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U.S. Nuclear Regulatory Commission
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CATAWBA NUCLEAR STATION, UNIT NOS. 1 AND 2
DOCKET NOS. 50-413 AND 50-414
RENEWED LICENSE NOS. NPF-35 AND NPF-52

MCGUIRE NUCLEAR STATION, UNIT NOS. 1 AND 2
DOCKET NOS. 50-369 AND 50-370
RENEWED LICENSE NOS. NPF-9 AND NPF-17

SUBJECT: RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION (RAI) REGARDING LICENSE AMENDMENT REQUEST PROPOSING CHANGES TO THE TECHNICAL SPECIFICATIONS 3.8.1 FOR CATAWBA NUCLEAR STATION, Units 1 and 2

REFERENCES:

1. Duke Energy letter, *License Amendment Request Proposing Changes to Catawba and McGuire Technical Specification 3.8.1, "AC Sources - Operating"*, dated May 2, 2017 (ADAMS Accession No. ML17122A116).

2. Duke Energy letter, *Supplement to License Amendment Request Proposing Changes to Catawba and McGuire Technical Specification 3.8.1, "AC Sources - Operating"*, dated July 20, 2017 (ADAMS Accession No. ML17201Q132).

3. Duke Energy letter, *Supplement to License Amendment Request Proposing Changes to Catawba and McGuire Technical Specification 3.8.1, "AC Sources - Operating"*, dated November 21, 2017 (ADAMS Accession No. ML17325A588).

4. Duke Energy letter, *Supplement to License Amendment Request Proposing Changes to Catawba and McGuire Technical Specification 3.8.1, "AC Sources – Operating",* dated October 8, 2018 (ADAMS Accession Nos. ML18281A010).

5. NRC E-Mail, *Request for Additional Information – Catawba Nuclear Station, Units 1 and 2 – ESPS LAR*, dated January 9, 2019 (ADAMS Accession No. ML19009A541).

6. Duke Energy letter, *Response to NRC Request for Additional Information (RAI) Regarding License Amendment Request Proposing Changes to the Technical Specifications 3.8.1 For McGuire Nuclear Station*, dated December 3, 2018 (ADAMS Accession No. ML18337A277).

Ladies and Gentlemen:

In Reference 1, as supplemented by References 2, 3, and 4, Duke Energy Carolinas, LLC (Duke Energy) submitted a License Amendment Request (LAR) for Catawba Nuclear Station (CNS), Units 1 and 2. The proposed change would extend the Completion Time for an inoperable diesel generator in Technical Specification (TS) 3.8.1, “AC Sources - Operating” at the station. The proposed change would also alter the AC power source operability requirements for the Nuclear Service Water System (NSWS), Control Room Area Ventilation System (CRAVS), Control Room Area Chilled Water System (CRACWS) and Auxiliary Building Filtered Ventilation Exhaust System (ABFVES) (i.e., shared systems).

By correspondence dated January 9, 2019 (Reference 5), the Nuclear Regulatory Commission (NRC) staff requested additional information from Duke Energy that is needed to complete the LAR review.

Attachment 1 provides Duke Energy’s response to the NRC RAI. Attachment 2 contains proposed markups of CNS TS 3.8.1, which supersede all previous submittals. Attachment 3 contains proposed markups of CNS TS 3.8.1 Bases, which supersede all previous submittals. Attachment 4 provides the comprehensive list of regulatory commitments that are associated with the LAR. Attachments 5 and 6 contain proposed markups of the CNS Renewed Facility Operating License (FOL) for Units 1 and 2, respectively. Commitment numbers 4 and 10 have been added to the CNS FOL markups as proposed license conditions. The proposed CNS TS 3.7.8 Bases provided in the October 8, 2018 letter (Reference 4) are still valid. The proposed CNS TS Bases 3.8.2, 3.7.10, 3.7.11, and 3.7.12 provided in the May 2, 2017 letter (Reference 1) are also still valid.

Attachment 7 provides a supplement to the McGuire Nuclear Station (MNS), Units 1 and 2 letter in reference 6. The Attachment 7 supplement provides proposed markups of the MNS Renewed Facility Operating License (FOL) for both units, a comprehensive list of MNS regulatory commitments that are associated with the LAR, and additional information regarding PRA model changes and ESPS diesel generator (DG) failure rates. Commitment Numbers 4 and 10 have been added to the MNS FOL markups as proposed license conditions. Attachment 8 contains proposed markups of the MNS TS 3.8.1 Bases, which supersedes all previous submittals.

The conclusions of the original No Significant Hazards Consideration and Environmental Consideration in the original LAR are unaffected by this RAI response.

In accordance with 10 CFR 50.91, Duke Energy is notifying the states of North Carolina and South Carolina of this LAR by transmitting a copy of this letter and attachments to the designated state official. Should you have any questions concerning this letter, or require additional information, please contact Art Zaremba, Manager – Nuclear Fleet Licensing, at 980-373-2062.

U.S. Nuclear Regulatory Commission
RA-19-0004

I declare under penalty of perjury that the foregoing is true and correct. Executed on March 7, 2019.

Sincerely,

Steve Snider
Vice President, Nuclear Engineering

NDE

Attachments:

1. Response to NRC Request for Additional Information
2. Revised Catawba Technical Specification 3.8.1 Marked Up Pages
3. Revised Catawba Technical Specification Bases 3.8.1 Marked Up Pages
4. Catawba Regulatory Commitments
5. Markup of Proposed Renewed Facility Operating License – CNS Unit 1
6. Markup of Proposed Renewed Facility Operating License – CNS Unit 2
7. McGuire Nuclear Station Supplemental Information
8. Revised McGuire Technical Specification Bases 3.8.1 Marked Up Pages

cc: (all with Attachments unless otherwise noted)

C. Haney, Regional Administrator USNRC Region II
J.D. Austin, USNRC Senior Resident Inspector
M. Mahoney, NRR Project Manager
L. Garner, Manager, SCDHEC

Attachment 1

Response to NRC Request for Additional Information

NRC Request for Additional Information:

By letter dated May 2, 2017 (Agencywide Documents Access management System (ADAMS) Accession No. ML17122A116), as supplemented by letters dated July 20, 2017 (ADAMS Accession No. ML 17201Q132), November 21, 2017 (ADAMS ML17325A588), and October 8, 2018 (ADAMS Accession No. ML18281A010), Duke Energy Carolinas, LLC (Duke Energy, the licensee), requested an amendment to Renewed License Nos. NPF-35 and NPF-52 for Catawba Nuclear Station (Catawba), Units 1 and 2. The proposed amendment would revise the Catawba Technical Specifications (TS) 3.8.1, “AC [Alternating Current] Sources – Operating,” to allow the extension of the Completion Time (CT) for an inoperable diesel generator (DG) from 72 hours to 14 days, and to ensure that at least one train of shared components has an operable emergency power supply. The proposed changes to TS 3.8.1 in the October 8, 2018 letter superseded the proposed TS 3.8.1 changes in all other letters.

The proposed TS changes in the October 8, 2018 letter would revise Catawba TS 3.8.1 by adding 1) new LCOs for the opposite unit AC power sources to supply power for the required shared systems; 2) new Required Actions (RAs) and CTs associated with Condition B (inoperable DG); and 3) new Conditions and associated RAs and CTs to address new the LCOs for shared systems. To support the 14-day extended CT request, Catawba will add a supplemental AC power source (i.e., two supplemental diesel generators (SDGs) per station) with the capability to power any emergency bus. The SDGs will have the capacity to bring the affected unit to cold shutdown. The supplemental AC power source will be referred to as the Emergency Supplemental Power Source (ESPS).

The LAR for Catawba, Units 1 and 2, dated May 2, 2017, states that the proposed change to the TS completion time (CT) has been developed using the risk-informed processes described in Regulatory Guide (RG) 1.174, Revision 2, “An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis" ADAMS Accession No. ML100910006), and RG 1.177, Revision 1, “An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications” (ADAMS Accession No. ML100910008). Based on Section 2.3.1 of RG 1.177, the technical adequacy of the probabilistic risk assessment (PRA) must be compatible with the safety implications of the TS change being requested and the role that the PRA plays in justifying that change. The RG 1.177 endorses the guidance provided in RG 1.200, Revision 2, "An Approach for Determining the Technical Adequacy of PRA Results for Risk-Informed Activities” (ADAMS Accession No. ML090410014), on PRA technical adequacy. The RG 1.200 describes a peer review process utilizing American Society of Mechanical Engineers/American Nuclear Society (ASME/ANS) PRA standard RA-Sa-2009, "Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications, Addendum A to RA-S-2008," as one acceptable approach for determining the technical adequacy of the PRA once acceptable consensus approaches or models have been established for evaluations that could influence the regulatory decision.

The NRC staff conducted an audit at Duke Energy offices in Charlotte, North Carolina from May 8 – 10, 2018 (ADAMS Accession No. ML18249A046). The Duke Energy staff was provided a set of audit questions that were discussed during the audit. NRC staff provided a verbal brief to Duke Energy at the end of the audit about what changes it intended to make to audit questions to develop requests for additional information (RAIs). Subsequent to the audit, Duke Energy submitted an LAR supplement, the October 8, 2018, addressing a majority of the Catawba, Units 1 and 2, audit questions. The NRC staff reviewed the material provided in the October 8, 2018 letter and determine that the supplemental information did not address all of the concerns raised during the audit.

Regulatory Requirements

The NRC's regulatory requirements related to the content of the TS are contained in Title 10 of the *Code of Federal Regulations* (10 CFR) at 10 CFR 50.36. For Limiting Conditions of Operation at 10 CFR 50.36(c)(2)(i), "Limiting conditions for operation are the lowest functional capability or performance levels of equipment required for safe operation of the facility. When a limiting condition for operation of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any *remedial action* permitted by the technical specifications until the condition can be met," (emphasis added).

Applicable regulatory guidance for Catawba, Units 1 and 2, is contained in: 1. Standard Technical Specifications for Westinghouse Plants, NUREG-1431, Revision 4 (STS, ADAMS Accession Number ML12100A222), and 2. Final Policy Statement (FPS) on Technical Specifications Improvements for Nuclear Power Reactors (FPS, 58 FR 39132).

10 CFR, Appendix A of Part 50, General Design Criterion (GDC) 17, "Electric Power Systems," requires, in part, that an onsite electric power system and an offsite electric power system be provided to permit functioning of structures, systems, and components important to safety. The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents. The onsite electric power supplies shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure.

The NRC staff also considered the following guidance document to evaluate the LAR:

Branch Technical Position (BTP) 8-8, "Onsite (Emergency Diesel Generators) and Offsite Power Sources Allowed Outage Time Extensions," was developed to provide guidance to the NRC staff for reviewing license amendment requests for Allowed Outage Time (AOT) or CT extensions for the onsite and offsite power AC sources to perform online maintenance of the power sources. In the May 2, 2017 letter, the licensee stated that the LAR provides a deterministic technical justification for extending the CTs and has been developed using the guidelines established in NUREG-0800, Branch Technical Position (BTP) 8-8.
Regulatory Guide (RG) 1.93, "Availability of Electric Power Sources," Revision 1, which provides guidelines that the NRC staff considers acceptable when the number of available electric power sources are less than the number of sources required by the limiting conditions for operation (LCOs) for a facility.

In order to complete its review, the NRC staff requests the following additional information. Please provide your response to the following requests for additional information (RAIs) within 30 days of the date of this correspondence.

<u>RAI-1 – Safe Shutdown Facility Credit for High Winds</u>

Section 4.2 of RG 1.200 states that the LAR should include, "[a] discussion of the resolution of the peer review findings and observations that are applicable to the parts of the PRA required for the application. This [discussion] should take the following forms:

- A discussion of how the PRA model has been changed

• A justification in the form of a sensitivity study that demonstrates the accident sequences or contributors significant to the application decision were not adversely impacted (remained the same) by the particular issue."

Attachment 8, "PRA Peer Review Findings and Resolutions," of the LAR provides PRA peer review facts and observations (F&Os) and dispositions for the Catawba PRAs. Catawba F&O WPR-C3-01 addresses questions about eight model assumptions used in the high winds PRA. The disposition in the LAR for this F&O stated that four assumptions were removed from the analysis and the other four were "revised and enhanced." During the May 2018 audit, given that modeling assumptions can have a significant impact on core damage frequency (CDF) and large early release frequency (LERF) results, the staff requested further information about how the assumptions were revised and justification that the revisions resolved the F&O.

The October 8, 2018 supplement, in response to audit Question 01.b, describes how the four remaining assumptions were revised to address the F&O. Regarding "Assumption 1 in Appendix A Section B.1 (Revision 0)" concerning Standby Shutdown Facility (SSF) accessibility following high wind events, the October 8, 2018 supplement states that the assumption in Revision 0 (i.e., straight line or tornado wind conditions will not prevent access to the SSF after one hour) "was enhanced to explain that the duration of the high wind events is expected to be less than one hour, that multiple travel pathways are available for the operators to take to the SSF, and debris from F1 wind events are not expected to block access to the SSF." In contrast, the response to audit Question 14.d states, "[m]inimal credit is given in the high winds case for the SSF due to operator action feasibility." Based on these statements, it is unclear to the NRC staff how SSF is credited, including SSF accessibility, in the high winds PRA model used for this application and the basis for the assumed credit. Also, it is unclear whether the treatment of SSF accessibility in the high winds PRA could potentially challenge the risk acceptance guidelines (i.e., key source of uncertainty and assumption in accordance with NUREG-1855, Revision 1).

Considering the observations above, the NRC staff requests the following additional information:

a) Provide clarification of the assumptions and associated bases for the accessibility to and credit for the SSF for all high winds events (i.e., F1 and higher high winds initiated events for straight winds, hurricanes, and tornados).

b) The treatment of SSF accessibility during high wind events is a source of model uncertainty. Provide qualitative or quantitative justification for why this source of model uncertainty does not change the conclusions of the LAR (e.g., provide description and results of an aggregate sensitivity study in accordance with NUREG-1855, Revision 1; or identify compensatory measures that will be implemented to reduce the risk and provide an assessment of the risk impact of these measures).

<u>Duke Energy RAI-1 Response</u>

a) The credit for the SSF is extended to F1 and F2 straight-line wind and tornado high wind-initiated events only if an EDG run failure occurs after one hour of successful EDG operation. No credit is taken for the SSF in hurricane events. No credit is taken for the SSF in straight line wind or tornado events higher than F2. Because the SSF is credited only in sequences with an initial success of an EDG, all of the SSF PRA functionality is credited, including prevention of a reactor coolant pump seal LOCA (RCPSL). The bases for this assumption is that high wind events are expected to be less than one hour, multiple travel pathways are available for the operators to take to get to the SSF, and debris from F1 and F2 wind events are not expected to block access to the SSF. Thus, SSF accessibility in F1 and F2 windspeeds is not a significant source of uncertainty.

b) An additional sensitivity study was not performed and the current treatment of the SSF accessibility does not change the conclusions of the LAR. The SSF is located in an open area, such that there are multiple pathways from the control room to the SSF. The yard is kept free from debris and storm preparations involve tying down equipment. Additionally, work control monitors the weather forecasts while scheduling maintenance. As described in Commitment 1 (Attachment 4), extended EDG maintenance will not be scheduled if high wind weather is anticipated. As described in section 7.2.3.3 of NUREG-1855 Rev.1, a conservative bias is used in this analysis for crediting the SSF during a high wind initiating event. A conservative assumption is that credit for the SSF is available only for F1 and F2 high wind-initiated events, straight-line winds and tornadoes, after the first hour of the initiating event. This conservative assumption leads to a higher risk estimate than if a more realistic assumption was adopted.

RAI-2 – ESPS High Wind Fragility Determination

The LAR states that Emergency Supplemental Power Source (ESPS) is intended to be the backup power supply for the 4160 volt bus whose emergency diesel generator (EDG) is removed from service and that, by design, the ESPS diesel generators (DGs) can also be readily connected to any of the four 4160 volt busses. The cutset and importance results provided in LAR Tables 7-31 through 7-36 show that crediting the ESPS for high wind events is risk important. Because of the risk importance of the ESPS and that the PRA modeling of the ESPS has not undergone an independent peer review, the NRC staff requires additional information about the modeling of the ESPS. Address the following:

a) The LAR states in Section 3.5.1, in relation to the Catawba ESPS system description, “[a]ll three weather enclosures (along with separately mounted components) will be designed to meet commercial International Building Code (IBC) and ASCE 7-10 criteria, including rain, snow, seismic and wind loading up to 130 mph gusts.” Discuss how ESPS is credited for each of the high wind categories and provide justification for this credit. Specifically justify the credit for high wind category F2-2 considering the design wind loading of 130 mph.

b) Section 6.1.5.4 of the LAR states that, “conservative straight line, and tornado specific, wind pressure fragilities were developed for the ESPS.” It provides further clarification in that, “the wind missile fragility values used for ESPS were those developed in the high winds PRA for the Main / Auxiliary transformers. This was based on the fact that these transformers are relatively large, outdoor, electrical equipment, similar to the ESPS system.” Provide a more detailed justification that the use of main / auxiliary transformer fragilities is appropriate for the ESPS enclosures. Include in this discussion a description of additional SSCs or features (e.g., concrete walls) that provide additional wind pressure and missile protection to the transformers and the equivalency of these features to those being provided for the ESPS enclosures.

c) The SSF and ESPS wind structure failure rates provided in Tables 7-31 through 7-36 of the LAR appear to demonstrate the ESPS structure is more robust than the SSF structure and are modeled somewhat differently. Table 7-35 of the LAR identifies two different failure probabilities for the ESPS for high wind interval 3-1 (i.e., basic events JESPS_HWP_31, "Wind Pressure Failure of ESPS due to High Wind Interval F3-1," with a probability of 2.41E-01, and JESPS_HWT_31, "Wind Pressure Failure of ESPS due to Tornado Interval F3-1," with a probability of 6.73E-01). For the SSF structure, however, the wind pressure failure probabilities in Tables 7-31 through 7-36 appear to be the same for straight winds, hurricane, and tornado events for the same high wind category. Provide justification for the different modelling approaches for the ESPS and the SSF. Specifically address the basis for using different failure probabilities for the same ESPS structure and wind category (e.g., JESPS_HWP_31 and JESPS_HWT_31) and the reason the SSF high wind failure rates appear to not make this distinction. Also, discuss the significance of these different modeling approaches.

d) If the response to this RAI results in a change to the high winds PRA model, use the high winds PRA model that incorporates the appropriate and consistent treatment of SSF and ESPS structural failure in the aggregate analysis requested in RAI-13.

Duke Energy RAI-2.a Response

The fragility of the ESPS system was assumed to be limited by the failure of the enclosures as their failure would be required before exposing the ESPS equipment to the high winds. The fragility was estimated by using the specified design wind speed and then removing the conservatism due to the safety factors following the guidance of EPRI 3002003107. "High-Wind Risk Assessment Guidelines." The fragilities based on the wind intervals are:

Straight Winds - Discretized Failure Probabilities for Ten Wind Speed Intervals for CNS					
Wind Speed Interval	**Lower Wind Speed (MPH)**	**Upper Wind Speed (MPH)**	**Representative Wind Speed By Arithmetic Mean (MPH)**	**Interval Fragility for Representative Wind Speed**	**Error Factor (EF)**
F1-1	73	85	79	1.40E-11	1.23
F1-2	85	98	92	2.03E-08	
F1-3	98	112	105	5.57E-06	
F2-1	112	126	119	3.40E-04	
F2-2	126	141	134	6.51E-03	
F2-3	141	157	149	5.38E-02	
F3-1	157	177	167	2.41E-01	
F3-2	177	206	192	6.51E-01	
F4	206	260	233	9.74E-01	
F5	260	320	290	1.00E+00	

Tornado - Discretized Failure Probabilities for Ten Wind Speed Intervals for CNS					
Wind Speed Interval	**Lower Wind Speed (MPH)**	**Upper Wind Speed (MPH)**	**Representative Wind Speed By Arithmetic Mean (MPH)**	**Interval Fragility for Representative Wind Speed**	**Error Factor (EF)**
F1-1	73	85	79	1.17E-06	1.27
F1-2	85	98	92	1.05E-04	
F1-3	98	112	105	2.93E-03	
F2-1	112	126	119	2.93E-02	
F2-2	126	141	134	1.36E-01	
F2-3	141	157	149	3.67E-01	
F3-1	157	177	167	6.73E-01	
F3-2	177	206	192	9.18E-01	
F4	206	260	233	9.97E-01	
F5	260	320	290	1.00E+00	

Therefore, the use of the representative fragilities across the entire high wind hazard curve (including for high wind category F2-2 and greater) for ESPS is acceptable and is in alignment with the high wind PRA used for the evaluation.

This information was provided as part of one of the calculations provided for the onsite audit. (Reference Appendix L of calculation CNC-1535.00-00-0218.) The failure of the ESPS system also includes the fragility of the Turbine building to account for electrical distribution equipment required for the ESPS system to supply a Safety Bus. Also note that the missile fragility contribution for ESPS is applied separately and not included in the previous two tables.

Duke Energy RAI-2.b Response

For Catawba, the ESPS wind missile fragility values are assumed to be the same as those applied for the McGuire Main / Auxiliary Transformers. This is an appropriate approximation since, as stated, the transformers are relatively large, outdoor, electrical equipment like the ESPS system and have one of the largest fragilities of the components included in the high winds PRA. Using these fragility values is more conservative because the McGuire Main / Auxiliary Transformers group is spatially more-open and is not surrounded by concrete walls. Additionally, since this treatment is an approximation, it provides the benefit of consistency between sites. No concrete walls are modeled in the near vicinity of the Main / Auxiliary Transformers group that was used as the representative ESPS wind missile fragility values. Given the proximity to the Turbine Building, the ESPS is expected to see a similar missile field as for the Main / Auxiliary Transformers. Additionally, the ESPS design includes weather enclosures which would potentially afford some protection from the missile field and the ESPS cables will be routed to the Turbine Building via trenches rather than exposed as is the case with the Main / Auxiliary Transformers (considered the primary vulnerability for transformers). The ESPS high wind pressure fragilities were developed separately and do not rely on the McGuire Main / Auxiliary Transformer fragility values.

The assumption of using the McGuire Main / Auxiliary Transformer missile fragility values is conservative and bounding for the Catawba ESPS.

Duke Energy RAI-2.c Response

The ESPS high wind fragilities are based only on the required design limits on the weather enclosure and applied as separate factors. The fragilities of the SSF system are based only on the structure housing the equipment and combined into a single fragility for each of the wind hazard intervals. The fragility of the SSF structure is based on the weighted average of various failure modes identified as part of the evaluation of the existing structure and include separate factors for the frame, roof and wall structural elements as well as the louvers. The results of the minor difference in the application of the fragilities are functionally equivalent. The difference between the HWP and HWT fragilities is that tornado loads include a delta pressure due the hazard in addition to the Bernoulli effect lift and drag pressures due to air flowing around and over the structure.

Duke Energy RAI-2.d Response

Because the high winds PRA model has been revised to incorporate the Rev. 4 internal events PRA model, the quantification results have been updated and are incorporated in the response to RAI-13. Since the fragilities in the high wind speeds are approaching unity which results in issues with the min-cut upper bound assumption inherent in the CAFTA cutset solution, the fragilities F3 and above are set to true for the ESPS during quantification.

RAI-3 – Modeling Alternative Alignments

The LAR for Catawba, dated May 2, 2017, states that the proposed change to the TS CT has been developed using the risk-informed processes described in RG 1.174, Revision 2, and RG 1.177, Revision 1. Based on Section 2.3.1 of RG 1.177, the technical adequacy of the PRA must be compatible with the safety implications of the TS change being requested and the role that the PRA plays in justifying that change. RG 1.177 endorses the guidance provided in RG 1.200, Revision 2, on PRA technical adequacy. The RG 1.200 describes a peer review process utilizing ASME/ANS PRA standard RA-Sa-2009 as one acceptable approach for determining the technical adequacy of the PRA once acceptable consensus approaches or models have been established for evaluations that could influence the regulatory decision. The PRA standard Supporting Requirement (SR) SY-A5 requires that both the normal and alternate alignments be modelled to the extent needed for core damage frequency (CDF) and large early release frequency (LERF) determination.

Based on the review of the LAR, as supplemented, the following provides NRC staff's observations on modeling alternate alignments and asymmetries for this application:

- Section 6.1.4.2 of the LAR states that the Catawba internal events model consists of separate models for each unit and accounts for multiple trains, whereas the internal flooding, high winds, and fire models are single unit that generally assumes Train-A operating.

- NRC staff notes, based on the incremental conditional core damage probability (ICCDP) and incremental conditional large early release probability (ICLERP) risk results reported in LAR Attachment 6, that even small changes in the PRA modeling need to reflect either asymmetries or the most limiting alignment that could potentially impact the conclusions of the LAR. It is not clear to NRC staff that the most limiting configurations (i.e., alignments) are always modeled in the PRAs from the point of calculating ICCDP and ICLERP. Because the LAR indicates that the

ICCDP and ICLERP for the proposed TS change meet the risk acceptance guidelines in RG 1.177 by a small margin, uncertainty in modeling assumptions could impact the conclusions of the application.

- Tables 6-3, 6-4, 6-26 through 6-33, and 6-38 through 6-45 of the LAR show that for each unit the same base case CDF and LERF values were used for both plant operating alignments (i.e., ESPS aligned to Train A bus, ESPS aligned to Train B bus) for internal events; whereas, the CDF and LERF values for the CT case (as well as for the non-CT case) are different between plant operating alignments. The NRC staff notes that the ICCDP, ICLERP, ΔCDF, and ΔLERF calculations should use the same alignment for all the calculated cases (i.e., base, CT, and non-CT).

- During the May 2018 audit, the NRC staff identified concerns about not including alternate alignments in the internal flood, high winds, and fire PRA models. NRC staff notes that the internal events results provided in Tables 6-26 through 6-33, and 6-38 through 6-45 of the LAR indicate differences of up to 23 percent for different train alignments. Given that the internal events PRA model provides the underlying basis for the internal flood, high winds, and fire models, issues associated with modelling asymmetries in these PRAs could significantly impact the application.
To address the observations above, the NRC staff requests the following additional information:

a) Provide updated risk results (i.e., ICCDP, ICLERP, ΔCDF, and ΔLERF for internal events, internal flooding, high winds, and fire PRA) for the most limiting configuration (based on ICCDP/ICLERP and using the same plant operating alignment for the base case, CT case, and non-CT case) that aggregate the PRA updates requested in RAI-13.

b) Provide justification that the plant operating alignment(s) used for the internal events, internal flooding, high winds, and fire PRA models in part (a) is the most limiting configuration in terms of calculating the ICCDP and ICLERP for the EDG CT.

Duke Energy RAI-3.a Response

Duke Energy provides updated risk results below in Tables 2 through 7 (i.e., ICCDP, ICLERP, ΔCDF, and ΔLERF for internal events, internal flooding, high winds, and fire PRA) for the most limiting configuration (based on ICCDP/ICLERP and using the same plant operating alignment for the base case, CT case, and non-CT case) that aggregate the PRA updates requested in RAI-13. The internal events and high winds PRA model revisions used to provide the updated risk results model both Train-A and Train-B equipment in either the running or standby mode of operation using split fractions. The internal flooding and fire models assume Train A is the running train and Train B is in standby (NOTE: the internal events model used to support the original LAR dated May 2, 2017 previously assumed Train A is the running train and Train B is in standby). Table 1 summarizes the alignments for the various hazard groups as follows and should be considered when reviewing the updated risk results of Tables 2 through 7:

Table 1
Alignments in Catawba PRA Hazard Models

Hazard	Train A	Train B
Internal Events	Modeled with split fractions as being either the running or standby train	Modeled with split fractions as being either the running or standby train
High Winds		
Internal Flooding	Modeled as the running train	Modeled as the standby train
Fire		

In addition to the alignments in Table 1 above, industry generic station blackout (SBO) failure rates were used in the PRA models that provide these updated risk results. Finally, point-estimate values were calculated and ACUBE was run on the associated cutsets to improve the accuracy of the Boolean quantification.

Table 2
RG 1.177 ICCDP Summary, ESPS to Train 2A

Hazard	14 Day CT	Base	Multiplier	ICCDP
Internal Events	5.20E-06	3.95E-06	14/365	4.79E-08
Internal Flooding	2.03E-05	1.66E-05	14/365	1.42E-07
High Winds	2.02E-05	5.60E-06	14/365	5.60E-07
Fire (limiting Unit)	2.85E-05	2.27E-05	14/365	2.22E-07
			Sum =	9.72E-07

Table 3
RG 1.177 ICLERP Summary, ESPS to Train 1A

Hazard	14 Day CT	Base	Multiplier	ICLERP
Internal Events	2.95E-07	2.03E-07	14/365	3.53E-09
Internal Flooding	2.99E-07	4.46E-08	14/365	9.76E-09
High Winds	1.88E-06	7.18E-07	14/365	4.46E-08
Fire (limiting Unit)	2.05E-06	1.54E-06	14/365	1.96E-08
			Sum =	7.74E-08

Table 4
351 Day ICCDP Risk Contribution Summary, ESPS to Train 2A

Hazard	ESPS credit	Base	Multiplier	ICCDP
Internal Events	3.27E-06	3.95E-06	351/365	-6.54E-07*
Internal Flooding	1.66E-05	1.66E-05	351/365	0.00E+00
High Winds	2.40E-06	5.60E-06	351/365	-3.08E-06*
Fire (limiting Unit)	2.24E-05	2.27E-05	351/365	-2.88E-07*
			Sum =	-4.02E-06*

*ICCDP is negative since ESPS adds an additional power source to the base case model.

Table 5
351 Day ICLERP Risk Contribution Summary, ESPS to Train 1A

Hazard	ESPS credit	Base	Multiplier	ICLERP
Internal Events	1.36E-07	2.03E-07	351/365	-6.44E-08
Internal Flooding	4.46E-08	4.46E-08	351/365	0.00E+00
High Winds	1.54E-07	7.18E-07	351/365	-5.42E-07
Fire (limiting Unit)	1.50E-06	1.54E-06	351/365	-3.85E-08
			Sum =	-6.45E-07

*ICLERP is negative since ESPS adds an additional power source to the base case model.

Table 6
ΔCDF For Entire Change, ESPS to Train 2A

Hazard	14 Day CT	351 Day	ΔCDF
Internal Events	4.79E-08	-6.54E-07	-6.06E-07
Internal Flooding	2.03E-05	0.00E+00	1.42E-07
High Winds	2.02E-05	-3.08E-06	-2.52E-06
Fire (limiting Unit)	2.85E-05	-2.88E-07	-6.60E-08
		Sum =	-3.05E-06

Table 7
ΔLERF For Entire Change, ESPS to Train 1A

Hazard	14 Day CT	351 Day	ΔLERF
Internal Events	3.53E-09	-6.44E-08	-6.09E-08
Internal Flooding	2.99E-07	0.00E+00	9.76E-09
High Winds	1.88E-06	-5.42E-07	-4.98E-07
Fire (limiting Unit)	2.05E-06	-3.85E-08	-1.89E-08
		Sum =	-5.68E-07

Duke Energy RAI-3.b Response

ICCDP and ICLERP for the EDG CT were calculated for ESPS aligned to Trains 1A, 2A, 1B, and 2B using the internal events, internal flooding, high winds, and fire PRA models. The alignment that resulted in the highest ICCDP is reported in the response to part (a). Similarly, the alignment that resulted in the highest ICLERP is reported in the response to part (a).

RAI-4 - Basic Event Failure Rate Anomalies Common Cause Failure

Section 5, “Quality Assurance,” of RG 1.174, Revision 2, states, “[w]hen a risk assessment of the plant is used to provide insights into the decisionmaking process, the PRA is to have been subject to quality control.”

NRC staff noted in LAR Attachment 7, “PRA Quantification Data Tables,” which provides a listing of basic events and their corresponding probabilities, some apparent anomalies exist that could impact the LAR. In the October 8, 2018 supplement in response to audit Question 05.a, it states that EDG failure rates were updated; however, it is unclear to the

NRC staff whether the common cause failure (CCF) probabilities were also updated.

a) Confirm that the CCF probabilities associated with EDG failures were updated in response to audit Question 05.a.

b) Alternatively, if CCF probabilities were not updated, incorporate the appropriate CCF probabilities for the diesel generators into the PRA models used for this LAR that aggregate the PRA updates requested in RAI-13.

Duke Energy RAI-4 Response

a) The common cause failure probabilities were not updated in response to the October 8, 2018 supplement audit question 05.a.

b) The RAI-13 response contains the aggregated results with CCF probabilities using the updated internal events model failure rates and CCF parameter estimations for Emergency Diesel Generators from US NRC "CCF Parameter Estimations, 2015 Update."

RAI-5 – Seismic Analysis Contribution to the Application

Section 2.3.2 of RG 1.177, Revision 1, states, "[t]he scope of the analysis should include all hazard groups (i.e., internal events, internal flood, internal fires, seismic events, high winds, transportation events, and other external hazards) unless it can be shown that the contribution from specific hazard groups does not affect the decision."

The October 8, 2018 supplement, in response to audit Question 08.a, presents an approach for determining the bounding seismic CDF and LERF increase for the impact of the 14-day EDG outage. As part of the approach, the seismic hazard was divided into six hazard bins and a mean frequency of exceedance was determined for each seismic bin. It appears that these bin frequencies were then combined with conditional core damage probabilities (CCDPs) estimated by using the CCDP resulting from an internal events PRA loss of offsite power (LOOP) initiating event. The response states that seismic events are assumed to result in a LOOP event or to be low enough in magnitude to be subsumed as an internal event. It is not clear to NRC staff that this approach of using internal event CCDPs as a surrogate for seismic event CCDPs produces bounding seismic risk estimates for several reasons. Of primary concern, is that this approach does not account for seismically-induced SSC failures including those that could coincide with the unavailability of an EDG producing potentially significant seismic risk contributions. Also, the response states that human error probabilities (HEPs) are not adjusted to account for seismic scenario specific conditions. NRC staff acknowledges that at a certain magnitude (seismic bin), the fragility of the EDGs may be 100% correlated if they are located on the same elevation and location. In this case, all EDGs either fail or are successful for a given seismic bin, and if all EDGs fail then it is irrelevant whether an EDG is unavailable for test or maintenance. However, for seismic bins in which all EDGS are successful, then the unavailable EDG could coincide with a seismically-induced failure of a non-EDG SSC that produces a significant seismic risk contribution. Considering these observations:

a) Provide justification (e.g., describe and provide the results of an appropriate sensitivity study) that the seismic risk impacts produced by the analysis provided in the October 8, 2018 supplement are bounding. As part of this justification, address how the risk contribution of seismic-induced SSC failures and seismic-impacted HFEs are considered

b) Alternatively, appropriately update the bounding analysis and provide the revised seismic risk estimates with the new PRA results generated in response to RAI-13.

Duke Energy RAI-5.a Response

The October 8, 2018 supplement provided a bounding seismic incremental CCDP of 1.87E-07 for the 14-day CT. The following analyses provide justification that the value provided can be considered as bounding.

For the analysis presented in this revised response, the seismic contribution to risk is addressed via two methodologies: 1) Use of the IPEEE seismic analysis and, 2) Use of a “seismic penalty”. Both approaches offer reasonable results and support the original bounding value.

1) Use of the IPEEE Analysis -

The Catawba seismic CDF (SCDF) provided in response to the Individual Plant Examination for External Events (IPEEE) is 1.6E-05 / yr. (Ref. 1). This is an appropriate bounding value for several reasons given below.

- Figure 1 below shows a comparison of the new GMRS to SSE acceleration response spectra (Ref. 2). From that figure, the design basis SSE exceeds the GMRS below 5.5 Hz, and the GMRS begins to exceed the Catawba SSE above 5.5 Hz. The peak acceleration of the new GMRS is 0.75g at 30 Hz. Ground motions at levels up to 2 times the SSE are expected to produce only a small probability of failure for safety-related SSCs due to conservative design practices. In the high frequency range greater than 10 Hz, structural displacements are small and are considered non-damaging. Thus, the seismic hazard used in the IPEEE evaluation is considered to be conservative in the lower frequency ranges.
- The IPEEE SCDF includes failures from relay chatter events. These types of events are found to occur typically in the high spectral frequency range. In 2017, Catawba performed a High Frequency Confirmation evaluation in response to the NRC's 50.54(f) letter using the methods in EPRI Report 3002004396 (Ref. 6). This evaluation (Refs. 4 and 5) identified over 300 components requiring additional assessment, 66 of which were determined to be outliers. These were subsequently resolved by operator action within existing plant procedures. Including the effects of relay chatter in the IPEEE (with a recovery probability of 0.1) is thus considered a conservative measure in the analysis. Based on its review of the high frequency confirmation report, the NRC staff concluded that the licensee appropriately implemented the high frequency confirmation guidance and identified and evaluated the high frequency seismic capacity of certain key installed plant equipment to ensure critical functions will be maintained following a seismic event up to the GMRS described in Catawba's Seismic Hazard and Screening Report (Ref. 7).
- The IPEEE SCDF does not consider mitigating strategies for accident sequences involving a total loss of power (which are the predominant makeup of the IPEEE cutsets). Such sequences would now be addressed using Catawba’s implementation of FLEX Order EA-12-049 requiring the licensee to develop, implement and maintain guidance and strategies to maintain or restore core cooling (Ref. 3).

- The IPEEE SCDF does not include the redundancy that would now be provided using ESPS. The ESPS diesel would likely be available and functional for station blackout events.
- The IPEEE SCDF does not include the Standby Shutdown Facility (SSF) which would be helpful with the mitigation of Station Blackout events by providing alternate RCP seal cooling, primary makeup, and instrumentation and controls to support longer term operation of the turbine-driven auxiliary feedwater pump. The SSF structure was initially screened out of the IPEEE due to its relatively low seismic capacity, as first reported in Catawba's IPE submittal (Ref. 8). However, it is expected the SSF would be available for earthquakes occurring in the lower frequency ranges.
- The IPEEE included random failures of SSCs. The EDG random failure values used in the current Catawba model of record (MOR) are approximately a factor of 3 lower than those used in the IPEEE due to improvements in equipment reliability and maintenance practices. Thus, the accident sequences involving random failures of the EDGs in the IPEEE are conservative.
- Since the IPEEE submittal in 1994, there have been no new plant modifications which would improve or worsen the effects of seismic events.

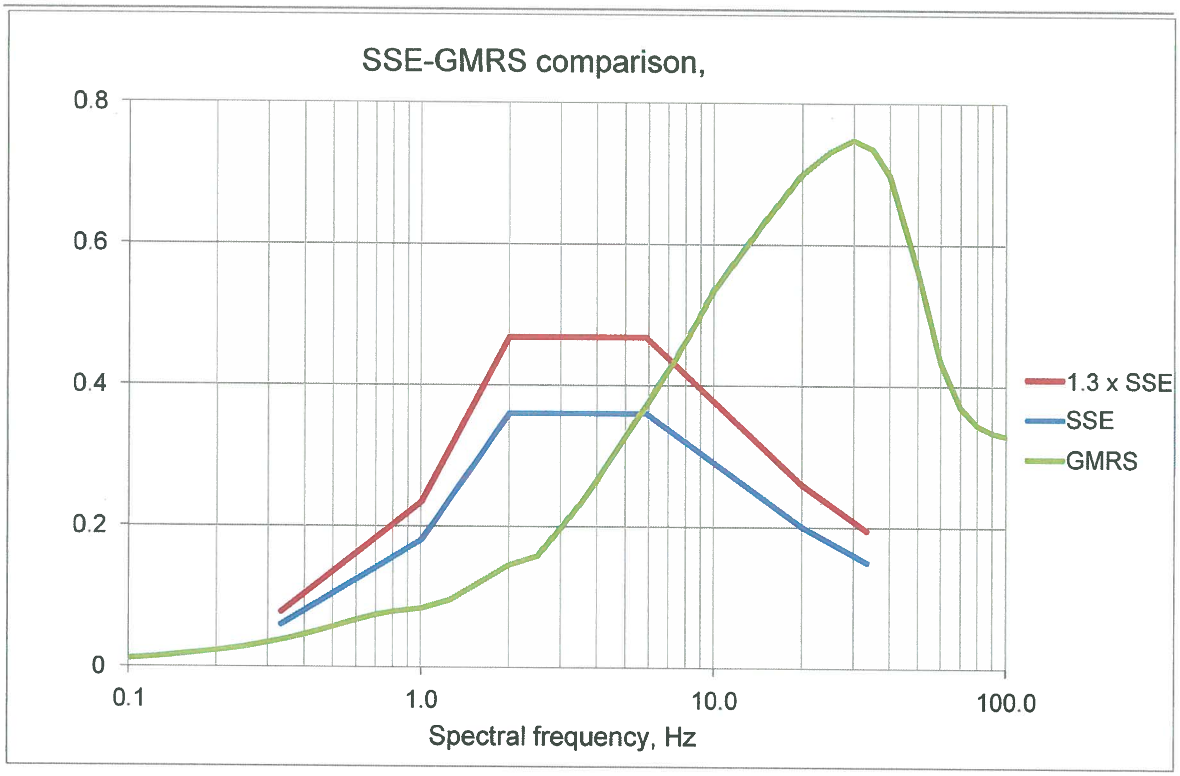

Figure 1 – Catawba Nuclear Station SSE v. GMRS

The model used to perform the IPEEE analysis was re-run with one EDG taken out of service. The resulting CDF was 2.0E-05 / yr., resulting in a delta of 4E-06 / yr. Thus, for the 14-day AOT, the CCDP is,

4E-06 x (14 / 365) = <u>1.5E-07</u>

The IPEEE also included various HFEs, the most predominant of which was the response to the relay chatter events discussed above. Also, as mentioned previously, the IPEEE analysis does not include the implementation of FLEX equipment. Given the risk significance of LOOP events, these would be the dominant accident sequences where FLEX would be required. Thus, not including FLEX introduces conservatism in the IPEEE results and further demonstrates the IPEEE SCDF can be considered a reasonable bounding value.

Other HFEs used in the IPEEE include responses to a loss of AFW. Even though high screening values were used for this assessment, all of accident sequences combined involving these other HFEs made only a small contribution to SCDF (< 3%).

2) Use of a "Seismic Penalty" -

If seismic failures of the same or similar SSCs are assumed to be correlated, the Conditional Core Damage Probability (CCDP) given a seismic event will remain unaltered whether equipment is out of service or not. Thus, for the ESPS configuration, any seismic delta risk is primarily driven by accident sequences involving the loss of offsite power (LOOP), random failures of EDG systems (Fail To Run = 0.0343), seismic failure of non-EDG systems and associated operator actions. Contributions from other accident sequences are negligible due to the aforementioned correlated failure of related SSCs. For the purpose of computing the bounding seismic delta risk, the following conservative assumptions are made:

- All non-EDG SSCs are assumed to be failed or their fragilities are set to one for all hazard bins, irrespective of their seismic capacities.
- All HEPs are set to one for all hazard bins. In other words, there are no bin specific HEPs.
- No credit is given for the potential recovery of the loss of offsite power.
- No consideration of other mitigating equipment such as FLEX.

The seismic LOOP fragility parameter values are taken from NUREG/CR-6544 as follows:

Am	=	Median peak ground acceleration capacity in terms of peak ground acceleration (PGA)
	=	0.3 g
β_R	=	Lognormal standard deviation for randomness
	=	0.3
β_U	=	Lognormal standard deviation for uncertainty
	=	0.45
HCLPF	=	High confidence of a low probability of failure capacity
	=	0.1 g

Based on the above considerations, the bounding seismic SCDF contribution by the accident sequences related to the ESPS configuration can be computed for the base case as follows:

Initiator Bin	Description	Lower Acc	Upper Acc	Representative Acceleration	Hazard Interval Frequency
%G01	Seismic Initiating Event (0.1g to < 0.15g)	0.1	0.15	0.12	2.05E-04
%G02	Seismic Initiating Event (0.15g to < 0.3g)	0.15	0.3	0.21	1.46E-04
%G03	Seismic Initiating Event (0.3g to < 0.5g)	0.3	0.5	0.39	3.54E-05
%G04	Seismic Initiating Event (0.5g to < 0.75g)	0.5	0.75	0.61	1.16E-05
%G05	Seismic Initiating Event (0.75g to < 1g)	0.75	1	0.87	4.05E-06
%G06	Seismic Initiating Event (1g to < 1.5g)	1	1.5	1.22	2.77E-06
%G07	Seismic Initiating Event (1.5g to < 10g)	1.5	10	3.87	1.59E-06

Base Case							
LOOP Fragility	EDG - Train A	EDG - Train B	Non-EDG Seismic Failure	Seismic HEP	CCDP	SCDF	Initiator Bin
4.881E-02	3.430E-02	3.430E-02	1.000E+00	1.000E+00	5.74E-05	1.18E-08	%G01
2.608E-01	3.430E-02	3.430E-02	1.000E+00	1.000E+00	3.07E-04	4.47E-08	%G02
6.816E-01	3.430E-02	3.430E-02	1.000E+00	1.000E+00	8.02E-04	2.84E-08	%G03
9.065E-01	3.430E-02	3.430E-02	1.000E+00	1.000E+00	1.07E-03	1.24E-08	%G04
9.750E-01	3.430E-02	3.430E-02	1.000E+00	1.000E+00	1.15E-03	4.65E-09	%G05
9.954E-01	3.430E-02	3.430E-02	1.000E+00	1.000E+00	1.17E-03	3.24E-09	%G06
1.000E+00	3.430E-02	3.430E-02	1.000E+00	1.000E+00	1.18E-03	1.87E-09	%G07
					Total SCDF =	1.07E-07	

Seismic CDF contribution for each hazard bin is computed by

SCDF = SIEF x CCDP

SIEF = Seismic Initiating Event Frequency, computed by Hazard Interval Frequency x LOOP Fragility

CCDP = Conditional Core Damage Probability, computed by Random failure rate of EDG A (0.0343) x Random failure rate of EDG B (0.0343 for base case and 1 for completion time case) x Seismic failure of non-EDG (conservatively set to 1) x Seismic HEP (conservatively set to 1).

The resulting bounding seismic SCDF contribution for the base case is 1.07E-07. Similarly, the bounding seismic SCDF contribution for the completion time case can be computed as follows:

Initiator Bin	Description	Lower Acc	Upper Acc	Representative Acceleration	Hazard Interval Frequency
%G01	Seismic Initiating Event (0.1g to < 0.15g)	0.1	0.15	0.12	2.05E-04
%G02	Seismic Initiating Event (0.15g to < 0.3g)	0.15	0.3	0.21	1.46E-04
%G03	Seismic Initiating Event (0.3g to < 0.5g)	0.3	0.5	0.39	3.54E-05
%G04	Seismic Initiating Event (0.5g to < 0.75g)	0.5	0.75	0.61	1.16E-05
%G05	Seismic Initiating Event (0.75g to < 1g)	0.75	1	0.87	4.05E-06
%G06	Seismic Initiating Event (1g to < 1.5g)	1	1.5	1.22	2.77E-06
%G07	Seismic Initiating Event (1.5g to < 10g)	1.5	10	3.87	1.59E-06

Completion Time Case							
LOOP Fragility	EDG - Train A	EDG - Train B	Non-EDG Seismic Failure	Seismic HEP	CCDP	SCDF	Initiator Bin
4.881E-02	3.430E-02	1.000E+00	1.000E+00	1.000E+00	1.67E-03	3.43E-07	%G01
2.608E-01	3.430E-02	1.000E+00	1.000E+00	1.000E+00	8.95E-03	1.30E-06	%G02
6.816E-01	3.430E-02	1.000E+00	1.000E+00	1.000E+00	2.34E-02	8.28E-07	%G03
9.065E-01	3.430E-02	1.000E+00	1.000E+00	1.000E+00	3.11E-02	3.60E-07	%G04
9.750E-01	3.430E-02	1.000E+00	1.000E+00	1.000E+00	3.34E-02	1.35E-07	%G05
9.954E-01	3.430E-02	1.000E+00	1.000E+00	1.000E+00	3.41E-02	9.46E-08	%G06
1.000E+00	3.430E-02	1.000E+00	1.000E+00	1.000E+00	3.43E-02	5.45E-08	%G07
					Total SCDF =	3.12E-06	

The resulting bounding seismic SCDF contribution for the completion case is 3.12E-06. Thus, the CCDP for the completion time case is computed as 3.01E-06 (=3.12E-06 – 1.07E-07) x 14/365 = 1.16E-07 /yr. It should be noted that the actual risk increase due to out of service equipment cannot be greater than this bounding value due to the conservative assumptions invoked above.

LERF Discussion

Catawba does not have a formal seismic LERF model. A qualitative discussion was provided in the IPEEE submittal and addressed LERF from a containment integrity, containment isolation and containment response perspective. No seismic vulnerabilities were identified.

Furthermore, Duke submitted a relief request for responding to the seismic portion of the 50.54(f) letter (Ref. 12) using seismic PRAs. In the relief request, Duke maintained performing SPRAs would not provide significant additional seismic risk insights (other than those already gleaned from the IPEEE submittal). In its response (Ref. 13), the Staff concluded the plant-specific combination of seismic hazard exceedances, the general estimation of the seismic CDF and the insights related to the conditional containment failure probabilities at Catawba indicated that the increase in seismic risk due to the reevaluated seismic hazard was addressed within the margin inherent in the design. Hence, a seismic PRA was deemed as no longer necessary to fulfill the response to the seismic portion of the 50.54(f) letter.

Therefore, since the seismic CDF values generated above using the IPEEE and seismic penalty analyses are conservative in nature and provide reasonable bounding values that are within the bounding value provided in the October 8, 2018 submittal, the corresponding LERF value would also be conservative and reasonable.

Conclusion:

Using two separate analyses, Duke has provided justification that the seismic risk impacts produced by the analysis provided in the October 8, 2018 supplement is bounding. In addition, Duke has addressed how the risk contribution of the seismic-induced SSC failures and seismic-impacted HFEs were considered.

Duke Energy RAI-5.b Response

No revision of the analysis is required based on response to part a) of this RAI.

RAI-6 – Avoiding Plant Configurations that Contribute to Significant Risk

Section 2.3 of RG 1.177, Revision 1, cites the need to avoid risk-significant plant configurations and discusses Tier 2 of a three-tiered approach for evaluating risk associated with proposed TS CT changes. According to Tier 2, the licensee should provide reasonable assurance that risk-significant plant equipment outage configurations will not occur when specific plant equipment is out of service consistent with the proposed TS change. Once the specific plant equipment are identified, an assessment can be made as whether certain enhancements to the TS or procedures are needed to avoid risk-significant plant configurations. In addition, Section 2.4 of RG 1.177 states, as part of the TS acceptance guidelines specific to permanent CT changes, the licensee should demonstrate that there are appropriate restrictions on dominant risk-significant configurations associated with the change. Section 2.4 of RG 1.177 also provides the risk acceptance guidelines for permanent CT changes, which also includes the need to demonstrate that there are appropriate restrictions on dominant risk-significant configurations associated with the CT change.

The LAR indicates that the ICCDP and ICLERP for the proposed TS change meet the risk acceptance guidelines in RG 1.177 by a small margin, and therefore, in accordance with Tier 2, it is important that plant configurations contributing to risk be avoided when the EDGs are taken out of service for the extended CT. Section 3.12.2 of the LAR provides a discussion of Tier 2 (“Avoidance of Risk-Significant Plant Configurations”) and identifies in LAR Table 1 those SSCs for Catawba that are important to the 14-day EDG CT based on SSC risk importance values presented in LAR Attachment 7. LAR Section 3.12.2 states that unavailability of the identified SSCs should be avoided during the extended CT. The October 8, 2018 supplement in response to audit Question 10, identifies several methods that are relied upon to avoid risk-significant plant configurations: Technical Specifications (TS), Selected Licensee Commitments (SLCs), cycle schedules, protected equipment schemes, and the Electronic Risk Assessment Tool (ERAT).

Section 6.1.5 of LAR Attachment 6 states, “[t]he CT case for Catawba has restricted test and maintenance on the items listed in Table 6-58 [of LAR Attachment 6].” Table 6-58 of the LAR provides the Catawba SSCs important to the 14-day EDG CT (Table 6-58 is identical to Table 1 of the LAR). The October 8, 2018 supplement, in response to audit Question 11.b, states that in the CT-case the test and maintenance probabilities for the following SSCs are set to zero in the PRA models: ESPS, opposite train EDG, turbine-driven Auxiliary Feedwater (AFW) pump (TDAFWP), and the SSF. The response states that these SSCs will remain in service utilizing the Protected Equipment and Work Management procedures. NRC staff notes that the calculated ICCDP and ICLERP values used to show alignment with the risk acceptance guidelines in RG 1.177 is based on ensuring this plant configuration. Considering these observations:

Propose a license condition that ensures (e.g., that implements the cited methods) the SSCs listed in LAR Table 1 (Table 6-58) will not be removed from service for planned maintenance or testing during the extended EDG CT.

Duke Energy RAI-6 Response

Duke Energy proposes the below license condition be added to the Facility Operating License (FOL) for Catawba Units 1 and 2 that will ensure the SSCs listed in Table 1 of the LAR dated May 2, 2017 will not be removed from service for planned maintenance or testing during the extended EDG CT. The proposed license condition is reflected in the Unit 1 and Unit 2 FOL markup (see Attachments 5 and 6).

Proposed License Condition:

During the extended DG Completion Times authorized by Amendment No. [XXX], the turbine-driven auxiliary feedwater pump will not be removed from service for elective maintenance activities. The turbine-driven auxiliary feedwater pump will be controlled as “protected equipment” during the extended DG CT. The Non-CT EDGs, ESPS, Component Cooling System, Safety Shutdown Facility, Nuclear Service Water System, motor driven auxiliary feedwater pumps, and the switchyard will also be controlled as “protected equipment.”

RAI-7 – Risk Calculations for the EDG CT Extension

Section 2.3 of RG 1.177, Revision 1, provides guidance on PRA modeling detail needed for TS changes. Section 2.3.3.1 of RG 1.177 states that the PRA “model should also be able to treat the alignments of components during periods when testing and maintenance are being carried out.” It also states that “[s]ystem fault trees should be sufficiently detailed to specifically include all the components for which surveillance tests and maintenance are performed and are to be evaluated.”

NRC staff observed that the Catawba internal flooding and high winds PRA risk results reported in LAR Attachment 6 were identical across units. For internal flooding, the October 8, 2018 supplement, in response to audit Question 11.a, states that the only significant difference between units is the addition of one internal flooding scenario to Unit 1 involving a break in the Main Feedwater piping in the Unit 1 doghouse which does not significantly impact the quantification results. For high winds, the supplement states that the Unit 1 results are adequate for Unit 2 based on the assumption that there is a high level of symmetry between units. Even though the response to Question 11.a identifies three shared systems between the units, with one of the systems (i.e., the Nuclear Service Water (RN) System) operating asymmetrically, that “[t]his assumption was found to be reasonable based on an update of the high winds analysis that incorporated the Unit 2 internal events model.”

However, contrary to the assertions cited above indicating that there is little asymmetry between units that impact the risk estimates for internal flooding and high winds, NRC staff notes that the internal events risk results presented in the LAR indicate significant differences in CDF and LERF values between units. Tables 6-15, 6-16, 6-26 through 6-33, and 6-38 through 6-45 of the LAR show the following observations for internal events CDF and LERF risk values (base, CT, and non-CT cases): (1) Unit 1 CDF values are higher than Unit 2 by an average of 36%, (2) Unit 2 LERF values are higher than Unit 1 by an average of 41%, (3) Unit 1 ΔCDF and ICCDP values are higher than Unit 2 by an average of 11%, (4) Unit 2 ΔLERF and ICLERP values are higher than Unit 1 by an average of 45%, and (5) the unit differences were based for the same plant configuration. The results presented in LAR Section 6.1.5.11 and the response to audit Question 14.a, which represent the most limiting configuration relative to CDF (Unit 1 Train A) and LERF (Unit 2 Train A), suggest that there are significant unit asymmetries. Since the internal events PRA model provides the underlying basis for the internal flooding and high winds PRA models, differences that are unaccounted for between units could significantly impact the internal flooding and high winds risk results.

Furthermore, because the LAR indicates that the ICCDP and ICLERP for the proposed TS change meet the risk acceptance guidelines in RG 1.177 by a small margin, uncertainty in modeling assumptions could impact the conclusions of the application.
Considering the observations above, the NRC staff requests the following additional information:

a) Explain how the single unit PRA models are representative or bounding for internal flooding and high winds (e.g., the most limiting) for Units 1 and 2. Include a discussion of how the single unit models account for the differences between units shown in the internal events risk results. Demonstrate that the differences between the single unit PRA models and Units 1 and 2 for risk-significant systems do not change the conclusions of the LAR. [Risk-significant systems considered by the NRC staff are those systems identified in LAR Table 1 and additional systems that appear to be risk-significant to the EDG CT based on information presented in tables provided in LAR Attachment 7 related to Fussell-Vesely (F-V) and Risk Achievement Worth (RAW) values for all Catawba hazard PRA models (e.g., 7-2, 7-3, 7-14, 7-15, 7-32, 7-48). These include, for example, motor-driven auxiliary feedwater, residual heat removal, chemical and volume control, 4160V switchgear, 600V components, 125 V direct current (dc) distribution (including batteries), ESFAS components (i.e. load shed, blackout logic), 6900 V switchgear, transformers, vital instrumentation and control power, main feedwater, hydrogen igniters, and air handling units.]

b) If the current modeling cannot be justified because the PRAs do not reflect the differences between units, then update the PRAs to reflect the difference between units in the Catawba PRA models used for this LAR that aggregate the PRA updates requested in RAI-13.

<u>Duke Energy RAI-7.a Response</u>

High Winds

As indicated in the response to RAI 9.b, Unit 1 and 2 high wind models are now based on the latest internal events PRA models. These models aggregate the PRA updates requested in RAI-13 and were used to re-evaluate the LAR PRA results.

Internal Flood

Since the internal flood (IF) model is based on the Unit 1 internal events model, Unit 2 systems have been investigated for similarity with those for Unit 1 to ensure that the same PRA results generally apply to both units. Because of the similarities in the containments at Unit 1 and Unit 2, the investigation focused on the individual plant systems modeled in the plant fault tree.

The unit comparison focused on differences in the system design or in component fault exposure times which would result in differences in the system fault trees. Design Basis Documents, Technical Specifications, system flow diagrams, electrical drawings, general arrangement drawings, manufacturer's drawings and manuals, and training documentation were examined and compared. This comparison was used as a basis to determine if further investigation was warranted.

Shared Systems

Instrument Air (VI) System

The instrument air system is shared between both units. Because of this, there are no unit differences and interdependencies except the power supplies to the VI compressors and other VI components, which are powered from different units to minimize the impact from an event on any given unit.

Standby Shutdown System (SSS)

During an emergency, the Standby Shutdown Facility (SSF) is used to achieve and maintain hot standby on one or both units. Operators can establish natural circulation in the NC System, initiate auxiliary feedwater, and line up SSS valves either in the control room or locally. Plant control is then to be shifted to the SSF. Primary and secondary inventory is controlled and primary natural circulation is verified once SSF control is established.

Electrical power needed to achieve and maintain hot standby is supplied by the SSF diesel generator. Non-LOOP initiators do not require the SSF diesel generator to be started for electrical power to the SSF functions. For those initiators, normal station power is sufficient.

Nuclear Service Water System (RN)

The source and intake section of the RN system is comprised of the standby nuclear service water dam, the standby nuclear service water intake structure, the nuclear service water intake structure, Lake Wylie, and the Standby Nuclear Service Water Pond (SNSWP). All of these are shared by both CNS units.

Flow enters each pit from either Lake Wylie or the SNSWP, and four RN pumps (1A, 1B, 2A, and 2B) supply nuclear service water to the entire station. RN pumps 1A and 2A draw water from the "A" pit and discharge into a common train A supply header that serves both units, and RN pumps 1B and 2B draw water from the "B" pit and discharge into a common train B supply header that serves both units.

Essential Auxiliary Power Systems

The 600 V ac essential auxiliary power system consists of two redundant safety trains, Train A and Train B per unit. The unit can be safely shut down with only one train in operation. The system consists of four essential load centers, their associated load center transformers, one shared-standby load center transformer per load center pair, and fifteen essential motor control centers.

Other equipment throughout the electrical distribution systems, such as 6.9/4.16 kV shared aux. transformers SATA and SATB, may be fed from either unit to power loads on either unit.

Unit Differences

The only significant unit difference identified by the review is that normal power to the SSF is supplied from Unit 1. However, the current modeling treatment is bounding for Unit 2 since for Unit 2, Unit 1 power is a diverse power source.

The following table considers the PRA impact of any unit differences for the specific equipment identified in RAI 7.a.

Table 1

Catawba SSCs Important to the LAR PRA Results

SSC	**Unit Differences (if any)**	**PRA Impact Associated with Using a Single-Unit Model**
Non-CT EDG	None	None
ESPS System	None	None
Component Cooling System (KC)	None	None
Turbine Driven AFW Pump (CA)	None	None
Safe Shutdown Facility (SS)	Normal power is supplied from Unit 1.	Use of the Unit 1 model is bounding. For Unit 2, Unit 1 is a diverse power source.
Nuclear Service Water System (RN)	N/A, shared SSC	None
Motor-Driven AFW Pumps (CA)	None	None
Switchyard	N/A, shared SSC	None
Residual Heat Removal (ND) system	None	None
Chemical and Volume Control (NV) system	None	None
4160 V switchgear	None	None
600 V components	600 V components are highly symmetric, with some differences in power distribution (e.g., different VI compressors are powered from different units)	Not significant due to highly symmetric distribution of power
125 V dc distribution (including batteries)	None	None
ESFAS components	None	None
6900 V switchgear	None	None
transformers	None	None
vital instrumentation and control power	None	None

Table 1

Catawba SSCs Important to the LAR PRA Results

SSC	Unit Differences (if any)	PRA Impact Associated with Using a Single-Unit Model
Main Feedwater System (CF)	None	None
Hydrogen Igniters	None	None
Air Handling Units	None	None
battery chargers	None	None
seal water injection	None	None

Internal Flood Considerations

The Catawba IF PRA includes Unit 1 and Unit 2 differences as follows. Although the IF PRA is built on the Unit 1 internal events model, Unit 2 is evaluated as well in several ways. First, Unit 2 specific or shared unit piping was included in the analysis for initiating event analysis. If Unit 2 piping was found to impact both units it was included in the model. In addition, Unit 2 specific areas were evaluated to determine whether scenarios could impact Unit 2 only or both units. If both units could be impacted (e.g. dual-unit trip), the scenario was included in the model. Shared or cross tied systems were also evaluated when developing scenarios as to whether they would be successful for the given scenario. During the internal flood walkdowns, the designated CNS Unit 1 flood areas were validated as applicable to CNS Unit 2, and any discrepancies were documented, retained for further analysis, and included in the model as appropriate.

Conclusion

Unit 1 and 2 high wind models are now based on the latest internal events PRA models. Thus, the issue of unit differences no longer applies for high winds.

For internal flood, the systems review discussed above and the review of unit differences for the risk-significant SSCs identified in LAR Table 1 and cited in RAI-7.a determined that the Unit 1 model is representative or bounding. The internal flooding analyses evaluated the impacts of Unit 2 on initiator and scenario development. SSCs that are shared between both units are implicitly modeled in the Unit 1 model. Internal flood walkdowns of the CNS Unit 1 flood areas were validated as being applicable to CNS Unit 2, and any discrepancies were documented, retained for further analysis, and included in the model as appropriate.

Thus, the reviews of the Catawba high wind and internal flood models have determined that the conclusions of the LAR remain valid.

Duke Energy RAI-7.b Response

As discussed in the response to RAI 7.a, the current modeling is justified because the PRAs adequately reflect the differences between units and aggregate the PRA updates requested in RAI-13.

RAI-8 – Implementation Verification of ESPS System

Regulatory Guide 1.174, Revision 2, provides quantitative guidelines on CDF, LERF, and identifies acceptable changes to these frequencies that result from proposed changes to the plant's licensing basis and describes a general framework to determine the acceptability of risk-informed changes. The NRC staff's review of the information in the LAR, as supplemented, has identified additional information that is required to fully characterize the risk estimates.

The estimated risk associated with the EDG CT extension is based on assumptions about an ESPS system that has not yet been installed and operator actions for which procedures have not been completed. Upon completion of these plant modifications and procedures, the PRA models will need to be assessed against the as-built, as-operated plant and updated, as necessary. Then new risk estimates will need to be generated and evaluated to confirm that the conclusions of the LAR have not changed.

In the October 8, 2018 supplement in response to audit Question 12, the licensee identifies eight "assignments" that involve the review and update of specific aspects of ESPS PRA modeling after the installation of the ESPS and completion of associated operating procedures. The NRC staff interprets these "assignments" as commitments; however, completing these "assignments" is necessary to ensure that the PRA modeling represents the as-built, as-operated ESPS system and the risk acceptance guidelines in RG 1.177 and RG 1.174 are met upon completion of the ESPS plant modifications and associated procedures.

Propose a license condition requiring that after the ESPS system is installed and applicable procedures updated and prior to implementing the 14-day EDG CT: (1) update the risk estimates associated with this LAR, as necessary, (including results of sensitivity studies) using PRA models that reflect the as-built, as-operated plant, and (2) confirm these updated risk estimates continue to meet the risk acceptance guidelines of RG 1.174 and RG 1.177.

<u>Duke Energy RAI-8 Response</u>

A license condition is proposed in Attachments 5 and 6, for Units 1 and 2, respectively, requiring that the risk estimates associated with the 14-day EDG Completion Time LAR (including those results of associated sensitivity studies) will be updated, as necessary to incorporate the as-built, as-operated ESPS modification. Duke Energy will confirm that any updated risk estimates continue to meet the risk acceptance guidelines of RG 1.174 and RG 1.177.

<u>RAI-9 – Internal Flooding and High Winds PRA Model Technical Adequacy and Updated Internal Events Logic Transferred to Other Hazard Models</u>

The LAR states that the proposed change to the TS CT has been developed using the risk-informed processes described in RG 1.174, Revision 2, and RG 1.177, Revision 1. Based on Section 2.3.1 of RG 1.177, the technical adequacy of the PRA must be compatible with the safety implications of the TS change being requested and the role that the PRA plays in justifying that change. The RG 1.177 endorses the guidance provided in RG 1.200, Revision 2, on PRA technical adequacy. Section 1 in Regulatory Position C of RG 1.200 states, "the PRA results used to support an application must be derived from a baseline PRA model that represents the as-built, as-operated plant to the extent needed to support the application. Consequently, the PRA needs to be maintained and upgraded, where necessary, to ensure it represents the as-built, as-operated plant."

The F&O WPR-A4-01, in LAR Attachment 8, states, “no evidence of satisfying the requirements of Part 2 [of ASME/ANS RA-Sa-2009], or basis for exceptions to the requirements, was provided.” The Part 2 of the ASME/ANS RA-Sa-2009 PRA standard pertains to the technical adequacy of the internal events PRA model used as the starting point for the high winds PRA plant response model. The disposition of this finding, provided in LAR Attachment 8, states the internal events model has undergone an update (i.e., Revision 4) to comply with RG 1.200, Revision 2. However, the response in the October 8, 2018 supplement to audit Question 13.a states that the version of the internal events PRA model used to develop the internal flooding, high winds, and fire PRA models was Revision 3 whose technical adequacy is based on the 2001 peer review. Furthermore, the response to audit Question 13.c states, “the 2015 peer reviews were performed on the Rev. 4 internal events models, which are significantly different from the Rev. 3 models.” Therefore, it appears that F&O WPR-A4-01 was not resolved because the updated Revision 4 internal events model was not incorporated in the high winds PRA model. Additionally, it is also unclear to the NRC staff how the technical adequacy of the underlying PRA model for internal flooding is addressed since it uses the same internal events model as the high winds PRA model. [The NRC staff notes that the licensee provided dispositions of the underlying internal events PRA model F&Os for the fire PRA according to the NRC letter dated February 8, 2017, “Catawba Nuclear Station, Units 1 and 2 – Issuance of Amendments Regarding National Fire Protection Association Standard NFPA 805 (CAC NOS. MF2936 and MF2937)” (ADAMS Accession No. ML16137A308). These F&Os may have a different impact on the internal flooding and high winds PRAs, and the associated dispositions provided in the NFPA 805 application may not be applicable for the internal flooding and high winds PRAs used for the LAR dated May 2, 2017. In addition, the February 8, 2017 NRC evaluation states that resolution of PRA RAI 02.f.e regarding F&O DA-02 required the incorporation of updated generic data and common cause failure rates in the fire PRA model. It is unclear whether this update was applied to the internal flooding and high winds PRA model.]

The response to audit Question 13.a further states that the internal events model has been updated to Revision 4, in which there are “[s]ignificant internal events model changes between revisions 3 and 4.” The supplement lists a few of the significant changes that could impact the internal flooding, fire and high winds PRAs, including: updated model data, updated human reliability analysis (HRA) (resulting in a change in HEP values), development of unit-specific models, addition of a condensate and condenser circulating water system models, addition of support system initiating events (SSIEs), transition from Multiple Greek Letter CCF method to alpha-factor method, and switching from a single alignment model to multiple alignments. Accordingly, it is not clear how the Catawba internal flooding, fire and high winds PRAs address the modeling updates performed for the internal events PRAs. These internal events updates appear to represent modeling improvements that result in a more realistic representation of the as-built, as-operated plant as prescribed in RG 1.200, Revision 2.

To address the above observations, provide the following information.

a) Provide a detailed justification that incorporating the Revision 4 internal events PRA model into the internal flooding, high winds, and fire PRA models does not change the conclusions of the LAR, as supplemented. This justification may include:

   - Provide the finding-level F&Os from the 2001 - 2002 internal events PRA model peer review with dispositions related to this application for internal flooding and high winds. Include a gap assessment addressing the differences between NEI 00-02 and RG 1.200, Revision 2 and provide justification that the identified gaps do not impact the insights and conclusions of this application.

- Describe all model changes (e.g., model changes to address: Revisions 3 and 4 F&Os, plant representation, level of detail, enhancements), in addition to those provided in the October 8, 2018 supplement, made to the internal events PRA (since Revision 3) that were not incorporated into the internal flooding, high winds, and fire PRA models. Provide detailed justification (e.g., describe and provide the results of an appropriate sensitivity study using the PRA models from the aggregate analysis requested in RAI-13) that incorporating these model changes into the internal flooding, high winds, and fire PRA models does not impact the conclusions of the LAR, as supplemented.

b) Alternatively to part (a), incorporate the Revision 4 internal events PRA model into the internal flooding, high winds and fire PRA model.

Duke Energy RAI-9.a Response

See response to RAI 9.b

Duke Energy RAI-9.b Response

The high winds model was incorporated into Revision 4 of the internal events PRA model and is now used for this application. This high winds PRA model update was aggregated into the PRA updates requested in RAI-13.

The Revision 4 internal event PRA model changes were incorporated into internal flood and fire PRA models and are now used for this application. The changes made to the internal flood and fire models based on the updates made to Revision 4 internal events model are as follows.

Relevant changes that were made to the internal flood and fire PRA models include updated database changes (e.g., failure probabilities and type codes) and the updated model data. Other relevant changes also included fault tree logic changes (e.g., ESPS; HVAC logic for selected components, update FWST logic, steam generator success criteria, service water pump logic, and VCT logic for flow diversion) and the use of equivalent modeling where gate mapping was not one-to-one.

Where a review determined a change to not be relevant to the internal flood and fire PRA models, the internal flood and fire models were not updated (e.g., non-fire and non-flood initiators; ATWS, MLOCA, and other non-fire and non-flood accident sequences; and human failure events not appropriate for the fire and flood hazards). The internal flood and fire PRA models were also not updated to incorporate the Revision 4 internal events PRA model when the change would have no impact on risk (e.g., gate or basic even naming). There is no impact to the LAR for both types of changes since the changes are not relevant to internal flood or fire or they have no impact on risk.

A review of all changes to the internal events PRA model identified only new Human Failure Events (HFE) as potentially impacting the proposed change. However, even if the new HFEs were to be incorporated into the updated fire and internal flood PRAs, then the total risk results (i.e., CDF and LERF) would decrease. Therefore, not incorporating the HFEs is conservative. Regarding the delta risk results (i.e., ΔCDF and ΔLERF), not incorporating the new HFEs was based on a consideration of the related risk contributions for the HFEs in internal events cutsets associated with initiators that are mapped to the fire or flood events in the fire or flood PRAs.

Overall, the risk results using the updated fire and internal flood PRAs with the changes described above supports the assertion that incorporating the discrepancies between the internal events PRA model of record and the fire and internal flood PRA models of record does not impact the conclusions of the ESPS LAR application.

RAI-10 – Sources of Model Uncertainty and Parametric Uncertainty

The LAR for Catawba, dated May 2, 2017, states that the proposed change to the TS CT has been developed using the risk-informed processes described in RG 1.174, Revision 2, and RG 1.177, Revision 1. Regulatory Position C of RG 1.174 states:

- In implementing risk-informed decisionmaking, LB [licensing basis] changes are expected to meet a set of key principles. … In implementing these principles, the staff expects [that]: … Appropriate consideration of uncertainty is given in the analyses and interpretation of findings. … NUREG-1855 provides further guidance.

- Section 2.5.2 further elaborates, because of the way the [risk] acceptance guidelines were developed, the appropriate numerical measures to use in the initial comparison of the PRA results to the acceptance guidelines are mean values. The mean values referred to are the means of the probability distributions [of the risk metrics] that result from the propagation of the uncertainties on the [PRA] input parameters and those model uncertainties explicitly represented in the model … under certain circumstances, a formal propagation of uncertainty may not be required if it can be demonstrated that the state-of-knowledge correlation [SOKC] is unimportant.

a) Revision 0 of NUREG-1855 (2009) primarily addressed sources of model uncertainty for internal events (including internal flooding) and references EPRI report 1016737, "Treatment of Parameter and Modeling Uncertainty for Probabilistic Risk Assessments" (2008), which provides a generic list of sources of model uncertainty and related assumptions for internal events. Revision 1 of NUREG-1855 (March 2017, ADAMS Accession No. ML17062A466) further clarifies the NRC staff decisionmaking process in addressing uncertainties and addresses all hazard groups (e.g., internal events, internal flooding, internal fire, seismic, low-power and shutdown, Level 2). NUREG-1855, Revision 1, cites use of EPRI reports 1016737 and 1026511, "Practical Guidance on the Use of Probabilistic Risk Assessment in Risk-Informed Applications with a Focus on the Treatment of Uncertainty" (2012), which complements the NUREG and provides a generic list of sources of model uncertainty for internal events, internal flooding, internal fires, seismic, low-power and shutdown, and Level 2 hazard groups. While LAR Section 3.12.4 states a review of potential modeling uncertainties was performed using Revision 1 of NUREG-1855, the discussion in LAR Section 6.2 and the results provided in LAR Attachment 9 indicate that Revision 0 of NUREG-1855 (and EPRI report 1016737) was used to evaluate sources of uncertainty for only internal events (including internal flooding).

i. Clarify which version of NUREG-1855 was used for the uncertainties analysis described in the LAR.

ii. Provide a detailed summary of the process used to evaluate sources of model uncertainty and related assumptions [both generic (e.g., EPRI reports 1016737 and 1026511) and plant-specific sources] in the internal events, internal flooding, high winds, and internal fires PRAs for their potential impact on this application. Include in this discussion an explanation of how the process aligns with guidance in NUREG-1855, Revision 1, or other NRC-accepted method.

iii. In accordance with the process described in Part (a.ii) above, describe any additional sources of model uncertainty and related assumptions relevant to the application that were not provided in LAR Attachment 9, and describe their impact on the application results.

iv. In accordance with NUREG-1855, Revision 1, for those sources of model uncertainty and related assumptions that could potentially challenge the risk acceptance guidelines (i.e., key uncertainties and assumptions), provide qualitative or quantitative justification for why these key uncertainties and assumptions do not change the conclusions of the LAR (e.g., describe and provide the results of an appropriate sensitivity study(ies) using the PRA models used to perform the aggregate analysis requested in RAI-13); describe and provide the results of a more detailed, realistic analysis to reduce the conservatism and uncertainty; propose compensatory measures and explain how they address the key uncertainties and assumptions).

b) Section 2.3.1 of Regulatory Guide 1.177 states that current good practice (i.e., CC II of the ASME/ANS PRA standard) is the level of detail needed for the PRA to be adequate for the majority of applications. Based on RG 1.174 and Section 6.4 of NUREG-1855, Revision 1, for a CC II risk evaluation, the mean values of the risk metrics (i.e., CDF, LERF) and the means of their incremental values (i.e., ICCDP, ICLERP) need to be compared against the risk acceptance guidelines. The mean values referred to are the means of the risk metric's probability distributions that result from the propagation of the uncertainties on the PRA input parameters and those model uncertainties explicitly represented in the model. In general, the point estimate CDF/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 state-of-knowledge correlation (SOKC) is unimportant (i.e., the risk results are well below the acceptance guidelines).

Attachment 6 of the LAR, as supplemented, provides the ICCDPs and ICLERPs for the proposed CT extension based on point estimate values of the risk metrics. The basis for using these point estimates is the results of an assessment provided in LAR Section 6.2.3, in which a parametric uncertainty analysis was performed on the internal events PRA to determine the baseline mean CDF and LERF which were then compared to the internal events baseline CDF and LERF determined using point estimate values. The comparison showed that the baseline CDF and LERF determined using point estimate values were within 10% of the means values. However, this approach is not consistent with NUREG-1855, Revision 1. For one reason, the licensee's parametric uncertainty analysis did not include the other hazards (i.e., internal flooding, high winds, and internal fires) and its impact on ICCDP and ICLERP, which challenge the risk acceptance guidelines (i.e., Regime 3 in NUREG-1855, Revision 1) and could potentially impact the conclusions of the LAR. Additionally, the LAR states that the parametric uncertainty was conducted on the internal events model before changes were made for this application and LAR Figures 1 through 4 do not provide any specific values (i.e., point estimate, mean) to validate the conclusion of Section 6.2.3.

i. Provide a detailed summary of the process used to evaluate parametric uncertainties in the calculation of ICCDP and ICLERP for the internal events, internal flooding, high winds, and internal fires PRAs. Include in this discussion an explanation of how the process is in accordance with Section 6, "Stage D - Assessing Parameter Uncertainty," of NUREG-1855, Revision 1, or other NRC accepted method. Justify any conclusions made that addressing the SOKC is not important to the quantitative conclusions of this application.

ii. In accordance with the process described in Part (b.i) above, provide the ICCDPs and ICLERPs for internal events, internal flooding, high winds, and internal fires as requested in RAI-13.

Duke Energy RAI-10.a Response

i. Revision 0 of NUREG-1855 was used for the uncertainties analysis described in the LAR.

ii. The process described in NUREG-1855 Revision 0 was used to evaluate the model uncertainties and assumptions associated with the PRAs that were presented in the LAR. Subsequently, the results were compared to NUREG-1855, Revision 1, and additional uncertainties in NUREG-1855, Revision 1, were addressed.

   As part of the assessment, the plant-specific model uncertainties documented in the notebooks associated with the internal flooding, high winds, and internal fires PRAs were assessed with respect to the ESPS application. The generic sources taken from EPRI reports 1016737 and 1026511 were also assessed.

iii. No additional sources of model uncertainty and related assumptions relevant to the application were identified.

iv. No additional sensitivity runs were required, beyond those given in the LAR, due to no additional sources of model uncertainty and related assumptions relevant to the application were identified.

Duke Energy RAI-10.b Response

i. The parametric uncertainties for all the hazards were evaluated by using the EPRI UNCERT code which samples the basic event / basic event type code parameter uncertainty distributions to propagate the uncertainty and develop a mean estimate and distribution for the CDF and LERF values presented. This code effectively accounts for the SOKC impacts as the sampling is performed on a failure mode (type code) basis. Since the SOKC impacts are evaluated by the UNCERT code, the corrections applied to adjust the CAFTA point estimate are removed before running the code. This results in the point estimate listed for the UNCERT run being reduced from the CAFTA produced point estimate. No peer review findings were identified with the methods used to account for SOKC. The risk results are compared against the risk acceptance guidelines given in Regulatory Guide 1.177, Revision 1. This process aligns with the guidance provided in Section 6 of NUREG-1855, Revision 1.

ii. The ICCDPs and ICLERPs for internal events, internal flooding, high winds, and internal fires for the four potential alignments of ESPS during a 14-day AOT are provided below. The limiting of these for ICCDP and for ICLERP are also provided in RAI 13. For each alignment, the ICCDP and ICLERP are below the risk acceptance guidelines given in Regulatory Guide 1.177, Revision 1.

RG 1.177 ICCDP Summary (Mean Aggregate Results Unit 1 A)

Hazard	14-Day CT	Base	Multiplier	ICCDP
Internal Events	6.46E-06	4.19E-06	14/365	8.73E-08
Internal Flooding	2.03E-05	1.66E-05	14/365	1.42E-07
High Winds	1.76E-05	5.73E-06	14/365	4.55E-07
Fire	2.89E-05	2.40E-05	14/365	1.89E-07
			Sum =	8.73E-07

RG 1.177 ICCDP Summary (Mean Aggregate Results Unit 1 B)

Hazard	14-Day CT	Base	Multiplier	ICCDP
Internal Events	6.25E-06	4.19E-06	14/365	7.90E-08
Internal Flooding	2.00E-05	1.66E-05	14/365	1.32E-07
High Winds	1.75E-05	5.73E-06	14/365	4.53E-07
Fire	2.71E-05	2.40E-05	14/365	1.21E-07
			Sum =	7.85E-07

RG 1.177 ICCDP Summary (Mean Aggregate Results Unit 2 A)

Hazard	14-Day CT	Base	Multiplier	ICCDP
Internal Events	5.41E-06	4.16E-06	14/365	4.77E-08
Internal Flooding	2.03E-05	1.66E-05	14/365	1.42E-07
High Winds	2.07E-05	5.72E-06	14/365	5.73E-07
Fire	2.81E-05	2.27E-05	14/365	2.06E-07
			Sum =	9.70E-07

RG 1.177 ICCDP Summary (Mean Aggregate Results Unit 2 B)

Hazard	14-Day CT	Base	Multiplier	ICCDP
Internal Events	5.31E-06	4.16E-06	14/365	4.39E-08
Internal Flooding	2.00E-05	1.66E-05	14/365	1.32E-07
High Winds	2.07E-05	5.72E-06	14/365	5.75E-07
Fire	2.77E-05	2.27E-05	14/365	1.90E-07
			Sum =	9.41E-07

RG 1.177 ICLERP Summary (Mean Aggregate Results Unit 1 A)

Hazard	14-Day CT	Base	Multiplier	ICCDP
Internal Events	3.17E-07	2.16E-07	14/365	3.90E-09
Internal Flooding	2.63E-07	4.46E-08	14/365	8.39E-09
High Winds	1.95E-06	7.46E-07	14/365	4.62E-08
Fire	2.01E-06	1.54E-06	14/365	1.77E-08
			Sum =	7.62E-08

RG 1.177 ICLERP Summary (Mean Aggregate Results Unit 1 B)

Hazard	14-Day CT	Base	Multiplier	ICCDP
Internal Events	2.88E-07	2.16E-07	14/365	2.78E-09
Internal Flooding	2.62E-07	4.46E-08	14/365	8.33E-09
High Winds	1.80E-06	7.46E-07	14/365	4.04E-08
Fire	1.86E-06	1.54E-06	14/365	1.20E-08
			Sum =	6.35E-08

RG 1.177 ICLERP Summary (Mean Aggregate Results Unit 2 A)

Hazard	14-Day CT	Base	Multiplier	ICCDP
Internal Events	2.88E-07	2.23E-07	14/365	2.50E-09
Internal Flooding	2.63E-07	4.46E-08	14/365	8.39E-09
High Winds	1.99E-06	6.99E-07	14/365	4.94E-08
Fire	1.72E-06	1.38E-06	14/365	1.30E-08
			Sum =	7.33E-08

RG 1.177 ICLERP Summary (Mean Aggregate Results Unit 2 B)

Hazard	14-Day CT	Base	Multiplier	ICCDP
Internal Events	2.63E-07	2.23E-07	14/365	1.56E-09
Internal Flooding	2.62E-07	4.46E-08	14/365	8.33E-09
High Winds	1.88E-06	6.99E-07	14/365	4.52E-08
Fire	1.70E-06	1.38E-06	14/365	1.21E-08
			Sum =	6.72E-08

RAI-11 – Supplement Fire PRA Results

RG 1.174, Revision 2, provides quantitative guidelines on CDF and LERF and identifies acceptable changes to these frequencies that result from proposed changes to the plant's licensing basis and describes a general framework to determine the acceptability of risk-informed changes. RG 1.177, Revision 1, provides risk acceptance guidelines on ICCDP and ICLERP that result from permanent changes to the licensee's TSs. The NRC staff review of the information in the LAR, as supplemented, has identified additional information that is required to fully characterize the risk estimates.

The October 8, 2018 supplement, in response to audit Question 14.a, shows a decrease in risk (i.e., a negative ICCDP and ICLERP) from the base case (two safety-related EDGs with auto-start capability) to the CT case (one safety-related EDG and one non-safety diesel generator with no auto-start capability) of 3.1E-06 for CDF and 3.7E-07 for LERF. It is unclear to the NRC staff why substituting a safety-related EDG with a non-safety diesel generator with no auto-start capability significantly reduces risk.

Explain how substituting a safety-related EDG with a non-safety diesel generator reduces fire risk. Include in this discussion changes in fire scenarios, significant accident scenarios, and significant cutset results.

Duke Energy RAI-11 Response

This response is based on the model used to provide the referenced results in this question. That model has been updated to address additional questions raised in RAI 9 and thus the model results presented in RAI 13 are slightly different than before. The fire model has been updated to address internal events model changes, which resulted in the reduction of the base and nominal cases mainly due to the data update resulting in lower random failure rates.

The inclusion of the ESPS system to the plant adds redundancy and diversity in the AC power supplies to the plant's Safety Buses. There are multiple levels of redundancy and diversity. The foremost AC power source is offsite power, unless offsite power is lost to the Safety Buses there is no need for emergency or alternate AC. The next layers are the two redundant Emergency Diesel generators per unit and the potential to cross-tie between Units. The next level is the capability of the SSF and Turbine Driven AFW. The final level of mitigation in the form of alternate AC power is the ESPS system.

The fire scenarios that would benefit from the addition of an alternate AC source in the form of the ESPS are scenarios in which offsite power is lost, a transmission path between the ESPS and Safety Bus exists, and other AC power sources (Emergency Diesels and cross-tie between the Units) are unavailable.

The restriction of test and maintenance on risk important equipment (e.g., turbine driven auxiliary feed pump and SSF) during the CT in combination with the diversity in AC power provided by the ESPS resulted in the decrease in risk.

In most scenarios the Turbine Driven AFW pump provides one of the decay heat removal success paths, so the restriction on test and maintenance reduces risk in these scenarios.

The restriction of maintenance on the Safe Shutdown Facility (SSF) is important for the control room abandonment scenarios as it is the only credited success path and the control room abandonment scenarios are independent of the status of the Emergency Diesels and the ESPS system. The SSF can also provide mitigation capabilities following scenarios involving a loss of offsite power and other plant system failures.

The restriction on service water (RN) maintenance is important as it applies to most fire scenarios as support for equipment cooling directly or through Component Cooling Water. This system also supports Emergency Diesel cooling. The ESPS is air cooled and does not require service water.

The scenarios that are impacted by an Emergency Diesel generator being out of service are 1) the turbine building fires that impact the 6.9kV buses that connect the emergency buses to offsite power and 2) fires that impact the safety related Emergency Buses associated with each Emergency Diesel.
In the scenarios where the 6.9kV buses are impacted the ESPS is not credited due to no transmission path to an Emergency Bus. This results in the loss of redundancy of the Emergency Diesel in the CT, leaving only the opposite train Emergency Diesel and the SSF for accident mitigation. But the availability of these power sources has been increased as test and maintenance on them has been restricted.

In the case where the fire was impacting the Emergency Bus associated with the Emergency Diesel in the CT, the alternate train Emergency Bus can be supplied by the non-CT Emergency Diesel or the ESPS. The mitigation capability also includes the SSF. All of these mitigation systems have increased availability due to the restriction on test and maintenance.

The most limiting scenarios would involve a fire on the Emergency Bus associated with the non-CT Emergency Diesel. In this case, the ESPS would be the only power supply besides offsite power to support the remaining Emergency Bus. The mitigation capability would also still include the SSF.

<u>RAI-12 – Application of Generic and Bayesian Updated Diesel Generator Failure Rates</u>

ASME/ANS 2009 PRA standard SR DA-D1 states for Capability Category (CC)-II, "[c]alculate realistic parameter estimates…When it is necessary to combine evidence from generic and plant-specific data, use a Bayes update process."

The October 8, 2018 supplement, in response to audit Question 14.b, states, "[t]he generic station blackout diesel failure rates from NUREG/CR-6928 2016 updated parameter estimates were used for ESPS failure rates for the aggregate sensitivity case." Whereas, for the best estimate case, the "extensive factory acceptance testing data was used to update the ESPS diesel generator failure rates." NRC staff notes that factory testing data should not be substituted for plant-specific data in the Bayesian update process. Factory data is not plant-specific data and would not account for differences in installation, environment, maintenance, testing, and operation between a factory and nuclear power plant. The staff understands that the ESPS diesel generators have not yet been installed at the site.

Incorporate in the PRA model the non-Bayesian updated failure rates for the ESPS diesels (i.e., the generic station blackout (SBO) diesel failure rates chosen by the licensee for this component) for the aggregate and all related sensitivity studies requested in RAI-13.

Duke Energy RAI-12 Response

The generic SBO failure rates were used for the ESPS diesels for the aggregate risk sensitivity as stated in the response audit question 5. Duke Energy's response to RAI-13 reflects the continued use of these generic failure rates in the aggregate risk sensitivity study.

However, Duke Energy's position is that the use of Bayesian update process is warranted for the generic SBO failure rates associated with the best estimate case for the following reasons:

1) The Bayesian update process is based on the performance of the actual equipment installed.
2) The Bayesian update process factors in testing that was performed during the time in which, according to the bathtub curve from reliability engineering, infant mortality causes would be the dominant failure mode.
3) The ESPS diesel generators are of a much newer design than the diesel generators that were added to plants to meet SBO / Appendix R requirements and incorporate over 30 years' worth of improvements.
4) The maintenance of the ESPS diesel generators is through the contract OEM, which will maintain the equipment to the factory specifications.
5) The ESPS diesel generators are designed for emergency use vice rail or marine diesel engines which are adopted for emergency use.

RAI-13 – Aggregate Update Analysis

Regulatory Guide 1.174, Revision 2, provides quantitative guidelines on CDF and LERF and identifies acceptable changes to these frequencies that result from proposed changes to the plant's licensing basis and describes a general framework to determine the acceptability of risk-informed changes. Regulatory Guide 1.177, Revision 1, provides risk acceptance guidelines on ICCDP and ICLERP and identifies acceptable changes to these probabilities that result from proposed changes to permanent changes to the licensee's TSs. The NRC staff review of the information in the LAR, as supplemented, has identified additional information that is required to fully characterize the risk estimates.

The PRA methods and treatments discussed in the following RAIs may need to be revised to be acceptable by the NRC staff:

- RAI-2.d regarding incorporation of the appropriate and consistent treatment of SSF and ESPS structural failure.

- RAI-3.a regarding modeling the most limiting plant configurations.

- RAI-4.b regarding update of CCFs to account for updated component failure rates.

- RAI-5.b regarding the seismic bounding analysis.

- RAI-7.b regarding modeling the differences between units.

- RAI-9.b regarding incorporation of the Revision 4 internal events PRA model for the underlying model used in the internal flooding and high winds PRA.

- RAI-10.b on providing ICCDP and ICLERP for all hazard groups in accordance with Section 6, "Stage D - Assessing Parameter Uncertainty," of NUREG-1855, Revision 1.

- RAI-12 regarding incorporation of the generic industry failure rate of SBO DGs.

In the supplement letter of October 8, 2018 in response to audit Question 14, an aggregate case study was provided that included resolution to audit questions as follows:

- Incorporation of updated NUREG-2169 fire ignition frequencies in the fire PRA (audit Question 04).

- Consistent use of appropriate EDG, SSF, and ESPS failure probabilities across the Catawba hazard PRAs (audit Question 05.a).

- Incorporation of appropriate non-safety equipment failure probabilities for the ESPS DGs in the Catawba PRA models (audit Question 05.b).

The NRC staff notes that no separate sensitivity studies results for each source of uncertainty, such as the ESPS HRA study, were provided in the supplement. In addition, the supplement response did not provide unit and configuration (train) specific results.

Furthermore, the response to audit Question 14.d identifies seven PRA model conservatisms that might be considered if the risk acceptance guidelines of RG 1.174 and 1.177 are exceeded. The NRC staff notes that no bounding quantitative estimates of risk (e.g., CDF, LERF, ICCDP, or ICLERP) were performed for several of these conservatisms.

To fully address the RAIs and the October 8, 2018 supplement aggregate results cited above, provide the following:

a) Provide the results of an aggregate analysis for each unit (including individual results for each hazard group) that reflect the combined impact on the LAR risk results (i.e., change in CDF, change in LERF, ICCDP and ICLERP in accordance with NUREG-1855, Revision 1) of: (1) the PRA updates required in response to the RAIs cited above, and (2) those updates incorporated in the aggregate analysis specified in the October 8, 2018 supplement. Also, provide updated results that reflect the combined updates to the PRA described above for: (1) the separate sensitivity studies discussed in the LAR, as supplemented (e.g., the sensitivity study referred to in LAR Section 6.2.5 and the aggregate sensitivity case in the October 8, 2018 supplement), and (2) the studies that address any identified key sources of uncertainty identified in the NUREG-1855, Revision 1 process.

b) For each RAI listed above, summarize how the issue(s) cited in the RAI were resolved for the PRA or LAR. If the resolution involved an update to the PRA models, then briefly summarize the PRA update. Also, confirm the aggregate analysis in part (a) included the PRA updates from the October 8, 2018 supplement.

c) Provide confirmation that the risk values in part (a) only reflect the modifications described in the LAR or in response to audit questions and RAIs. Otherwise, describe any additional changes to the Catawba PRA models in support of the aggregate analysis in part (a) that were not described in the LAR dated May 2, 2017 or in part (b) of this RAI. Provide justification that these additional changes, if any, meet the requirement in RG 1.200 that "the PRA results used to support an application must be derived from a baseline PRA model that represents the as-built, as-operated plant to the extent needed to support the application."

d) Confirm that the updated aggregate analysis and sensitivity results still meet the risk acceptance guidelines in RG 1.177, Revision 1, and RG 1.174, Revision 2.

e) If the risk acceptance guidelines are exceeded, then identify which guidelines are exceeded and provide justification that support the conclusions of the LAR in accordance with NUREG-1855, "Guidance on the Treatment of Uncertainties Associated with PRAs in Risk-Informed Decision Making," Revision 1. This justification should be of sufficient detail to provide assurance that the risk acceptance guidelines are met for this application and may include, but not be limited to, the following: 1) describing and providing the results of a more detailed, realistic analysis to reduce conservatism and uncertainty; 2) proposing compensatory measures and discuss their quantifiable impact on the risk results; and 3) discussing the conservatisms in the analysis and their quantifiable impact on the risk results.

<u>Duke Energy RAI-13.a Response</u>

The most limiting plant and alignment configuration results are presented in the tables below based on the responses to RAIs 3, 9, and 10b.

The differences between Units have been determined and the most limiting result for each case is presented below. For CDF, the overall limiting train and unit is train A on Unit 2. For LERF, the overall limiting train and unit is train A on Unit 1.

The failure rates for the ESPS Diesels are set to the Generic SBO failure rates as provided in RAI 4, for both the aggregate sensitivity and the best estimate cases.
The mean values for the aggregate results of the limiting trains are presented below:

RG 1.177 ICCDP Summary (Mean Aggregate Results Unit 2 A Train limiting)

Hazard	14 Day CT	Base	Multiplier	ICCDP
Internal Events	5.41E-06	4.16E-06	14/365	4.77E-08
Internal Flooding	2.03E-05	1.66E-05	14/365	1.42E-07
High Winds	2.07E-05	5.72E-06	14/365	5.73E-07
Fire	2.81E-05	2.27E-05	14/365	2.06E-07
			Sum =	9.70E-07

RG 1.177 ICLERP Summary (Mean Aggregate Results Unit 1 A Train Limiting)

Hazard	14 Day CT	Base	Multiplier	ICLERP
Internal Events	3.17E-07	2.16E-07	14/365	3.90E-09
Internal Flooding	2.63E-07	4.46E-08	14/365	8.39E-09
High Winds	1.95E-06	7.46E-07	14/365	4.62E-08
Fire	2.01E-06	1.54E-06	14/365	1.77E-08
			Sum =	7.62E-08

The overall CDF and LERF impact of the CT and addition of the ESPS system still represents a risk decrease. (The values presented include the conservatism and changes required for the aggregate risk calculation.)

351 Day ICCDP Risk Contribution Summary (Mean Aggregate Results Unit 2 A Train limiting)

Hazard	ESPS credit	Base	Multiplier	ICCDP
Internal Events	3.54E-06	4.16E-06	351/365	-6.00E-07
Internal Flooding	1.66E-05	1.66E-05	351/365	0.00E+00
High Winds	2.48E-06	5.72E-06	351/365	-3.12E-06
Fire	2.23E-05	2.27E-05	351/365	-4.14E-07
			Sum =	-4.14E-06

351 Day ICLERP Risk Contribution Summary (Mean Aggregate Results Unit 1 A Train Limiting)

Hazard	ESPS credit	Base	Multiplier	ICLERP
Internal Events	1.43E-07	2.16E-07	351/365	-7.00E-08
Internal Flooding	4.46E-08	4.46E-08	351/365	0.00E+00
High Winds	1.62E-07	7.46E-07	351/365	-5.62E-07
Fire	1.50E-06	1.54E-06	351/365	-4.52E-08
			Sum =	-6.77E-07

The total risk results assuming one 14-day CT entry and ESPS nominal availability for the remainder of the year are shown below:

∆CDF For Entire Change (Mean Aggregate Results Unit 2 A Train limiting)

Hazard	14-day CT	351 Day	∆CDF
Internal Events	4.77E-08	-6.00E-07	-5.52E-07
Internal Flooding	1.42E-07	0.00E+00	1.42E-07
High Winds	5.73E-07	-3.12E-06	-2.55E-06
Fire	2.06E-07	-4.14E-07	-2.07E-07
		Sum =	-3.17E-06

∆LERF For Entire Change (Mean Aggregate Results Unit 1 A Train limiting)

Hazard	14-day CT	351 Day	∆LERF
Internal Events	3.90E-09	-7.00E-08	-6.61E-08
Internal Flooding	8.39E-09	0.00E+00	8.39E-09
High Winds	4.62E-08	-5.62E-07	-5.15E-07
Fire	1.77E-08	-4.52E-08	-2.75E-08
		Sum =	-6.01E-07

The limiting alignments of point estimates from RAI 3 are presented below. For CDF, the overall limiting train and unit is train A on Unit 2. For LERF, the overall limiting train and unit is train A on Unit 1.

RG 1.177 ICCDP Summary (Best Estimate Unit 2 A Train limiting)

Hazard	14 Day CT	Base	Multiplier	ICCDP
Internal Events	5.20E-06	3.95E-06	14/365	4.79E-08
Internal Flooding	2.03E-05	1.66E-05	14/365	1.42E-07
High Winds	2.02E-05	5.60E-06	14/365	5.60E-07
Fire	2.85E-05	2.27E-05	14/365	2.22E-07
			Sum =	9.72E-07

RG 1.177 ICLERP Summary (Best Estimate Unit 1 A Train limiting)

Hazard	14 Day CT	Base	Multiplier	ICLERP
Internal Events	2.95E-07	2.03E-07	14/365	3.53E-09
Internal Flooding	2.99E-07	4.46E-08	14/365	9.76E-09
High Winds	1.88E-06	7.18E-07	14/365	4.46E-08
Fire	2.05E-06	1.54E-06	14/365	1.96E-08
			Sum =	7.74E-08

The overall CDF and LERF impact of the AOT and addition of the ESPS system represents a risk decrease, similar to the aggregate sensitivity.

351 Day ICCDP Risk Contribution Summary (Best Estimate Unit 2 A Train limiting)

Hazard	ESPS credit	Base	Multiplier	ICCDP
Internal Events	3.27E-06	3.95E-06	351/365	-6.54E-07
Internal Flooding	1.66E-05	1.66E-05	351/365	0.00E+00
High Winds	2.40E-06	5.60E-06	351/365	-3.08E-06
Fire	2.24E-05	2.27E-05	351/365	-2.88E-07
			Sum =	-4.02E-06

351 Day ICLERP Risk Contribution Summary (Best Estimate Unit 1 A Train limiting)

Hazard	ESPS credit	Base	Multiplier	ICLERP
Internal Events	1.36E-07	2.03E-07	351/365	-6.44E-08
Internal Flooding	4.46E-08	4.46E-08	351/365	0.00E+00
High Winds	1.54E-07	7.18E-07	351/365	-5.42E-07
Fire	1.50E-06	1.54E-06	351/365	-3.85E-08
			Sum =	-6.45E-07

The total risk results assuming one 14-day CT entry and ESPS nominal availability for the remainder of the year are shown below:

ΔCDF For Entire Change (Best Estimate Unit 2 A Train limiting)

Hazard	14-day CT	351 Day	ΔCDF
Internal Events	4.79E-08	-6.54E-07	-6.06E-07
Internal Flooding	1.42E-07	0.00E+00	1.42E-07
High Winds	5.60E-07	-3.08E-06	-2.52E-06
Fire	2.22E-07	-2.88E-07	-6.60E-08
		Sum =	-3.05E-06

ΔLERF For Entire Change (Best Estimate Unit 1 A Train limiting)

Hazard	14-day CT	351 Day	ΔLERF
Internal Events	3.53E-09	-6.44E-08	-6.09E-08
Internal Flooding	9.76E-09	0.00E+00	9.76E-09
High Winds	4.46E-08	-5.42E-07	-4.98E-07
Fire	1.96E-08	-3.85E-08	-1.89E-08
		Sum =	-5.68E-07

A bounding seismic ICCDP estimate for the 14-day CT is 1.87E-7. The two methodologies presented in RAI 5 align with this bounding seismic ICCDP estimate. The overall change of including ESPS is a risk improvement, even when the bounding seismic estimate is considered. The bounding seismic ICLERP estimate for the 14-day CT is 2.60E-8. These bounding seismic ICCDP and ICLERP estimates, as provided in the October 8, 2018 supplement, are not based on a Reg. Guide 1.200 model.

Duke Energy RAI-13.b Response

- RAI-2.d regarding incorporation of the appropriate and consistent treatment of SSF and ESPS structural failure.

The appropriate and consistent treatment of SSF and ESPS structural failures is included in response to RAI 2.d.

- RAI-3.a regarding the incorporation of the most limiting plant configurations.

The most limiting plant and alignment configuration results are included in responses to RAIs 3 and 13.

- RAI-4.b regarding update of CCFs to account for updated component failure rates.

Appropriate CCFs were used for all hazards per response to RAI-4.b.

- RAI-5.b regarding the seismic bounding analysis.

The seismic analysis as described in RAI-5 was used.

- RAI-7.b regarding modeling the differences between units.

The limiting Unit (from fire) was presented in the analysis. Response to RAI-7.b demonstrated no significant differences between the Units for Internal Events, High Winds, and Internal Flooding.

- RAI-9.b regarding incorporation of the Revision 4 internal events PRA model for the underlying model used in the internal flooding and high winds PRA.

The incorporation of the Revision 4 internal events PRA model for the internal flooding and high winds PRA is presented in RAI 9.

- RAI-10.b on providing ICCDP and ICLERP for all hazard groups in accordance with Section 6, "Stage D - Assessing Parameter Uncertainty," of NUREG-1855, Revision 1.

The aleatory (parameter) uncertainty values are presented in the response to RAI 10.b.

The modifications that were made for the previous October 8, 2018 supplement RAI-4 response continue to be included unless modified by the RAIs discussed in this (RAI 13.b) response.

- RAI-12 regarding incorporation of the generic industry failure rate of SBO DGs.

Generic industry SBO DG failure rates were incorporated per RAI-12.

Duke Energy RAI-13.c Response

The model used for the ESPS RAI 3 response development included minor refinements to ensure that the ESPS system was properly credited for mitigation capabilities. The refinements include:

1) Deletion of power breakers that are already defined to be within the EDG component boundary
2) Added prohibited maintenance combinations to flag file based on commitments and technical specifications
3) Modeling changes to credit hot leg creep rupture phenomena to depressurize the vessel prior to failure in the LERF model
4) Used calc. type 3 (Mission Time, No Repair) for EDG Fail to Run failure modes
5) Refined operator action for ESPS alignment based on developed procedures and subsequently developed HRA dependency analysis for HFE combinations
6) The SSF was credited in F2 straight-line wind and tornado high wind-initiated events after the first hour of the initiating event, as discussed in RAI 1

Duke Energy RAI-13.d Response

The overall application associated with adding ESPS to the Catawba Nuclear Station is a risk improvement.

The aggregate sensitivity and best estimate cases continue to meet the acceptance guidelines in RG 1.177, Revision 1, and RG 1.174, Revision 2.

Additionally, the presented analysis contains the following conservatisms:

- Flex equipment is not credited, but would be available and deployed if needed.

- The reliability data collected by the PRA as part of the data update process shows the FLEX equipment is reliable.
    - FLEX Generator - Fail to Start as 3E-03 per demand and Fail to Run as 1E-3 per hour
    - FLEX Pumps – Fail to Start as 5E-03 per demand and Fail to Run as 2E-3 per hour
- The FLEX equipment has been deployed for various reasons, so the operator actions and procedures have been exercised, increasing the reliability of these actions.

- The high winds model does not credit the recovery of offsite power. For F1 and F2 straight-line winds, the recovery of offsite power is credible. In addition, the EDG extended AOT requires a check of weather and a Safety Related EDG will not be removed from service if the weather forecast has potential for severity. Thus, the High Wind contribution is significantly overstated.

Duke Energy RAI-13.e Response

The risk acceptance guidelines continue to be met. No additional actions required.

RAI-14 – Catawba Facts and Observations (F&O) Closure Process

Section 2 of RG 1.200, Revision 2, states for the applicable technical requirements, "the staff anticipates that current good practice, i.e., Capability Category II of the ASME/ANS standard, is the level of detail that is adequate for the majority of the applications," and, "[a] peer review is needed to determine if the intent of the requirements in the standard is met."

The NRC staff observed (ADAMS Accession No. ML18117A187) that independent reviews were performed to close F&Os for the Catawba LERF and internal flooding PRAs. However, it is not clear whether these independent reviews were performed consistent with the process documented in Appendix X to Nuclear Energy Institute (NEI) 05-04, NEI 07-12, and NEI 12-13, "Close-out of Facts and Observations," as accepted, with conditions, by NRC in the letter from Joseph Giitter and Mary Jane Ross-Lee (NRC) to Greg Krueger (NEI) dated May 3, 2017 (ADAMS Accession Number ML17079A427).

The October 8, 2018 supplement, in response to audit Question 16, provided details related to the above closure reviews and the approved NEI Appendix X (Independent Assessment Team option). The response indicated that "the same individuals who performed the 2015 Independent Review were contracted again in 2017 to perform a second independent review, including an assessment of whether or not each F&O resolution constitutes an upgrade to the PRA." To confirm that the independent reviews were performed consistent with NEI Appendix X, clarify whether any F&O resolutions were determined to be a PRA upgrade(s) and, if so, whether a focused-scope peer review was performed concurrently with these independent reviews. If so, provide the following:

a) Summary of the scope of the peer review, and

b) Detailed descriptions of any new F&Os generated from the peer review and the associated dispositions for the application.

Duke Energy RAI-14 Response

a) All internal flood and LERF F&O resolutions were determined to be updates/maintenance, rather than upgrades. As such, no focused-scope peer review is required.

b) Because no focused-scope peer review is required, no new F&O's were generated for the internal flood and LERF PRA models.

RAI-15

In Attachment 1, "Catawba Technical Specification Marked Up Pages," of the supplemental LAR dated October 8, 2018, the licensee proposed to add a new LCO 3.8.1.d that would require the operability of opposite unit DG(s) and a new Required Actions (RAs), and to revise and renumber existing RAs for TS 3.8.1 Condition B (one LCO 3.8.1.b DG inoperable).

New LCO 3.8.1.d would state "The DG(s) from the opposite unit necessary to supply power to the NSWS, CRAVS, CRACWS and ABFVES."

New RA B.1 would state "Verify both DGs on the opposite unit operable," with a CT of "1 hour and once per 12 hours thereafter."

Revised and renumbered RA B.4.2 would state: "Perform SR 3.8.1.2 for operable DG(s)."

The NRC staff notes the following discrepancies:

It appears that the proposed RA B.1 is similar to the revised and renumbered RA B.4.2 with respect to the operability of the opposite unit DGs because the existing Surveillance Requirements (SR) 3.8.1.2 in RA B.4.2 verifies the operability of the remaining DGs including the opposite unit DG (s) by verifying that each DG can start from standby conditions and achieve steady state voltage and frequency within the required ranges.

It does not appear that a discussion of the basis for the 1-hour and 12-hour CTs for the new RA B.1 was provided.

a. Provide a discussion that explains how the operability of the LCO 3.8.1.d DGs will be verified by RA B.1.

b. Provide a discussion that describes the basis and derivation of the CTs (1 hour and once per 12 hours thereafter) for RA B.1.

Duke Energy RAI-15 Response

a. The proposed RA B.1 is for an administrative verification of OPERABILITY. There is reasonable expectation of OPERABILITY for the LCO 3.8.1.d DG(s) when licensed operators verify that all the following conditions exist:

    - The DG Surveillance Requirements are met.

- The normal operator rounds for the DG are up-to-date and have been performed satisfactorily.
- The DG and its support systems have not been logged as inoperable or non-functional.
- There are no items being tracked via the Adverse Condition Monitoring and Contingency Planning sheet that calls into question OPERABILITY of the DG.
- There are no in-progress OPERABILITY determinations or functionality assessments for the DG and its support systems.

b. The initial CT of 1 hour for RA B.1 is based on the recognized importance of ensuring the LCO 3.8.1.d DG(s) is OPERABLE to power one train of shared systems during the time the LCO 3.8.1.b DG is inoperable. The 1 hour allows sufficient time to perform this verification if the inoperability of the LCO 3.8.1.b DG was unplanned.

The proposed 12-hour Completion Time (CT) of RA B.1 was chosen due to the Catawba operator shifts being 12 hours. In addition, BTP 8-8 states:

> The availability of AAC or supplemental power source shall be checked every 8-12 hours (once per shift).

The proposed change includes provisions for Catawba to ensure availability of ESPS "once per 12 hours." Thus, "once per 12 hours" for the RA B.1 CT allows Catawba to verify operability of LCO 3.8.1.d DG(s) and availability of ESPS at the same time intervals.

The Calvert Cliffs precedent that was closely followed uses "1 hour and 24 hours thereafter." Catawba has proposed a more conservative CT (12 hours vice 24 hours).

RAI-16

In Attachment 1 of the October 8, 2018 letter, the licensee proposed to revise TS 3.8.1 Condition B (i.e., one LCO 3.8.1.b DG inoperable) to extend the CT for restoring the DG to operable status beyond the existing 72-hour and up to 14 days, provided the ESPS is available. The licensee proposed 4 CTs to restore the inoperable LCO 3.8.1.b DG to operable status (RA B.6).

RA B.6 would state: "Restore DG to operable status," with the following CTs:

72 hours from discovery of unavailable
ESPS AND
24 hours from discovery of unavailable ESPS when in extended Completion
Time AND
14
days
AND
17 days from discovery of failure to meet LCO 3.8.1.a or LCO 3.8.1.b

RA B.5 would state: "Ensure availability of Emergency Supplemental Power Source (ESPS)," with the following CT:

Prior to entering the extended CT of Action B.6 AND
Once per 12 hours thereafter.

In Section 2.1, "Catawba Evaluation of the TS 3.8.1 Change Request," of the October 8, 2018 letter, the licensee states:

> The CT of 72 hours from discovery of unavailable ESPS of new RA B.6 (formerly RA B.4) is based on the existing CT for an inoperable DG. The 24 hour CT of new RA B.6 is based on Branch Technical Position 8-8 and indicates that if the ESPS unavailability occurs sometime after 72 hours of continuous DG inoperability (i.e., after entering the extended CT for an inoperable DG), then the remaining time to restore the ESPS to available status or restore the DG to operable status is limited to 24 hours.

In the Catawba current TS, the existing 72-hour CT is based on RG 1.93, which states, in part:

> If the available onsite ac power sources are one less than the LCO, power operation may continue for a period that should not exceed 72 hours, provided that the redundant diesel generator is assessed within 24 hours to be free from common-cause failure or is verified to be operable in accordance with plant-specific technical specifications.

The guidance in RG 1.93 relates to redundant power sources. The allowed power operation period of 72 hours starts from the time the available onsite ac power sources (i.e., DGs) are found to be one less than the LCO (i.e., one DG is inoperable).

The NRC staff has identified the following discrepancies:

The proposed CT of "72 hours from discovery of unavailable ESPS" of new RA B.6 (inoperable DG) would begin on discovery that both an inoperable DG exists and the ESPS is unavailable, as stated in the LAR, whereas the existing 72-hour CT for an inoperable DG begins when the DG is inoperable based on RG 1.93. Thus, the proposed "72 hours from discovery of

unavailable ESPS" would not be "based on the existing CT for an inoperable DG," as stated in the LAR.

The proposed CT of "72 hours from discovery of unavailable ESPS" would allow the DG to remain inoperable beyond the existing 72-hour CT without an available ESPS or a supplemental AC power source since the proposed 72-hour CT would begin on discovery that both an inoperable DG exists and the ESPS is unavailable.

The proposed CTs for RA B.6 do not identify a non-extended CT or a time for entering the extended CT that would indicate when the RA B.5 (ensure the availability of ESPS) would be performed within the first CT (i.e., prior to entering the extended CT of RA B.6) and when the proposed 24-hour CT (i.e., 24 hours from discovery of unavailable ESPS when in extended CT) of RA B.6 would be applicable.

a. Provide a discussion that explains how the proposed CT of "72 hours from discovery of unavailable ESPS" of RA B.6 is based on the existing 72-hour CT for an inoperable

DG that begins when the DG is found inoperable. If the proposed CT is not based on the existing 72-hour CT, provide a revised CT for RA B.6 so that the CT for restoring the inoperable LCO 3.8.1.b DG to operable status would not exceed 72 hours from the time the LCO 3.8.1.b DG was found inoperable (i.e., Condition B) or provide a justification for the new CT.

b. Provide a discussion that explains how entry into the extended CT is identified in the proposed CTs for RA B.6 to allow the implementation of RA B.5 prior to entering the extended CT of RA B.6, and to apply the 24-hour CT of RA B.6.

Duke Energy RAI-16 Response

Duke Energy proposes the following changes in red (also shown in Attachment 2):

The CT for proposed RA B.5 is revised as follows:

B.5	Evaluate availability of Emergency Supplemental Power Source (ESPS).	1 hour ~~Prior to entering the extended Completion Time of ACTION B.6~~ AND Once per 12 hours thereafter

The existing RA B.4 is renamed "B.6." The associated CT is revised to state:

"72 hours from discovery of unavailable ESPS**

AND

24 hours from discovery of Condition B entry ≥ 48 hours concurrent with unavailability of ESPS ~~unavailable ESPS when in extended Completion Time~~

AND

14 days

AND

17 days from discovery of failure to meet LCO 3.8.1.a or LCO 3.8.1.b"

Since proposed RA B.5 specifies to "evaluate", discovering the ESPS unavailable does not result in the RA being not met. On discovery of an unavailable ESPS, the CT for RA B.6 starts the 72 hour and/or 24 hour clock. This change is consistent with Brunswick Steam Electric Plant TS 3.8.1 precedent (ADAMS Accession No. ML13329A362).

If the ESPS is or becomes unavailable with an inoperable LCO 3.8.1.b DG, then action is required to restore the ESPS to available status or to restore the DG to OPERABLE status within 72 hours from discovery of unavailable ESPS. However, if the ESPS unavailability occurs at or sometime after 48 hours of continuous LCO 3.8.1.b DG inoperability, then the remaining time to restore the ESPS to available status or to restore the DG to OPERABLE status is limited to 24 hours.

The 72 hour and 24 hour Completion Times allow for an exception to the normal "time zero" for beginning the allowed outage time "clock." The 72 hour Completion Time only begins on discovery that both:

a. An inoperable DG exists; and
b. ESPS is unavailable.

The 24 hour Completion Time only begins on discovery that:

a. An inoperable DG exists for ≥ 48 hours; and
b. ESPS is unavailable.

RAI-17

BTP 8-8 recommends that the time to make the supplemental or alternate AC (AAC) power source available, including cross-connection, should be approximately 1 hour to enable restoration of battery chargers and control reactor coolant system inventory. Also, plants must assess their ability to cope with loss of all AC power (i.e., SBO) for one hour independent of an AAC power source to support the one-hour time for making this supplemental power source available

In the May 2, 2017 letter, the licensee states:

The SDGs will become one of the options in ECA-0.0 for restoring AC power. Observations of the operators on the plant simulator show that it takes about 20 minutes for the operators to get to the point in the procedure to attempt to restore power from any source. If the ESPS is the chosen source of power, operators would be dispatched to place it in service. […]

The ESPS will constitute two supplemental DGs capable of powering any one of the 4160 V essential buses on either unit during an SBO within one hour from the time that the emergency procedures direct their use as the emergency power source. […]

CNS [Catawba Nuclear Station] […] take[s] credit for its respective SSF [Standby Shutdown Facility] diesel generator as the AAC Source for coping with a SBO within 10 minutes of a SBO event.
CNS's […] coping times during a SBO are not affected by the proposed change to extend the CT for one inoperable DG. The coping times are calculated based on guidance provided in NUMARC 87-00 [Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors, Revision 1, Nuclear Management and Resources Council, Inc., August 1991].

BTP 8-8 states that plants must assess the capability to cope with the loss of all AC power for one hour independent of a supplemental AC power source. CNS […] ha[s] […] performed calculations for SBO coping that demonstrate each [unit] is a 4-hour coping plant.

The NRC staff has identified the following discrepancies:

It appears that the ESPS would be connected to supply power to the 4160 volts (V) bus within 1 hour and 20 minutes from the start of the SBO event since the ESPS would power the 4160 V bus within 1 hour from the time that the emergency procedures direct their use as the emergency power source, and it would take 20 minutes to get to that time. This indicates that the time to make the ESPS available to supply power to the station would not be within the approximately one hour timeframe described in the LAR.

The 4-hour SBO coping duration for Catawba is the time the plant can cope with an SBO event using the SSF. The availability of the SSF within 10 minutes of an SBO event indicates that Catawba can cope with the SBO without (or independent of) the SSF for 10 minutes and not for 1 hour, as stated in the BTP 8-8.

a- Clarify the estimated time it would take to connect the ESPS power source (i.e., the two supplemental DGs) to the station's safety bus from the start of an SBO event.
b- Provide a discussion that summarizes the calculations or analysis performed in accordance with NUMARC 87-00 guidance to assess the Catawba ability to cope with the loss of all AC power (i.e., SBO) for 1 hour or the period of time clarified in above question until the ESPS is connected to the shutdown buses, as stated in BTP 8-8. Also, include in the discussion a summary of the coping analysis conclusions.

Duke Energy RAI-17 Response

a. Since the original application for ESPS was submitted, CNS has completed sufficient installation of ESPS equipment and facility tie-ins. A time line was obtained and validated by licensed and auxiliary operators, for implementation of the emergency procedure for station blackout (SBO) and aligning ESPS to power an essential bus on the SBO unit. A team consisting of a licensed operator and Auxiliary operators simulated the operator dispatch times and the time it takes to energize the 4160V safety bus once local actions are completed. Multiple local validations, for both units, were obtained and documented. A breaker at the training center was used to obtain the length of time it takes to rack in and rack out the breakers. The longest and most conservative local times were used.

   The validated total time from the loss of power to the 4160V safety bussed to re-energize a 4160V safety bus through a unit transformer using ESPS was 50 minutes. A more conservative time limit, taking into account the CNS standard desired margin for time critical actions of ≥ 20% and the 50-minute case, is 60 minutes from time power is lost to the 4160V busses. Duke Energy meets the "approximated one hour" requirement and the operators will be held accountable to a 60-minute timeframe to account for desired margin.

b. Duke Energy has an approved calculation for CNS that assesses the ability to cope with an extended loss of all AC power referred to as an Extended Loss of AC Power (ELAP) event which is equivalent to Station Block Out (SBO) without taking any credit for the Standby Shutdown Facility (SSF). The calculation demonstrates the amount of time available for recovery actions to take place to restore onsite power before the core uncovers and fuel damage becomes imminent. The calculation included a reactor coolant pump seal leak, turbine-driven (T/D) AFW (CA) pump is available, and assumed that the SSF is unavailable. The calculation concludes that the length of time between SBO event initiation and the onset of significant core uncover is greater than 2 hours. Therefore, CNS clearly demonstrates the ability to cope with the SBO event for the 60-minute duration cited in response to part a. above until the ESPS is connected to a 4160V safety bus.

RAI-18

In Attachment 1 of the October 8, 2018 letter, the licensee proposed a new Condition C that would state "Required Action and associated Completion Time of Required Action B.1 not met." Two alternate RA C.1.1 and RA C.1.2 are proposed for Condition C.

RA C.1.1 would state "Restore both DGs on the opposite unit to operable status," with a CT of 72 hours.

RA C.1.2 would state "Restore the LCO 3.8.1.b DG to operable status," with a CT of 72 hours. The proposed RA B.1 would state: "Verify LCO 3.8.1.d DG(s) operable." The CT for RA B.1 would state: "1 hour and once per 12 hours thereafter.

In Section 2.1 of the October 8 letter, the licensee stated that the 72-hour CT for the new RA C.1.1 and RA C.1.2 is in accordance with Regulatory Guide (RG) 1.93, which indicates operation may continue in this condition for a period that should not exceed 72 hours.

RG 1.93 states, in part:

> If the available onsite ac electric power sources are two less than the LCO, power operation may continue for a period that should not exceed 2 hours.
>
> If the available onsite ac power sources are one less than the LCO, power operation may continue for a period that should not exceed 72 hours, provided that the redundant diesel generator is assessed within 24 hours to be free from common-cause failure or is verified to be operable in accordance with plant-specific technical specifications

The guidance in RG 1.93 relates to redundant power sources. The power operation period of 2 hours is applicable to two inoperable AC power sources, and the period of 72 hours starts from the time the available onsite ac power sources (i.e., DGs) are one less than the LCO (i.e., one DG is inoperable). Also, the power operation period of 72 hours allowed per RG 1.93 starts from the time the available onsite ac power sources (i.e., DGs) are one less than the LCO (i.e., one DG is inoperable).

The NRC staff has identified the following discrepancies:

If two redundant DGs in the opposite unit would be inoperable in Condition C, the CT for restoring both inoperable DGs to operable status (RA C.1.1) would be 2 hours, as recommended in RG 1.93. However, the proposed CT for RA C.1.1 is 72 hours and is not consistent with RG 1.93.

The proposed RA C.1.2 and associated CT would allow the LCO 3.8.1.b DG to remain inoperable for a time longer than 72 hours because the proposed 72-hour CT for C.1.2 would start from the time of discovery of the inoperability of both DGs on the opposite unit by RA B.1 (i.e., 1 hour and once per 12 hours thereafter), and not from the time of discovery of inoperable

LCO 3.8.1.b DG, as described in RG 1.93. This indicates that the proposed 72-hour CT for RA C.1.2 would not be in accordance with RG 1.93, as stated in the LAR.

a. Provide a discussion of how the proposed 72-hour CT for new RA C.1.1 (restore both DGs on the opposite unit to operable status) is consistent with RG 1.93 with respect to two inoperable DGs.

b. Provide a discussion that explains how the 72-hour CT for RA C.1.2 (restore LCO 3.8.1.b DG to operable status) is in accordance with RG 1.93 so that the CT for RA C.1.2 would not exceed 72 hours from the time the LCO 3.8.1.b DG is found inoperable.

Duke Energy RAI-18 Response

a. The proposed Condition C in the October 8, 2018 submittal is deleted from the CNS TS 3.8.1.

b. RA C.1.2 was not in accordance with RG 1.93 as cited in the October 8, 2018 submittal because the CT could exceed 72 hours. Therefore, the proposed Condition C in the October 8, 2018 submittal is deleted from the CNS TS 3.8.1. Condition D from the October 8, 2018 submittal is now renamed to Condition C (Shown in Attachment 2).

RAI-19

In Attachment 1 of the October 8, 2018 letter, the licensee proposed a new Condition D that would state: “one LCO 3.8.1.c offsite circuit is inoperable.” The RAs would be modified by a Note.

The proposed Note would state: “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 a train.”

RA D.3 would state: “Declare NSWS, CRAVS, CRACWS and ABFVES supported by the inoperable offsite circuit inoperable,” with a CT of 72 hours.

In Section 2.1 of the October 8, 2018 letter, the licensee stated that the Note would allow “new Condition D to provide requirements for the loss of a LCO 3.8.1.c offsite circuit and LCO 3.8.1.d DG without regard to whether a train is de-energized. “

10 CFR 50.36(c)(2) states:

> When an LCO of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the technical specifications until the condition can be met.

The staff notes that the new Condition D is not related to the loss of an LCO 3.8.1.d DG, and as such, would not provide the requirements for the loss of an LCO 3.8.1.d DG. In addition, the proposed RAs would not require the restoration of the LCO 3.8.1.c offsite circuit to operable status or other remedial actions to meet the TS LCO 3.8.1.c, as required by 10 CFR 50.36(c)(2).

1- Clarify how the proposed Note for the new Condition D would allow the new Condition D to provide requirements for the loss of a LCO 3.8.1.d DG, as stated above.

2- Provide a discussion that explains how the proposed RAs for the new Condition D would allow the TS LCO 3.8.1 to be met, as required by 10 CFR 50.36(c)(2).

Duke Energy RAI-19 Response

a. (Note: Condition D in Attachment 2 is marked up and now renamed to Condition C) The Note above the Required Actions associated with Condition C is consistent with the Calvert Cliffs precedent. Condition C addresses the inoperability of one LCO 3.8.1.c qualified offsite circuit between the offsite transmission network and the opposite unit's Onsite Essential Auxiliary Power System. If Condition C is entered for one LCO 3.8.1.c offsite circuit inoperable concurrently with one LCO 3.8.1.d DG inoperable associated with the same train of shared systems and the NSWS pump(s), then the NOTE requires the licensed operator to enter all applicable Conditions and Required Actions of TS 3.8.9 "Distribution Systems - Operating". Specifically, in the case where an inoperable LCO 3.8.1.c qualified offsite circuit and an inoperable LCO 3.8.1.d DG both support the same train of shared systems and NSWS pump(s), TS 3.8.9 Condition A must be entered because there is no longer assurance that the train of "Distribution Systems - Operating" can be energized to the proper voltage. Both units would enter TS 3.8.9 Condition A in this instance since there is no power source to a train of shared systems and NSWS pump(s) (refer to CNS LCO 3.0.9). This action is consistent with CNS current application of TS 3.8.9 with the concurrent inoperability of a DG and inoperability of a qualified offsite circuit impacting the same train of "Distribution Systems – Operating" aligned to power shared systems and NSWS pump(s).

b. Proposed RA D.3 (renamed to C.3) from the October 2018 submittal would not allow LCO 3.8.1 to be met. In order to comply with 10 CFR 50.36(c)(2), RA C.3 has been revised as follows:

C~~D~~.3 ~~Declare NSWS, CRAVS, CRACWS or ABFVES supported by the inoperable offsite circuit inoperable.~~ Restore LCO 3.8.1.c offsite circuit to OPERABLE status.	72 hours

Consistent with the time provided in ACTION A, operation may continue in Condition C for a period that should not exceed 72 hours. With one required LCO 3.8.1.c 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 circuits and DGs are adequate to supply electrical power to the onsite Class 1 E Distribution System. If the LCO 3.8.1.c required offsite circuit cannot be restored to OPERABLE status within 72 hours, then Condition K (now renamed as Condition I in Attachment 2) must be entered immediately.

RAI-20

In Attachment 1 of the October 8, 2018 letter, the licensee proposed a new Condition E that would apply when one LCO 3.8.1.d DG is inoperable. The RAs for new Condition E would be modified by a Note.

The Note would state: “Enter applicable Conditions and Required Actions of LCO 3.8.9, “Distribution Systems - Operating,” when Condition E is entered with no AC power source to a train.”

RA E.1 would state: “verify both LCO 3.8.1.b DGs operable, the opposite unit’s DG operable and ESPS available,” with a CT of “1 hour and once per 12 hours thereafter.”

RA E.4.2 would state: “Perform SR 3.8.1.2 for operable DG(s).”

RA E.5 would state: “Declare NSWS, CRAVS, CRACWS and ABFVES supported by the inoperable DG inoperable,” with a CT of “14 days.”
In Section 2.1 of the October 8, 2018 letter, the licensee states:

> [The Note] allow new Condition E to provide requirements for the loss of a LCO 3.8.1.c offsite circuit and LCO 3.8.1.d DG without regard to whether a train is de-energized.
>
> The verification in this RA [E.1] provides assurance that the other three safety-related DGs and the ESPS are capable of supplying the Class 1E AC Electrical Power Distribution System.
>
> The CT of 14 days is justified by new RA E.1 (verify both unit-specific DGs are operable, the other opposite unit DG is operable and the ESPS is available). The 14 day CT is also consistent with the proposed CT in ACTION B when ESPS is available.

10 CFR 50.36(c)(2) states:

> When an LCO of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the technical specifications until the condition can be met.

The NRC staff has identified the following discrepancies:

The new Condition E is not related to the loss of an LCO 3.8.1.c offsite circuit, and as such, it appears to not provide the requirements for the loss of an LCO 3.8.1.c offsite circuit.

It does not appear that a discussion of the basis is for the 1-hour and 12-hour CTs for the new RA E.1 was provided.
It does not appear that a CT for the proposed RA E.5 (declare NSWS, CRAVS, CRACWS and ABFVES supported by the inoperable DG inoperable) when the ESPS is unavailable consistent with the proposed CT for Condition B (i.e., one LCO 3.8.1.b DG inoperable) was provided.

The proposed RAs for the new Condition E appear to not require the restoration of the LCO 3.8.1.d DG to operable status to meet the TS LCO 3.8.1, as required by 10 CFR 50.36(c)(2).

a. Clarify how the proposed Note for the new Condition E would allow the new Condition E to provide requirements for the loss of a LCO 3.8.1.c offsite circuit, as stated above.

b. Provide a discussion that explains the basis for the proposed CTs (i.e., 1 hour and once per 12 hours thereafter) for new RA E.1.

c. Provide a discussion about the RAs and associated CTs for Condition E for the case when the ESPS is unavailable.

d. Provide a discussion that explains how the proposed RAs for the new Condition E would allow the TS LCO 3.8.1 to be met, as required by 10 CFR 50.36(c)(2).

Duke Energy RAI-20 Response

(Note: Condition E in Attachment 2 is marked up and renamed to Condition D)

a. The Note above the Required Actions associated with Condition D is consistent with the Calvert Cliffs precedent. Condition D addresses the inoperability of one LCO 3.8.1.d DG aligned to the opposite unit Onsite Essential Auxiliary Power System that is supplying power to a train of shared systems and to the respective NSWS pump(s). If Condition D is entered for one LCO 3.8.1.d DG concurrently with one LCO 3.8.1.c offsite circuit inoperable associated with the same train of shared systems and NSWS pump(s), then the Note requires the licensed operator to enter all applicable Conditions and Required Actions of TS 3.8.9 "Distribution Systems - Operating". Specifically, in the case where an inoperable LCO 3.8.1.d DG and an inoperable LCO 3.8.1.c qualified offsite circuit both support the same train of shared systems and NSWS pump(s), TS 3.8.9 Condition A must be entered because there is no longer assurance that the train of "Distribution Systems - Operating" can be energized to the proper voltage. Both units would enter TS 3.8.9 Condition A in this instance since there is no power source to a train of shared systems and NSWS pump(s) (refer to CNS LCO 3.0.9). This action is consistent with CNS current application of TS 3.8.9 with the concurrent inoperability of a DG and inoperability of a qualified offsite circuit impacting the same train of "Distribution Systems - Operating" aligned to power shared systems and NSWS pump(s).

b. The initial CT of 1 hour for RA D.1 is based on the recognized importance of ensuring the LCO 3.8.1.b DGs are OPERABLE when a LCO 3.8.1.d DG is inoperable. The 1 hour allows sufficient time to perform this verification if the inoperability of the LCO 3.8.1.d DG was unplanned.

The proposed 12-hour Completion Time (CT) of RA D.1 was chosen due to the Catawba operator shifts being 12 hours. In addition, BTP 8-8 states:

> The availability of AAC or supplemental power source shall be checked every 8-12 hours (once per shift).

The proposed change includes provisions for Catawba to ensure availability of ESPS “once per 12 hours.” Thus, “once per 12 hours” for the RA D.1 CT allows Catawba to verify operability of the unit DGs.

The Calvert Cliffs precedent that was closely followed uses “1 hour and 24 hours thereafter.” Catawba has proposed a more conservative CT (12 hours vice 24 hours).

c. RA D.1 is revised to "Verify both LCO 3.8.1.b DGs OPERABLE and the opposite unit's DG OPERABLE." The availability of ESPS has been removed, as shown in Attachment 2.

d. Proposed RA E.5 from the October 8, 2018 submittal would not allow LCO 3.8.1 to be met. In order to comply with 10 CFR 50.36(c)(2), the RA E.5 from the October 8, 2018 submittal has been replaced with RA D.5 and RA D.6 as follows:

~~E.5 Declare NSWS, CRAVS, CRACWS or ABFVES supported by the inoperable DG inoperable.~~	~~14 days~~
D.5 Evaluate availability of ESPS.	1 hour <u>AND</u> Once per 12 hours thereafter
<u>AND</u>	
D.6 Restore LCO 3.8.1.d DG to OPERABLE status.	72 hours from discovery of unavailable ESPS <u>AND</u> 24 hours from discovery of Condition D entry ≥ 48 hours concurrent with unavailability of ESPS <u>AND</u> 14 days <u>AND</u> 17 days from discovery of failure to meet LCO 3.8.1.c or LCO 3.8.1.d

In Condition D, the remaining OPERABLE DGs, unavailable ESPS, and offsite power circuits are adequate to supply electrical power to the Class 1E Distribution System. The 14 day 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.

If the ESPS is or becomes unavailable with an inoperable LCO 3.8.1.d DG, then action is required to restore the ESPS to available status or to restore the DG to OPERABLE status within 72 hours from discovery of unavailable ESPS. However, if the ESPS unavailability occurs at or sometime after 48 hours of continuous LCO 3.8.1.d DG inoperability, then the remaining time to restore the ESPS to available status or to restore the DG to OPERABLE status is limited to 24 hours.

The 72 hour and 24 hour Completion Times allow for an exception to the normal “time zero” for beginning the allowed outage time “clock.” The 72 hour Completion Time only begins on discovery that both:

a. An inoperable DG exists; and
b. ESPS is unavailable.

The 24 hour Completion Time only begins on discovery that:

a. An inoperable DG exists for ≥ 48 hours; and
b. ESPS is unavailable.

Therefore, when one LCO 3.8.1.d DG is inoperable due to either preplanned maintenance (preventive or corrective) or unplanned corrective maintenance work, the Completion Time can be extended from 72 hours to 14 days if ESPS is verified available for backup operation.

<u>RAI-21</u>

In Attachment 1 of the October 8, 2018 letter, the licensee proposed a new Condition F that would be applicable when the RA E.1 (verify both LCO 3.8.1.b DGs operable, the opposite unit’s DG operable and ESPS available) and associated CT (1 hour and once per 12 hours thereafter) are not met. Three alternate RAs F1.1, F.1.2, and F.1.3 are proposed for Condition F.

RA F.1.1 would state “Restore both LCO 3.8.1.b DGs to operable status and ESPS to available status,” within the CT of “72 hours.”

RA F.1.2 would state “Restore both LCO 3.8.1.d DG to operable status” within the CT of “72 hours.”

RA F.1.3 would state “Declare NSWS, CRAVS, CRACWS and ABFVES supported by the inoperable DG inoperable.

In Section 2.1 of the October 8, 2018 letter, the licensee states:

> The 72-hour CT for RA F.1.1 and RA F.1.2 is consistent with Regulatory Guide 1.93 […].
>
> New RA F.1.3 reflects that if the opposite unit DG that is necessary to supply power to the NSWS, CRA VS, CRACWS and ABFVES cannot be restored to operable status within 72 hours, then the NSWS, CRAVS, CRACWS and ABFVES components associated with the inoperable DG must be declared inoperable.

RG 1.93 states, in part:

> If the available onsite ac electric power sources are two less than the LCO, power operation may continue for a period that should not exceed 2 hours.
>
> If the available onsite ac power sources are one less than the LCO, power operation may continue for a period that should not exceed 72 hours, provided that the redundant diesel generator is assessed within 24 hours to be free from common-cause failure or is verified to be operable in accordance with plant-specific technical specifications

The guidance in RG 1.93 relates to redundant power sources. The power operation period of 2 hours is applicable to two inoperable AC power sources, and the period of 72 hours starts from the time the available onsite ac power sources (i.e., DGs) are one less than the LCO (i.e., one DG is inoperable).

The NRC staff has identified the following discrepancies:

If two redundant LCO 3.8.1.b DGs and two redundant DGs in the opposite unit would be inoperable in Condition F, the CT for restoring either both inoperable LCO 3.8.1.b DGs or one DG in the opposite unit to operable status (RA F.1.1) would be 2 hours, as recommended in RG 1.93. However, the proposed CT for RA F.1.1 is 72 hours and is not consistent with RG 1.93.

The proposed RA F.1.2 and associated CT (i.e., restore the LCO 3.8.1.d DG to operable status within 72 hours) would allow the Catawba power operation to exceed 72 hours if the LCO 3.8.1.d DG would become inoperable (proposed Condition E) because the proposed 72-hour for F.1.2 would start from the time the RA E.1 (i.e., verify both LCO 3.8.1.b DGs operable, the opposite unit's DG and ESPS available) and associated CT (i.e., 1 hour [from discovery of LCO 3.8.1.d DG inoperability] and once per 12 hours thereafter) are not met, and not from the time the LCO 3.8.1.d DG is found inoperable. It would appear that the proposed 72-hour CT for RA C.1.2 would not be in accordance with RG 1.93.

Two DGs (i.e., both LCO 3.8.1.b or one LCO 3.8.1.b DG that provides power to the shared systems and one LCO 3.8.1.d DG are inoperable) would be inoperable in Condition F. Thus, the CT for restoring the LCO 3.8.1.d DG to operable status (RA F.1.2) would be 2 hours, as recommended in RG 1.93. However, the proposed CT for RA F.1.2 is 72 hours and is not consistent with RG 1.93.

It does not appear that a discussion of the specific inoperable DG which supported shared systems would be declared inoperable in RA F.1.3 was provided, as more than one DG would be inoperable in Condition F.

a. Provide a discussion of how the proposed 72-hour CT for new RA F.1.1 (restore both LCO 3.8.1.b DGs to operable status and ESPS to available status) is consistent with RG 1.93 with respect to two inoperable LCO 3.8.1.b DGs.

b. Provide a discussion that explains how the proposed 72-hour CT for new RA F.1.2 is consistent with RG 1.93 so that the CT for RA F.1.2 would not exceed 72 hours from the time the LCO 3.8.1.d DG is found inoperable.

c. Provide a discussion of how the proposed 72-hour CT for new RA F.1.2 (restore LCO 3.8.1.d DG to operable status) is consistent with RG 1.93 with respect to two inoperable DGs (i.e., one LCO 3.8.1.b DG and one LCO 3.8.1.d DG) that supply power to the shared systems.

d. Provide a discussion that explains the specific inoperable DG of which the supported shared systems would be declared inoperable in RA F.1.3. Also, provide a discussion that clarifies whether the trains of shared systems supported by all inoperable DGs would be declared inoperable, as more than one DG (i.e., LCO 3.8.1.d DG and LCO 3.8.1.b DG(s)) would be inoperable in Condition F; and provide the basis for the CTs for declaring the train of shared systems supported by each inoperable DG inoperable.

Duke Energy RAI-21 Response

If one LCO 3.8.1.b DG is inoperable when in Condition D, then Condition B will be entered for that LCO 3.8.1.b DG. If both LCO 3.8.1.b DGs are inoperable when in Condition D, then the proposed Condition G will be entered. Thus, the proposed Condition F in the October 8, 2018 submittal is deleted from TS 3.8.1. Condition H from the October 8, 2018 submittal is now renamed to Condition F (Shown in Attachment 2).

RAI-22

In Attachment 1 of the October 8, 2018 letter, the proposed Condition K would apply when the RA and associated CT of Condition A, C, F, G, H, I, or J are not met; or RA and associated CT of RA B.2, B.3, B.4.1, B.4.2, or B.6 are not met; or RA and associated CT of RA E.2, E.3, E.4.1, E.4.2, or E.5 are not met.

The proposed RA K.1 would state “Be in Mode 3” within a CT of 6 hours.

The proposed RA K.2 would state “Be in Mode 5” within a CT of 36 hours.

The staff has identified the following discrepancies:

The proposed Condition K does not address the case when an RA and associated CT of the proposed new Condition D are not met. In addition, the proposed TS changes does not discuss actions when the RA D.1, D.2, or D.3 and associated CT of Condition D are not met.

In case the proposed LCO 3.8.1.d would require only one opposite unit DG to supply power to the shared systems, Catawba would enter Condition K to bring the unit to Mode 3 in 6 hours and Mode 5 in 36 hours if the DG that would not be required by LCO 3.8.1.d would not be restored to operable status (RA C.1.1 and RA F.1.1) within the proposed 72-hour CT. This would subject the unit to transients associated with the orderly shutdown.

In case the ESPS would not be restored to available status as required by the proposed new RA F.1.1 within the proposed 72-hour CT, Catawba would enter Condition K to bring the unit to Mode 3 in 6 hours and Mode 5 in 36 hours. This would subject the unit to transients associated with the orderly shutdown.

a. Provide a discussion of the applicable actions when the RAs and associated CTs of the new Condition D are not met.

b. In case the proposed LCO 3.8.1.d would require only one opposite unit DG to be operable, provide a discussion that explains the reasons for entering Condition K to shut down the unit and, as a result, subject the unit to transients associated with the shutdown when the opposite unit DG that would not be required by LCO 3.8.1.d could not be restored to operable status by the proposed RA C.1.1 and RA F.1.1.

c. Provide a discussion that explains the reasons for entering Condition K to shut down the unit and, as a result, subject the unit to transients associated with the shutdown when the ESPS cannot be restored to available status, as required by the proposed RA F.1.1.

Duke Energy RAI-22 Response

Condition K is renamed to Condition I and revised as follows (Shown in Attachment 2):

I. ~~K.~~ Required Action and Associated Completion Time of Condition A, C, E, F, G, or H not met. OR Required Action and Associated Completion Time of Required Action B.2, B.3, B.4.1, B.4.2, or B.6 not met. OR Required Action and Associated Completion Time of Required Action D.2, D.3, D.4.1, D.4.2, or D.6 not met.	I~~K~~.1 Be in MODE 3. AND I~~K~~.2 Be in MODE 5.

Condition C (previously named Condition D) has been added to Condition I (previously named Condition K). Condition F from the October 8, 2018 submittal has been deleted.

RAI-23

In Attachment 1 of the October 8, 2018 letter, the proposed note to the SRs section would state:

Note: SR 3.8.1.1 through SR 3.8.1.20 are only applicable to LCO 3.8.1.a and LCO 3.8.1.b AC sources. SR 3.8.1.21 is only applicable to LCO 3.8.1.c and LCO 3.8.1.d AC sources.

The proposed SR 3.8.1.21 would state:

SR 3.8.1.21 For the LCO 3.8.1.c and LCO 3.8.1.d AC electrical sources. SR 3.8.1.1, SR 3.8.1.2, SR 3.8.1.4, SR 3.8.1.5, and SR 3.8.1.6 are required to be met.

The NRC staff notes that a discussion about the reasons for excluding SR 3.8.1.3, SR 3.8.1.7, SR 3.8.1.8, SR 3.8.1.9, SR 3.8.1.10, SR 3.8.1.11, SR 3.8.1.12, SR 3.8.1.13, SR 3.8.1.14, SR 3.8.1.15, SR 3.8.1.16, SR 3.8.1.17, SR 3.8.1.18, SR 3.8.1.19, and SR 3.8.1.20 from the SRs required for the LCO 3.8.1.c and LCO 3.8.1.d AC electrical power sources was not provided. Provide a discussion that explains why the performance of SR 3.8.1.3 and SR 3.8.1.7 through SR 3.8.1.20 are not required for the LCO 3.8.1.c and LCO 3.8.1.d AC power sources.

Duke Energy RAI-23 Response

The proposed Note and SR 3.8.1.21 have been deleted, as shown in Attachment 2. All SRs associated with TS 3.8.1 are applicable to LCO 3.8.1.c and LCO 3.8.1.d AC power sources for the proposed change.

Attachment 2

Revised Catawba Technical Specification 3.8.1 Marked Up Pages

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 AC Sources—Operating

LCO 3.8.1 The following AC electrical sources shall be OPERABLE:

a. Two qualified circuits between the offsite transmission network and the Onsite Essential Auxiliary Power System; and

b. Two diesel generators (DGs) capable of supplying the Onsite Essential Auxiliary Power Systems; and

c. The qualified circuit(s) between the offsite transmission network and the opposite unit's Onsite Essential Auxiliary Power System necessary to supply power to the shared systems and the Nuclear Service Water System (NSWS) pump(s); and

d. The DG(s) from the opposite unit necessary to supply power to the shared systems and the NSWS pump(s);

AND

The automatic load sequencers for Train A and Train B shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

---NOTE---
The opposite unit electrical power sources in LCO 3.8.1.c and LCO 3.8.1.d are not required to be OPERABLE when the associated shared systems and NSWS pump(s) are inoperable.

ACTIONS

--NOTE--

LCO 3.0.4.b is not applicable to DGs.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One LCO 3.8.1.a offsite circuit inoperable.	A.1 Perform SR 3.8.1.1 for required OPERABLE offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND	
	A.2 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 offsite circuit to OPERABLE status.	72 hours AND ~~6~~ 17 days from discovery of failure to meet LCO 3.8.1.a or LCO 3.8.1.b

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One LCO 3.8.1.b DG inoperable.	B.1 Verify LCO 3.8.1.d DG(s) OPERABLE.	1 hour AND Once per 12 hours thereafter
	AND	
	B.~~1~~2 Perform SR 3.8.1.1 for the required offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND	
	B.~~2~~3 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~~4.1 Determine OPERABLE DG(s) is not inoperable due to common cause failure.	24 hours
	OR	
	B.~~3~~4.2 Perform SR 3.8.1.2 for OPERABLE DG(s).	24 hours
	AND	
		(continued)

ACTIONS

Evaluate

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.5 ~~Ensure~~ availability of Emergency Supplemental Power Source (ESPS).	~~Prior to entering the extended Completion Time of ACTION B.6~~ 1 hour AND Once per 12 hours thereafter
	AND	
	~~B.4~~B.6 Restore DG to OPERABLE status.	72 hours from discovery of unavailable ESPS AND ~~6 days from discovery of failure to meet LCO~~ 24 hours from discovery of ~~unavailable ESPS when in extended Completion Time~~ Condition B entry ≥ 48 hours concurrent with unavailability of ESPS AND 14 days AND 17 days from discovery of failure to meet LCO 3.8.1.a or LCO 3.8.1.b

ACTIONS

~~C. Required Action and associated Completion Time of Required Action B.1 not met.~~	~~C.1.1 Restore both DGs on the opposite unit to OPERABLE status.~~ ~~OR~~ ~~C.1.2 Restore LCO 3.8.1.b DG to OPERABLE status.~~	~~72 hours~~
C ~~D.~~ One LCO 3.8.1.c offsite circuit inoperable.	-------------------NOTE------------------ Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems—Operating," when Condition C ~~D~~ is entered with no AC power source to a train. ---	
	C.1 ~~D.1~~ Perform SR 3.8.1.1 for the required offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND	
	C.2 ~~D.2~~ Declare NSWS, CRAVS, CRACWS or ABFVES with no offsite power available inoperable when the redundant NSWS, CRAVS, CRACWS or ABFVES is inoperable.	24 hours from discovery of no offsite power to one train concurrent with inoperability of redundant required feature(s)
	AND	
	~~D.3 Declare NSWS, CRAVS, CRACWS and ABFVES supported by the inoperable offsite circuit inoperable.~~ C.3 Restore LCO 3.8.1.c offsite circuit to OPERABLE status.	72 hours

ACTIONS

D ~~E~~. One LCO 3.8.1.d DG inoperable.	------------------NOTE------------------ Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems—Operating," when Condition ~~E~~ D is entered with no AC power source to a train. --	
	D.1 ~~E.1~~ Verify both LCO 3.8.1.b DGs OPERABLE~~,~~ and the opposite unit's DG OPERABLE ~~and ESPS available~~.	1 hour AND Once per 12 hours thereafter
	AND	
	D.2 ~~E.2~~ Perform SR 3.8.1.1 for the required offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND	
	D.3 ~~E.3~~ Declare NSWS, CRAVS, CRACWS or ABFVES supported by the inoperable DG inoperable when the redundant NSWS, CRAVS, CRACWS or ABFVES is inoperable.	4 hours from discovery of Condition ~~E~~ D concurrent with inoperability of redundant required feature(s)
	AND	

ACTIONS

D ~~E~~. (continued)	D.4.1 ~~E.4.1~~ Determine OPERABLE DG(s) is not inoperable due to common cause failures. OR D.4.2 ~~E.4.2~~ Perform SR 3.8.1.2 for OPERABLE DG(s). AND INSERT 1 ~~E.5 Declare NSWS, CRAVS, CRACWS and ABFVES supported by the inoperable DG inoperable.~~	24 hours 24 hours ~~14 days~~
~~F. Required Action and associated Completion Time of Required Action E.1 not met.~~	~~F.1.1 Restore both LCO 3.8.1.b DGs and opposite unit's DG to OPERABLE status and ESPS to available status.~~ ~~OR~~ ~~F.1.2 Restore LCO 3.8.1.d DG to OPERABLE status.~~ ~~OR~~ ~~F.1.3 Declare NSWS, CRAVS, CRACWS and ABFVES supported by the inoperable DG inoperable.~~	~~72 hours~~

INSERT 1

D.5 Evaluate availability of ESPS.	1 hour AND Once per 12 hours thereafter
AND	
D.6 Restore LCO 3.8.1.d DG to OPERABLE status.	72 hours from discovery of unavailable ESPS AND 24 hours from discovery of Condition D entry ≥ 48 hours concurrent with unavailability of ESPS AND 14 days AND 17 days from discovery of failure to meet LCO 3.8.1.c or LCO 3.8.1.d

ACTIONS

E ~~CG~~.	Two LCO 3.8.1.a offsite circuits inoperable. OR ~~One LCO 3.8.1.a offsite inoperable and one LCO 3.8.1.c offsite circuit inoperable.~~ One LCO 3.8.1.a offsite circuit that provides power to the shared systems inoperable and one LCO 3.8.1.c offsite circuit that provides power to the shared systems inoperable. OR Two LCO 3.8.1.c offsite circuits inoperable.	E ~~CG~~.1 Declare required feature(s) inoperable when its redundant required feature(s) is inoperable. AND E ~~CG~~.2 Restore one offsite circuit to OPERABLE status.	12 hours from discovery of Condition ~~C~~ ~~G~~ E concurrent with inoperability of redundant required features 24 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F ~~D~~H. One LCO 3.8.1.a offsite circuit inoperable. AND One LCO 3.8.1.b DG inoperable.	-------------------NOTE------------------ Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems—Operating," when Condition ~~D~~ ~~H~~ F is entered with no AC power source to any train. ---	
	F ~~D~~H.1 Restore offsite circuit to OPERABLE status.	12 hours
	OR	
	F ~~D~~H.2 Restore DG to OPERABLE status.	12 hours
G ~~E~~I. Two LCO 3.8.1.b DGs inoperable. OR ~~LCO 3.8.1.b DG inoperable and one LCO 3.8.1.d DG inoperable.~~ OR Two LCO 3.8.1.d DGs inoperable.	G ~~E~~I.1 Restore one DG to OPERABLE status.	2 hours
H ~~F~~J. One automatic load sequencer inoperable.	H ~~F~~J.1 Restore automatic load sequencer to OPERABLE status.	12 hours

One LCO 3.8.1.b DG that provides power to the shared systems inoperable and one LCO 3.8.1.d DG that provides power to the shared systems inoperable.

ACTIONS (continued)

			I	
I ~~G~~K.	Required Action and associated Completion Time of Condition A, ~~B~~C, ~~C, D, E, or~~ E, F, G, H, or ~~I, or J~~ not met. OR Required Action and associated Completion Time of Required Action B.2, B.3, B.4.1, B.4.2, or B.6 not met. OR Required Action and associated Completion Time of Required Action ~~E.2, E.3, E.4.1, E.4.2, or E.5~~ D.2, D.3, D.4.1, D.4.2, or D.6 not met.	~~G~~K.1 Be in MODE 3. AND ~~G~~K.2 Be in MODE 5. I	6 hours 36 hours
~~H~~L. J	Three or more LCO 3.8.1.a and LCO 3.8.1.b AC sources inoperable. OR Three or more LCO 3.8.1.c and LCO 3.8.1.d AC sources inoperable.	~~H~~L.1 Enter LCO 3.0.3. J	Immediately

SURVEILLANCE REQUIREMENTS

~~-----NOTE-----~~
~~SR 3.8.1.1 through SR 3.8.1.20 are only applicable to LCO 3.8.1.a and LCO 3.8.1.b AC sources. SR 3.8.1.21 is only applicable to LCO 3.8.1.c and LCO 3.8.1.d AC sources.~~
~~-----~~

	SURVEILLANCE	FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each offsite circuit.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.2	-----NOTES----- 1. Performance of SR 3.8.1.7 satisfies this SR. 2. All DG starts may be preceded by an engine prelube period and followed by a warmup period prior to loading. 3. A modified DG start involving idling and gradual acceleration to synchronous speed may be used for this SR as recommended by the manufacturer. When modified start procedures are not used, the time, voltage, and frequency tolerances of SR 3.8.1.7 must be met. ----- Verify each DG starts from standby conditions and achieves steady state voltage $\geq$ 3950 V and $\leq$ 4580 V, and frequency $\geq$ 58.8 Hz and $\leq$ 61.2 Hz.	In accordance with the Surveillance Frequency Control Program

(continued)

No changes to this page

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.20	-------------------------------------NOTE--------------------------- All DG starts may be preceded by an engine prelube period. --- Verify when started simultaneously from standby condition, each DG achieves, in ≤ 11 seconds, voltage of ≥ 3950 V and frequency of ≥ 57 Hz and maintains steady state voltage ≥ 3950 V and ≤ 4580 V, and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.21	For the LCO 3.8.1.c and LCO 3.8.1.d AC electrical sources, SR 3.8.1.1, SR 3.8.1.2, SR 3.8.1.4, SR 3.8.1.5, and SR 3.8.1.6 are required to be met.	In accordance with the Surveillance Frequency Control Program

Attachment 3

Revised Catawba Technical Specification Bases 3.8.1 Marked Up Pages

(For Information Only)

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources—Operating

BASES

BACKGROUND

The unit Essential Auxiliary Power Distribution System AC sources consist of the offsite power sources (preferred power sources, normal and alternate(s)), and the onsite standby power sources (Train A and Train B diesel generators (DGs)). As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safety Feature (ESF) systems.

The onsite Class 1E AC Distribution System is divided into redundant load groups (trains) so that the loss of any one group does not prevent the minimum safety functions from being performed. Each train has connections to two preferred offsite power sources and a single DG.

At the 600V level of the onsite Class 1E AC Distribution System, each unit has one motor control center (MCC), 1EMXG and 2EMXH, that each supply power to a train of shared systems. The term shared systems is defined as the shared components of Train A or Train B of Nuclear Service Water System (NSWS), Control Room Area Ventilation System (CRAVS), Control Room Area Chilled Water System (CRACWS) and Auxiliary Building Filtered Ventilation Exhaust System (ABFVES) whose power supply can be swapped between the Units. The MCC 1EMXG is normally aligned to receive power from load center 1ELXA but if desired or required to maintain operability of the Train A shared systems, can be swapped to receive power from load center 2ELXA. The MCC 2EMXH is normally aligned to receive power from load center 2ELXB but if desired or required to maintain operability of the Train B shared systems, can be swapped to receive power from load center 1ELXB. The four NSWS pumps (1A, 2A, 1B and 2B) are shared components that receive power at the Unit and Train specific 4160V level of the onsite Class 1E AC Distribution System and whose power supply cannot be swapped between the Units. Therefore, the four NSWS pumps are not part of the "shared systems," as defined above, because the power supply for a particular NSWS pump cannot come from the opposite unit.

There are also provisions to accommodate the connecting of the Emergency Supplemental Power Source (ESPS) to one train of either unit's Class 1E AC Distribution System. The ESPS consists of two 50% capacity non-safety related commercial grade DGs. Manual actions are

BACKGROUND (continued)

required to align the ESPS to the station and only one of the station's four onsite Class 1E Distribution System trains can be supplied by the ESPS at any given time. The ESPS is made available to support extended Completion Times in the event of an inoperable DG as well as a defense-in-depth source of AC power to mitigate a station blackout event. The ESPS would remain disconnected from the Class 1E AC Distribution System unless required for supplemental power to one of the four 4.16 kV ESF buses.

From the transmission network, two electrically and physically separated circuits provide AC power, through step down station auxiliary transformers, to the 4.16 kV ESF buses. A detailed description of the offsite power network and the circuits to the Class 1E ESF buses is found in the UFSAR, Chapter 8 (Ref. 2).

A qualified offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the onsite Class 1E ESF bus(es).

Certain required unit loads are returned to service in a predetermined sequence in order to prevent overloading the transformer supplying offsite power to the onsite Class 1E Distribution System. Within 1 minute after the initiating signal is received, all automatic and permanently connected loads needed to recover the unit or maintain it in a safe condition are returned to service via the load sequencer.

The onsite standby power source for each 4.16 kV ESF bus is a dedicated DG. DGs A and B are dedicated to ESF buses ETA and ETB, respectively. A DG starts automatically on a safety injection (SI) signal (i.e., low pressurizer pressure or high containment pressure signals) or on an ESF bus degraded voltage or undervoltage signal (refer to LCO 3.3.5, "Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation"). After the DG has started, it will automatically tie to its respective bus after offsite power is tripped as a consequence of ESF bus undervoltage or degraded voltage, independent of or coincident with an SI signal. With no SI signal, there is a 10 minute delay between degraded voltage signal and the DG start signal. The DGs will also start and operate in the standby mode without tying to the ESF bus on an SI signal alone. Following the trip of offsite power, a sequencer strips loads from the ESF bus. When the DG is tied to the ESF bus, loads are then sequentially connected to its respective ESF bus by the automatic load sequencer. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading the DG by automatic load application.

BACKGROUND (continued)

In the event of a loss of preferred power, the ESF electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a Design Basis Accident (DBA) such as a loss of coolant accident (LOCA).

Certain required unit loads are returned to service in a predetermined sequence in order to prevent overloading the DG in the process. Approximately 1 minute after the initiating signal is received, all loads needed to recover the unit or maintain it in a safe condition are returned to service.

Ratings for Train A and Train B DGs satisfy the requirements of Regulatory Guide 1.9 (Ref. 3). The continuous service rating of each DG is 7000 kW with 10% overload permissible for up to 2 hours in any 24 hour period. The ESF loads that are powered from the 4.16 kV ESF buses are listed in Reference 2.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the UFSAR, Chapter 6 (Ref. 4) and Chapter 15 (Ref. 5), assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the Accident analyses and is based upon meeting the design basis of the unit. This results in maintaining at least one train of the onsite or offsite AC sources OPERABLE during Accident conditions in the event of:

a. An assumed loss of all offsite power or all onsite AC power; and

b. A worst case single failure.

The AC sources satisfy Criterion 3 of 10 CFR 50.36 (Ref. 6).

LCO

Two qualified circuits between the offsite transmission network and the onsite Essential Auxiliary Power System and separate and independent DGs for each train ensure availability of the required power to shut down

LCO (continued)

the reactor and maintain it in a safe shutdown condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Additionally, the qualified circuit(s) between the offsite transmission network and the opposite unit onsite Essential Auxiliary Power System when necessary to power shared systems and the NSWS pump(s) and the opposite unit DG(s) when necessary to power shared systems and the NSWS pump(s) ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an AOO or a postulated DBA.

Qualified offsite circuits are those that are described in the UFSAR and are part of the licensing basis for the unit.

In addition, one required automatic load sequencer per train must be OPERABLE.

Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the ESF buses.

The 4.16 kV essential system is divided into two completely redundant and independent trains designated A and B, each consisting of one 4.16 kV switchgear assembly, three 4.16 kV/600 V transformers, two 600 V load centers, and associated loads.

Normally, each Class 1E 4.16 kV switchgear is powered from its associated non-Class 1E train of the 6.9 kV Normal Auxiliary Power System as discussed in "6.9 kV Normal Auxiliary Power System" in Chapter 8 of the UFSAR (Ref. 2). Additionally, a standby source of power to each 4.16 kV essential switchgear, not required by General Design Criterion 17, is provided from the 6.9 kV system via two separate and independent 6.9/4.16 kV transformers. These transformers are shared between units and provide the capability to supply a standby source of preferred power to each unit's 4.16 kV essential switchgear from either unit's 6.9 kV system. A key interlock scheme is provided to preclude the possibility of connecting the two units together at either the 6.9 or 4.16 kV level.

Each train of the 4.16 kV Essential Auxiliary Power System is also provided with a separate and independent emergency diesel generator to supply the Class 1E loads required to safely shut down the unit following a design basis accident. Additionally, each diesel generator is capable of supplying its associated 4.16 kV blackout switchgear through a connection with the 4.16 kV essential switchgear.

LCO (continued)

Each DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This will be accomplished within 11 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions such as DG in standby with the engine hot and DG in standby with the engine at ambient conditions. Additional DG capabilities must be demonstrated to meet required Surveillance, e.g., capability of the DG to revert to standby status on an ECCS signal while operating in parallel test mode.

Proper sequencing of loads, including tripping of nonessential loads, is a required function for DG OPERABILITY.

The AC sources in one train must be separate and independent (to the extent possible) of the AC sources in the other train. For the DGs, separation and independence are complete.

For the offsite AC sources, separation and independence are provided to the extent practical.

LCO 3.8.1.c and LCO 3.8.1.d both use the word “necessary” to clarify that the qualified offsite circuit(s) in LCO 3.8.1.c and the DG(s) from the opposite unit in LCO 3.8.1.d are required to shut down the reactor and maintain it in a safe shutdown condition after an AOO or a postulated DBA.

LCO 3.8.1.c specifies that the qualified circuit(s) between the offsite transmission network and the opposite unit’s Onsite Essential Auxiliary Power System be OPERABLE when necessary to supply power to the shared systems and NSWS pump(s). LCO 3.8.1.d specifies that the DG(s) from the opposite unit be OPERABLE when necessary to supply power to the shared systems and NSWS pump(s). The LCO 3.8.1.c AC sources in one train must be separate and independent (to the extent possible) of the LCO 3.8.1.c AC sources in the other train. These requirements, in conjunction with the requirements for the applicable unit AC electrical power sources in LCO 3.8.1.a and LCO 3.8.1.b, ensure that power is available to two trains of the shared NSWS, CRAVS, CRACWS and ABFVES, as well as to the NSWS pump(s).

With no equipment inoperable, two LCO 3.8.1.c AC sources are required to be OPERABLE and two LCO 3.8.1.d AC sources are required to be OPERABLE for each unit. For example, with both units in MODE 1, Unit 1 LCO 3.8.1.c is met by an OPERABLE 2A offsite circuit and an

LCO (continued)

OPERABLE 2B offsite circuit. LCO 3.8.1.d is met by an OPERABLE 2A DG and an OPERABLE 2B DG. In a normal plant alignment, the 2A offsite circuit and the 2A DG are relied upon as the normal and emergency power supplies for the 2A NSWS Pump, a shared component. The 2B offsite circuit and the 2B DG are relied upon as the normal and emergency power supplies for the 2B NSWS Pump, a shared component, as well as the Train B shared systems that are powered at the 600V level of the onsite Class 1E AC Distribution System. For Unit 2, LCO 3.8.1.c is met by an OPERABLE 1A offsite circuit and an OPERABLE 1B offsite circuit. LCO 3.8.1.d is met by an OPERABLE 1A DG and an OPERABLE 1B DG. In a normal plant alignment, the 1A offsite circuit and the 1A DG are relied upon as the normal and emergency power supplies for the 1A NSWS Pump, a shared component, as well as the Train A shared systems that are powered at the 600V level of the onsite Class 1E AC Distribution System. The 1B offsite circuit and the 1B DG are relied upon as the normal and emergency power supplies for the 1B NSWS Pump, shared component.

APPLICABILITY

The AC sources and sequencers are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

A Note has been added taking exception to the Applicability requirements for the required AC sources in LCO 3.8.1.c and LCO 3.8.1.d provided the associated shared systems and NSWS pump(s) are inoperable. This exception is intended to allow declaring the shared systems and NSWS pump(s) supported by the opposite unit inoperable either in lieu of declaring the opposite unit AC sources inoperable, or at any time subsequent to entering ACTIONS for an inoperable opposite unit AC source.

This exception is acceptable since, with the shared systems and NSWS pump(s) supported by the opposite unit inoperable and the associated ACTIONS entered, the opposite unit AC sources provide no additional assurance of meeting the above criteria.

APPLICABILITY (continued)

The AC power requirements for MODES 5 and 6 are covered in LCO 3.8.2, "AC Sources—Shutdown."

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable DG. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable DG 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.

~~When entering Required Actions for inoperable offsite circuit(s) and/or DG(s), it is also necessary to enter the applicable Required Actions of any shared systems LCOs when either normal or emergency power to shared components governed by these LCOs becomes inoperable. These LCOs include 3.7.8, “Nuclear Service Water System (NSWS)”; 3.7.10, “Control Room Area Ventilation System (CRAVS)”; 3.7.11, “Control Room Area Chilled Water System (CRACWS)”; and 3.7.12, “Auxiliary Building Filtered Ventilation Exhaust System (ABFVES)”.~~

A.1

To ensure a highly reliable power source remains with one LCO 3.8.1.a offsite circuit inoperable, it is necessary to verify the OPERABILITY of the remaining required 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 not met. However, if a second required circuit fails SR 3.8.1.1, the second offsite circuit is inoperable, and Condition ~~C~~E, for two offsite circuits inoperable, is entered.

A.2

Required Action A.2, which only applies if the train cannot be powered from an offsite source, is intended to provide assurance that an event coincident with a single failure of the associated DG will not result in a complete loss of safety function of critical redundant required features.

ACTIONS (continued)

These features are powered from the redundant AC electrical power train. This includes motor driven auxiliary feedwater pumps. The turbine driven auxiliary feedwater pump is required to be considered a redundant required feature, and, therefore, required to be determined OPERABLE by this Required Action. Three independent AFW pumps are required to ensure the availability of decay heat removal capability for all events accompanied by a loss of offsite power and a single failure. System design is such that the remaining OPERABLE motor driven auxiliary feedwater pump is not by itself capable of providing 100% of the auxiliary feedwater flow assumed in the safety analysis.

The Completion Time for Required Action A.2 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. The train has no offsite power supplying it loads; and

b. A required feature on the other train is inoperable.

If at any time during the existence of Condition A (one LCO 3.8.1.a offsite circuit inoperable) a redundant required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

Discovering no offsite power to one train of the onsite Class 1E Electrical Power Distribution System coincident with one or more inoperable required support or supported features, or both, that are associated with the other train that has offsite power, results in starting the Completion Times for the Required Action. 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 circuits 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

According to Regulatory Guide 1.93 (Ref. 7), operation may continue in

ACTIONS (continued)

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.

The second Completion Time for Required Action A.3 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet ~~the LCO~~LCO 3.8.1.a or LCO 3.8.1.b. If Condition A is entered while, for instance, a LCO 3.8.1.b DG is inoperable and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to ~~72 hours~~14 days. This could lead to a total of ~~144 hours~~17 days, since initial failure to meet ~~the LCO~~LCO 3.8.1.a or LCO 3.8.1.b, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional ~~72 hours~~14 days (for a total of ~~9~~ 31 days) allowed prior to complete restoration of ~~the LCO~~LCOs 3.8.1.a and 3.8.1.b. The ~~6~~ 17 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet ~~the LCO~~LCO 3.8.1.a or LCO 3.8.1.b. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and ~~6~~ 17 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action A.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time that ~~the LCO~~LCO 3.8.1.a or LCO 3.8.1.b was initially not met, instead of at the time Condition A was entered.

B.1

It is required to administratively verify the LCO 3.8.1.d DG(s) OPERABLE within 1 hour and to continue this action once per 12 hours thereafter until restoration of the required LCO 3.8.1.b DG is accomplished. This verification provides assurance that the LCO 3.8.1.d DG is capable of supplying the onsite Class 1E AC Electrical Power Distribution System.

ACTIONS (continued)

If one LCO 3.8.1.d DG is discovered to be inoperable when performing the administrative verification of operability, then Condition D is entered for that DG. If two LCO 3.8.1.d DGs are discovered to be inoperable when performing the administrative verification of operability, then Condition G is entered.

B.~~1~~2

To ensure a highly reliable power source remains with an inoperable LCO 3.8.1.b DG, it is necessary to verify the availability of the required 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.

B.~~2~~3

Required Action B.~~2~~ 3 is intended to provide assurance that a loss of offsite power, during the period that a LCO 3.8.1.b DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related trains. This includes motor driven auxiliary feedwater pumps. The turbine driven auxiliary feedwater pump is required to be considered a redundant required feature, and, therefore, required to be determined OPERABLE by this Required Action. Three independent AFW pumps are required to ensure the availability of decay heat removal capability for all events accompanied by a loss of offsite power and a single failure. System design is such that the remaining OPERABLE motor driven auxiliary feedwater pump is not by itself capable of providing 100% of the auxiliary feedwater flow assumed in the safety analysis. Redundant required feature failures consist of inoperable features associated with a train, redundant to the train that has an inoperable LCO 3.8.1.b DG.

The Completion Time for Required Action B.~~2~~ 3 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. An inoperable LCO 3.8.1.b DG exists; and

b. A required feature on the other train (Train A or Train B) is inoperable.

ACTIONS (continued)

If at any time during the existence of this Condition (one LCO 3.8.1.b DG inoperable) a required feature subsequently becomes inoperable, this Completion Time would begin to be tracked.

Discovering one required LCO 3.8.1.b DG inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with the OPERABLE DG, results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is Acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

In this Condition, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 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.

B.~~3~~4.1 and B.~~3~~4.2

Required Action B.~~3~~4.1 provides an allowance to avoid unnecessary testing of OPERABLE DG(s). 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 other DG(s), the other DG(s) would be declared inoperable upon discovery and Condition ~~E~~D and/or ~~I~~G of LCO 3.8.1, as applicable, would be entered. Once the failure is repaired, the common cause failure no longer exists, and Required Action B.~~3~~4.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG(s), 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~~4.1 or B.~~3~~4.2, the problem investigation process 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.

These Conditions are not required to be entered if the inoperability of the DG is due to an inoperable support system, an independently testable component, or preplanned testing or maintenance. If required, these

ACTIONS (continued)

Required Actions are to be completed regardless of when the inoperable DG is restored to OPERABLE status.

According to Generic Letter 84-15 (Ref. 8), 24 hours is reasonable to confirm that the OPERABLE DG(s) is not affected by the same problem as the inoperable DG.

B.5

In order to extend the Completion Time for an inoperable DG from 72 hours to 14 days, it is necessary to ensure the availability of the ESPS within 1 hour of entry into TS 3.8.1 LCO and every 12 hours thereafter.

Since Required Action B.5 only specifies "evaluate," discovering the ESPS unavailable does not result in the Required Action being not met (i.e. the evaluation is performed). However, on discovery of an unavailable ESPS, the Completion Time for Required Action B.6 starts the 72 hour and/or 24 hour clock.

ESPS availability requires that:

1) The load test has been performed within 30 days of entry into the extended Completion Time. The Required Action evaluation is met with an administrative verification of this prior to testing; and

2) ESPS fuel tank level is verified locally to be ≥ 24 hour supply; and

3) ESPS supporting system parameters for starting and operating are verified to be within required limits for functional availability (e.g., battery state of charge).

The ESPS is not used to extend the Completion Time for more than one inoperable DG at any one time.

~~B.4~~B.6

~~According to Regulatory Guide 1.93 (Ref. 7), operation may continue in Condition B for a period that should not exceed 72 hours.~~
In accordance with Branch Technical Position 8-8 (Ref. 14), operation may continue in Condition B for a period that should not exceed 14 days, provided a supplemental AC power source is available.

In Condition B, the remaining OPERABLE DGs, available ESPS and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The ~~72 hour~~14 day Completion Time

ACTIONS (continued)

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.

If the ESPS is or becomes unavailable with an inoperable LCO 3.8.1.b DG, then action is required to restore the ESPS to available status or to restore the DG to OPERABLE status within 72 hours from discovery of unavailable ESPS. However, if the ESPS unavailability occurs at or sometime after 48 hours of continuous LCO 3.8.1.b DG inoperability, then the remaining time to restore the ESPS to available status or to restore the DG to OPERABLE status is limited to 24 hours.

The 72 hour and 24 hour Completion Times allow for an exception to the normal “time zero” for beginning the allowed outage time “clock.” The 72 hour Completion Time only begins on discovery that both:

a. An inoperable DG exists; and
b. ESPS is unavailable.

The 24 hour Completion Time only begins on discovery that:

a. An inoperable DG exists for ≥ 48 hours; and
b. ESPS is unavailable.

Therefore, when one LCO 3.8.1.b DG is inoperable due to either preplanned maintenance (preventive or corrective) or unplanned corrective maintenance work, the Completion Time can be extended from 72 hours to 14 days if ESPS is verified available for backup operation.

The ~~second~~ fourth Completion Time for Required Action B.~~4~~ 6 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet ~~the LCO~~LCO 3.8.1.a or LCO 3.8.1.b. If Condition B is entered while, for instance, ~~an~~ a LCO 3.8.1.a offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 72 hours. This could lead to a total of ~~144 hours~~17 days, since initial failure to meet ~~the LCO~~LCO 3.8.1.a or LCO 3.8.1.b, to restore the DG. At this time, ~~an~~ a LCO 3.8.1.a offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of ~~9~~ 20 days) allowed prior to complete restoration of ~~the LCO~~LCO 3.8.1.a and LCO 3.8.1.b. The ~~6~~ 17 day Completion Time provides a limit on time allowed in a specified condition after discovery of failure to meet ~~the LCO~~LCO 3.8.1.a or LCO 3.8.1.b. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector

ACTIONS (continued)

between the ~~72 hour~~14 day and ~~6~~ 17 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action B.~~2~~3, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed time "clock." This will result in establishing the "time zero" at the time that ~~the LCO~~LCO 3.8.1.a or LCO 3.8.1.b was initially not met, instead of at the time Condition B was entered.

C.1

Condition C addresses the inoperability of the LCO 3.8.1.c qualified offsite circuit(s) between the offsite transmission network and the opposite unit's Onsite Essential Auxiliary Power System when the LCO 3.8.1.c qualified offsite circuit(s) is necessary to supply power to the shared systems and NSWS pump(s). If Condition C is entered concurrently with the inoperability of LCO 3.8.1.d DG(s) the NOTE requires the licensed operator to evaluate if the TS 3.8.9 "Distribution Systems – Operating" requirement that "OPERABLE AC electrical power distribution subsystems require the associated buses, load centers, motor control centers, and distribution panels to be energized to their proper voltages" continues to be met. In the case where the inoperable LCO 3.8.1.c qualified offsite circuit and inoperable LCO 3.8.1.d DG are associated with the same train there is no longer assurance that train of "Distribution Systems – Operating" can be energized to the proper voltage and therefore TS 3.8.9 Condition A must be entered.

To ensure a highly reliable power source remains with one required LCO 3.8.1.c offsite circuit inoperable, it is necessary to verify the OPERABILITY of the remaining required 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 not met. However, if a second required circuit fails SR 3.8.1.1, the second offsite circuit is inoperable, and Condition A and E, as applicable, for the two offsite circuits inoperable, is entered.

C.2

Required Action C.2, which only applies if the train cannot be powered from an offsite source, is intended to provide assurance that an event coincident with a single failure of the associated DG will not result in a complete loss of safety function for the NSWS, CRAVS, CRACWS or the ABFVES. The Completion Time for Required Action C.2 is intended to allow the operator time to evaluate and repair any discovered

ACTIONS (continued)

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. The train has no offsite power supplying its loads: and

b. NSWS, CRAVS, CRACWS or ABFVES on the other train that has offsite power is inoperable.

If at any time during the existence of Condition C (one required LCO 3.8.1.c offsite circuit inoperable) a train of NSWS, CRAVS, CRACWS or ABFVES becomes inoperable, this Completion Time begins to be tracked.

Discovering no offsite power to one train of the onsite Class 1E Electrical Power Distribution System coincident with one train of NSWS, CRAVS, CRACWS or ABFVES that is associated with the other train that has offsite power, results in starting the Completion Times for the Required Action. 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 circuits 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 NSWS, CRAVS, CRACWS or ABFVES. 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.

C.3

Consistent with the time provided in ACTION A, operation may continue in Condition C for a period that should not exceed 72 hours. With one required LCO 3.8.1.c 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 circuits and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System.

If the LCO 3.8.1.c required offsite circuit cannot be restored to OPERABLE status within 72 hours, then Condition I must be entered immediately.

ACTIONS (continued)

D.1

Condition D addresses the inoperability of the LCO 3.8.1.d DG(s) aligned to the opposite unit Onsite Essential Auxiliary Power System that is supplying power to a train of shared systems and to the respective NSWS pump(s). If Condition D is entered concurrently with the inoperability of LCO 3.8.1.c qualified offsite circuit, the NOTE requires the licensed operator to evaluate if the TS 3.8.9 “Distribution Systems – Operating” requirement that “OPERABLE AC electrical power distribution subsystems require the associated buses, load centers, motor control centers, and distribution panels to be energized to their proper voltages” continues to be met. In the case where the inoperable LCO 3.8.1.d DG and inoperable LCO 3.8.1.c qualified offsite circuit are associated with the same train there is no longer assurance that train of “Distribution Systems – Operating” can be energized to the proper voltage and therefore TS 3.8.9 Condition A must be entered.

It is required to administratively verify the LCO 3.8.1.b safety-related DGs OPERABLE and the opposite unit’s DG OPERABLE within one hour and to continue this action once per 12 hours thereafter until restoration of the required LCO 3.8.1.d DG and the opposite unit’s DG is accomplished. This verification provides assurance that the LCO 3.8.1.b safety-related DGs and the opposite unit’s DG is capable of supplying the onsite Class 1E AC Electrical Power Distribution System.

If one LCO 3.8.1.b DG is discovered to be inoperable when performing the administrative verification of operability, then Condition B is entered for that DG. If two LCO 3.8.1.b DGs are discovered to be inoperable, then Condition G is entered. If one LCO 3.8.1.b DG that provides power to shared systems is discovered inoperable and the LCO 3.8.1.d DG that was initially inoperable provides power to shared systems, then Condition G is also entered. If one LCO 3.8.1.b DG that provides power to shared systems is discovered inoperable and the LCO 3.8.1.d DG that was initially inoperable only provides power to its respective NSWS pump, then Condition B is entered for the LCO 3.8.1.b DG.

If the second LCO 3.8.1.d DG, which is the other opposite unit’s DG, is found to be inoperable when performing the administrative verification of operability, then Condition G is entered.

D.2

To ensure a highly reliable power source remains with one required LCO 3.8.1.d DG inoperable, it is necessary to verify the OPERABILITY of the required offsite circuits on a more frequent basis. Since the Required

ACTIONS (continued)

Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action 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.

D.3

Required Action D.3 is intended to provide assurance that a loss of offsite power, during the period one required LCO 3.8.1.d DG is inoperable, does not result in a complete loss of safety function for the NSWS, CRAVS, CRACWS or the ABFVES. The Completion Time 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. An inoperable LCO 3.8.1.d DG exists; and

b. NSWS, CRAVS, CRACWS or ABFVES on the other train that has emergency power is inoperable.

If at any time during the existence of this Condition (the LCO 3.8.1.d DG inoperable) a train of NSWS, CRAVS, CRACWS or ABFVES becomes inoperable, this Completion Time begins to be tracked.

Discovering the LCO 3.8.1.d DG inoperable coincident with one train of NSWS, CRAVS, CRACWS or ABFVES that is associated with the other train that has emergency power results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

In this Condition, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the NSWS, CRAVS, CRACWS or ABFVES may have been lost; however, function has not been lost. The four hour Completion Time also takes into account the capacity and capability of the remaining NSWS, CRAVS, CRACWS and ABFVES train, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

D.4.1 and D.4.2

Required Action D.4.1 provides an allowance to avoid unnecessary

ACTIONS (continued)

testing of OPERABLE DGs. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG(s), SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on other DG(s), the other DG(s) would be declared inoperable upon discovery and Condition B and I of LCO 3.8.1, as applicable, would be entered. Once the failure is repaired, the common cause failure no longer exists and Required Action D.4.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG(s), performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of the DG(s).

In the event the inoperable DG is restored to OPERABLE status prior to completing either D.4.1 or D.4.2, the problem investigation process will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition D.

According to Generic Letter 84-15 (Ref. 8), 24 hours is reasonable to confirm that the OPERABLE DG(s) is not affected by the same problem as the inoperable DG.

D.5

In order to extend the Completion Time for an inoperable DG from 72 hours to 14 days, it is necessary to ensure the availability of the ESPS within 1 hour of entry into TS 3.8.1 LCO and every 12 hours thereafter.

Since Required Action D.5 only specifies “evaluate,” discovering the ESPS unavailable does not result in the Required Action being not met (i.e. the evaluation is performed). However, on discovery of an unavailable ESPS, the Completion Time for Required Action D.6 starts the 72 hour and/or 24 hour clock.

ESPS availability requires that:

1) The load test has been performed within 30 days of entry into the extended Completion Time. The Required Action evaluation is met with an administrative verification of this prior to testing; and

2) ESPS fuel tank level is verified locally to be ≥ 24 hour supply; and

3) ESPS supporting system parameters for starting and operating are verified to be within required limits for functional availability (e.g., battery state of charge).

ACTIONS (continued)

The ESPS is not used to extend the Completion Time for more than one inoperable DG at any one time.

D.6

In accordance with Branch Technical Position 8-8 (Ref. 14), operation may continue in Condition D for a period that should not exceed 14 days, provided a supplemental AC power source is available.

In Condition D, the remaining OPERABLE DGs, unavailable ESPS, and offsite power circuits are adequate to supply electrical power to the Class 1E Distribution System. The 14 day 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.

If the ESPS is or becomes unavailable with an inoperable LCO 3.8.1.d DG, then action is required to restore the ESPS to available status or to restore the DG to OPERABLE status within 72 hours from discovery of unavailable ESPS. However, if the ESPS unavailability occurs at or sometime after 48 hours of continuous LCO 3.8.1.d DG inoperability, then the remaining time to restore the ESPS to available status or to restore the DG to OPERABLE status is limited to 24 hours.

The 72 hour and 24 hour Completion Times allow for an exception to the normal “time zero” for beginning the allowed outage time “clock.” The 72 hour Completion Time only begins on discovery that both:

a. An inoperable DG exists; and
b. ESPS is unavailable.

The 24 hour Completion Time only begins on discovery that:

a. An inoperable DG exists for ≥ 48 hours; and
b. ESPS is unavailable.

Therefore, when one LCO 3.8.1.d DG is inoperable due to either preplanned maintenance (preventive or corrective) or unplanned corrective maintenance work, the Completion Time can be extended from 72 hours to 14 days if ESPS is verified available for backup operation.

The fourth Completion Time for Required Action D.6 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet LCO 3.8.1.c or LCO 3.8.1.d. If Condition D is entered

ACTIONS (continued)

while, for instance, a LCO 3.8.1.c offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 72 hours. This could lead to a total of 17 days, since initial failure to meet LCO 3.8.1.c or LCO 3.8.1.d, to restore the DG. At this time, a LCO 3.8.1.c offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of 20 days) allowed prior to complete restoration of LCO 3.8.1.c and LCO 3.8.1.d. The 17 day Completion Time provides a limit on time allowed in a specified condition after discovery of failure to meet LCO 3.8.1.c or LCO 3.8.1.d. This limit is considered reasonable for situations in which Conditions C and D are entered concurrently. The "AND" connector between the 14 day and 17 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

~~C~~E.1 and ~~C~~E.2

Condition E is entered when both offsite circuits required by LCO 3.8.1.a are inoperable, or when the offsite circuit required by LCO 3.8.1.c and one offsite circuit required by LCO 3.8.1.a are concurrently inoperable. Condition E is also entered when two offsite circuits required by LCO 3.8.1.c are inoperable.

Required Action ~~C~~E.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. 7) 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 motor driven auxiliary feedwater pumps. Single train features, such as turbine driven auxiliary pumps, are not included in the list.

The Completion Time for Required Action ~~C~~E.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:

ACTIONS (continued)

a. All required offsite circuits are inoperable; and

b. A required feature is inoperable.

If at any time during the existence of Condition ~~C~~ E (two LCO 3.8.1.a offsite circuits inoperable or one LCO 3.8.1.a offsite circuit and one LCO 3.8.1.c offsite circuit inoperable or two LCO 3.8.1.c offsite circuits inoperable) a required feature becomes inoperable, this Completion Time begins to be tracked.

According to Regulatory Guide 1.93 (Ref. 7), operation may continue in Condition ~~C~~ E 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 affect 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

ACTIONS (continued)

operation continues in accordance with Condition A or C, as applicable.

~~D~~F.1 and ~~D~~F.2

Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it were inoperable, resulting in de-energization. Therefore, the Required Actions of Condition ~~D~~ F are modified by a Note to indicate that when Condition ~~D~~ F is entered with no AC source to any train, the Conditions and Required Actions for LCO 3.8.9, "Distribution Systems—Operating," must be immediately entered. This allows Condition ~~D~~ F to provide requirements for the loss of one offsite circuit and one DG, without regard to whether a train is de-energized. LCO 3.8.9 provides the appropriate restrictions for a de-energized train.

According to Regulatory Guide 1.93 (Ref. 7), operation may continue in Condition ~~D~~ F for a period that should not exceed 12 hours.

In Condition ~~D~~F, 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~~ E (loss of ~~both~~ two 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.

~~E~~G.1

With ~~Train A and Train B DGs~~two LCO 3.8.1.b DGs inoperable, there are no remaining standby AC sources to provide power to most of the ESF systems. With one LCO 3.8.1.b DG that provides power to the shared systems inoperable and one LCO 3.8.1.d DG that provides power to the shared systems inoperable, there are no remaining standby AC sources to the shared systems. Also, with two DGs required by LCO 3.8.1.d inoperable, there are no remaining standby AC sources to the two opposite unit NSWS pump(s) and at least one train of shared systems. 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

ACTIONS (continued)

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 7, with both LCO 3.8.1.b DGs inoperable, with one LCO 3.8.1.b DG that provides power to the shared systems and one LCO 3.8.1.d DG that provides power to the shared systems inoperable, or with two DGs required by LCO 3.8.1.d inoperable, operation may continue for a period that should not exceed 2 hours.

~~F~~H.1

The 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. When a sequencer is inoperable, its associated unit and train related offsite circuit and DG must also be declared inoperable and their corresponding Conditions must also be entered. The 12 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.

~~G~~I.1 and ~~G~~I.2

~~If the inoperable AC electric power sources cannot be restored to OPERABLE status within the required Completion Time,~~If any Required Action and associated Completion Time of Conditions A, C, F, G, or H are not met, the unit must be brought to a MODE in which the LCO does not apply. Furthermore, if any Required Action and associated Completion Time of Required Actions B.2, B.3, B.4.1, B.4.2, B.6, D.2, D.3, D.4.1, D.4.2, and D.6 are not met, 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.

ACTIONS (continued)

~~H~~J.1

Condition ~~H~~J corresponds to a level of degradation in which all redundancy in ~~the~~ LCO 3.8.1.a and LCO 3.8.1.b AC electrical power supplies has been lost or in which all redundancy in LCO 3.8.1.c and LCO 3.8.1.d 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.

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, Appendix A, GDC 18 (Ref. 9). Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The SRs for demonstrating the OPERABILITY of the DGs are in accordance with the recommendations of Regulatory Guide 1.9 (Ref. 3), Regulatory Guide 1.108 (Ref. 10), and Regulatory Guide 1.137 (Ref. 11), as addressed in the UFSAR.

Where the SRs discussed herein specify voltage and frequency tolerances, the following is applicable. The minimum steady state output voltage of 3950 V is 95% of the nominal 4160 V output voltage. This value allows for voltage drop to the terminals of 4000 V motors whose minimum operating voltage is specified as 90% or 3600 V. It also allows for voltage drops to motors and other equipment down through the 120 V level where minimum operating voltage is also usually specified as 90% of name plate rating.

The specified maximum steady state output voltage of 4580 V is equal to the maximum operating voltage specified for 4000 V motors. It ensures that for a lightly loaded distribution system, the voltage at the terminals of 4000 V motors is no more than the maximum rated operating voltages. The specified minimum and maximum frequencies of the DG are 58.8 Hz and 61.2 Hz, respectively. These values are equal to ± 2% of the 60 Hz nominal frequency and are derived from the recommendations given in Regulatory Guide 1.9 (Ref. 3).

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.

2. UFSAR, Chapter 8.

3. Regulatory Guide 1.9, Rev. 2, December 1979.

4. UFSAR, Chapter 6.

5. UFSAR, Chapter 15.

6. 10 CFR 50.36, Technical Specifications, (c)(2)(ii).

7. Regulatory Guide 1.93, Rev. 0, December 1974.

8. Generic Letter 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," July 2, 1984.

9. 10 CFR 50, Appendix A, GDC 18.

10. Regulatory Guide 1.108, Rev. 1, August 1977 (Supplement September 1977).

11. Regulatory Guide 1.137, Rev. 1, October 1979.

12. ASME, Boiler and Pressure Vessel Code, Section XI.

13. Response to a Request for Additional Information (RAI) concerning the June 5, 2006 License Amendment Request (LAR) Applicable to Technical Specification (TS) 3.8.1, “AC Sources-Operating,” Surveillance Requirement (SR) 3.8.1.13, (TAC NOS. MD3217, MD3218, MD3219, and MD3220), April 4, 2007.

14. Branch Technical Position 8-8, February 2012.

Attachment 4

Regulatory Commitments

Catawba Nuclear Station, Units 1 and 2

The following table identifies the regulatory commitments in this document by Duke Energy Carolinas, LLC (Duke Energy) for the Catawba Nuclear Station, Units 1 and 2. Any other statements in this submittal represent intended or planned actions, and are provided for information purposes. They are not considered to be regulatory commitments.

COMMITMENT	TYPE		SCHEDULED COMPLETION DATE
	One-time	Continuing Compliance	
1. The preplanned diesel generator (DG) maintenance will not be scheduled if severe weather conditions are anticipated. Weather conditions will be evaluated prior to intentionally entering the extended DG Completion Time (CT) and will not be entered if official weather forecasts are predicting severe weather conditions (i.e., thunderstorm, tornado or hurricane warnings). Operators will monitor weather forecasts each shift during the extended DG CT. If severe weather or grid instability is expected after a DG outage begins, station managers will assess the conditions and determine the best course for returning the DG to operable status.		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.
2. Component testing or maintenance of safety systems and important non-safety equipment in the offsite power systems that can increase the likelihood of a plant transient (unit trip) or loss of offsite power (LOOP) will be avoided during the extended DG CT.		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.

3. No discretionary switchyard maintenance will be performed during the extended DG CT.		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.
4. The turbine-driven auxiliary feed water pump will not be removed from service for elective maintenance activities during the extended CT. The turbine-driven auxiliary feed water pump will be controlled as “protected equipment” during the extended DG CT. The Non-CT EDGs, ESPS, Component Cooling System, Safe Shutdown Facility, Nuclear Service Water System, motor driven auxiliary feed water pumps, and the switchyard will also be controlled as “protected equipment.” (license condition)		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.
5. During the extended DG CT, the Emergency Supplemental Power Source (ESPS) will be routinely monitored during operator rounds, with monitoring criteria identified in the operator rounds. The ESPS will be monitored for fire hazards during operator rounds.		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.
6. Licensed Operators and Auxiliary Operators will be trained on the purpose and use of the ESPS and the revised emergency procedure (EP) actions. Personnel performing maintenance on the ESPS will be trained.		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.

7. The system load dispatcher will be contacted once per day to ensure no significant grid perturbations (high grid loading unable to withstand a single contingency of line or generation outage) are expected during the extended DG CT.		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.
8. TS required systems, subsystems, trains, components and devices that depend on the remaining power sources will be verified to be operable and positive measures will be provided to preclude subsequent testing or maintenance activities on these systems, subsystems, trains, components and devices during the extended DG CT.		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.
9. Prior to entering the extended CT for an inoperable DG on one unit, when both units are in the TS 3.8.1 Modes of APPLICABILITY, the station will ensure that the shared systems are powered by an operable Class 1E AC Distribution System with an operable DG, from opposite units.		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.
10. The risk estimates associated with the 14-day EDG Completion Time LAR (including those results of associated sensitivity studies) will be updated, as necessary to incorporate the as-built, as-operated ESPS modification. Duke Energy will confirm that any updated risk estimates continue to meet the risk acceptance guidelines of RG 1.174 and RG 1.177. (license condition)	X		Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.

Attachment 5

Markup of Proposed Renewed Facility Operating License

CNS Unit 1

Amendment Number	Additional Condition		Implementation Date
250	Upon implementation of the Amendment adopting TSTF-448, Rev. 3, the determination of CRE unfiltered air inleakage as required by SR 3.7.10.4, in accordance with Technical Specification 5.5.16.c(i), the assessment of CRE habitability as required by Technical Specification 5.5.16.c.(ii), and the measurement of CRE pressure as required by Technical Specification 5.5.16.d, shall be met. Following implementation: (a) The first performance of SR 3.7.10.4 in accordance with Technical Specification 5.5.16.c(i) shall be within the specified Frequency of 6 years, plus the 18 month allowance of SR 3.0.2, as measured from November 12, 2002, the date of the most recent successful tracer gas test, as stated in the December 9, 2003 letter response to Generic Letter (GL) 2003-01, or within the next 18 months if the time period since the most recent successful tracer gas test is greater than 6 years. (b) The first performance of the periodic assessment of CRE habitability, Technical Specification 5.5.16.c(ii), shall be within 3 years, plus the 9 month allowance of SR 3.0.2 as measured from November 12, 2002, the date of the most recent successful tracer gas test, as stated in the December 9, 2003 letter response to GL 2003-01, or within the next 9 months if the time period since the most recent successful tracer gas test is greater than 3 years. (c) The first performance of the periodic measurement of CRE pressure, Technical Specification 5.5.16.d, shall be within 18 months, plus the 138 days allowed by SR 3.0.2, as measured from September 1, 2007, the date of the most recent successful pressure measurement test, or within 138 days if not performed previously.		Within 60 days of date of amendment

Insert 1

Insert 1

Amendment Number	Additional Conditions	Implementation Date
NNN	During the extended DG Completion Times authorized by Amendment No. [NNN], the turbine-driven auxiliary feed water pump will not be removed from service for elective maintenance activities. The turbine-driven auxiliary feed water pump will be controlled as “protected equipment” during the extended DG CT. The Non-CT EDGs, ESPS, Component Cooling System, Safe Shutdown Facility, Nuclear Service Water System, motor driven auxiliary feed water pumps, and the switchyard will also be controlled as “protected equipment.”	Upon implementation of Amendment No. [NNN].
NNN	The risk estimates associated with the 14-day EDG Completion Time LAR (including those results of associated sensitivity studies) will be updated, as necessary to incorporate the as-built, as-operated ESPS modification. Duke Energy will confirm that any updated risk estimates continue to meet the risk acceptance guidelines of RG 1.174 and RG 1.177.	Upon implementation of Amendment No. [NNN].

Attachment 6

Markup of Proposed Renewed Facility Operating License

CNS Unit 2

Amendment Number	Additional Condition		Implementation Date
245	Upon implementation of the Amendment adopting TSTF-448, Rev. 3, the determination of CRE unfiltered air inleakage as required by SR 3.7.10.4, in accordance with Technical Specification 5.5.16.c(i), the assessment of CRE habitability as required by Technical Specification 5.5.16.c.(ii), and the measurement of CRE pressure as required by Technical Specification 5.5.16.d, shall be met. Following implementation: (a) The first performance of SR 3.7.10.4 in accordance with Technical Specification 5.5.16.c(i) shall be within the specified Frequency of 6 years, plus the 18 month allowance of SR 3.0.2, as measured from November 12, 2002, the date of the most recent successful tracer gas test, as stated in the December 9, 2003 letter response to Generic Letter (GL) 2003-01, or within the next 18 months if the time period since the most recent successful tracer gas test is greater than 6 years. (b) The first performance of the periodic assessment of CRE habitability, Technical Specification 5.5.16.c(ii), shall be within 3 years, plus the 9 month allowance of SR 3.0.2 as measured from November 12, 2002, the date of the most recent successful tracer gas test, as stated in the December 9, 2003 letter response to GL 2003-01, or within the next 9 months if the time period since the most recent successful tracer gas test is greater than 3 years. (c) The first performance of the periodic measurement of CRE pressure, Technical Specification 5.5.16.d, shall be within 18 months, plus the 138 days allowed by SR 3.0.2, as measured from September 1, 2007, the date of the most recent successful pressure measurement test, or within 138 days if not performed previously.		Within 60 days of date of amendment

Insert 2

Insert 2

Amendment Number	Additional Conditions	Implementation Date
SSS	During the extended DG Completion Times authorized by Amendment No. [SSS], the turbine-driven auxiliary feed water pump will not be removed from service for elective maintenance activities. The turbine-driven auxiliary feed water pump will be controlled as "protected equipment" during the extended DG CT. The Non-CT EDGs, ESPS, Component Cooling System, Safe Shutdown Facility, Nuclear Service Water System, motor driven auxiliary feed water pumps, and the switchyard will also be controlled as "protected equipment."	Upon implementation of Amendment No. [SSS].
SSS	The risk estimates associated with the 14-day EDG Completion Time LAR (including those results of associated sensitivity studies) will be updated, as necessary to incorporate the as-built, as-operated ESPS modification. Duke Energy will confirm that any updated risk estimates continue to meet the risk acceptance guidelines of RG 1.174 and RG 1.177.	Upon implementation of Amendment No. [SSS].

Attachment 7

McGuire Nuclear Station Supplemental Information

Duke Energy Response to McGuire RAI-22.c.01 – Additional Model Changes

The model used for the ESPS RAI 14 response development included changes from the updated model of record, as well as minor refinements to ensure that the ESPS system was properly credited for mitigation capabilities. The risk reductions were a result of the model of record changes. The model changes between the two models of records (for internal events, high winds and internal flooding) were:

1) Number of demands for Primary PORVs and Primary Safeties adjusted for simple overpressure events
2) HRA dependencies for six combinations updated to account for less than complete dependence of human action for SSF initiation and human action for cooldown and depressurization during an SBO
3) Invalid failure mode for Primary PORVs removed.

In addition, minor refinements were made to ensure ESPS was properly credited:

Model Changes for Refinement of ESPS Credit

Gate	Change	Reason for Change
H1B, No NV Injection Flow From NV Train 1B	• Replicated subtree H12B. Named the new subtree "H12B-E". • Inputs to H12B-E are the same as for H12B except that gate H12B-E has H18B-E as an input instead of H18B • Inputs to H18B-E are the same as for H18B except that gate H18B-E has H32B-E as an input instead of H32B • Inputs to H32B-E are the same as for H32B except that gate H32B-E has H33B-E as an input instead of H33B • Inputs to H33B-E are the same as for H33B except that gate H33B-E has P1ETB-ESPS as an input instead of P1ETB • Locally deleted gate H12B as an input to gate H12	This gate supports Safety Injection from the NV system. (Initiators for which ESPS credit is not feasible are excluded by gate JESPS-INITSWOC, Initiators for which ESPS power cannot be credited due to timing concerns.)
YFNVB, Safety Injection From NV-B System Fails	• Added gate H12B-E as an input • Locally deleted gate H12B as an input	This gate supports Feed and Bleed using the NV system for SGTR events.
H33BR, NV Pump 1B Support Systems Fail	• Locally deleted gate P1ETB as an input • Added gate P1ETB-ESPS as an input	This gate supports Safety Injection from the NV system during the Recirc. mode of core cooling.
TOABR-F, Sequence ToABP Failures	• Added gate PACLOSS as an input • Locally deleted gate PACLOSS-E as an input	Ensures that SBO Feed and Bleed sequences do not credit ESPS due to timing considerations.

Model Changes for Refinement of ESPS Credit

Gate	Change	Reason for Change
P1ELXB, Loss of Power on Unit 1 600 V ac Load Center 1ELXB	• Locally deleted gate P1ETB as an input • Added gate P1ETB-ESPS as an input	Credits ESPS for providing power to numerous accident mitigation equipment.
P1ELXD, Loss of Power on Unit 1 600 V ac Load Center 1ELXD	• Locally deleted gate P1ETB as an input • Added gate P1ETB-ESPS as an input	Credits ESPS for providing power to Cont. Air Return Fan 1B and PORV block valves 1NC35B and 1NC31B.
F635, Extended Loss of All ac Power	• Added gate PACLOSS-E as an input • Locally deleted gate PACLOSS as an input	Supports aligning alternate suction source to the CA TDP during an ELAP event.
PACLOST, All AC Power is Lost	• Added gate PACLOSS-E as an input • Locally deleted gate PACLOSS as an input	Credits ESPS for providing power prior to aligning power from the SSF.

Duke Energy supplemental information to McGuire RAI-16

The July 10, 2018 supplement provided a bounding seismic incremental CCDP of 2.68E-08 for the 14-day CT. For the analysis presented in this revised response, the seismic contribution to risk is addressed via two methodologies: 1) Use of the IPEEE seismic analysis and, 2) Use of a “seismic penalty”. Both approaches offer reasonable results to provide a bounding value.

1) Use of the IPEEE Analysis -

   The McGuire seismic CDF (SCDF) provided in response to the Individual Plant Examination for External Events (IPEEE) is 1.1E-05 / yr. (Ref. 1). This is an appropriate bounding value for several reasons given below.

   - Figure 1 below shows a comparison of the new GMRS to SSE acceleration response spectra (Ref. 2). From that figure, the design basis SSE exceeds the GMRS below 6 Hz, and the GMRS begins to exceed the McGuire SSE above 6 Hz. The peak acceleration of the new GMRS is ~0.7g at 35 Hz. Ground motions at levels up to 2 times the SSE are expected to produce only a small probability of failure for safety-related SSCs due to conservative design practices. In the high frequency range greater than 10 Hz, structural displacements are small and are considered non-damaging. Thus, the seismic hazard used in the IPEEE evaluation is considered to be conservative in the lower frequency ranges.
   - The IPEEE SCDF includes failures from relay chatter events. These types of events are found to occur typically in the high spectral frequency range. In 2017, McGuire performed a High Frequency Confirmation evaluation in response to the NRC's 50.54(f) letter using the methods in EPRI Report 3002004396 (Ref. 6). This evaluation (Refs. 4 and 5) identified nearly 300 components requiring additional assessment, 28 of which were determined to be outliers. These were subsequently resolved by operator action within existing plant procedures. Including the effects of relay chatter in the IPEEE (with a

recovery probability of 0.1) is thus considered a conservative measure in the analysis. Based on its review of the high frequency confirmation report, the NRC staff concluded that the licensee appropriately implemented the high frequency confirmation guidance and identified and evaluated the high frequency seismic capacity of certain key installed plant equipment to ensure critical functions will be maintained following a seismic event up to the GMRS described in McGuire's Seismic Hazard and Screening Report (Ref. 7).

- The IPEEE SCDF does not consider mitigating strategies for accident sequences involving a total loss of power (which are the predominant makeup of the IPEEE cutsets). Such sequences would now be addressed using McGuire's implementation of FLEX Order EA-12-049 requiring the licensee to develop, implement and maintain guidance.
- The IPEEE SCDF does not include the redundancy that would now be provided using ESPS. The ESPS diesel would likely be available and functional for station blackout events.
- The IPEEE SCDF does not include the Standby Shutdown Facility (SSF) which would be helpful with the mitigation of Station Blackout events by providing alternate RCP seal cooling, primary makeup, and instrumentation and controls to support longer term operation of the turbine-driven auxiliary feedwater pump. The SSF structure was initially screened out of the IPEEE due to its relatively low seismic capacity, as first reported in McGuire's IPE submittal (Ref. 8). However, it is expected the SSF would be available for earthquakes occurring in the lower frequency ranges.
- The IPEEE included random failures of SSCs. The EDG random failure values used in the current McGuire model of record (MOR) are approximately a factor of 9 lower than those used in the IPEEE due to improvements in equipment reliability and maintenance practices. Thus, the accident sequences involving random failures of the EDGs in the IPEEE are conservative.
- Since the IPEEE submittal in 1994, McGuire has installed a higher storage capacity Condensate Storage Tank (CST) on each unit to provide a more reliable source of AFW.

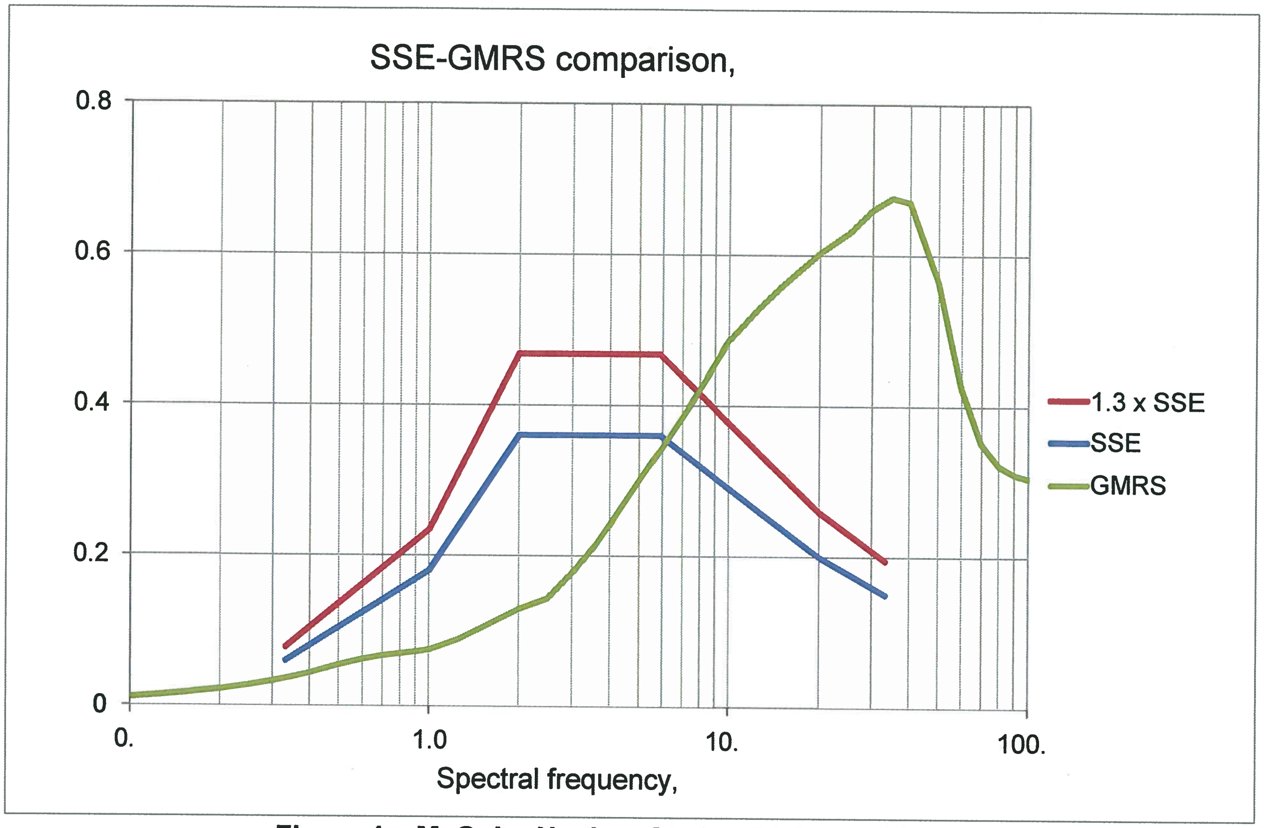

Figure 1 – McGuire Nuclear Station SSE v. GMRS

The model used to perform the IPEEE analysis was re-run with one EDG taken out of service. The resulting CDF was 1.7E-05 / yr., resulting in a delta of 6E-06 / yr. Thus, for the 14-day AOT, the incremental CCDP is,

6E-06 x (14 / 365) = <u>2.3E-07</u>

The IPEEE also included various HFEs, the most predominant of which was the response to the relay chatter events discussed above. Also, as mentioned previously, the IPEEE analysis does not include the implementation of FLEX equipment. Given the risk significance of LOOP events, these would be the dominant accident sequences where FLEX would be required. Thus, not including FLEX introduces conservatism in the IPEEE results and further demonstrates the IPEEE SCDF can be considered a reasonable bounding value.

The IPEEE also included various HFEs, the most predominant of which was the failure of an operator to align the 'A' train of NSW to the NSW Pond (the assured source of AFW). This was assigned a conservative screening value.

Other HFEs used in the IPEEE include responses to relay chatter events and failing to go to an auxiliary control panel following a loss of the main control boards. Even though high screening values were used for this assessment, all of accident sequences combined involving these other HFEs made only a small contribution to SCDF (~ 1%).

2) Use of a “Seismic Penalty” -

If seismic failures of the same or similar SSCs are assumed to be correlated, the Conditional Core Damage Probability (CCDP) given a seismic event will remain unaltered whether equipment is out of service or not. Thus, for the ESPS configuration, any seismic delta risk is primarily driven by accident sequences involving the loss of offsite power (LOOP), random failures of EDG systems (Fail To Run = 0.0177), seismic failure of non-EDG systems and associated operator actions. Contributions from other accident sequences are negligible due to the aforementioned correlated failure of related SSCs. For the purpose of computing the bounding seismic delta risk, the following conservative assumptions are made:

- All non-EDG SSCs are assumed to be failed or their fragilities are set to one for all hazard bins, irrespective of their seismic capacities.
- All HEPs are set to one for all hazard bins. In other words, there are no bin specific HEPs.
- No credit is given for the potential recovery of the loss of offsite power.
- No consideration of other mitigating equipment such as FLEX.

The seismic LOOP fragility parameter values are taken from NUREG/CR-6544 as follows:

Am	=	Median peak ground acceleration capacity in terms of peak ground acceleration (PGA)
	=	0.3 g
β_R	=	Lognormal standard deviation for randomness
	=	0.3
β_U	=	Lognormal standard deviation for uncertainty
	=	0.45
HCLPF	=	High confidence of a low probability of failure capacity
	=	0.1 g

Based on the above considerations, the bounding seismic SCDF contribution by the accident sequences related to the ESPS configuration can be computed for the base case as follows:

Initiator Bin	Description	Lower Acc	Upper Acc	Representative Acceleration	Hazard Interval Frequency
%G01	Seismic Initiating Event (0.1g to < 0.15g)	0.1	0.15	0.12	1.58E-04
%G02	Seismic Initiating Event (0.15g to < 0.3g)	0.15	0.3	0.21	1.11E-04
%G03	Seismic Initiating Event (0.3g to < 0.5g)	0.3	0.5	0.39	2.80E-05
%G04	Seismic Initiating Event (0.5g to < 0.75g)	0.5	0.75	0.61	9.59E-06
%G05	Seismic Initiating Event (0.75g to < 1g)	0.75	1	0.87	3.49E-06
%G06	Seismic Initiating Event (1g to < 1.5g)	1	1.5	1.22	2.46E-06
%G07	Seismic Initiating Event (1.5g to < 10g)	1.5	10	3.87	1.46E-06

Base Case							
LOOP Fragility	EDG - Train A	EDG - Train B	Non-EDG Seismic Failure	Seismic HEP	CCDP	SCDF	Initiator Bin
4.881E-02	1.770E-02	1.770E-02	1.000E+00	1.000E+00	1.53E-05	2.42E-09	%G01
2.608E-01	1.770E-02	1.770E-02	1.000E+00	1.000E+00	8.17E-05	9.07E-09	%G02
6.816E-01	1.770E-02	1.770E-02	1.000E+00	1.000E+00	2.14E-04	5.98E-09	%G03
9.065E-01	1.770E-02	1.770E-02	1.000E+00	1.000E+00	2.84E-04	2.72E-09	%G04
9.750E-01	1.770E-02	1.770E-02	1.000E+00	1.000E+00	3.05E-04	1.07E-09	%G05
9.954E-01	1.770E-02	1.770E-02	1.000E+00	1.000E+00	3.12E-04	7.67E-10	%G06
1.000E+00	1.770E-02	1.770E-02	1.000E+00	1.000E+00	3.13E-04	4.57E-10	%G07
					Total SCDF =	2.25E-08	

Seismic CDF contribution for each hazard bin is computed by

SCDF = SIEF x CCDP

SIEF = Seismic Initiating Event Frequency, computed by Hazard Interval Frequency x LOOP Fragility

CCDP = Conditional Core Damage Probability, computed by Random failure rate of EDG A (0.0177) x Random failure rate of EDG B (0.0177 for base case and 1 for completion time case) x Seismic failure of non-EDG (conservatively set to 1) x Seismic HEP (conservatively set to 1).

The resulting bounding seismic SCDF contribution for the base case is 2.25E-08. Similarly, the bounding seismic SCDF contribution for the completion time case can be computed as follows:

Initiator Bin	Description	Lower Acc	Upper Acc	Representative Acceleration	Hazard Interval Frequency
%G01	Seismic Initiating Event (0.1g to < 0.15g)	0.1	0.15	0.12	1.58E-04
%G02	Seismic Initiating Event (0.15g to < 0.3g)	0.15	0.3	0.21	1.11E-04
%G03	Seismic Initiating Event (0.3g to < 0.5g)	0.3	0.5	0.39	2.80E-05
%G04	Seismic Initiating Event (0.5g to < 0.75g)	0.5	0.75	0.61	9.59E-06
%G05	Seismic Initiating Event (0.75g to < 1g)	0.75	1	0.87	3.49E-06
%G06	Seismic Initiating Event (1g to < 1.5g)	1	1.5	1.22	2.46E-06
%G07	Seismic Initiating Event (1.5g to < 10g)	1.5	10	3.87	1.46E-06

Completion Time Case							
LOOP Fragility	EDG - Train A	EDG - Train B	Non-EDG Seismic Failure	Seismic HEP	CCDP	SCDF	Initiator Bin
4.881E-02	1.770E-02	1.000E+00	1.000E+00	1.000E+00	8.64E-04	1.37E-07	%G01
2.608E-01	1.770E-02	1.000E+00	1.000E+00	1.000E+00	4.62E-03	5.12E-07	%G02
6.816E-01	1.770E-02	1.000E+00	1.000E+00	1.000E+00	1.21E-02	3.38E-07	%G03
9.065E-01	1.770E-02	1.000E+00	1.000E+00	1.000E+00	1.60E-02	1.54E-07	%G04
9.750E-01	1.770E-02	1.000E+00	1.000E+00	1.000E+00	1.73E-02	6.02E-08	%G05
9.954E-01	1.770E-02	1.000E+00	1.000E+00	1.000E+00	1.76E-02	4.33E-08	%G06
1.000E+00	1.770E-02	1.000E+00	1.000E+00	1.000E+00	1.77E-02	2.58E-08	%G07
					Total SCDF =	1.27E-06	

The resulting bounding seismic SCDF contribution for the completion case is 1.27E-06. Thus, the incremental CCDP for the completion time case is computed as 1.25E-06 (=1.27E-06 – 2.25E-08) x 14/365 = 4.79E-08. It should be noted that the actual risk increase due to out of service equipment cannot be greater than this bounding value due to the conservative assumptions invoked above.

LERF Discussion

McGuire does not have a formal seismic LERF model. A qualitative discussion was provided in the IPEEE submittal and addressed LERF from a containment integrity, containment isolation and containment response perspective. No seismic vulnerabilities were identified.

Furthermore, Duke submitted a relief request for responding to the seismic portion of the 50.54(f) letter (Ref. 11) using seismic PRAs. In the relief request, Duke maintained performing SPRAs would not provide significant additional seismic risk insights (other than those already gleaned from the IPEEE submittal). In its response (Ref. 12), the Staff concluded the plant-specific combination of seismic hazard exceedances, the general estimation of the seismic CDF and the insights related to the conditional containment failure probabilities at McGuire indicated that the increase in seismic risk due to the reevaluated seismic hazard was addressed within the margin inherent in the design. Hence, a seismic PRA was deemed as no longer necessary to fulfill the response to the seismic portion of the 50.54(f) letter.

Therefore, since the seismic CDF values generated above using the IPEEE and seismic penalty analyses are conservative in nature and provide reasonable bounding values, the corresponding LERF value would also be conservative and reasonable.

Conclusion:

Duke has provided two separate revised bounding analyses which are higher than the bounding value given in the July 10, 2018 supplement. Even though Duke acknowledges these values are higher than originally given, adequate justification was provided to verify that the seismic risk impacts produced by the analysis are addressed and the analyses are considered to be bounding. In addition, Duke has addressed how the risk contribution of the seismic-induced SSC failures and seismic-impacted HFEs were considered. The seismic contribution still remains a small contribution to risk.

The IPEEE analysis includes several conservatisms highlighted above, including EDG failure rates much larger than currently used in the model of record. Also, considering the seismic penalty method includes the updated GMRS data, the more appropriate seismic incremental CCDP value would be that calculated using the seismic penalty method (4.8E-08). With these various estimates, the Reg. Guide 1.177 and 1.174 acceptance criteria continue to be met. Seismic risk continues to be a small contribution to the risk impact. The overall application continues to be a risk improvement (decrease in overall risk.)

Duke Energy supplemental information for MNS RAI-22 and CNS RAI-13

Failure rates for the ESPS diesels for start and run failures for all hazards were obtained from U.S. Nuclear Regulatory Commission, "Component Reliability Data Sheets 2015 Update", https://nrcoe.inl.gov/resultsdb/publicdocs/AvgPerf/ComponentReliabilityDataSheets2015.pdf, February 2017. These rates are applied for both CNS and MNS responses.

APPENDIX B

ADDITIONAL CONDITIONS

FACILITY OPERATING LICENSE NO. NPF-9

Duke Power Power Company LLC shall comply with the following conditions on the schedules noted below:

Amendment Number	Additional Conditions	Implementation Date
269	The Licensee shall perform an analysis, in the form of either a topical report or site-specific analysis, describing how the current P-T limit curves at 34 Effective Full Power Years (EFPY) for McGuire Unit 1 and the methodology used to develop these curves considered all Reactor Vessel (RV) materials (beltline and non-beltline) and the lowest service temperature of all ferritic Reactor Coolant Pressure Boundary (RCPB) materials, as applicable, consistent with the requirements of 10 CFR Part 50, Appendix G. This analysis shall be provided to the NRC within one year after NRC approval of the March 5, 2012 McGuire Measurement Uncertainty Recapture (MUR) License Amendment Request.	See Condition
269	McGuire Nuclear Station switchyard voltages required (so as not to impact the degraded voltage relay settings), corresponding to Unit 1 post-MUR uprate conditions, will be evaluated prior to implementation of MUR on Unit 1. However, if at the time of this evaluation, Ujnit 1 is not capable of realizing the expected maximum post-MUR uprate MWt power level and/or Unit 1 is not capable of generating the expected maximum post-MUR uprate MWe, then an additional evaluation will be performed when Unit 1 has these capabilities. If this additional evaluation is necessary, any changes in the switchyard voltages required (so as not to impact the degraded voltage relay settings), corresponding to conditions associated with the additional Unit 1 MWt capability and/or the additional Unit 1 MWe capability, will be evaluated prior to raising Unit 1 reactor core full steady state power to the expected maximum post-MUR uprate MWt power level and/or prior to Unit 1 generating the expected maximum post-MUR uprate MWe.	See Condition

Insert 1

Insert 1

Amendment Number	Additional Conditions	Implementation Date
YYY	During the extended DG Completion Times authorized by Amendment No. [YYY], the turbine-driven auxiliary feed water pump will not be removed from service for elective maintenance activities. The turbine-driven auxiliary feed water pump will be controlled as “protected equipment” during the extended DG CT. The Non-CT EDGs, ESPS, Component Cooling System, Safe Shutdown Facility, Nuclear Service Water System, Chemical and Volume Control System, Diesel Air Compressors, Residual Heat Removal System, motor driven auxiliary feed water pumps, and the switchyard will also be controlled as “protected equipment.”	Upon implementation of Amendment No. [YYY].
YYY	The risk estimates associated with the 14-day EDG Completion Time LAR (including those results of associated sensitivity studies) will be updated, as necessary to incorporate the as-built, as-operated ESPS modification. Duke Energy will confirm that any updated risk estimates continue to meet the risk acceptance guidelines of RG 1.174 and RG 1.177.	Upon implementation of Amendment No. [YYY].

APPENDIX B

ADDITIONAL CONDITIONS

FACILITY OPERATING LICENSE NO. NPF-17

Duke Energy Carolinas, LLC shall comply with the following conditions on the schedules noted below:

Amendment Number	Additional Conditions	Implementation Date
249	The Licensee shall perform an analysis, in the form of either a topical report or site-specific analysis, describing how the current P-T limit curves at 34 Effective Full Power Years (EFPY) for McGuire Unit 2 and the methodology used to develop these curves considered all Reactor Vessel (RV) materials (beltline and non-beltline) and the lowest service temperature of all ferritic Reactor Coolant Pressure Boundary (RCPB) materials, as applicable, consistent with the requirements of 10 CFR Part 50, Appendix G. This analysis shall be provided to the NRC within one year after NRC approval of the March 5, 2012 McGuire Measurement Uncertainty Recapture (MUR) License Amendment Request.	See Condition

Insert 2

Insert 2

Amendment Number	Additional Conditions	Implementation Date
ZZZ	During the extended DG Completion Times authorized by Amendment No. [ZZZ], the turbine-driven auxiliary feed water pump will not be removed from service for elective maintenance activities during the extended CT. The turbine-driven auxiliary feed water pump will be controlled as “protected equipment” during the extended DG CT. The Non-CT EDGs, ESPS, Component Cooling System, Safe Shutdown Facility, Nuclear Service Water System, Chemical and Volume Control System, Diesel Air Compressors, Residual Heat Removal System, motor driven auxiliary feed water pumps, and the switchyard will also be controlled as “protected equipment.”	Upon implementation of Amendment No. [ZZZ].
ZZZ	The risk estimates associated with the 14-day EDG Completion Time LAR (including those results of associated sensitivity studies) will be updated, as necessary to incorporate the as-built, as-operated ESPS modification. Duke Energy will confirm that any updated risk estimates continue to meet the risk acceptance guidelines of RG 1.174 and RG 1.177.	Upon implementation of Amendment No. [ZZZ].

Regulatory Commitments

McGuire Nuclear Station, Units 1 and 2

The following table identifies the regulatory commitments in this document by Duke Energy Carolinas, LLC (Duke Energy) for the McGuire Nuclear Station, Units 1 and 2. Any other statements in this submittal represent intended or planned actions, and are provided for information purposes. They are not considered to be regulatory commitments.

COMMITMENT	TYPE		SCHEDULED COMPLETION DATE
	One-time	Continuing Compliance	
1. The preplanned diesel generator (DG) maintenance will not be scheduled if severe weather conditions are anticipated. Weather conditions will be evaluated prior to intentionally entering the extended DG Completion Time (CT) and will not be entered if official weather forecasts are predicting severe weather conditions (i.e., thunderstorm, tornado or hurricane warnings). Operators will monitor weather forecasts each shift during the extended DG CT. If severe weather or grid instability is expected after a DG outage begins, station managers will assess the conditions and determine the best course for returning the DG to operable status.		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.
2. Component testing or maintenance of safety systems and important non-safety equipment in the offsite power systems that can increase the likelihood of a plant transient (unit trip) or loss of offsite power (LOOP) will be avoided during the extended DG CT.		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.

3. No discretionary switchyard maintenance will be performed during the extended DG CT.		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.
4. The turbine-driven auxiliary feed water pump will not be removed from service for elective maintenance activities during the extended CT. The turbine-driven auxiliary feed water pump will be controlled as "protected equipment" during the extended DG CT. The Non-CT EDGs, ESPS, Component Cooling System, Safe Shutdown Facility, Nuclear Service Water System, Chemical and Volume Control System, Diesel Air Compressors, Residual Heat Removal System, motor driven auxiliary feed water pumps, and the switchyard will also be controlled as "protected equipment." (license condition)		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.
5. During the extended DG CT, the Emergency Supplemental Power Source (ESPS) will be routinely monitored during operator rounds, with monitoring criteria identified in the operator rounds. The ESPS will be monitored for fire hazards during operator rounds.		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.

6. Licensed Operators and Auxiliary Operators will be trained on the purpose and use of the ESPS and the revised emergency procedure (EP) actions. Personnel performing maintenance on the ESPS will be trained.		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.
7. The system load dispatcher will be contacted once per day to ensure no significant grid perturbations (high grid loading unable to withstand a single contingency of line or generation outage) are expected during the extended DG CT.		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.
8. TS required systems, subsystems, trains, components and devices that depend on the remaining power sources will be verified to be operable and positive measures will be provided to preclude subsequent testing or maintenance activities on these systems, subsystems, trains, components and devices during the extended DG CT.		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.
9. Prior to entering the extended CT for an inoperable DG, when both units are in the TS 3.8.1 Modes of APPLICABILITY, the station will ensure that each train of shared systems is powered by an operable Class 1E AC Distribution System with an operable DG, from opposite units.		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.

10. The risk estimates associated with the 14-day EDG Completion Time LAR (including those results of associated sensitivity studies) will be updated, as necessary to incorporate the as-built, as-operated ESPS modification. Duke Energy will confirm that any updated risk estimates continue to meet the risk acceptance guidelines of RG 1.174 and RG 1.177. (license condition)	X		Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.

Attachment 8

Revised McGuire Technical Specification Bases 3.8.1 Marked Up Pages

(For Information Only)

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources—Operating

BASES

BACKGROUND

The unit Essential Auxiliary or Class 1E AC Electrical Power Distribution System AC sources consist of the offsite power sources (preferred power sources, normal and alternate(s)), and the onsite standby power sources (Train A and Train B diesel generators (DGs)). As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safety Feature (ESF) systems.

The onsite Class 1E AC Distribution System is divided into redundant load groups (trains) so that the loss of any one group does not prevent the minimum safety functions from being performed. Each train has connections to two preferred offsite power sources and a single DG.

At the 600V level of the onsite Class 1E AC Distribution System, there are two motor control centers (MCC) per train (for a total of four MCCs) that supply all of the shared systems on both units. The MCCs 1EMXG and 1EMXH supply Train A shared systems. The MCCs 2EMXG and 2EMXH supply Train B shared systems. The term shared systems is defined as the shared components of Train A or Train B of Nuclear Service Water System (NSWS), Control Room Area Ventilation System (CRAVS), Control Room Area Chilled Water System (CRACWS) and Auxiliary Building Filtered Ventilation Exhaust System (ABFVES). The MCCs 1EMXG and 1EMXH are normally aligned to receive power from load centers 1ELXA (1EMXH) and 1ELXC (1EMXG) but if desired or required to maintain operability of the Train A shared systems, can be swapped to receive power from load centers 2ELXA (1EMXH) and 2ELXC (1EMXG). The MCCs 2EMXG and 2EMXH are normally aligned to receive power from load centers 2ELXB (2EMXH) and 2ELXD (2EMXG) but if desired or required to maintain operability of the Train B shared systems, can be swapped to receive power from load centers 1ELXB (2EMXH) and 1ELXD (2EMXG).

There are also provisions to accommodate the connecting of the Emergency Supplemental Power Source (ESPS) to one train of either unit's Class 1E AC Distribution System. The ESPS consists of two 50% capacity non-safety related commercial grade DGs. Manual actions are required to align the ESPS to the station and only one of the station's four onsite Class 1E Distribution System trains can be supplied by the ESPS

BACKGROUND (continued)

at any given time. The ESPS is made available to support extended Completion Times in the event of an inoperable DG as well as a defense-in-depth source of AC power to mitigate a station blackout event. The ESPS would remain disconnected from the Class 1E AC Distribution System unless required for supplemental power to one of the four 4.16 kV ESF buses.

Offsite power is supplied to the unit switchyard(s) from the transmission network by two transmission lines. From the switchyard(s), two electrically and physically separated circuits provide AC power, through step down station auxiliary transformers, to the 4.16 kV ESF buses. A detailed description of the offsite power network and the circuits to the Class 1E ESF buses is found in the UFSAR, Chapter 8 (Ref. 2).

A qualified offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the onsite Class 1E ESF bus(es).

The offsite transmission systems normally supply their respective unit's onsite power supply requirements. However, in the event that one or both buslines of a unit become unavailable, or by operational desire, it is acceptable to supply that unit's offsite to onsite power requirements by aligning the affected 4160V bus of the opposite unit via the standby transformers, SATA and SATB in accordance with Regulatory Guides 1.6 and 1.81 (Ref. 12 and 13). In this alignment, each unit's offsite transmission system could simultaneously supply its own 4160V buses and one (or both) of the buses of the other unit.

Although a single auxiliary transformer (1ATA, 1ATB, 2ATA, 2ATB) is sized to carry all of the auxiliary loads of its unit plus both trains of essential 4160V loads of the opposite unit, the LCO would not be met in this alignment due to separation criteria.

Each unit's Train A and B 4160V bus must be derived from separate ~~offsite buslines~~qualified offsite circuits. The first ~~offsite power supply~~qualified offsite circuit can be derived from any of the four buslines (1A, 1B, 2A, or 2B). The second ~~offsite power supply~~qualified offsite circuit must not derive its power from the same ~~busline~~ qualified offsite circuit as the first. Additionally, the Train A and Train B Class 1E AC Distribution Systems providing power to the Train A and Train B shared systems must not derive their power from the same qualified offsite circuit.

BACKGROUND (continued)

Acceptable train and unit specific breaker alignment options are described below:

<u>Unit 1 A Train</u>

1. BL1A-1ATA-1TA-1ATC-1ETA
2. BL1B-1ATB-1TA-1ATC-1ETA
3. BL1A-1ATA-1TC-SATA-1ETA
4. BL1B-1ATB-1TC-SATA-1ETA
5. BL2A-2ATA-2TC-SATA-1ETA
6. BL2B-2ATB-2TC-SATA-1ETA

<u>Unit 1 B Train</u>

1. BL1B-1ATB-1TD-1ATD-1ETB
2. BL1A-1ATA-1TD-1ATD-1ETB
3. BL1B-1ATB-1TB-SATB-1ETB
4. BL1A-1ATA-1TB-SATB-1ETB
5. BL2B-2ATB-2TB-SATB-1ETB
6. BL2A-2ATA-2TB-SATB-1ETB

<u>Unit 2 A Train</u>

1. BL2A-2ATA-2TA-2ATC-2ETA
2. BL2B-2ATB-2TA-2ATC-2ETA
3. BL2A-2ATA-2TC-SATA-2ETA
4. BL2B-2ATB-2TC-SATA-2ETA
5. BL1A-1ATA-1TC-SATA-2ETA
6. BL1B-1ATB-1TC-SATA-2ETA

<u>Unit 2 B Train</u>

1. BL2B-2ATB-2TD-2ATD-2ETB
2. BL2A-2ATA-2TD-2ATD-2ETB
3. BL2B-2ATB-2TB-SATB-2ETB
4. BL2A-2ATA-2TB-SATB-2ETB
5. BL1B-1ATB-1TB-SATB-2ETB
6. BL1A-1ATA-1TB-SATB-2ETB

Certain required unit loads are returned to service in a predetermined sequence in order to prevent overloading the transformer supplying offsite power to the onsite Class 1E Distribution System. Typically (via accelerated sequencing), within 1 minute after the initiating signal is received, all loads needed to recover the unit or maintain it in a safe condition are returned to service.

BACKGROUND (continued)

The onsite standby power source for each 4.16 kV ESF bus is a dedicated DG. DGs A and B are dedicated to ESF buses ETA and ETB, respectively. A DG starts automatically on a safety injection (SI) signal (i.e., low pressurizer pressure or high containment pressure signals) or on an ESF bus degraded voltage or undervoltage signal (refer to LCO 3.3.5, "Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation"). After the DG has started, it will automatically tie to its respective bus after offsite power is tripped as a consequence of ESF bus undervoltage or degraded voltage, independent of or coincident with an SI signal. The DGs will also start and operate in the standby mode without tying to the ESF bus on an SI signal alone. Following the trip of offsite power, a sequencer strips loads from the ESF bus. When the DG is tied to the ESF bus, loads are then sequentially connected to its respective ESF bus by the automatic load sequencer. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading the DG by automatic load application.

In the event of a loss of preferred power, the ESF electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a Design Basis Accident (DBA) such as a loss of coolant accident (LOCA).

Certain required unit loads are returned to service in a predetermined sequence in order to prevent overloading the DG in the process. Typically (via accelerated sequencing), within 1 minute after the initiating signal is received, all loads needed to recover the unit or maintain it in a safe condition are returned to service.

Ratings for Train A and Train B DGs satisfy the requirements of Regulatory Guide 1.9 (Ref. 3). The continuous service rating of each DG is 4000 kW with 10% overload permissible for up to 2 hours in any 24 hour period. The ESF loads that are powered from the 4.16 kV ESF buses are listed in Reference 2.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the UFSAR, Chapter 6 (Ref. 4) and Chapter 15 (Ref. 5), assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

APPLICABLE SAFETY ANALYSES (continued)

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the Accident analyses and is based upon meeting the design basis of the unit. This results in maintaining at least one train of the onsite or offsite AC sources OPERABLE during Accident conditions in the event of:

a. An assumed loss of all offsite power or all onsite AC power; and

b. A worst case single failure.

The AC sources satisfy Criterion 3 of 10 CFR 50.36 (Ref. 6).

LCO

Two qualified circuits between the offsite transmission network and the onsite Class 1E Electrical Power System and separate and independent DGs for each train ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Additionally, the qualified circuit(s) between the offsite transmission network and the opposite unit onsite Essential Auxiliary Power System when necessary to power shared systems and the opposite unit DG(s) when necessary to power shared systems ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an AOO or a postulated DBA.

Qualified offsite circuits are those that are described in the UFSAR and are part of the licensing basis for the unit.

In addition, one required automatic load sequencer per train must be OPERABLE.

Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the ESF buses.

The 4.16 kV essential system is divided into two completely redundant and independent trains designated A and B, each consisting of one 4.16 kV switchgear assembly, two 4.16 kV/600 V load centers, and associated loads.

Normally, each Class 1E 4.16 kV switchgear is powered from its associated non-Class 1E train of the 6.9 kV Normal Auxiliary Power System as discussed in "6.9 kV Normal Auxiliary Power System" in Chapter 8 of the UFSAR (Ref. 2). Additionally, an alternate source of

LCO (continued)

power to each 4.16 kV essential switchgear is provided from the 6.9 kV system via a separate and independent 6.9/4.16 kV transformer. Two transformers are shared between units and provide the capability to supply an alternate source of power to each unit's 4.16 kV essential switchgear from either unit's 6.9 kV system. A key interlock scheme is provided to preclude the possibility of connecting the two units together at either the 6.9 or 4.16 kV level.

Each train of the 4.16 kV Essential Auxiliary Power System is also provided with a separate and independent emergency diesel generator to supply the Class 1E loads required to safely shut down the unit following a design basis accident.

Each DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This will be accomplished within 11 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions such as DG in standby with the engine hot and DG in standby with the engine at ambient conditions. Additional DG capabilities must be demonstrated to meet required Surveillance, e.g., capability of the DG to revert to standby status on an ECCS signal while operating in parallel test mode.

Proper sequencing of loads is a function of Sequencer OPERABILITY. Proper load shedding is a function of DG OPERABILITY. Proper tripping of non-essential loads is a function of AC Bus OPERABILITY (Condition A of Technical Specification 3.8.9).

The AC sources in one train must be separate and independent (to the extent possible) of the AC sources in the other train. For the DGs, separation and independence are complete.

LCO 3.8.1.c and LCO 3.8.1.d both use the word “necessary” to clarify when and how to apply these LCOs on a per unit basis. The word “necessary” clarifies that the qualified offsite circuit(s) in LCO 3.8.1.c and the DG(s) from the opposite unit in LCO 3.8.1.d are aligned to the opposite unit Onsite Essential Auxiliary Power System that is supplying power to a train of shared systems.

LCO 3.8.1.c specifies that the qualified circuit(s) between the offsite transmission network and the opposite unit’s Onsite Essential Auxiliary Power System be OPERABLE when necessary to supply power to the shared systems. LCO 3.8.1.d specifies that the DG(s) from the opposite unit be OPERABLE when necessary to supply power to the shared systems. The qualified offsite circuit necessary to supply power to one train of shared systems must be separate and independent (to the extent possible) of the qualified circuit which provides power to the other train of

LCO (continued)

shared systems. These requirements, in conjunction with the requirements for the applicable unit AC electrical power sources in LCO 3.8.1.a and LCO 3.8.1.b, ensure that power is available to two trains of the shared NSWS, CRAVS, CRACWS and ABFVES.

For example, with both units in MODE 1, the normal power alignment per plant procedures with no inoperable equipment is to have the Train A shared systems powered from Unit 1 (1EMXG and 1EMXH) and the Train B shared systems powered from Unit 2 (2EMXG and 2EMXH). In this normal alignment, Unit 1 LCO 3.8.1.c is met by an OPERABLE 2B offsite circuit and LCO 3.8.1.d is met by an OPERABLE 2B DG. Since the 2A offsite circuit and 2A DG are not necessary to supply power to a train of shared systems in the normal power alignment, they are not Unit 1 LCO 3.8.1.c and LCO 3.8.1.d AC sources for this example. For Unit 2, LCO 3.8.1.c is met by an OPERABLE 1A offsite circuit and LCO 3.8.1.d is met by an OPERABLE 1A DG. Since the 1B offsite circuit and 1B DG are not necessary to supply power to a train of shared systems in the normal power alignment, they are not Unit 2 LCO 3.8.1.c and LCO 3.8.1.d AC sources for this example.

Another power alignment per plant procedures with no inoperable equipment is to have the Train A shared systems powered from Unit 1 and the Train B shared systems also powered from Unit 1. In this off-normal alignment, Unit 2 LCO 3.8.1.c is met by both an OPERABLE 1A offsite circuit and an OPERABLE 1B offsite circuit. Unit 2 LCO 3.8.1.d is met by both an OPERABLE 1A DG and an OPERABLE 1B DG. Similarly, the Train A and Train B shared systems can both be powered from Unit 2. In this off-normal alignment, Unit 1 LCO 3.8.1.c is met by both an OPERABLE 2A offsite circuit and an OPERABLE 2B offsite circuit. Unit 1 LCO 3.8.1.d is met by both an OPERABLE 2A DG and an OPERABLE 2B DG.

~~Both normal and emergency power must be OPERABLE for a shared component to be OPERABLE. If normal or emergency power supplying a shared component becomes inoperable, then the Required Actions of the affected shared component LCO must be entered independently for each unit that is in the MODE of applicability of the shared component LCO. The shared component LCOs are:~~

~~3.7.7 - Nuclear Service Water System (NSWS),~~
~~3.7.9 - Control Room Area Ventilation System (CRAVS),~~
~~3.7.10 - Control Room Area Chilled Water System (CRACWS), and~~
~~3.7.11 - Auxiliary Building Filtered Ventilation Exhaust System (ABFVES).~~

APPLICABILITY

The AC sources and sequencers are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

A Note has been added taking exception to the Applicability requirements for the required AC sources in LCO 3.8.1.c and LCO 3.8.1.d provided the associated shared systems are inoperable. This exception is intended to allow declaring the shared systems supported by the opposite unit inoperable either in lieu of declaring the opposite unit AC sources inoperable, or at any time subsequent to entering ACTIONS for an inoperable opposite unit AC source.

This exception is acceptable since, with the shared systems supported by the opposite unit inoperable and the associated ACTIONS entered, the opposite unit AC sources provide no additional assurance of meeting the above criteria.

The AC power requirements for MODES 5 and 6 are covered in LCO 3.8.2, "AC Sources—Shutdown."

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable DG. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable DG 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

To ensure a highly reliable power source remains with one LCO 3.8.1.a offsite circuit inoperable, it is necessary to verify the OPERABILITY of the remaining required 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 not met. However, if a second required circuit fails SR 3.8.1.1, the second offsite circuit is inoperable, and Condition ~~C~~E, for two offsite circuits inoperable, is entered.

ACTIONS (continued)

A.2

Required Action A.2, which only applies if the train cannot be powered from an offsite source, is intended to provide assurance that an event coincident with a single failure of the associated DG will not result in a complete loss of safety function of critical redundant required features. These features are powered from the redundant AC electrical power train. This includes motor driven auxiliary feedwater pumps. The turbine driven auxiliary feedwater pump is required to be considered a redundant required feature, and, therefore, required to be determined OPERABLE by this Required Action. Three independent AFW pumps are required to ensure the availability of decay heat removal capability for all events accompanied by a loss of offsite power and a single failure. System design is such that the remaining OPERABLE motor driven auxiliary feedwater pump is not by itself capable of providing 100% of the auxiliary feedwater flow assumed in the safety analysis.

The Completion Time for Required Action A.2 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. The train has no offsite power supplying its loads; and
b. A required feature on the other train is inoperable.

If at any time during the existence of Condition A (one LCO 3.8.1.a offsite circuit inoperable) a redundant required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

Discovering no offsite power to one train of the onsite Class 1E Electrical Power Distribution System coincident with one or more inoperable required support or supported features, or both, that are associated with the other train that has offsite power, results in starting the Completion Times for the Required Action. 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 circuits 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.

ACTIONS (continued)

A.3

According to Regulatory Guide 1.93 (Ref. 7), 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.

The second Completion Time for Required Action A.3 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet ~~the LCO~~LCO 3.8.1.a or LCO 3.8.1.b. If Condition A is entered while, for instance, a LCO 3.8.1.b DG is inoperable and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to ~~72 hours~~14 days. This could lead to a total of ~~144 hours~~17 days, since initial failure to meet ~~the LCO~~LCO 3.8.1.a or LCO 3.8.1.b, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional ~~72 hours~~14 days (for a total of ~~9~~ 31 days) allowed prior to complete restoration of ~~the LCO~~LCOs 3.8.1.a and 3.8.1.b. The ~~6~~ 17 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet ~~the LCO~~LCO 3.8.1.a or LCO 3.8.1.b. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and ~~6~~ 17 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action A.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time that ~~the LCO~~LCO 3.8.1.a or LCO 3.8.1.b was initially not met, instead of at the time Condition A was entered.

B.1

It is required to administratively verify the LCO 3.8.1.d DG(s) OPERABLE within one hour and to continue this action once per 12 hours thereafter

ACTIONS (continued)

until restoration of the required LCO 3.8.1.b DG(s) is accomplished. This verification provides assurance that the LCO 3.8.1.d DG is capable of supplying the onsite Class 1E AC Electrical Power Distribution System.

If one LCO 3.8.1.d DG is discovered to be inoperable when performing the administrative verification of operability, then Condition D is entered for that DG. If two LCO 3.8.1.d DGs are discovered to be inoperable when performing the administrative verification of operability, then Condition G is entered.

B.~~1~~2

To ensure a highly reliable power source remains with an inoperable LCO 3.8.1.b DG, it is necessary to verify the availability of the required 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.

B.~~2~~3

Required Action B.~~2~~ 3 is intended to provide assurance that a loss of offsite power, during the period that a LCO 3.8.1.b DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related trains. This includes motor driven auxiliary feedwater pumps. The turbine driven auxiliary feedwater pump is required to be considered a redundant required feature, and, therefore, required to be determined OPERABLE by this Required Action. Three independent AFW pumps are required to ensure the availability of decay heat removal capability for all events accompanied by a loss of offsite power and a single failure. System design is such that the remaining OPERABLE motor driven auxiliary feedwater pump is not by itself capable of providing 100% of the auxiliary feedwater flow assumed in the safety analysis. Redundant required feature failures consist of inoperable features associated with a train, redundant to the train that has an inoperable LCO 3.8.1.b DG.

The Completion Time for Required Action B.~~2~~ 3 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. An inoperable LCO 3.8.1.b DG exists; and

ACTIONS (continued)

b. A required feature on the other train (Train A or Train B) is inoperable.

If at any time during the existence of this Condition (one LCO 3.8.1.b DG inoperable) a required feature subsequently becomes inoperable, this Completion Time would begin to be tracked.

Discovering one required LCO 3.8.1.b DG inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with the OPERABLE DG, results in starting the Completion

Time for the Required Action. Four hours from the discovery of these events existing concurrently is Acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

In this Condition, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 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.

B.~~3~~4.1 and B.~~3~~4.2

Required Action B.~~3~~4.1 provides an allowance to avoid unnecessary testing of OPERABLE DG(s). 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 other DG(s), the other DG(s) would be declared inoperable upon discovery and Condition ~~E~~D and/or G of LCO 3.8.1, as applicable, would be entered. Once the failure is repaired, the common cause failure no longer exists, and Required Action B.~~3~~4.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG(s), 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~~4.1 or B.~~3~~4.2, the problem investigation process 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.

ACTIONS (continued)

These Conditions are not required to be entered if the inoperability of the DG is due to an inoperable support system, an independently testable component, or preplanned testing or maintenance. If required, these Required Actions are to be completed regardless of when the inoperable DG is restored to OPERABLE status.

According to Generic Letter 84-15 (Ref. 8), 24 hours is reasonable to confirm that the OPERABLE DG(s) is not affected by the same problem as the inoperable DG.

B.5

In order to extend the Completion Time for an inoperable DG from 72 hours to 14 days, it is necessary to verify the availability of the ESPS within 1 hour of entry into TS 3.8.1 LCO and every 12 hours thereafter. Since Required Action B.5 only specifies “evaluate,” discovering the ESPS unavailable does not result in the Required Action being not met (i.e. the evaluation is performed). However, on discovery of an unavailable ESPS, the Completion Time for Required Action B.6 starts the 72 hour and/or 24 hour clock.

ESPS availability requires that:

1) The load test has been performed within 30 days of entry into the extended Completion Time. The Required Action evaluation is met with an administrative verification of this prior to testing; and

2) ESPS fuel tank level is verified locally to be ≥ 24 hour supply; and

3) ESPS supporting system parameters for starting and operating are verified to be within required limits for functional availability (e.g., battery state of charge).

The ESPS is not used to extend the Completion Time for more than one inoperable DG at any one time.

~~B.4~~B.6

~~According to Regulatory Guide 1.93 (Ref. 7), operation may continue in Condition B for a period that should not exceed 72 hours.~~
In accordance with Branch Technical Position 8-8 (Ref. 14), operation may continue in Condition B for a period that should not exceed 14 days, provided a supplemental AC power source is available.

In Condition B, the remaining OPERABLE DGs, available ESPS and offsite circuits are adequate to supply electrical power to the onsite

ACTIONS (continued)

Class 1E Distribution System. The ~~72 hour~~14 day 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.

If the ESPS is or becomes unavailable with an inoperable LCO 3.8.1.b DG, then action is required to restore the ESPS to available status or to restore the DG to OPERABLE status within 72 hours from discovery of unavailable ESPS. However, if the ESPS unavailability occurs at or sometime after 48 hours of continuous LCO 3.8.1.b DG inoperability, then the remaining time to restore the ESPS to available status or to restore the DG to OPERABLE status is limited to 24 hours.

The 72 hour and 24 hour Completion Times allow for an exception to the normal "time zero" for beginning the allowed outage time "clock." The 72 hour Completion Time only begins on discovery that both:

a. An inoperable DG exists; and
b. ESPS is unavailable.

The 24 hour Completion Time only begins on discovery that:

a. An inoperable DG exists for ≥ 48 hours; and
b. ESPS is unavailable.

Therefore, when one LCO 3.8.1.b DG is inoperable due to either preplanned maintenance (preventive or corrective) or unplanned corrective maintenance work, the Completion Time can be extended from 72 hours to 14 days if ESPS is verified available for backup operation.

The ~~second~~ fourth Completion Time for Required Action ~~B.4~~B.6 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet ~~the LCO~~LCO 3.8.1.a or LCO 3.8.1.b. If Condition B is entered while, for instance, ~~an~~ a LCO 3.8.1.a offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 72 hours. This could lead to a total of ~~144 hours~~17 days, since initial failure to meet ~~the LCO~~LCO 3.8.1.a or LCO 3.8.1.b, to restore the DG. At this time, ~~an~~ a LCO 3.8.1.a offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of ~~9~~ 20 days) allowed prior to complete restoration of ~~the LCO~~LCO 3.8.1.a and LCO 3.8.1.b. The ~~6~~ 17 day Completion Time provides a limit on time allowed in a specified condition after discovery of failure to meet ~~the LCO~~LCO 3.8.1.a or LCO 3.8.1.b. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the ~~72 hour~~14 day and ~~6~~ 17 day Completion Times means that

ACTIONS (continued)

both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action B.~~2~~3, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed time "clock." This will result in establishing the "time zero" at the time that ~~the LCO~~LCO 3.8.1.a or LCO 3.8.1.b was initially not met, instead of at the time Condition B was entered.

C.1

Condition C addresses the inoperability of the LCO 3.8.1.c qualified offsite circuit(s) between the offsite transmission network and the opposite unit's Onsite Essential Auxiliary Power System when the LCO 3.8.1.c qualified offsite circuit(s) is necessary to supply power to the shared systems. If Condition C is entered concurrently with the inoperability of LCO 3.8.1.d DG(s) the NOTE requires the licensed operator to evaluate if the TS 3.8.9 "Distribution Systems – Operating" requirement that "OPERABLE AC electrical power distribution subsystems require the associated buses, load centers, motor control centers, and distribution panels to be energized to their proper voltages" continues to be met. In the case where the inoperable LCO 3.8.1.c qualified offsite circuit and inoperable LCO 3.8.1.d DG are associated with the same train there is no longer assurance that train of "Distribution Systems – Operating" can be energized to the proper voltage and therefore TS 3.8.9 Condition A must be entered.

To ensure a highly reliable power source remains with one required LCO 3.8.1.c offsite circuit inoperable, it is necessary to verify the OPERABILITY of the remaining required 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 not met. However, if a second required circuit fails SR 3.8.1.1, the second offsite circuit is inoperable, and Condition A and E, as applicable, for the two offsite circuits inoperable, is entered.

C.2

Required Action C.2, which only applies if the train cannot be powered from an offsite source, is intended to provide assurance that an event coincident with a single failure of the associated DG will not result in a complete loss of safety function for the NSWS, CRAVS, CRACWS or the ABFVES. The Completion Time for Required Action C.2 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:

ACTIONS (continued)

a. The train has no offsite power supplying its loads; and

b. NSWS, CRAVS, CRACWS or ABFVES on the other train that has offsite power is inoperable.

If at any time during the existence of Condition C (one required LCO 3.8.1.c offsite circuit inoperable) a train of NSWS, CRAVS, CRACWS or ABFVES becomes inoperable, this Completion Time begins to be tracked.

Discovering no offsite power to one train of the onsite Class 1E Electrical Power Distribution System coincident with one train of NSWS, CRAVS, CRACWS or ABFVES that is associated with the other train that has offsite power, results in starting the Completion Time for the Required Action. 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 circuits 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 NSWS, CRAVS, CRACWS or ABFVES. 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.

C.3

Consistent with the time provided in ACTION A, operation may continue in Condition C for a period that should not exceed 72 hours. With one required LCO 3.8.1.c 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 circuits and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System.

If the LCO 3.8.1.c required offsite circuit cannot be restored to OPERABLE status within 72 hours, then Condition I must be entered immediately.

D.1

Condition D addresses the inoperability of the LCO 3.8.1.d DG(s) aligned to the opposite unit Onsite Essential Auxiliary Power System that is supplying power to a train of shared systems. If Condition D is entered

ACTIONS (continued)

concurrently with the inoperability of LCO 3.8.1.c qualified offsite circuit the NOTE requires the licensed operator to evaluate if the TS 3.8.9 “Distribution Systems – Operating” requirement that “OPERABLE AC electrical power distribution subsystems require the associated buses, load centers, motor control centers, and distribution panels to be energized to their proper voltages” continues to be met. In the case where the inoperable LCO 3.8.1.d DG and inoperable LCO 3.8.1.c qualified offsite circuit are associated with the same train there is no longer assurance that train of “Distribution Systems – Operating” can be energized to the proper voltage and therefore TS 3.8.9 Condition A must be entered.

It is required to administratively verify the CO 3.8.1.b safety-related DGs OPERABLE within one hour and to continue this action once per 12 hours thereafter until restoration of the required LCO 3.8.1.d DG is accomplished. This verification provides assurance that the LCO 3.8.1.b safety-related DGs is capable of supplying the onsite Class 1E AC Electical Power Distribution System.

If one LCO 3.8.1.b DG is discovered to be inoperable when performing the administrative verification of operability, then Condition B is entered for that DG. If two LCO 3.8.1.b DGs are discovered to be inoperable or the LCO 3.8.1.b DG that provides power to the NSWS, CRAVS, CRACWS and ABFVES inoperable when performing the administrative verification of operability, then Condition G is entered.

D.2

To ensure a highly reliable power source remains with one required LCO 3.8.1.d DG inoperable, it is necessary to verify the OPERABILITY of the required 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 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.

D.3

Required Action D.3 is intended to provide assurance that a loss of offsite power, during the period one required LCO 3.8.1.d DG is inoperable, does not result in a complete loss of safety function for the NSWS, CRAVS, CRACWS or the ABFVES. The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for 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:

ACTIONS (continued)

a. An inoperable LCO 3.8.1.d DG exists; and

b. NSWS, CRAVS, CRACWS or ABFVES on the other train that has emergency power is inoperable.

If at any time during the existence of this Condition (the LCO 3.8.1.d DG inoperable) a train of NSWS, CRAVS, CRACWS or ABFVES becomes inoperable, this Completion Time begins to be tracked.

Discovering the LCO 3.8.1.d DG inoperable coincident with one train of NSWS, CRAVS, CRACWS or ABFVES that is associated with the other train that has emergency power results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

In this Condition, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the NSWS, CRAVS, CRACWS or ABFVES may have been lost; however, function has not been lost. The four hour Completion Time also takes into account the capacity and capability of the remaining NSWS, CRAVS, CRACWS and ABFVES train, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

D.4.1 and D.4.2

Required Action D.4.1 provides an allowance to avoid unnecessary testing of OPERABLE DGs. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG(s), SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on other DG(s), the other DG(s) would be declared inoperable upon discovery and Condition B and I of LCO 3.8.1, as applicable, would be entered. Once the failure is repaired, the common cause failure no longer exists and Required Action D.4.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG(s), performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of the DG(s).

In the event the inoperable DG is restored to OPERABLE status prior to completing either D.4.1 or D.4.2, the problem investigation process will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition D.

ACTIONS (continued)

According to Generic Letter 84-15 (Ref. 8), 24 hours is reasonable to confirm that the OPERABLE DG(s) is not affected by the same problem as the inoperable DG.

D.5.1 and D.5.2

In Condition D, the remaining OPERABLE DGs and offsite power circuits are adequate to supply electrical power to the Class 1E Distribution System.

If the LCO 3.8.1.d DG cannot be restored to OPERABLE status within 72 hours or the NSWS, CRAVS, CRACWS and ABFVES components supported by the inoperable LCO 3.8.1.d DG cannot be re-aligned to be supplied by an OPERABLE DG within 72 hours, then Condition I is entered.

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.

~~C~~E.1 and ~~C~~E.2

Condition E is entered when both offsite circuits required by LCO 3.8.1.a are inoperable, or when the offsite circuit required by LCO 3.8.1.c and one offsite circuit required by LCO 3.8.1.a are concurrently inoperable, if the LCO 3.8.1.a offsite circuit is credited with providing power to the NSWS, CRAVS, CRACWS and ABFVES. Condition E is also entered when two offsite circuits required by LCO 3.8.1.c are inoperable.

Required Action ~~C~~E.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. 7) 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 motor driven auxiliary feedwater pumps. Single train features, such as turbine driven auxiliary pumps, are not included in the list.

The Completion Time for Required Action ~~C~~E.1 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This

ACTIONS (continued)

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~~ E (two LCO 3.8.1.a offsite circuits inoperable, or one LCO 3.8.1.a offsite circuit that provides power to the NSWS, CRAVS, CRACWS and ABFVES inoperable and the required LCO 3.8.1.c offsite circuit inoperable, or two offsite circuits required by LCO 3.8.1.c inoperable) a required feature becomes inoperable, this Completion Time begins to be tracked.

According to Regulatory Guide 1.93 (Ref. 7), operation may continue in Condition ~~C~~ E 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.

ACTIONS (continued)

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 or C, as applicable.

~~D~~F.1 and ~~D~~F.2

Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it were inoperable, resulting in de-energization. Therefore, the Required Actions of Condition ~~D~~ F are modified by a Note to indicate that when Condition ~~D~~ F is entered with no AC source to any train, the Conditions and Required Actions for LCO 3.8.9, "Distribution Systems—Operating," must be immediately entered. This allows Condition ~~D~~ F to provide requirements for the loss of one offsite circuit and one DG, without regard to whether a train is de-energized. LCO 3.8.9 provides the appropriate restrictions for a de-energized train.

According to Regulatory Guide 1.93 (Ref. 7), operation may continue in Condition ~~D~~ F for a period that should not exceed 12 hours.

In Condition ~~D~~F, 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~~ E (loss of ~~both~~ two 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.

~~E~~G.1

With ~~Train A and Train B DGs~~two LCO 3.8.1.b DGs inoperable, there are no remaining standby AC sources to provide power to most of the ESF systems. With one LCO 3.8.1.d DG inoperable and the LCO 3.8.1.b DG that provides power to the NSWS, CRAVS, CRACWS and ABFVES inoperable, or with two DGs required by LCO 3.8.1.d inoperable, there are no remaining standby AC sources to the NSWS, CRAVS, CRACWS and ABFVES. 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

ACTIONS (continued)

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 7, with both LCO 3.8.1.b DGs inoperable, or with the LCO 3.8.1.b DG that provides power to the NSWS, CRAVS, CRACWS and ABFVES and the LCO 3.8.1.d DG inoperable, or with two DGs required by LCO 3.8.1.d inoperable, operation may continue for a period that should not exceed 2 hours.

~~F~~H.1

The 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 12 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.

~~G~~I.1 and ~~G~~I.2

~~If the inoperable AC electric power sources cannot be restored to OPERABLE status within the required Completion Time,~~If any Required Action and associated Completion Time of Conditions A, C, E, F, G, or H, are not met, the unit must be brought to a MODE in which the LCO does not apply. Furthermore, if any Required Action and associated Completion Time of Required Actions B.2, B.3, B.4.1, B.4.2, B.6, E.2, E.3, E.4.1, E.4.2, E.5.1 or E.5.2 are not met, 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~~J.1

Condition ~~H~~J corresponds to a level of degradation in which all redundancy in ~~the~~ LCO 3.8.1.a and LCO 3.8.1.b AC electrical power supplies has been lost or in which all redundancy in LCO 3.8.1.c and LCO 3.8.1.d 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.

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, Appendix A, GDC 18 (Ref. 9). Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The SRs for demonstrating the OPERABILITY of the DGs are in accordance with the recommendations of Regulatory Guide 1.9 (Ref. 3) and Regulatory Guide 1.137 (Ref. 11), as addressed in the UFSAR.

Since the McGuire DG manufacturer, Nordberg, is no longer in business, McGuire engineering is the designer of record. Therefore, the term "manufacturer's or vendor's recommendations" is taken to mean the recommendations as determined by McGuire engineering, with specific Nordberg input as it is available, that were intended for the DGs, taking into account the maintenance, operating history, and industry experience, when available.

Where the SRs discussed herein specify voltage and frequency tolerances, the following is applicable. The minimum steady state output voltage of 3740 V is 90% of the nominal 4160 V output voltage. This value allows for voltage drop to the terminals of 4000 V motors whose minimum operating voltage is specified as 90% or 3600 V. It also allows for voltage drops to motors and other equipment down through the 120 V level where minimum operating voltage is also usually specified as 90% of name plate rating. The specified maximum steady state output voltage of 4580 V is equal to the maximum operating voltage specified for 4000 V motors. It ensures that for a lightly loaded distribution system, the voltage at the terminals of 4000 V motors is no more than the maximum rated operating voltages. The specified minimum and maximum frequencies of

the DG are 58.8 Hz and 61.2 Hz, respectively. These values are equal to ± 2% of the 60 Hz nominal frequency and are derived from the recommendations given in Regulatory Guide 1.9 (Ref. 3).

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. UFSAR, Chapter 8.
3. Regulatory Guide 1.9, Rev. 3, July 1993.
4. UFSAR, Chapter 6.
5. UFSAR, Chapter 15.
6. 10 CFR 50.36, Technical Specifications, (c)(2)(ii).
7. Regulatory Guide 1.93, Rev. 0, December 1974.
8. Generic Letter 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," July 2, 1984.
9. 10 CFR 50, Appendix A, GDC 18.
10. Regulatory Guide 1.137, Rev. 1, October 1979.
11. IEEE Standard 308-1971.
12. Regulatory Guide 1.6, Rev. 0, March 1971.
13. Regulatory Guide 1.8.1, Rev. 1, January 1975.
14. Branch Technical Position 8-8, February 2012.