NRR-DMPSPEm Resource

From: Mahoney, Michael
Sent: Wednesday, January 9, 2019 3:56 PM
To: Art Zaremba
Cc: 'Edwards, Nicole D'
Subject: Request for Additional Information - Catawba Nuclear Station, Units 1 and 2 - ESPS LAR

Art,

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 The proposed changes to TS 3.8.1 in the October 8, 2018 letter superseded the proposed TS 3.8.1 changes in all other letters.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 McGuire, 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.

RAI-1 – Safe Shutdown Facility Credit for High Winds

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).

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.

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.

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.

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.

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.

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 ∆CDF and ICCDP values are higher than Unit 2 by an average of 11%, (4) Unit 2 ∆LERF 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.

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.

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

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 models used for this application that aggregate the PRA updates requested in RAI-13.

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.

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.

RAI-12 – Application of Generic and Bayesian Updated Diesel Generator Failure Rates

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.

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.

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.

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.

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.

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.

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.

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).

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).

RAI-21

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.

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.

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.

Once this email is added to ADAMS, I will provide the accession number for your reference.

Thanks
Mike

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From: Mahoney, Michael

Created By: Michael.Mahoney@nrc.gov

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Tracking Status: None
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