In the application of Risk-Informed Completion Times, a significant consideration in the screening of external hazards is whether particular plant configurations could impact the decision on whether a particular hazard that screens under the normal plant configuration and the base risk profile would still screen given the particular configuration. Review of screened hazards concludes that there are no configuration specific considerations related to the screening assessment provided for the normal plant alignment.

Table E4-6: Other External Hazards Screening

Group	Hazard	Screened (Y/N)	Criterion	Discussion
Biological	Biological Events	Y	C5	Sudden influxes are not applicable to the plant design: (1) closed loop systems for Component Cooling Water System (CC) and (2) chemical control of Asiatic clams and debris removal provided by Station Service Water (SW) subsystems. SW system design addressed GL 89-13 for periodic flushing/heat exchanger monitoring and IN 88-37 for prevention of flow blockage. Slowly developing growth can be detected and mitigated by surveillance. There is sufficient time to respond to these hazards before system operation would be jeopardized.
External Fire	Forest Fire	Y	C3	Not applicable to the site because of limited vegetation, as confirmed in walkdown and discussion with plant staff. Land surrounding the CPNPP site is kept cleared such that a forest fire cannot propagate to the site.
	Grass Fire	Y	C3	Not applicable to the site cause of limited vegetation, as confirmed in walkdown and discussion with plant staff. Land surrounding the CPNPP site is kept cleared such that grass fire cannot propagate to the site.
Meteor / Satellite Strike	Meteor / Satellite Strike	Y	C2	The event has a low initiating event frequency. Per R&R-PN-205 [Ref. 11] the probability of a meteorite or satellite strike is less than 1E-09.
Extreme Temperature	Frost	Y	C1	Frost has lesser damage potential than snow and ice. CPNPP is designed for freezing temperature, which are infrequent and short in duration. Principal effects of this hazard would be to cause a loss of off-site power which is addressed in the weather-related Loss of Offsite Power initiating event in the internal events PRA model.
	Frazil Ice (Ice Cover)	Y	C3	Ice blockage causing flooding is not applicable to the site because of location (no nearby rivers and climate conditions, i.e. low air temperatures about -6°C or lower). CPNPP is designed for freezing temperatures, which are infrequent and short in duration. Historical floods are limited to precipitation runoff into streams and rivers; thus the area is not subject to floods from ice jams.

Table E4-6: Other External Hazards Screening				
Group	**Hazard**	**Screened (Y/N)**	**Criterion**	**Discussion**
	High Summer Temperature	Y	C1	CPNPP is designed for this hazard. Associated plant trips have not occurred and are not expected. The principal effect of elevated temperature would be reduced level in the Safe Shutdown Impoundment (SSI) that serves as the plant's ultimate heat sink. The TS LCO 3.7.9 imposes a limit of 102°F for the SW intake temperature and a minimum of 770 feet for the SSI level during normal operation. These effects would take place slowly allowing time to initiate orderly plant reductions, including shutdowns. Temperature data presented in the FSAR are consistent with the performance of the ultimate heat sink within the established design basis. The historical extreme maximum temperature is reported as 108°F
	Low Winter Temperature	Y	C1	Low winter temperature can be screened out since the hazard presents the same or lesser damage potential than the hazards for which the plant has been designed. On occasion, artic air masses push through the region and cause some of the coldest temperatures. Cold spells, however, rarely last more than a few days. Temperature data presented in the FSAR indicate the historical extreme minimum temperature of 10°F.
Ground Shifts	Avalanche	Y	C3	Topography of CPNPP precludes the possibility of a snow avalanche.
	Coastal Erosion	Y	C3	The inland location of CPNPP precludes the possibility of coastal erosion.
	Landslides	Y	C3	Land sliding and/or reservoir slope failures are not an expected source of flood waves. Natural slopes are 3:1 (Horizontal to Vertical), or flatter, except for occasional local portions of slope which are steeper (ranging to 2:1 or 1:1). Slope failures are improbable, but small localized sloughs conceivably might occur from erosion and/or weathering of the exposed edges of claystone seams from beneath overlying, more resistant rock zones. The small waves resulting from such failures will not adversely affect CPNPP facilities.
	Sinkholes	Y	C3	The reservoir is formed in the Glen Rose formation, a predominately limestone sequence. Information developed regarding this formation indicated it is relatively impermeable and free of sinkholes and solutioning. Thus, significant loss of water is improbable.

Table E4-6: Other External Hazards Screening				
Group	**Hazard**	**Screened (Y/N)**	**Criterion**	**Discussion**
	Soil Shrink-Swell	Y	C1	Based on geology and seismology information the impact from shrink or swell is expected to be negligible. Regarding the stability of subsurface materials, there is no evidence in the site region indicating actual or potential uplift or subsidence, cavernous or karst terrain, tectonic warping or deformational zones pertinent to the site. Zones of alteration, weathering, structural weaknesses, unrelieved residual stresses or geological hazardous materials are not in evidence.
Heat Sink Effects	Drought	Y	C5	Drought effects would take place slowly allowing time for orderly plant reductions, including shutdowns. Drought conditions (extended periods of widespread meager precipitation) are known to occur in Texas. The most sever this century in Texas occurred during 1954-1956. Low flow in Squaw Creek or in the Brazos River is not of concern to plant safety because station cooling water is obtained from SCR. Low flow considerations are significant in terms of successful over-all plant operations and agreements are in place to provide supplemental water from Lake Granbury on the Brazos River.
	Low Lake or River Water Level	Y	C1	This hazard has been considered in the design of the UHS. The TS LCO 3.7.9 imposes a minimum of 770 feet for the SSI level during normal operation. These effects would take place slowly allowing time to initiate orderly plant reductions, including shutdowns.
	River Diversion	Y	C1	Lake Granbury, which is on the Brazos River, will be a major source of makeup cooling water. The loss of Lake Granbury makeup water due to the diversion of the Brazos River is highly improbable. Above Lake Granbury, the Brazos River channel is cut into bedrock which precludes any reasonable possibility of the river changing its channel significantly within the life of the CPNPP and thus affecting the supply of water.
High Wind	Extreme (High) Winds and Tornados	N	None, Bounding Penalty	See Section 4 for discussion on the High Winds penalty.

Table E4-6: Other External Hazards Screening

Group	Hazard	Screened (Y/N)	Criterion	Discussion
	Hail	Y	C1, C4	History of large hail near the Comanche Peak site indicates potentially damaging hailstorms are infrequent. The principal effects of a hail event would be a potential challenge to offsite power and exposed equipment, and equipment within non-safety buildings. The weather-related loss of offsite power is addressed in the internal events PRA. Hail impact on SSCs is bounded by the effects of tornado missiles addressed in the high wind PRA.
	Hurricane	Y	C4	The inland location reduces the effects of hurricanes for CPNPP. In addition, this hazard in included in the analysis for extreme winds and tornados.
	Sandstorm	Y	C3	Sandstorms are not applicable at the CPNPP site where the surrounding areas is described as open terrain with gently rolling hills. Additionally, a review of Fort Worth experience observed dust storms with visibilities of one mile or less were infrequent.
Industrial Accidents	Military Facility Accidents	Y	C3	Within the 10-mile area, there are no military bases, missile sites, military firing ranges or munitions facilities. The nearest military bases are Carswell Air Force Base, approximately 38 miles north-northeast, and Fort Hood, approximately 65 miles south. There are no missile sites within 50 miles.
	Industrial Facility Accidents	Y	C3	Neither an accidental explosion, nor a toxic chemical release from a nearby industrial facility will pose a hazard to the plant. Within the 10-mile areas, there are no chemical plants and storage facilities, tank farms or upstream sources of corrosive or oil discharges. There are no industrial facilities within 5 miles of the site, and those at greater distances are not significant to CPNPP from a safety standpoint.
	Mining Accident	Y	C3	There are no mining operations in the vicinity of CPNPP. The Engineering Geological Evaluation noted that except for the removal of minor quantities of sand, gravel and dimension stone in the site vicinity, no mining has occurred.

Table E4-6: Other External Hazards Screening				
Group	**Hazard**	**Screened (Y/N)**	**Criterion**	**Discussion**
	Pipeline Accident	Y	C1, PS2	Hazardous materials regularly manufactured, stored, used, or transported in the site vicinity are limited to crude oil and natural gas transported through the pipelines (one transporting crude oil and the other three transporting gas). There is no significant hazard from toxic releases or explosions involving these pipelines that could interact with the plant. Explosive hazard impacts and control room habitability impacts meet the 1975 SRP requirements (RGs 1.91 and 1.78). Additional detailed qualitative analysis in regard to the screening of the industrial accident hazard is provided in R&R-PN-205 [Ref. 11].
	Release of Chemicals from On-Site Storage	Y	C1	Water systems (CW and SW) are chemically treated for control of biological growth with solutions of sodium hypochlorite and sodium bromide. The diluted sodium hypochlorite and sodium bromide solutions which in diluted form will not present a threat to control room habitability. Liquified chlorine stored within the site boundary will not exceed 150 lbs. capacity and only small quantities of 20 lbs. or less will be stored within the protected areas. Various acids and caustics are stored on-site but pose no hazard to the plant. Chemical Hazards stored and transported in the vicinity of the plant are analyzed in accordance with CPNPP Technical Specifications 5.5.20.
	Toxic Gas	Y	C4	Toxic gas is included under Release of Chemicals in Onsite Storage, Industrial or Military Facility Accident, and Transportation Accidents.
Internal Flooding	Internal Flooding	N	None, Detailed PRA	A detailed Internal Flood PRA is performed for CPNPP.
Lightning Strikes	Lightning Strikes	Y	C1, C4	Lightning strikes are not uncommon in nuclear power plant experience; they have the potential to result in a loss of offsite power or surges in instrument output if grounding is not fully effective. The plant design basis includes a Lightning Protection System to minimize damage to structures or equipment by providing a suitable path for the stroke current. CPNPP has incorporated industry and plant specific data for LOOP and plant trip due to a transient, however other causes are also included such that the impacts from lightning are no greater than already modeled in the internal events PRA. This conclusion is also confirmed with a bounding analysis in Section 5.2.3.

Table E4-6: Other External Hazards Screening				
Group	**Hazard**	**Screened (Y/N)**	**Criterion**	**Discussion**
External Flooding	High Tide	Y	C3	The inland location of CPNPP precludes the possibility of a high tide condition. High water level effects from this hazard do not apply for CPNPP based on the small size of Squaw Creek Reservoir and the shutdown impoundment. The site grade is at elevation 810 feet, which provides 20.3 feet of freeboard above the Probable Maximum Flood (PMF) and superimposed wave runup on Squaw Creek Reservoir. The site grade is well above the maximum water levels conceivable on the Brazos River. Hence, the site will be unaffected by river flooding of any kind and will not be affected by tsunami, seiche, or ice flooding.
	Precipitation, Intense	Y	C1, PS2	Effects of local intense precipitation (LIP) are incorporated into the Probable Maximum Flood (PMF) for the site, which is used in bounding external flooding calculations. Re-evaluation resulted in a minor increase in maximum flood elevation due to LIP. Subsequent engineering evaluation determined resulting flood heights within safety-related structures did not affect mitigating strategy equipment and were bounded by internal flood results. Additional detailed qualitative analysis in regard to the screening of the external flooding hazard is provided in R&R-PN-205 [Ref. 11].
	Tsunami	Y	C3	Plant location precludes the possibility of a tsunami. This site is nearly 300 miles from the Gulf of Mexico and the plant will be over 800 feet above sea level. Therefore, tsunami flooding will not occur.
	Storm Surge	Y	C3	There are no existing large bodies of water near the site that would allow development of either surge or seiche; therefore, there is no history of surge and seiches in the site vicinity. The small size, relatively shallow depth and irregular shape of Squaw Creek Reservoir indicates that there is a minimum probability of either surges or seiches occurring in the reservoir. Therefore, surge and seiche should not be considered significant at this site. Re-evaluation addressed storm surge due to the probable maximum hurricane and because CPNPP Units 1&2 are located greater than 250 miles inland from the Gulf of Mexico, and at a site grade of 810 ft, hurricanes are not expected to be a potential flooding hazard.

Table E4-6: Other External Hazards Screening				
Group	**Hazard**	**Screened (Y/N)**	**Criterion**	**Discussion**
	Seiche	Y	C3	There are no existing large bodies of water near the site that would allow development of either surge or seiche; therefore, there is no history of surge and seiches in the site vicinity. The small size, relatively shallow depth and irregular shape of Squaw Creek Reservoir indicates that there is a minimum probability of either surges or seiches occurring in the reservoir. Therefore, surge and seiche should not be considered significant at this site. Re-evaluation determined seismic induced seiche is bounded by the site PMF and potential for landslide induced seiche is not plausible based on a slope stability analysis of the Squaw Creek Reservoir.
	Waves	Y	C1, C4	Effects of wind-generated waves and flood waves are incorporated into the Probable Maximum Flood (PMF) for the site, which is used in bounding external flooding calculations. Evaluation of external flood mechanisms, including combined effects, concluded waves will not challenge safety-related structures.
Seismic Activity	Seismic Activity	N	None, Bounding Penalty	See Section 0 for discussion on the Seismic penalty.
Snow and Ice	Snow and Ice	Y	C1, C4	CPNPP is not subject to ice flooding or ice jams. Snowmelt was not considered in establishing the PMF.
Transportation Accidents	Air: Aircraft Impact	Y	PS2, PS4	There are no airports within five miles of the Station. Furthermore, there are no airports with greater than 500 d2 ("d" is the distance in miles from the Station) movements per year within 10 miles, nor are there any airports with projected operations in excess of 1000 d2 movements per year within 50 miles. Data from the National Transportation Safety Board is used with a statistical model (causation probability, or the probability of an aircraft totally losing control) and the geometrical probability of random collision. This method applied with conservative inputs includes review of the four air routes within 10 square miles of the site and the inflight crash rater per mile for aircraft using the airway; it results in the probability of an aircraft crashing into the CPNPP site as 1.91E-07 per year. For a CCDP assumed as 1.0, the hazards due to aircraft crashes is thus screened based on CDF <1.0E-06. Additional detailed qualitative analysis in regard to the screening of the transportation accident hazard is provided in R&R-PN-205 [Ref. 11].

Table E4-6: Other External Hazards Screening				
Group	**Hazard**	**Screened (Y/N)**	**Criterion**	**Discussion**
	Land: Vehicle Impact or Explosion Railroad Explosion	Y	C3	Site area access is by a plant railroad, which connects to the Atchison, Topeka, and Santa Fe Railroad Company main line at Tolar, Texas (distance to junction is approximately 11 miles), by a plant access road which connects to FM 56 (approximately 8900 feet southwest of the center line between the Containment buildings) and by County road 213 (also known as Coates Rd) which connects to State Highway 144. Access by rail or road is controlled by CPNPP. Due to the long distance from the closest road (rural or highway) to the plant, any accidental explosion will not endanger the safe operation of the plant. Physical damage to the plant caused by a truck colliding with plant structures is considered minimal due to the distance between main roads and highways and the plant structures.
	Water: Collisions with Intake Structures Explosion	Y	C3	The Service Water Intake Structure is located on the Safe Shutdown Impoundment which is not open to public transportation. Therefore, a significant collision with this structure is not considered a credible event.
	Fog	Y	C4	Fog occurs relatively infrequently in the region and around the site. The occurrence of heavy fog would not impact plant operations or the ability to achieve safe shutdown if necessary, however, fog affects the frequency of occurrence of the air, land, and water transportation hazards, and is indirectly considered in those hazards.
Turbine-Generated Missiles	Turbine-Generated Missiles	Y	C1	The overall probability of generating external turbine missiles which could pose a threat to safety related SSCs, P4, is less than the overall NRC of 1E-7 per year, thereby ensuring an acceptable risk rate for the loss of an essential system from a single event.
Volcanic Activity	Volcanic Activity	Y	C3	Not applicable to the site because of location. The geologic history shows no evidence for volcanic activity in the area.

5.0 References

1. Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09-A, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0-A, dated October 12, 2012 (ADAMS Accession No. ML12286A322)
2. Letter from Jennifer M. Golder (NRC) to Biff Bradley (NEI), "Final Safety Evaluation for Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09-A, 'Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines,'" dated May 17, 2007 (ADAMS Accession No. ML071200238).
3. ASME/ANS RA-Sa-2009, "Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications," Addendum A to RAS-2008, ASME, New York, NY, American Nuclear Society, La Grange Park, Illinois, February 2009
4. NUREG-1855, "Guidance on the Treatment of Uncertainties Associated with PRAs in Risk-Informed Decision Making," Revision 1, March 2017
5. NUREG-1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events – Seismic," Comanche Peak Steam Electric Station, August 1994.
6. Generic Issue 199, "Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern United States on Existing Plants," Nuclear Regulatory Commission (NRC), August 2010.
7. CP-200400324, "Seismic Hazard and Screening Report (CEUS Sites), Response to NRC Request for Information Pursuant to 10 CFR 50.54(f) Regarding Recommendation 2.1 of the Near-Term Task Force Review of Insights from the Fukushima Dai-ichi Accident," Luminant Power's Letter Log # TXX-14037, dated March 27, 2014.
8. R&R-PN-008A, Revision 5, "Internal Initiating Events Data Analysis," Comanche Peak Nuclear Power Plant," November 2016.
9. EPRI 3002015993, "Loss of Offsite Power Seismic Fragility Guidance," Electric Power Research Institute (EPRI), August 2019.
10. NUREG-75/087, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, LWR Edition," 1975.
11. R&R-PN-205, Revision 5, "Screening and Conservative Analysis for Other External Hazards," October 2020.
12. CN-RAM-20-002, Revision 0, "Comanche Peak High Winds PRA Hazard Analysis,", October 2020.
13. EPRI 3002005287, "Identification of External Hazards for Analysis in Probabilistic Risk Assessment: Update of Report 1022997," Palo Alto, CA: 2015.
14. Regulatory Guide (RG) 1.200, Revision 3, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," December 2020.

ENCLOSURE 5

License Amendment Request

Comanche Peak Nuclear Power Plant, Units 1 and 2

NRC Docket Nos. 50-445 and 50-446

Revise Technical Specifications to Adopt Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times – RITSTF Initiative 4b"

Baseline Core Damage Frequency (CDF) and Large Early Release Frequency (LERF)

1.0 Introduction

Section 4.0, Item 6 of the Nuclear Regulatory Commission's (NRC) Final Safety Evaluation for NEI 06-09-A, Revision 0-A, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," [Ref. 1] requires that the license amendment request (LAR) provide the plant-specific total CDF and LERF to confirm applicability of the limits of Regulatory Guide (RG) 1.174, Revision 1 [Ref. 2]. Note that RG 1.174, Revision 2 [Ref. 3], issued by the NRC in May 2011, did not revise these limits.

The purpose of this enclosure is to demonstrate that the CPNPP total Core Damage Frequency (CDF) and Large Early Release Frequency (LERF) are below the guidelines established in RG 1.174. RG 1.174 does not establish firm limits for total CDF and LERF but recommends that risk-informed applications be implemented only when the total plant risk is no more than about 1E-4/year for CDF and 1E-5/year for LERF. Demonstrating that these limits are met confirms that the risk metrics of NEI-06-09-A can be applied to the CPNPP risk-informed completion time (RICT) program.

2.0 Technical Approach

Table 1 lists the CPNPP Unit 1 and Unit 2 CDF and LERF values that resulted from quantification of the baseline PRA models (i.e., internal events [Ref. 6] and [Ref. 7], internal flood [Ref. 8], and internal fire [Ref. 9]) . This table also includes an estimate of the seismic [Ref. 10] and high winds [Ref. 11] contribution to CDF and LERF. Other external hazards are below the accepted screening criteria and, therefore, do not contribute significantly to the totals. Note that the baseline values are representative of the average test and maintenance (T&M) PRA model.

Table 1: CPNPP Units 1 and 2 Baseline PRA Model Results				
CPNPP Unit 1				
Baseline CDF			Baseline LERF	
Internal Events	1.10E-06		Internal Events	1.06E-07
Internal Flood	1.19E-07		Internal Flood	5.00E-09
Internal Fire	5.62E-05		Internal Fire	7.89E-06
Seismic(1)	0		Seismic(1)	0
High Winds(2)	4.09E-06		High Winds(2)	2.35E-07
Other External Events	No significant contribution		Other External Events	No significant contribution
Total Unit 1 CDF	***6.15E-05***		***Total Unit 1 LERF***	***8.24E-06***
CPNPP Unit 2				
Baseline CDF			Baseline LERF	
Internal Events	1.02E-06		Internal Events	1.02E-07
Internal Flood	1.39E-07		Internal Flood	5.88E-09
Internal Fire	4.29E-05		Internal Fire	5.69E-06
Seismic(1)	0		Seismic(1)	0
High Winds(2)	4.09E-06		High Winds(2)	2.35E-07
Other External Events	No significant contribution		Other External Events	No significant contribution
Total Unit 2 CDF	***4.81E-05***		***Total Unit 2 LERF***	***6.03E-06***

Notes:
1. Per Enclosure 4, the baseline seismic CDF and LERF are assumed to be zero (i.e., in order to maximize the calculate incremental risk).
2. Per Enclosure 4, the baseline high winds CDF and LERF are developed and are representative of a "penalty" factor. The high winds penalty is procedurally adjusted based on the component(s) to which the RICT is applied

The values presented in Table 1 are point estimate results for the CPNPP PRA models. Mean values are estimated by propagation of aleatory uncertainty in the PRA models. For internal events, the analysis shows that there is less than a 5% impact from the SOKC. For consistency, the EPRI UNCERT program was used, and shows a point estimate of 3.59E-06 and 1.91E-07 for CDF and LERF, respectively, while the mean values are 3.75E-06 and 1.97E-07 for CDF and LERF, respectively. Note that UNCERT performs preprocessing on the cutsets and therefore the relative difference between the point estimate and mean is relative. The uncertainty results for internal flooding are negligible as compared to the point estimates. The fire PRA is sampled on distributions assigned for ignition frequency, heat release rate, circuit failure likelihood, and spurious operation duration, going beyond the state of practice. There is a less than 1% impact from SOKC as compared to the point estimates for CDF and LERF for the Fire PRA.

As demonstrated in the total CDF and LERF are within the guidelines set forth in RG 1.174 and support small changes in risk that may occur during RICT entries following TSTF-505 implementation. Therefore, CPNPP TSTF-505 implementation is consistent with NEI 06-09-A guidance.

3.0 References

1. ML071200238, "Final Safety Evaluation for Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09, 'Risk-Informed Technical Specifications Initiative 4B, Risk-

Managed Technical Specification (RMTS) Guidelines,'" Nuclear Regulatory Commission, May 17, 2007.
2. Regulatory Guide 1.174, Revision 1, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," November 2002.
3. Regulatory Guide 1.174, Revision 2, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," May 2011.
4. Regulatory Guide 1.174, Revision 3, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," January 2018.
5. Regulatory Guide 1.174, Revision 2
6. R&R-PN-022, Revision 5, "Level 1 Internal Events Quantification," October 2016.
7. R&R-PN-035, Revision 5, "Level 2 Internal Events Quantification," November 2016.
8. R&R-PN-021, Revision 5, "Internal Flood Analysis," May 2019.
9. CN-RAM-13-038, Revision 3, "Qualitative Screening, Quantitative Screening, Quantification, and Uncertainty Analysis for CPNPP Fire PRA."
10. LTR-RAM-20-45, Revision 0, "Seismic Hazard Analysis to Support Comanche Peak RICT LAR," May 2020.
11. LTR-RAM-20-99, Revision 1, "High Wind Hazard Analysis to Support Comanche Peak RICT LAR," November 2020.

ENCLOSURE 9

License Amendment Request

Comanche Peak Nuclear Power Plant, Units 1 and 2

NRC Docket Nos. 50-445 and 50-446

Revise Technical Specifications to Adopt Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times – RITSTF Initiative 4b"

Key Assumptions and Sources of Uncertainty

1.0 Introduction

The purpose of this enclosure is to disposition the impact of Probabilistic Risk Assessment (PRA) modeling epistemic uncertainty for the Risk Informed Completion Time (RICT) Program. Nuclear Energy Institute (NEI) topical report NEI 06-09-A [Ref. 1], "Risk-Informed Technical Specification Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines", Revision 0, Section 2.3.4, Item 10 requires an evaluation to determine insights that will be used to develop risk management actions (RMAs) to address these uncertainties. The baseline internal events, internal flooding, and internal fire PRA models document assumptions and sources of uncertainty and these were reviewed during the respective hazard peer reviews. The approach take is, therefore, to review these documents to identify the items which may be directly relevant to the RICT program calculations, to perform sensitivity analyses where appropriate, to discuss the results and to provide dispositions for the RICT program.

NEI 06-09-A [Ref. 1] requires that uncertainty be addressed in RICT program Real Time Risk tools by consideration of the translation from the PRA model. The Real Time Risk Model also referred to as the Configuration Risk Management (CRM) model includes internal events, flooding events, fire events, and penalties for seismic and high wind risk. The model translation uncertainties evaluation and impact assessment are limited to new uncertainties that could be introduced by application of the Real Time Risk tool during RICT Program calculations.

The list of assumptions and sources of uncertainty for all PRA models were reviewed to identify those which would be significant for the evaluation of this application. If the CPNPP PRA model used a non-conservative treatment, or methods that are not commonly accepted, the underlying assumption or source of uncertainty was reviewed to determine its impact on this application. To identify these assumptions and sources of uncertainty both plant-specific and generic sources of uncertainty were considered. All PRA notebooks were reviewed, and sources of uncertainty were compiled and characterized in the CPNPP Uncertainty Analysis Notebook. The identification and characterization of the sources of uncertainty was performed consistent with the requirements of the ASME/ANS PRA Standard (ASME/ANS RA-Sa-2009 [Ref. 6]). This evaluation meets the intent of steps C-1 and E-1 of NUREG-1855, Revision 1 [Ref. 2]. To assess the impact of sources of uncertainties on the TSTF-505 application, a review of the base case sources of uncertainty for the CPNPP PRA models was performed. Each identified uncertainty was evaluated with respect to its potential to significantly impact the decisions of this submittal. This evaluation meets the intent of the screening portion for steps C-2 and E-2 of NUREG-1855, Revision 1 [Ref. 2].

The characterization of assumptions and uncertainties for the baseline at-power PRA model is performed in R&R-PN-041 [Ref. 7] for internal events and internal flood, and CN-RAM-13-038 [Ref. 8] for internal fire. In general, the process used is as follows:

1. All plant-specific assumptions and uncertainties from the PRA notebooks are reviewed and dispositioned for potential impact on the baseline PRA model. At this stage, generic sources of uncertainty are included in the assessment.
2. Generic and plant-specific assumptions and sources of model uncertainty that have not been characterized in the individual PRA notebooks, are retained for further evaluation.
3. Any remaining assumptions and uncertainties (generic or plant-specific) are characterized and applicable sensitivities are performed to assess impacts of those items on the baseline PRA model.

The characterization of the assumptions and uncertainties of the baseline models is generally representative of the impacts that those assumptions and uncertainties will have on the TSTF-505 application. However, a complete review of these assumptions was performed to identify specific assumptions and sources of uncertainty that could have a unique impact for TSTF-505. Key CPNPP PRA model specific assumptions and sources of uncertainty for this application were identified and dispositioned in Section 2 for internal events (including internal flooding), internal fire, and for the translation (real time risk) model. The general guidance was used to determine whether an assumption or source of uncertainty would be key for the TSTF-505 application:

1. Conservative Modeling – If the assumption or source of uncertainty resulted in a conservative impact on the baseline PRA model, the assumption or source of uncertainty was assessed to not have a significant impact on the calculation of risk-informed completion times. It is expected that for a conservative modeling choice to have a significant impact on a RICT, the impact on the baseline PRA model would need to be significantly conservative. Modeling of this type is typically not included in the PRA model as it would mask risk insights.

2. Consensus Model or Method – if the assumption or source of uncertainty was introduced as part of a consensus model or method, the assumption or source of uncertainty was assessed to be "state-of-practice" and was not considered a key assumption or source of uncertainty for the application. Modeling choices based on consensus models or methods are generally supported by NRC safety evaluations (SEs) or industry standard practices where no reasonable alternative exists.

3. Various Modeling Areas – In some cases, assumptions and sources of uncertainty were classified based on the respective PRA model areas (e.g., component screening, seasonal variations, CCF modeling, alignments). It is expected that items of this type could have the largest impact on a calculated completion time. For example, given a component is taken out of service for corrective maintenance, choices in CCF modeling could have a significant impact on the result. These items were further dispositioned in Section 2.0.

The conclusion of this review is that no additional sensitivity analyses are required to address the CPNPP PRA model specific assumptions or sources of uncertainty for TSTF-505.

2.0 Assessment of Internal Events, Internal Flooding, Internal Fire, and Translation (Real Time Risk Model) PRA Epistemic Uncertainty Impacts

Table 1 documents a review of the CPNPP internal events, internal flooding, internal fire, and translation (real time risk model) sources of model uncertainty that were designated as having a potential impact on applications, and more specifically, as pertaining to TSTF-505. Furthermore, the sources of model uncertainty that were designated as having a potential impact on TSTF-505 were generally related to a subset of modeling areas, specifically: assumed alignments, failure mode screening, common cause failures, and translation (real time risk). The CPNPP PRA notebooks consistently discuss modeling choices, assumptions, and sources of uncertainty, which results in the duplication of sources of model uncertainty across notebooks. For this reason, individual sources of model uncertainty, as well as a sample of uncertainties that are generic across the PRA documents, are discussed as applicable in Table 1.

SOKC is assessed via proper parametrization of events in the PRA model and propagation via a sampling method (Monte Carlo). If SOKC is significant (greater than 10%, as defined in

EPRI 1016737, and consistent with NUREG-1855 (which refers to the EPRI report for guidance on SOKC treatment)), the missing correlation would be artificially introduced to the cutsets. This cutset manipulation involves determining multiplicative factors that can be added to cutsets. RICT in general does not influence the underlying reliability data, which is the source of SOKC for PRAs. Thus, it is not expected that a RICT for any particular component would require a reassessment of SOKC.

Table 1: Disposition of Key Sources of Assumptions and Uncertainties Related to TSTF-505

ID	Summary of Assumption/Uncertainty	Part of Model Affected	Generic Impact on Risk Applications	Evaluation of TSTF-505 Impact	Included in TSTF-505 LAR?
1	The baseline model is generally used for two types of quantifications: (1) to generate a T&M yearly average output and (2) to generate configuration-specific output. Because the model is static (i.e., boundary conditions cannot be changed dynamically), these two methods are essentially identical, but the interpretation is different. For the average T&M quantification, systems with trains that alternate throughout the year (running (or protected) vs. standby) have been set with Train A running; however, the interpretation in this case is that it is a generic train (similar to the unit alignments), with the understanding that the represented train is alternating throughout the year. This is important because the results of this quantification should not be interpreted as having a particular train unavailable at any given time.	Unavailability modeling.	The treatment provides a realistic risk estimate for an average test and maintenance (T&M) quantification.	Average test & maintenance probabilities are substituted in the configuration risk model. Given this change, the configuration risk model is appropriate and will not impact the risk calculations for RICT.	No.
2	The manual action included to start any pump that is standby conservatively assumes that if the operator fails to start one pump, he necessarily fails to start any of them (if more than one were needed to be started).	Station service water HFE modeling	The treatment is conservative.	The treatment is conservative and will not impact the instantaneous risk calculations for RICT.	No.
3	The RC system is assumed to be operating, with PORVs and PSVs in standby. The PRA models the potential for either PORV train's block valve to be closed with alignment tags. The static (average) model uses these house events to represent the probability throughout the year of block valves being closed.	Reactor Coolant system PORV block valve probability	The treatment is realistic for an average test and maintenance (T&M) quantification, however, in configuration-specific applications, the block valve probability can introduce optimism.	The configuration risk model allows the setting of the block valve by use of a house event which is specified prior to the RICT calculation. Therefore, the PORV block valve probability is treated realistically in the configuration risk model.	No.
4	Various systems are structured such that T&M unavailability is applied only to the standby train. The basic event values for both trains are added together to account for the total unavailability. Applying this method ensures that T/M is applied appropriately regardless of which train is set to standby at the time of quantification.	Unavailability modeling	The treatment is conservative for an average test and maintenance (T&M) quantification, however, in configuration-specific applications, the treatment is realistic.	Average test & maintenance probabilities are substituted in the configuration risk model. Given this change, the configuration risk model is appropriate and will not impact the risk calculations for RICT.	No.
5	Various systems include logic to include certain aspects of modeling at various times of the year. The XHOSCWSUMMER event is used in the model for summer operation. When this event is set to TRUE, additional cooling from the vent-chilled water system is required.	System modeling – seasonal variation	Seasonal variation needs to be included, as appropriate in the configuration-specific applications. If seasonal variation isn't accounted for, the PRA results could be optimistic.	House events are included in the model to specify seasonal conditions (e.g., XHOSCWSUMMER). The alignment tags are specified in the configuration risk runs to account for the seasonal conditions and are therefore treated realistically and will not impact the instantaneous risk calculations for RICT.	No.

Table 1: Disposition of Key Sources of Assumptions and Uncertainties Related to TSTF-505

ID	Summary of Assumption/Uncertainty	Part of Model Affected	Generic Impact on Risk Applications	Evaluation of TSTF-505 Impact	Included in TSTF-505 LAR?
6	The CPNPP PRA model is built using the EPRI CAFTA software. CAFTA includes an automated tool to create common cause groups and develop necessary common cause basic events. The CAFTA common cause tool has a limitation in which it does not re-evaluate common cause basic event probabilities given the failure of an independent component. The CAFTA common cause software calculates all common cause basic event probabilities assuming equipment that is taken out of service is removed for preventive maintenance.	Software limitations - Common Cause	NUREG.CR-5485 Appendix E discusses two methods for calculating common cause basic event probabilities: when the equipment is taken out for preventative maintenance, and when the equipment is out of service because it has failed. If the equipment has been taken out of service because a failure has occurred, then the common cause basic events could optimistic. CCF is modeled in the CPNPP PRA model using the NRC/INL CCF data set and EPRI CAFTA CCF tool. Additionally, the Multiple Greek Letter (MGL) model is used to generate CCF basic event probabilities. The different combinations of common cause failures are included as separate basic events. Consistent with RG 1.177, Revision 2 Section A-1.3.1.1, modification to the MGL parameters are not made for planned (preventive) maintenance activities. For corrective maintenance activities, the MGL parameters are also not modified and this treatment is assessed further for TSTF-505.	For corrective maintenance activities, the MGL parameters are not modified. TSTF-505 requires operators to perform root cause investigations when a component fails or is degraded to ensure similar equipment will not experience common modes of failure. In the case that a RICT calculation is necessary, operators will take Risk Management Actions to ensure common modes of failure are minimized. Comanche Peak uses the following process for identifying RMAs for emergent conditions during the RICT: (1) RMAS are identified and implemented to prevent or minimize the probability of emergent events while a RICT is active, ensure that mitigating and control features are available, and maintain defense-in-depth, and (2) RMAs encompass the following three categories: Actions to increase risk awareness and control, actions to reduce the duration of maintenance activities, and actions to minimize the magnitude of the risk increase.	No.
7	The baseline PRA model includes a plant availability factor (with a value < 1.0) for certain aspects of the PRA model (i.e., SSIE modeling). In non-SSIE modeling, the plant availability factor is implicitly included in the calculation of initiating event frequencies.	Plant Availability Factor	Since the real time risk model evaluates the instantaneous risk during at-power conditions, the use of a plant availability factor less than 1.0 is not appropriate. Due to variation in modeling, logic was added to modify the top event probability by a factor of 1/PAF. The value of 1/PAF is >1 which could impact the rare-event approximation. In general, when the rare-event approximation is invalidated it results in a conservative result.	The additional modeling could potentially have a conservative impact on risk calculations. However, since the calculations evaluate a delta for TSTF-505, the conservatism will not have an impact on RICT calculations.	No.
8	The baseline seismic risk use in the RICT model is assumed to be zero (i.e., to maximize the calculate incremental risk), whereas there will always be some level of baseline seismic risk for a zero-maintenance plant configuration. Therefore, the incremental seismic risk will always be overstated using a seismic penalty based on the total estimated risk.	Seismic Penalty Factor	Applications that evaluate baseline results could be impacted by this assumption since the baseline results will show no seismic risk. On the other hand, the seismic penalty factor will provide a conservative estimate of delta risk for equipment out of service conditions.	Assuming that the baseline seismic risk is zero will result in conservative instantaneous risk calculations for RICT calculations.	No.

Table 1: Disposition of Key Sources of Assumptions and Uncertainties Related to TSTF-505					
ID	**Summary of Assumption/Uncertainty**	**Part of Model Affected**	**Generic Impact on Risk Applications**	**Evaluation of TSTF-505 Impact**	**Included in TSTF-505 LAR?**
9	The limiting HCLPF approach assumes that a failure of a component with seismic capacity at that HCLPF leads directly to core damage. However, even common failure of a given set of components (e.g., all emergency diesel generators) would not lead directly to core damage. There are few SSCs whose failure would lead to seismic core damage with any significant frequency of occurrence. Examples could be important structures, or the reactor pressure vessel, etc. Such failures generally involve HCLPFs much higher than the 0.12g value assumed for the bounding calculation.	Seismic Penalty Factor	The assumption is conservative.	The assumption is conservative.	No.
10	In a seismic PRA, seismic impacts to similar components (e.g., all the emergency diesel generators) Are typically assumed to be correlated unless there are reasons to justify otherwise. Correlation has the effect of introducing common cause impacts. So, if one train of emergency AC power fails seismically, both trains are modeled to fail given the same seismic event. In general, most seismic impacts would effectively be equivalent to Technical Specification loss of function. The assumption of full correlation is less realistic at low g level; for low magnitude earthquakes, a single train seismic-induced failure is more realistic than a fully correlated failure of both trains. This approach, therefore, cannot fully capture the added risk increase of a configuration change during a very low magnitude earthquake. On the other hand, the scenarios with very low magnitude seismic events are essentially captured by the internal events risk scenarios. At very low seismic events, the more realistic event is a seismic-induced LOOP. If not, other seismic failures are experienced, the additional risk resulting from a seismic-induced LOOP can be estimated by simply comparing the Initiating Event Frequency (IEF). The total IEF for a seismic-induced LOOP can be estimated by a simple integration of the plant hazard curve with the generic fragility for LOOP from EPRI guidance, which results in a total IEF of 2.84E-06. This is approximately 0.02% of the total IEF of the internal events LOOP. On this basis, the potentially underestimated risk is judged to be non-significant.	Seismic Penalty Factor	The approach of seismic correlation is an industry consensus method. The approach in general is conservative. The potential underestimation at low g-levels is non-significant.	The approach of seismic correlation is an industry consensus method. The approach in general is conservative. The potential underestimation at low g-levels is non-significant.	No.
11	The estimates associated with the initiating event frequency for each wind interval have some level of uncertainty given the assumption that a LOOP occurs at a certain likelihood depending on the wind level, and with no recovery.	High Wind Penalty Factor	The High Wind penalty factor is developed assuming no LOOP recovery for all wind events, this is a conservative assumption.	The High Wind penalty factor is developed assuming no LOOP recovery for all wind events, this is a conservative assumption.	No.

3.0 References

1. Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09-A, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0-A, October 2012 (ADAMS Accession No. ML12286A322).
2. NUREG-1855, Revision 1, "Guidance on Treatment of Uncertainties Associated with PRA in Risk-Informed Decision-making," U.S. Nuclear Regulatory Commission, March 2017.
3. *Practical Guidance on the Use of Probabilistic Risk Assessment in Risk-Informed Applications with a Focus on the Treatment of Uncertainty.* EPRI, Palo Alto, CA: 2012. 1026511.
4. *Treatment of Parameter and Model Uncertainty for Probabilistic Risk Assessments.* EPRI, Palo Alto, CA: 2008. 1016737.
5. Regulatory Guide (RG) 1.200, Revision 2, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," U.S. Nuclear Regulatory Commission, March 2009.
6. ASME/ANS RA-Sa-2009, "Addenda to ASME/ANS RA-S-2008 Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications," 2009.
7. R&R-PN-041, Revision 5, "Sensitivity and Uncertainty," January 2019.
8. CN-RAM-13-038, Revision 3, "Qualitative Screening, Quantitative Screening, Quantification, and Uncertainty Analysis for CPNPP Fire PRA," December 2019.

ENCLOSURE 11

License Amendment Request

Comanche Peak Nuclear Power Plant, Units 1 and 2

NRC Docket Nos. 50-445 and 50-446

Revise Technical Specifications to Adopt Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times – RITSTF Initiative 4b"

Monitoring Program

1.0 Introduction

Section 4.0, Item 12 of the NRC Final Safety Evaluation (Reference 1) for NEI 06-09-A (Reference 2) requires that the license amendment request (LAR) provide a description of the implementation and monitoring program as described in Regulatory Guide (RG) 1.174, "An Approach For Using Probabilistic Risk Assessment In Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," Revision 3? (Reference 3), and NEI 06-09-A (Reference 2).

This enclosure provides a description of the process applied to monitor the cumulative risk impact of implementation of the Comanche Peak Risk-Informed Completion Time (RICT) Program, specifically the calculation of cumulative risk of extended Completion Times (CTs). Calculation of the cumulative risk for the RICT Program is discussed in Step 14 of Section 2.3.1 and Step 7.1 of Section 2.3.2 of NEI 06-09-A, Risk Informed Technical Specifications Initiative 4b (Reference 2). General requirements for a Performance Monitoring Program for risk-informed applications are discussed in Element 3 of Regulatory Guide (RG) 1.174 (Reference 3).

2.0 Description of Monitoring Program

The intent of the Comanche Peak RICT Program is to manage the annual use of the RICT to maintain the annual plant risk below the {total plant risk thresholds} of 1.0E-4/yr and 1.0E-5/yr for CDF and LERF, respectively. Recognizing that this target may be exceeded from time to time, the Comanche Peak RICT program includes an additional calculation of cumulative risk impact at least once every 48 months as part of the periodic review and update of the PRA models. For the assessment period under evaluation, data will be collected for the risk increase associated with each application of an extended CT for both core damage frequency (CDF) and large early release frequency (LERF), and the total risk will be calculated by summing all risk associated with each RICT application. This summation is the change in CDF or LERF above the zero maintenance baseline levels during the period of operation in the extended CT (i.e., beyond the front-stop CT). The change in risk will be converted to average annual values. The total average annual change in risk for extended CTs will be compared to the guidance of RG 1.174, Figures 4 and 5 (Reference 4), acceptance guidelines for CDF and LERF, respectively. If the actual annual risk increase is acceptable (i.e., not in Region I of Figures 4 and 5 of RG 1.174), then RICT program implementation is acceptable for the assessment period. Otherwise, further assessment of the cause of exceeding the acceptance guidelines of RG 1.174 and implementation of any necessary corrective actions to ensure future plant operation is within the guidelines will be conducted under the corrective action program.
The evaluation of cumulative risk will also identify areas for consideration, such as:

- RICT applications that dominated the risk increase
- Risk contributions from planned vs. emergent RICT applications
- Risk Management Actions (RMA) implemented but not credited in the risk calculations
- Risk impact from applying RICT to avoid multiple shorter duration outages
- Any specific RICT application that incurred a large proportion of the risk

Based on a review of the considerations above, corrective actions will be developed and implemented as appropriate. These actions may include:

- Administrative restrictions on the use of RICTs for specific high-risk configurations
- Additional RMAs for specific configurations
- Rescheduling planned maintenance activities
- Deferring planned maintenance to shutdown condition

- Use of temporary equipment to replace out-of-service systems, structures, or components (SSC)
- Plant modifications to reduce risk impact of future planned maintenance configurations

In addition to impacting cumulative risk, implementation of the RICT Program may potentially impact the unavailability of SSCs. The Maintenance Rule (MR) monitoring programs under 10 CFR 50.65 provide for evaluation and disposition of unavailability impacts which may be incurred from implementation of the RICT Program. The SSCs in the scope of the RICT Program which are also in the scope of the MR allows the use of the MR Program.

NEI 06-09 states that "The NRC staff anticipates that the use of extended CTs within an RMTS program is unlikely to be a routine practice since licensees already accomplish planned maintenance activities within the existing TS CTs. Although the RMTS are permitted to be applied to planned maintenance activities, other requirements, such as the 10CFR50.65 performance monitoring, and regulatory oversight of equipment performance, are disincentives to a licensee to incur significant additional unavailability of plant equipment, even when allowed by an RMTS program. This provides a further control on the use of the RMTS which could result in a significant increase in equipment unavailability and the commensurate risk."

For the purpose of tracking the performance of equipment that, when degraded, can affect the conclusions of the licensee's engineering evaluation and integrated decision- making that support the change to the licensing basis, the RICT program relies on various plant programs including Corrective Action Program (STA-422), Equipment Reliability program (STA-748), Maintenance Rule (STA-744) program and the Mitigating System Performance Index (MSPI). Each of these programs monitors and trends equipment performance.

Maintenance Rule (MR) is currently based on NUMARC 93-01 and uses a set of performance metrics. The monitoring of these kinds of metrics will continue if CPNPP goes to an alternate MR program. The current set of programs used at CPNPP considers and monitors significant components affecting ALL hazards associated with the RICT program, fire, high winds, internal flood, etc. The programs are established with risk information as input to ensure program actions are commensurate with safety importance of SSCs:

- Equipment Reliability Programs address safety importance through classification of critical components, based in part on risk information
- Risk metrics are used expert panel deliberations and to identify risk importance for system functions and set appropriate goals in Maintenance Rule
- Reliability and unavailability of safety important systems is quantitatively evaluated on a periodic basis for MSPI
- Timeliness of corrective actions and effectiveness of program feedback are evaluated in periodic assessments

The programs are established to ensure a focus on safety importance, to anticipate adverse trends and to implement timely actions that prevent degraded performance. The Maintenance Rule performance monitoring provisions and Mitigating System Performance Index thresholds assist in tracking the performance of equipment and correcting poor performance before plant safety can be compromised.

These programs ensure the assumptions and analysis used to support the PRA model and the LAR are maintained.

The monitoring program for the MR, along with the specific assessment of cumulative risk impact described above, serve as the Implementation and Monitoring Program for the RICT Program as described in Element 3 of RG 1.174 (Reference 3) and NEI 06-09-A (Reference 2).

3.0 References

1. Letter from Jennifer M. Golder (NRC) to Biff Bradley (NEI), "Final Safety Evaluation for Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09-A, 'Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines'," dated May 17, 2007 (ADAMS Accession No. ML071200238)
2. Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09-A, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0-A, dated October 12, 2012 (ADAMS Accession No. ML12286A322)
3. Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment In Risk- Informed Decisions on Plant-Specific Changes to the Licensing Basis," Revision 1, November 2002
4. Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment In Risk- Informed Decisions on Plant-Specific Changes to the Licensing Basis," Revision 2, May 2011

ENCLOSURE 12
License Amendment Request

Comanche Peak Nuclear Power Plant, Units 1 and 2
NRC Docket Nos. 50-445 and 50-446

Revise Technical Specifications to Adopt Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times – RITSTF Initiative 4b"

<u>Risk Management Action Examples</u>

1.0 Introduction

This enclosure describes the process for identification and implementation of Risk Management Actions (RMA) applicable during extended Completion Times (CT) and provides examples of RMAs. RMAs are governed by plant procedures for planning and scheduling maintenance activities. The procedures provide guidance for the determination and implementation of RMAs when entering the Risk-Informed Completion Time (RICT) Program consistent with the guidance provided in NEI 06-09-A, Revision 0-A [Ref. 1].

2.0 Responsibilities

In the Comanche Peak RICT Program, all entries, both planned and emergent, will be identified and tracked through the use of plant procedures for planning and scheduling maintenance activities. Work Management is responsible for developing the RMAs with assistance from other site organizations, including Operations, Engineering, Fire Protection and PRA. Operations is responsible for approval and implementation of RMAs.

In certain situations, such as an emergent change to plant conditions while operating in an extended RICT completion time, Operations is also responsible for developing and implementing RMAs to mitigate the immediate effects of the change.

3.0 Procedural Guidance

For planned maintenance activities, implementation of RMAs is required if it is anticipated that the risk management action time (RMAT) will be exceeded. For emergent activities, RMAs must be implemented if the RMAT is reached. Also, if an emergent event occurs requiring recalculation of a RMAT already in place, the procedure requires a reevaluation of the existing RMAs for the new plant configuration to determine if new RMAs are appropriate. These requirements of the RICT Program are consistent with the guidance of NEI 06-09-A.

For emergent entry into a RICT, if the extent of condition is not known, RMAs related to the success of redundant and diverse SSCs and reducing the likelihood of initiating events relying on the affected function will be developed and implemented to address the increased likelihood of a common cause event.

RMAs will be implemented in accordance with current procedures (e.g., Ref. 2 and 3) no later than the time at which an incremental core damage probability (ICDP) of 1E-6 is reached, and no later than the time when an incremental large early release probability (ILERP) of 1E-7 is reached. If, as the result of an emergent condition, the instantaneous core damage frequency (ICDF) or the instantaneous large early release frequency (ILERF) exceeds 1E-3 per year or 1E-4 per year, respectively, RMAs are also required to be implemented. These requirements are consistent with the guidelines of NEI 06-09-A.

In general, RMAs are developed to reduce overall risk by minimizing the potential for transients, increasing the potential for detection of abnormal conditions (e.g., fires), and maximizing the availability of mitigating systems. A key consideration is the effect of the inoperable component(s) on function redundancy and defense-in-depth. By determining which structures, systems, or components (SSCs) are most important from a CDF or LERF perspective for a specific plant configuration, RMAs may be created to protect these SSCs. Similarly, knowledge of the initiating event or sequence contribution to the configuration-specific CDF or LERF allows development of RMAs that enhance the capability to mitigate such events. The guidance in NUREG-1855 [Ref. 4] and EPRI TR-1026511 [Ref. 5] will be used in examining PRA results for significant contributors for the configuration, to aid in

identifying appropriate compensatory measures (e.g., related to risk- significant systems that may provide diverse protection, or important support systems or human actions). Enclosure 9 identifies several areas of uncertainty in the Comanche Peak PRA models that will be considered in defining configuration-specific RMAs when entering a RICT.

It is possible to credit RMAs in RICT calculations, to the extent the associated plant equipment and operator actions are modeled in the PRA; however, such quantification of RMAs is neither required nor expected by NEI 06-09-A. Nonetheless, if RMAs will be credited to determine RICTs, the procedure instructions will be consistent with the guidance in NEI 06-09-A.

NEI 06-09-A classifies RMAs into the three categories described below:

1. Actions to increase risk awareness and control, for example:
   - Shift brief
   - Pre-job brief
   - Training
   - Presence of system engineer or other expertise related to the activity
   - Special purpose procedure to identify risk sources and contingency plans
2. Actions to reduce the duration of maintenance activities, for example:
   - Pre-stage materials
   - Conduct training on mock-ups
   - Perform the activity around the clock
   - Perform walk-downs on the actual system(s) to be worked on prior to beginning work
3. Actions to minimize the magnitude of the risk increase, for example:
   - Suspend or minimize activities on redundant systems
   - Suspend or minimize activities on other systems that adversely affect the CDF or LERF
   - Suspend or minimize activities on systems that may cause a trip or transient to minimize the likelihood of an initiating event that the out-of-service component is meant to mitigate
   - Use temporary equipment to provide backup power, ventilation, etc.
   - Reschedule other risk-significant activities

4.0 Examples

Example generic RMAs that should be considered are provided below. Scenario-specific RMAs should also be considered.

- Provide shiftly "Pre-Job Brief" to each crew, including covering the manual actions to use equipment that was made inoperable/unavailable solely due to component protection measures (e.g., pull-to-lock (PTL)).
- Establish Roving Fire Watches
- Restrict work activities involving components that if lost or failed could result in a direct plant trip or transient
- Suspend maintenance on or in the vicinity of important equipment, such as: EDGs, APGs, TDAFWP, MDAFWPs, 1E switchgear and MCCs, CCPs, CCWPs and SSWPs; including placing restriction signage on doorways and barricades at applicable equipment

- Restrict work and access to the 345 KV and 138 KV switchyards (except for normal rounds)
- Restrict work on opposite unit Station Service Water (SSW) and Component Cooling Water (CCW) Systems (ensure cross-tie features remain available)
- Ensure surveillances are current, prior to planned RICT entry, for any supported train related components (Examples: EDGs, Auxiliary Feedwater pumps, Safety Chilled Water components.
- Limit test and maintenance that could cause a transient or other event on the unit
- Limit heavy load lifts
- Avoid use of cranes/man-lifts in and around off-site power lines and equipment as well as the power block and turbine buildings.
- Evaluate hot work and transient combustibles in or around any protected train:
  - Restrict Transient Combustible Storage in critical areas, such as: EDG rooms, switchgear rooms, UPS/inverter rooms, MCR/CSR/RSP and in the unaffected opposite train component areas.
  - Suspend Hot Work activities in critical areas, such as: EDG rooms, switchgear rooms, UPS/inverter rooms, MCR/CSR/RSP and in the unaffected opposite train component areas.
- Consider extended weather forecast in relation to plant condition

Multiple example RMAs that may be considered during a RICT Program entry to reduce the risk impact and ensure adequate defense-in-depth are provided below. Specific examples are given for unavailability of:

- One Diesel Generator (DG)
- One Offsite Source
- One Battery Charger
- One Residual Heat Removal (RHR) pump
- One AC Distribution System Train
- One DC Distribution System Train

4.1 One Diesel Generator Inoperable

1) Actions to increase risk awareness and control.
   - Brief the on-shift operations crew concerning the unit activities, including any compensatory measures established.
     - Specific focus areas would be to review appropriate emergency or abnormal operating procedures for:
       - Loss of Offsite Power events
       - Station blackout events
       - Loss of Secondary Heat Sink events
       - Component Cooling Malfunction events
       - LOCA events
     - Other Operator Actions of importance resulting from the configuration:
       - Actions to protect the Shutdown seals
       - Actions to maintain the availability AFW pumps
       - Actions to manually control AFW pump flow due to loss of control of the flow control valves, HV-2459,60, 6162 PV-2453A/B and 2454A/B open
   - Perform a walkdown and validation of the opposite train DG to validate standby/readiness condition

- Perform a walkdown and validation of the AFW trains to validate standby / readiness condition
- Perform a walkdown of and confirm availability of applicable suppression, detection and fire barriers for the following equipment areas:
  - Unit Auxiliary Transformers (uUT)
  - Station Service Auxiliary Transformers (uST)
  - Start-up Transformers (XST1/2)
  - Electrical Equipment (Safety Related Switchgear) and Battery Room Control Room
  - Cable Spreading Room
- For the above equipment areas, minimize the accumulation of transient combustibles in accordance with the station Fire Protection program
- Notify the Transmission Grid Manager (TGM) of the configuration so that any planned activities with the potential to cause a grid disturbance are deferred.
  - Discuss projected grid loading conditions with the TGM to identify if a planned entry into DG unavailability should be deferred

2) Actions to reduce the duration of maintenance activities.
   - For preplanned RICT entry, create a sub schedule related to the specific evolution which is reviewed for personnel resource availability.
   - Confirm parts availability prior to entry into a preplanned RICT.

3) Actions to minimize the magnitude of the risk increase.
   - Proactively implement RMAs during times of high grid stress conditions, such as during high demand conditions (Hands-Off).
   - Evaluate weather conditions for threats to the reliability of offsite power supplies.
   - Defer elective maintenance in the switchyard, on the station electrical distribution systems, and on the Start-up, Station Service Auxiliary and Unit Auxiliary transformers associated with both units.
   - Defer planned maintenance or testing that affects the reliability of operable DGs and their associated support equipment which affect common system availability. Treat these components as protected equipment.
   - Maintain other unit CCW and SSW trains to allow crosstie from the other unit.
   - Defer planned maintenance or testing on redundant train safety systems. If testing or maintenance activities must be performed, perform a review of the potential risk impact.
   - Implement 10 CFR 50.65(a)(4) fire-specific RMAs associated with the affected DGs, as required.
   - Implement 10 CFR 50.65(a)(4) equipment protection schemes in accordance with STA-600, as required.
   - Maintain detection, suppression, and fire barriers intact and minimize transient combustibles for those Fire Areas identified as being significant for the configuration.

4.2 One Offsite Power Source Inoperable

1) Actions to increase risk awareness and control.
   - Brief the on-shift operations crew concerning the unit activities, including any compensatory measures established
     - Specific focus areas would be to review appropriate emergency or

abnormal operating procedures for:
  - Loss of Offsite Power events
  - Station blackout events
  - Loss of Secondary Heat Sink events
  - Station Service Water and Component Cooling Malfunction events
  - LOCA events
- o Other Operator Actions of importance resulting from the configuration:
  - Actions to protect the Shutdown seals
  - Actions to maintain the availability of the AFW pumps
  - Actions to control AFW pump flow due to loss of control of the flow control valves, HV-2459,60, 6162 PV-2453A/B and 2454A/B open
- Perform a walkdown and validation of the DGs to validate standby/ readiness condition
- Perform a walkdown and validation of the AFW trains to validate standby/ readiness condition
- Perform a walkdown and validation of the remaining Off-Site Power feed and transformers
- Perform a walkdown of and confirm availability of applicable suppression, detection, and fire barriers for the following areas:
  - o Auxiliary Building
  - o Electrical Equipment (Safety Related Switchgear) and Battery Room
  - o Cable Spreading Room
  - o Control Room
  - o Electrical Equipment Area/Remote Shutdown Control Room
  - o Safeguards Building
- For the above areas, minimize the accumulation of transient combustibles in accordance with the station Fire Protection program
- Notify the TGM of the configuration so that any planned activities with the potential to cause a grid disturbance are deferred.
  - o Discuss projected grid loading conditions with the TGM to identify if a planned entry into DG unavailability should be deferred.

2) Actions to reduce the duration of maintenance activities.
   - For preplanned RICT entry, create a sub schedule related to the specific evolution which is reviewed for personnel resource availability.
   - Confirm parts availability prior to entry into a preplanned RICT.
3) Actions to minimize the magnitude of the risk increase.
   - Proactively implement RMAs during times of high grid stress conditions, such as during high demand conditions (Hands-Off).
   - Evaluate weather conditions for threats to the reliability of offsite power supplies.
   - Defer elective maintenance in the switchyard, on the station electrical distribution systems, and on the Start-up, Station Service Auxiliary and Unit Auxiliary transformers associated with both units.
   - Defer planned maintenance or testing that affects the reliability of operable DGs and their associated support equipment which affect common system availability. Treat these as protected equipment.
   - Maintain opposite unit SSW and CCW to allow crosstie from other unit.
   - Defer planned maintenance or testing on redundant train safety systems. If

testing or maintenance activities must be performed, a review of the potential risk impact will be performed.

- Implement 10 CFR 50.65(a)(4) fire-specific RMAs, as required.
- Implement 10 CFR 50.65(a)(4) equipment protection schemes in accordance with STA-600, as required.
- Maintain detection, suppression, and fire barriers intact and minimize transient combustibles for those Fire Areas identified as being significant for the configuration.

4.3 One Battery Charger Inoperable

1) Actions to increase risk awareness and control.
   - Brief the on-shift operations crew concerning the unit activities, including any compensatory measures established. Specific focus areas would be to review appropriate emergency or abnormal operating procedures for:
     - Actions to protect the Shutdown seals
     - Actions to maintain Station Service Water and Component Cooling Water and Component Cooling Water
     - Actions to maintain UPS Room cooling/Safety Chilled Water
   - Perform a walkdown and validation of the DGs to validate standby/readiness condition
   - Perform a walkdown and validation of the unaffected AFW trains to validate standby/readiness condition
   - Perform a walkdown of and confirm availability of applicable suppression, detection, and fire barriers for the following areas:
     - Associated ESF Switchgear Room
     - Electrical Equipment Area & Battery Room
     - Control and Cable Spreading Rooms
   - For the above fire areas, minimize the accumulation of transient combustibles in accordance with the station Fire Protection program
   - Notify the TGM of the configuration so that any planned activities with the potential to cause a grid disturbance are deferred.
     - Discuss projected grid loading conditions with the TGM to identify if a planned entry into DG unavailability should be deferred
2) Actions to reduce the duration of maintenance activities.
   - For preplanned RICT entry, create a sub schedule related to the specific evolution which is reviewed for personnel resource availability.
   - Confirm parts availability prior to entry into a preplanned RICT.
3) Actions to minimize the magnitude of the risk increase.
   - Proactively implement RMAs during times of high grid stress conditions, such as during high demand conditions (Hands-Off).
   - Evaluate weather conditions for threats to the reliability of offsite power supplies.
   - Defer elective maintenance in the switchyard, on the station electrical distribution systems, and on the Start-up, Station Service Auxiliary and Unit Auxiliary transformers associated with both units.
   - Defer planned maintenance or testing that affects the reliability of operable DGs and their associated support equipment which affect common system availability. Treat these as protected equipment.

- Protect the remaining DC electrical buses in that unit. Protect opposite unit power supplies for remaining pumps in loop affected by the inoperable SSC.
- Defer planned maintenance or testing on redundant train safety systems. If testing or maintenance activities must be performed, a review of the potential risk impact will be performed.
- Remove nonessential loads from battery to extend time voltage will remain above minimum required level.
- Implement 10 CFR 50.65(a)(4) fire-specific RMAs, as required.

4.4 One RHR Pump Inoperable

1) Actions to increase risk awareness and control.
   - Brief the on-shift operations crew concerning the unit activities, including any compensatory measures established
     - o Specific focus areas would be to review appropriate emergency or abnormal operating procedures for:
       - SGTR events to transition to shutdown cooling
       - LOCA events – including implementation of Containment Sump recirculation
       - Station Service Water and Component Cooling Malfunction events
       - Loss of Protection or Instrument bus
       - Malfunction of 6900/480 KV or 130/345 KV systems
     - o Other Operator Actions of importance resulting from the configuration:
       - Actions to protect the Shutdown seals
       - Actions to maintain the availability of the AFW pumps
       - Actions to control AFW pump flow due to loss of control of the flow control valves, HV-2459,60, 6162 PV-2453A/B and 2454A/B open
     - o Perform a walkdown and validation of the opposite RH train to validate standby/ readiness condition
     - o Perform a walkdown and validation of the opposite CCW and SSW train to validate standby/readiness condition
     - o Perform a walkdown and validation of the AFW trains to validate standby / readiness condition
     - o Perform a walkdown and validation of the containment sump recirculation valve and control logic to validate standby/ readiness condition
     - o Perform a walkdown of and confirm availability of applicable suppression, detection, and fire barriers for the following areas:
       - Control Room/Cable Spreading Room
       - Electrical Equipment Area/Remote Shutdown Control Room Electrical Equipment (Safety Related Switchgear) and Battery Room Associated Diesel Generator Room
       - Safeguards Building General Area
       - Auxiliary Building General Area
   - For the above fire areas, minimize the accumulation of transient combustibles in accordance with the station Fire Protection program.
2) Actions to reduce the duration of maintenance activities.
   - For preplanned RICT entry, create a sub schedule related to the specific evolution which is reviewed for personnel resource availability.
   - Confirm parts availability prior to entry into a preplanned RICT.

3) Actions to minimize the magnitude of the risk increase.
   - Defer planned maintenance or testing that affects the opposite train RHR Pump and its associated support equipment and treat those SSCs as protected equipment.
   - Defer planned maintenance or testing that affects the opposite train CCW, CCW HX its associated support equipment and treat those SSCs as protected equipment.
   - Implement 10 CFR 50.65(a)(4) fire-specific RMAs associated with the affected RHR Pump.
   - Implement 10 CFR 50.65(a)(4) equipment protection schemes in accordance with STA-600, as required.
   - Maintain detection, suppression, and fire barriers intact and minimize transient combustibles for those Fire Areas identified as being significant for the configuration.

4.5 One AC Distribution System Train Inoperable

1) Actions to increase risk awareness and control:
   - Brief the on-shift operations crew concerning the unit activities, including any compensatory measures established.
     - o Specific focus areas would be to review appropriate normal, abnormal, and emergency operating procedures for:
       - Loss Offsite Power
       - Station Blackout
       - Loss of Heat Sink
       - Component Cooling Water Malfunctions
       - Station Service Water Malfunctions
       - Safety Chilled Water System Malfunctions
       - Uninterruptable Power Supply HVAC
     - o Other Operator Actions of importance resulting from the configuration:
       - Maintaining RCP seals
       - Maintaining AFW pumps
       - Manual control of AFW flow
   - Validate opposite train 6.9 kV and 480 V bus readiness.
   - Validate opposite train MDAFWP and TDAFWP readiness.
   - Validate fire protection suppression, detection, and barrier readiness for:
     - o Startup Transformers, XST1, XST1A, XST2, and XST2A (inservice transformers)
     - o Opposite train Class 1E 6.9 kV and 480 V switchgear locations
     - o Opposite train Class 1E 118 V inverter rooms
     - o Cable Spreading Rooms
     - o Control Room
     - o Opposite train MDAFWP and TDAFWP rooms
   - Minimize accumulation of transient combustibles around protected equipment and rooms in accordance with site Fire Protection Program.
   - Notify Transmission Grid Manager (TGM) of plant configuration so planned activities that could affect grid stability or availability may be deferred.
     - o Collaborate with TGM to identify if any planned entry should be rescheduled.

2) Actions to reduce the duration of maintenance activities:
   - For planned RICT entry, create a schedule for the specific evolution which

allocates resources.
- For planned RICT entry, validate all parts are available onsite prior to entry.

3) Actions to minimize the magnitude of the risk increase:
   - Proactively implement RMAs during times of high grid stress, such as high demand conditions (Ordered "Hands Off" conditions).
   - Evaluate weather conditions that could impact offsite power sources.
   - Defer elective maintenance on protected equipment (switchyard, DGs, transformers, and distribution system components).
   - Defer planned maintenance or testing that affects the reliability of operable DGs and their associated support equipment which affect common system availability.
   - Maintain opposite Unit CCW and SSW trains to allow cross-connect between Units.
   - Defer planned maintenance or testing on redundant train safety systems. If testing or maintenance activities must be performed, perform a review of the potential risk impact.
   - Implement 10 CFR 50.65(a)(4) fire-specific RMAs associated with the affected AC Distribution train in accordance with STI-604.05, *On-Line Fire Risk Management*, as required.
   - Implement 10 CFR 50.65(a)(4) equipment protection schemes in accordance with STA-600, *Protecting Plant Equipment and Sensitive Equipment Controls,* as required.
   - Maintain Fire Protection detection, suppression, and barriers intact.
   - Minimize transient combustibles and suspend hot work for those Fire Areas identified as having the credited safe shutdown path impacted by the equipment being unavailable.

4.6 One DC Distribution System Train Inoperable

1) Actions to increase risk awareness and control:
   - Brief the on-shift operations crew concerning the unit activities, including any compensatory measures established.
     - Specific focus areas would be to review appropriate normal, abnormal, and emergency operating procedures for:
       - Maintaining Protection and Instrument Bus power (118 VAC / 125 VDC)
       - Station Blackout
       - Component Cooling Water Malfunctions
       - Station Service Water Malfunctions
       - Safety Chilled Water System Malfunctions
       - Uninterruptable Power Supply HVAC
     - Other Operator Actions of importance resulting from the configuration:
       - Maintaining RCP seals
       - Maintaining AFW pumps
       - Manual control of AFW flow
   - Validate opposite train Class 1E 6.9 kV and 480 V buses readiness.
   - Validate opposite train Class 1E batteries readiness.
   - Validate opposite train 118 VAC Vital (Protection and Instrument) bus readiness.
   - Validate opposite train MDAFWP and TDAFWP readiness.

- Validate fire protection suppression, detection, and barrier readiness for:
    - Startup Transformers, XST1, XST1A, XST2, and XST2A (inservice transformers)
    - Opposite train Class 1E 6.9 kV and 480 V switchgear locations
    - Opposite train Class 1E 118 V inverter rooms
    - Cable Spreading Rooms
    - Control Room
    - Opposite train MDAFWP and TDAFWP rooms
- Minimize accumulation of transient combustibles around protected equipment and rooms in accordance with site Fire Protection Program.
- Notify Transmission Grid Manager (TGM) of plant configuration so planned activities that could affect grid stability or availability may be deferred.
    - Collaborate with TGM to identify if any planned entry should be rescheduled.

2) Actions to reduce the duration of maintenance activities:
- For planned RICT entry, create a schedule for the specific evolution which allocates resources.
- For planned RICT entry, validate all parts are available onsite prior to entry.

3) Actions to minimize the magnitude of the risk increase:
- Proactively implement RMAs during times of high grid stress, such as high demand conditions (Ordered "Hands Off" conditions).
- Evaluate weather conditions that could impact offsite power sources.
- Defer elective maintenance on protected equipment (switchyard, DGs, transformers, inverters, batteries, and distribution system components).
- Defer planned maintenance or testing that affects the reliability of operable DGs and their associated support equipment which affect common system availability.
- Maintain opposite Unit CCW and SSW trains to allow cross-connect between Units.
- Defer planned maintenance or testing on redundant train safety systems. If testing or maintenance activities must be performed, perform a review of the potential risk impact.
- Implement 10 CFR 50.65(a)(4) fire-specific RMAs associated with the affected DC Distribution train in accordance with STI-604.05, *On-Line Fire Risk Management*, as required.
- Implement 10 CFR 50.65(a)(4) equipment protection schemes in accordance with STA-600, *Protecting Plant Equipment and Sensitive Equipment Controls,* as required.
- Maintain Fire Protection detection, suppression, and barriers intact.
- Minimize transient combustibles and suspend hot work for those Fire Areas identified as having the credited safe shutdown path impacted by the equipment being unavailable.

5.0 References

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