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

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

SUBJECT: RESPONSE TO NRC RAI CLARIFICATIONS 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. 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 Catawba Nuclear Station*, *Units 1 and 2*, dated March 7, 2019 (ADAMS Accession No. ML19066A354).

6. NRC E-Mail, *Catawba – ESPS PRA-Related Clarifications*, dated June 1, 2019 (ADAMS Accession No. ML19170A269).

7. NRC E-Mail, *Catawba – ESPS TS-Related Clarifications*, dated June 5, 2019 (ADAMS Accession No. ML19169A091).

Ladies and Gentlemen:

In Reference 1, as supplemented by References 2 – 5, 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 correspondences dated June 1st and 5th, 2019 (References 6 and 7, respectively), the Nuclear Regulatory Commission (NRC) staff requested RAI clarifications from Duke Energy that is needed to complete the LAR review.

Attachment 1 provides Duke Energy's response to the NRC PRA-related RAI clarifications. Attachment 2 contains Duke Energy's response to the NRC TS-related RAI clarifications. Attachments 3 and 4 contain proposed markups of the CNS Renewed Facility Operating License (FOL) for Units 1 and 2, respectively. Commitment number 1 provided in the March 7, 2019 letter (Reference 5) has been added to the CNS FOL markups as a proposed license condition. Attachment 5 contains the proposed markups of CNS TS 3.8.1.

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 state of 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.

I declare under penalty of perjury that the foregoing is true and correct. Executed on July 10, 2019.

Sincerely,

Steve Snider
Vice President, Nuclear Engineering

NDE

Attachments:

1. Response to NRC PRA-related RAI Clarifications
2. Response to NRC TS-related RAI Clarifications
3. Markup of Proposed Renewed Facility Operating License – CNS Unit 1
4. Markup of Proposed Renewed Facility Operating License – CNS Unit 2
5. Proposed CNS Technical Specification 3.8.1 Marked up

cc: (all with Attachments unless otherwise noted)

L. Dudes 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 PRA-related RAI Clarifications

NRC PRA-related RAI Clarifications:

Question 01.a.01 – Safe Shutdown Facility (SSF) Credit for High Winds

The cutset results in Table 7-31, "Top 25 Delta Cutsets – CNS High Winds CDF," of LAR Attachment 7, dated May 2, 2017, show the Standby Shutdown Facility (SSF) is credited in F3 high wind events [i.e., cutsets # 7, 8, 9, 13, and 25 contain either basic events HW31SSF (all high winds failure of SSF for high wind intervalF3-1) or HW32SSF (all high winds failure of SSF for high wind interval F3-2)]. However, the response to RAI 01.a, dated March 7, 2019, states, "[t]he credit for the SSF is extended to F1 and F2 straight-line wind and tornado high wind-initiated events only … [n]o credit is taken for the SSF in straight[-]line wind or tornado events higher than F2." The response to RAI 13.c, dated March 7, 2019, indicates changes were made to the high winds probabilistic risk assessment (PRA) to credit SSF in F2 straight-line and tornado high wind events, but this response does not indicate removal of SSF credit in F3 and higher wind events. Therefore, there appears to be an inconsistency between the LAR and the response to RAIs 01 and 13.

Explain how SSF is credited for F3 high wind events in the high winds PRA used to calculate the results provided in response to RAI 13. As appropriate, provide revised responses for RAI 01 and 13 for the above explanation, including a description and justification of any changes to the Catawba high winds PRA in support of the aggregate analysis (i.e., RAI 13.c).

Duke Energy 01.a.01 Response:

As part of addressing the RAIs in the March 7, 2019 letter (ADAMS Accession No. ML19066A354), the high wind PRA analysis was mapped to the updated internal events PRA model and reassessed. Due to restructuring of the fault trees in the updated internal events PRA model, no credit is given for the SSF for high wind events higher than F2 windspeeds. Thus, the responses given in RAI 1 and 13 provided on March 7, 2019 are consistent with the current updated high wind PRA analysis for the ESPS evaluation.

Since the current analysis does not credit the SSF for high wind events higher than F2 windspeeds and aligns with the RAI 1 response provided on March 7, 2019, no additional analysis is needed for RAI 13.

A clarification for RAI 13 is that the mapping of the high wind PRA analysis to the updated internal events PRA model for the ESPS evaluation resulted in no credit being given for the SSF for high wind events higher than F2.

Question 10.b.01 – Sources of Model Uncertainty and Parametric Uncertainty

The response to RAI 10.b, dated March 7, 2019, states for the parametric uncertainty analysis,

Since the SOKC [state-of-knowledge correlation] impacts are evaluated by the UNCERT code, the corrections applied to adjust the CAFTA point estimate are removed before running the [UNCERT] code. This results in the point estimate listed for the UNCERT run being reduced from the CAFTA produced point estimate.

The nature of these CAFTA corrections is unclear, including why these corrections are made and why they are appropriate.

Specifically explain what is meant by “the corrections applied to adjust the CAFTA point estimate are removed before running the code” in response to RAI 10.b, dated March 7, 2019. Include in this discussion: (1) the correction values applied; (2) the purpose of these corrections in adjusting the CAFTA point estimate risk values; (3) why are these corrections removed before running the code; and (4) how they affect the final risk values provided in the LAR, as supplemented, and provide a technical justification why it is appropriate if they have more than a minimal impact.

Duke Energy 10.b.01 Response:

The correction value applied is 4.33. The value comes from WCAP-17154-P, Revision 1, “ISLOCA Risk Model”, which is based on failure rates from NUREG/CR-6928.

The purpose of the correction value is to adjust the cutset frequency in CAFTA where correlation between basic events is appropriate to generate the appropriate risk result. Per WCAP-17154-P, Revision 1, Appendix D:

> “whenever a cutset contains multiple terms that use the same failure rate data, the mean frequency of the cutset will be greater than the product of the mean probabilities of its terms. This effect is due to the fact that the terms in a cutset are distributions, not point values. When all of the terms are totally independent of each other, the mean of the cutset is the product of the means of its constituent terms. However, when two or more of the terms are correlated, i.e., not independent, the mean frequency of the cutset should be assessed via a statistical sampling process, e.g., a Monte Carlo process which accounts for the cutset basic event data distributions. The cutset mean frequency generated via this sampling process will be greater than the product of the means of its terms. This effect is called the State of Knowledge Correlation (SOKC), because it accounts for the state of knowledge associated with the frequency/probability of correlated terms.
>
> Use of a statistical sampling process (e.g., UNCERT) to calculate risk results, such as core damage frequency (CDF) or large early release frequency (LERF), automatically accounts for the SOKC effect. However, most risk analysis software tools (e.g., CAFTA) only generate point estimates using mean values of its contributing terms. These point estimates do not account for the SOKC. Thus, the point estimate risk results generated with these tools must be adjusted to account for the SOKC when these results involve cutsets which contain correlated basic events.”

Therefore, when using CAFTA, the SOKC is not correctly accounted for, it is added into the appropriate cutsets with the correction value.

Since, UNCERT already accounts for the SOKC, the correction value (that was added when the cutsets were quantified in CAFTA) is set to unity (with no uncertainty) in the cutsets prior to running the UNCERT code.

There is no impact on the final risk values provided in the LAR, as supplemented.

Question 13.01 - Aggregate Update Analysis

The response to RAI 13, dated March 7, 2019, provided the risk results for the mean aggregate (sensitivity) case and best estimate case based on the most limiting plant and alignment

configuration along with descriptions of PRA model updates. The following observations are noted regarding the response to RAI 13:

- The results between the mean aggregate (sensitivity) case and the best estimate case are nearly identical. However, it is not clear what the difference is between these two cases, because the response did not define or describe the differences between the mean aggregate (sensitivity) and the best estimate cases.

- The response to RAI 13.d states the aggregate risk estimates (based on the combined contribution from internal events, internal flooding, high winds, and fire) for both cases meet the risk acceptance guidelines of Regulatory Guide (RG) RG 1.177 and RG 1.174, and therefore, the licensee did not address RAI 13.e for exceeding the guidelines. However, these risk estimates excluded the seismic contribution, which is required by RG 1.177. Including the seismic contribution, the aggregate risk estimates exceed the risk acceptance guidelines for incremental conditional core damage probability (ICCDP) and incremental conditional large early release probability (ICLERP) by about 16% and 3%, respectively. As a result, the licensee should address RAI 13.e regarding exceedance of the risk acceptance guidelines. Though the response did identify a few conservatisms in the risk analysis (e.g., FLEX is not credited in the PRA, and the high winds PRA does not credit recovery of offsite power), the response did not provide any quantifiable measures of their impact on risk. Issues associated with crediting FLEX in the PRA are discussed in NRC memorandum, "Assessment of the Nuclear Energy Institute 16-06, Crediting Mitigating Strategies in Risk-Informed Decision Making, Guidance for Risk-Informed Changes to Plants Licensing Basis," dated May 30, 2017 (ADAMS Accession No. ML17031A269).

- The response to RAI 13.c states the operator action for aligning the Emergency Supplemental Power Source (ESPS) was refined based on developed procedures and subsequently developed a dependency analysis for human failure event (HFE) combinations. The nature of these refinements is unclear (e.g., was the level of detail increased to produce more realistic results, were model uncertainties that have been introduced by assumptions removed via the development of more sophisticated models). Based on the risk assessment results presented in LAR Attachment 7 for Catawba, operator failure associated with implementing ESPS is a significant contributor to the change in risk results for this LAR. This demonstrates the importance of calculating a realistic human error probability (HEP) for this operator action. Therefore, the NRC staff has a general need to confirm the reasonableness of the updated HEP for the ESPS operator action.

To address the observations above, the NRC staff requests the following additional information.

a) Describe the mean aggregate (sensitivity) case and how it differs from the best estimate case in the response to RAI 13.a.

b) With regards to exceedance of the RG 1.177 risk acceptance guidelines, provide justification that the risk results in the aggregate analysis in response to RAI 13.a (i.e., aggregated ICCDP and ICLERP based on the combined contribution from internal events, internal flooding, high winds, fire, and seismic) are acceptable for this application. This justification should be of sufficient detail and may include the following: (1) provide the results of a more detailed, realistic analysis to reduce conservatism and uncertainty and describe this analysis in detail; (2) propose compensatory measures and their associated quantifiable/quantitative impact on the risk

results; and (3) discuss the conservatisms in the analysis and their quantifiable/quantitative impact on the risk results.

c) With regards to the response to RAI 13.c, describe and justify the refinements made to the ESPS operator actions, including the associated human reliability analysis and dependency analysis. Provide sufficient details to justify the basis for the revised HEP values and dependency analysis combination values, including how the time available and time required to complete operator action was estimated, walk-throughs, operator interviews, and joint human event probability (JHEP) floor values. As necessary, provide updated discussions of the ESPS operator action in those parts of the LAR and LAR supplement dated October 8, 2018 (e.g., response to RAIs 06 and 07) that are no longer current or valid.

Additionally, the NRC staff believe that Regulatory Commitment number 1 (related to severe weather) should be escalated to a license condition. This is requested to address uncertainties associated with the high winds PRA (which were identified in the March 7, 2019 response) and the fact that high winds dominate the risk profile.

Duke Energy 13.01.a Response:

The mean aggregate results were generated using the UNCERT code and the best estimate case was generated using the CAFTA quantification engine. Running with UNCERT allows the calculation of the mean value, accounting for the uncertainties in the basic event probabilities whereas running with CAFTA generates a point estimate based on the basic event probabilities while ignoring any associated uncertainty.

Duke Energy 13.01.b Response:

Overall the application is a reduction to plant risk. The application remains a risk reduction with the addition of the seismic risk estimate. The addition of ESPS allows for the improved diversification of power generating systems for loss of offsite power scenarios.

With the contribution from seismic for CDF and LERF, the risk estimates (based on internal events, internal flooding, high winds and seismic) exceed the acceptance guidelines for ICCDP and ICLERP. The limitations of the seismic model have been discussed in the response to RAI 5, dated March 7, 2019 (ADAMS Accession No. ML19066A354). The conservatisms and limitations that exists within this model lead to higher obtained values for CDF and LERF for the seismic contribution to the calculated ICCDP and ICLERP.

Maintenance activities that require the extended completion time will limit the exposure to potential high wind scenarios (from severe weather or hurricanes). This requirement is proposed to be a license condition for the application, as shown in Attachments 3 and 4. The site will determine if the potential for severe weather exists prior to performing work on the emergency diesel generator. In doing so, the site will verify weather data for the selected time frame and will avoid time frames in which severe weather could occur. Forecasting data has improved markedly and in general the seven-day forecast accuracy is around 80% [Ref. 1]. Given that the seven-day forecast would cover 50% of the required Completion Time, the high winds contribution can be reduced by 40% as the forecasted weather would preclude events that would normally make up the high winds analysis. This reduction to the high winds analysis during the Completion Time results in risk estimates that are under the required risk thresholds and does not credit FLEX for mitigation (Tables 1 and 2).

Credit of the FLEX in PRA can be used to mitigate accident sequences. In the experiences of Duke Energy and the industry (EPRI TR 3002013018 [Ref. 2]), the dominant failures associated with crediting FLEX are the operator actions to implement the FLEX equipment. Component level failures make up a much smaller contribution to the failure probabilities. FLEX actions can vary in complexity from relatively simple actions like refilling fuel in a pump for the required mission time, to complex actions like retrieving and aligning pump or generators to provide water or power. These actions have a large variation in the human error probability, generally ranging from as high as 0.4 to as low as 1E-03. This is based on EPRI documented experiences and adjust upward to account for uncertainties and potential dependencies. In general, the operator actions will bound the analysis. A failure probability of 0.4 was used as the bounding human error probability. The equipment failure probabilities are much less than this value and therefore does not contribute significantly to the risk profile as equipment failures would be at least one to two orders of magnitude below the human failures. FLEX was designed for mitigation of external hazards such as high winds and seismic events. Given that at least 50% of high wind sequences and over 50% of the seismic results involve a diesel run failure allowing additional time to implement FLEX strategies, a conservative estimate that FLEX can be applied to 35% of the results for high winds and seismic hazards was assumed. Applying FLEX to 35% of the results for high winds and seismic yields and overall risk reduction of 21%. In crediting FLEX even in an overly conservative case like this, for applicable external hazards would produce risk deltas that meet the applicable regulatory guidelines. Therefore, given this conservative credit, the results in risk estimates are under the required risk thresholds (Tables 3 and 4).

No credit was taken for additional conservatisms that would further decrease the risk deltas. The high winds analysis assumed a loss of offsite power event for every high wind sequence. This is an additional large conservatism.

As demonstrated in the tables below, credit for review of the weather forecast for severe weather and credit for FLEX provides confidence that the risk increase (including seismic) associated with the extended Completion Time for an inoperable DG is less than the acceptance criteria.

In addition, combining the credit for FLEX in mitigating external hazards and the reduction for the exposure to potential severe weather during the allowed outage time for the diesel provides and additional margin for the acceptance criteria for ICCDP and ICLERP. This is shown in Tables 5 and 6.

Supporting tables

High Winds Reduction

Table 1: RG 1.177 ICCDP Summary (Aggregate Sensitivity 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	1.24E-05	5.72E-06	14/365	2.56E-07
Fire	2.81E-05	2.27E-05	14/365	2.06E-07
Seismic	5.42E-06	5.44E-07	14/365	1.87E-07
			Sum =	8.39E-07

Table 2: RG 1.177 ICLERP Summary (Aggregate Sensitivity 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	1.17E-06	7.46E-07	14/365	1.63E-08
Fire	2.01E-06	1.54E-06	14/365	1.77E-08
Seismic	7.96E-07	1.19E-07	14/365	2.60E-08
			Sum =	7.23E-08

FLEX Credit Only

Table 3: RG 1.177 ICCDP Summary (Aggregate Sensitivity 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	1.64E-05	4.52E-06	14/365	4.56E-07
Fire	2.81E-05	2.27E-05	14/365	2.06E-07
Seismic	4.28E-06	4.30E-07	14/365	1.48E-07
			Sum =	9.99E-07

Table 4: RG 1.177 ICLERP Summary (Aggregate Sensitivity 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	1.54E-06	5.89E-07	14/365	3.65E-08
Fire	2.01E-06	1.54E-06	14/365	1.77E-08
Seismic	6.29E-07	9.40E-08	14/365	2.05E-08
			Sum =	8.70E-08

FLEX and High Wind Reduction Credit

Table 5: RG 1.177 ICCDP Summary (Aggregate Sensitivity 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	9.84E-05	4.52E-06	14/365	2.04E-07
Fire	2.81E-05	2.27E-05	14/365	2.06E-07
Seismic	4.28E-06	4.30E-07	14/365	1.48E-07
			Sum =	7.48E-07

Table 6: RG 1.177 ICLERP Summary (Aggregate Sensitivity 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	9.24E-07	5.89E-07	14/365	1.28E-08
Fire	2.01E-06	1.54E-06	14/365	1.77E-08
Seismic	6.29E-07	9.40E-08	14/365	2.05E-08
			Sum =	6.33E-08

References:

1. https://scijinks.gov/forecast-reliability/
2. Human Reliability Analysis (HRA) for Diverse and Flexible Mitigation Strategies (FLEX) and Use of Portable Equipment, EPRI TR 3002013018, November 2018

Duke Energy 13.01.c Response:

Between the time of the May 2, 2017, LAR submittal and the March 7, 2019, RAI Response, the procedure associated with the ESPS operator action was finalized and approved. The calculated HEP included in the May 2, 2017 LAR submittal was based on a draft procedure. With the approved procedure and discussions with operations, updated operator timings were developed, validated, and inputted to calculate an updated HEP. With the updated timing, a more accurate dependency analysis was generated.

The risk values provided in RAI 13.01.b response, reflect the updated dependency analysis and upon issuance of the Catawba amendment for the 14 day DG Completion Time, Duke Energy will confirm that the risk estimates continue to meet the risk acceptance guidelines of RG 1.174 and RG 1.177 using the final issued ESPS procedure, associated HRA modeling, and the conservatism considered in response to RAI 13.01.b in accordance with the proposed license condition (Commitment 10) from the letter dated, March 7, 2019 (ADAMS Accession No. ML19066A354).

Attachment 2

Response to NRC TS-related RAI Clarifications

NRC TS-related RAI Clarifications:

We are aware that you already know the following statements, but for the sake of communication and for you to know our thought process, we state the following:

To meet the TS 3.7.8 LCO, the TS Bases states:

While the NSWS is operating in the normal dual supply and discharge header alignment, an NSWS train is considered OPERABLE during MODES 1, 2, 3, and 4 when:

a. 1. Both NSWS pumps on the NSWS loop are OPERABLE; or

2. One unit's NSWS pump is OPERABLE and one unit's flowpath to the non-essential header, AFW pumps, and Containment Spray heat exchangers are isolated (or equivalent flow restrictions); and

b. The associated piping, valves, and instrumentation and controls required to perform the safety related function are OPERABLE.

This operability requirement makes provision for a single failure in any NSWS loop to have a remaining NSWS loop which has two NSWS pumps capable of supplying a unit 1 and a unit 2 NSWS train for accident mitigation and opposite unit cooldown. Two pumps/loop are necessary since the flowpath isolations described in a.2 above are not enacted.

The conclusion we draw from this is that 4 pumps must be operable to ensure each unit has two NSWS trains OPERABLE. The TS 3.7.8 LCO requirements account for the automatic MOV lineups that occur depending whether Lake Wylie is available and what unit experiences the DBA. If any NSWS Pump single failure would occur after a DBA, the two NSWS pumps on the NSWS loop that has two OPERABLE NSWS pumps ensures that each unit has one operable NSWS Train for accident mitigation and opposite unit cooldown. For example, if the A NSWS loop has the two operable NSWS pumps (1A and 2A) then the two NSWS trains 1A and 2A perform the necessary safety functions.

Your draft response for Required Action C.2
The purpose of Required Action C.2, as you stated in your draft response, and is also stated in your TS 3.8.1 Bases and is also described in the Standard Technical Specifications is to “provide assurance that an event coincident with a single failure of the associated diesel generator (DG) will not result in a complete loss of safety function.”

In your response to question 1, you addressed the case where “If the NSWS pumps were added to proposed Required Action C.2.” The scenario you discussed (1B offsite circuit is inoperable and the 2A NSWS pump became inoperable) concludes that the 1A and 2B NSWS pumps remain operable. You also stated the 1B NSWS pump although declared inoperable because of the RA C.2, still has emergency power (1B DG). We agree so far. But, now consider the scenario that RA C.2 is in place to address, i.e. “provide assurance that an event coincident with a single failure of the associated diesel generator (DG) will not result in a complete loss of safety function.” If an event occurred, i.e. a DBA and a single failure of the 1B DG, the only NSWS pumps running would be NSWS pumps 1A and 2B. The question now is, “with neither NSWS loop having two NSWS pumps (as the TS 3.7.8 Bases says is necessary), is there a loss of safety function?” The TS Bases statement above that require two NSWS pumps in a loop to make the associated unit 1 and unit 2 NSWS trains operable, strongly imply that one NSWS

pump each in loops A and B, although capable of supplying the same GPM as two NSWS pumps in the same loop, may not distribute the flow as needed. If this case is a loss of safety function, then RA C.2 should include the NSWS pumps.

We are aware that you stated in your October 8, 2018 letter that the 1B and 2A NSWS pumps supplied all necessary NSWS flow to mitigate a DBA in one unit and cooldown the opposite unit and that you included a change to the TS 3.7.8 Bases stating that "one operable NSWS pump on each loop has sufficient capacity to supply post LOCA loads on one unit and shutdown and cooldown loads on the other unit." Your October 8, 2018 letter also stated that the loops were isolated from each other when stating that the 1B and 2A NSWS pumps were sufficient. We understand the capacity of any two NSWS pumps would be sufficient, but the necessary valve lineup would also have to be achieved.

Your draft response for Required Action D.3
The purpose of Required Action D.3, as you stated in your draft response, and is also stated in your TS 3.8.1 Bases and is also described in the Standard Technical Specifications is to "provide assurance that a loss of offsite power, during the period the LCO 3.8.1 d DG that is necessary to supply power to a train of shared systems is inoperable, does not result in a complete loss of safety function."

In your response to question 1, you addressed the case where "If the NSWS pumps were added to proposed Required Action D.3." The scenario you discussed (1B DG is inoperable and the 2A NSWS pump became inoperable) concludes that the 1A and 2B NSWS pumps remain operable. You also stated the 1B NSWS pump although declared inoperable because of the RA D.3, still has and normal power (1B offsite power). We agree so far. But, now consider the scenario that RA D.3 is in place to address. i.e., "provide assurance that a loss of offsite power, during the period the LCO 3.8.1 d DG that is necessary to supply power to a train of shared systems is inoperable, does not result in a complete loss of safety function." If a loss of offsite power occurred, the only NSWS pumps running would be NSWS pumps 1A and 2B. The same question stated above for proposed RA C.2 exists for this scenario, RA D.3. If this case is a loss of safety function, then RA D.3 should include the NSWS pumps.

Consider one unit in Mode 5

TS Bases 3.7.8 states:
"One NSWS loop containing one OPERABLE NSWS pump has sufficient capacity to maintain one unit indefinitely in MODE 5 (commencing 36 hours following a trip from RTP) while supplying the post LOCA loads of the other unit. Thus, after a unit has been placed in MODE 5, only one NSWS pump and its associated emergency diesel generator are required to be OPERABLE on each loop, in order for the system to be capable of performing its required safety function, including single failure considerations."

One NSWS pump operable in each NSWS loop satisfies the LCO requirements of TS 3.7.8. If the DG associated with one of those NSWS pumps became inoperable, and the other NSWS pump became inoperable the operating unit would be in a 72-hour Completion Time in TS 3.7.8 and TS 3.8.1. But it could possibly lose all NSWS and safety function if there were a loss of offsite power. This would suggest that NSWS pumps should be included in RA D.3. Similar reasoning would apply for proposed RA C.2

Duke Energy Response:

Catawba Technical Specification (TS) 5.5.15, "Safety Function Determination Program (SFDP)" defines a loss of safety function as follows:

> "A loss of safety function exists when, assuming no concurrent single failure, a safety function assumed in the accident analysis cannot be performed"

The CNS TS definition of "loss of safety function" is consistent with the NRC staff's Inspection Manual Chapter 0326 for operability which defines "Specified Function/Specified Safety Function" as the following:

> "03.15 Specified Function/Specified Safety: The definition of operability refers to the capability to perform the "specified function" at non-improved TS plants or "specified safety function" at improved STS plants. The specified function/specified safety function of an SSC is that specified safety function(s) in the CLB for the facility."

There is not a loss of safety function with one Nuclear Service Water System (NSWS) pump on each loop (e.g., 1A and 2B NSWS pumps operable and 1B and 2A NSWS pumps inoperable). The safety function "assumed in the accident analysis" for the CNS NSWS when both units are operating is to remove heat in support of ECCS operation such that a LOCA can be mitigated on one unit and support a normal shutdown of the remaining unit. The following system actuations occur for the LOCA, dual-unit LOOP event:

- NSWS supply to the 1A, 1B, 2A and 2B Component Cooling heat exchangers (no operator action required for either unit)
- NSWS supply to the 1A, 1B, 2A and 2B DG Engine Jacket Water Coolers (no operator action required for either unit)
- NSWS supply to the A or B Control Room Area chiller condenser (Condensers A and B are shared between units; no operator action required for either unit)
- NSWS supply to two Containment Spray heat exchangers for the accident unit (Aligned by operator action from the Control Room when the unit transfers from safety injection mode to sump recirculation mode.)
- NSWS supply to Auxiliary Feedwater automatically aligns if low pump suction pressure is detected (no operator action required for either unit)

Duke Energy has demonstrated that a LOCA can be mitigated and the other unit can be brought to a safe, cold shutdown with any combination of two NSWS pumps. That information was provided on the docket by letter dated October 8, 2018. It should also be noted that all necessary NSWS functions for the immediate (i.e., safety injection mode) response to the LOOP/LOCA event are automatic. No operator action (e.g., NSWS valve manipulations), other than aligning the NSWS to the Containment Spray heat exchangers from the Control Room when the unit is taken to the sump recirculation mode from the safety injection mode, is required for the accident unit. The valve positioning in the LOOP/LOCA event is verified during train specific Engineered Safeguards Features (ESF) testing. Each NSWS train is flow balance tested in the LOOP/LOCA alignment, with throttle valves appropriately adjusted, to assure that all components receive sufficient flow to meet the requirements of the LOOP/LOCA event.

Duke Energy proposes the following changes, in red, to the CNS TS 3.8.1 provided in the March 7, 2019 letter (also shown in Attachment 5):

C. 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 is entered with no AC power source to a train. ---	
	C.1 Perform SR 3.8.1.1 for the required offsite circuit(s).	1 hour <u>AND</u> Once per 8 hours thereafter
	<u>AND</u>	
	C.2 Declare NSWS (including the NSWS pump), CRAVS, CRACWS or ABFVES with no offsite power available inoperable when the redundant NSWS (including the NSWS pump), 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)
	<u>AND</u>	
	C.3 Restore LCO 3.8.1.c offsite circuit to OPERABLE status.	72 hours

D. 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 D is entered with no AC power source to a train. ---	
	D.1 Verify both LCO 3.8.1.b DGs OPERABLE and the opposite unit's DG OPERABLE.	1 hour AND Once per 8 hours thereafter
	AND	
	D.2 Perform SR 3.8.1.1 for the required offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND	
	D.3 Declare NSWS (including the NSWS pump), CRAVS, CRACWS or ABFVES supported by the inoperable DG inoperable when the redundant NSWS (including the NSWS pump), CRAVS, CRACWS or ABFVES is inoperable.	4 hours from discovery of Condition D concurrent with inoperability of redundant required feature(s)
	AND	

Attachment 3

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].
NNN	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.	Upon implementation of Amendment No. [NNN].

Attachment 4

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].
SSS	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.	Upon implementation of Amendment No. [SSS].

Attachment 5

Proposed CNS Technical Specification 3.8.1 Marked up

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.5 Evaluate availability of Emergency Supplemental Power Source (ESPS).	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 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

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. 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 is entered with no AC power source to a train. --	
	C.1 Perform SR 3.8.1.1 for the required offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND	
	C.2 Declare NSWS (including the NSWS pump), CRAVS, CRACWS or ABFVES with no offsite power available inoperable when the redundant NSWS (including the NSWS pump), 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	
	C.3 Restore LCO 3.8.1.c offsite circuit to OPERABLE status.	72 hours

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. 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 D is entered with no AC power source to a train. --	
	D.1 Verify both LCO 3.8.1.b DGs OPERABLE and the opposite unit's DG OPERABLE.	1 hour AND Once per 12 hours thereafter
	AND	
	D.2 Perform SR 3.8.1.1 for the required offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND	
	D.3 Declare NSWS (including the NSWS pump), CRAVS, CRACWS or ABFVES supported by the inoperable DG inoperable when the redundant NSWS (including the NSWS pump), CRAVS, CRACWS or ABFVES is inoperable.	4 hours from discovery of Condition D concurrent with inoperability of redundant required feature(s)
	AND	(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. (continued)	D.4.1 Determine OPERABLE DG(s) is not inoperable due to common cause failures. OR D.4.2 Perform SR 3.8.1.2 for OPERABLE DG(s).	24 hours 24 hours
	AND 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 (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
~~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 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.	~~C~~E.1 Declare required feature(s) inoperable when its redundant required feature(s) is inoperable. AND ~~C~~E.2 Restore one offsite circuit to OPERABLE status.	12 hours from discovery of Condition ~~C~~ E concurrent with inoperability of redundant required features 24 hours
~~D~~F. 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~~F is entered with no AC power source to any train. --- ~~D~~F.1 Restore offsite circuit to OPERABLE status. OR ~~D~~F.2 Restore DG to OPERABLE status.	 12 hours 12 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
~~E~~G. Two LCO 3.8.1.b DGs inoperable. OR 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. OR Two LCO 3.8.1.d DGs inoperable.	~~E~~G.1 Restore one DG to OPERABLE status.	2 hours
~~F~~H. One automatic load sequencer inoperable.	~~F~~H.1 Restore automatic load sequencer to OPERABLE status.	12 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
~~G~~I. Required Action and associated Completion Time of Condition A, ~~B,~~ C, ~~D,~~ E, ~~or~~ 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.	~~G~~I.1 Be in MODE 3. AND ~~G~~I.2 Be in MODE 5.	6 hours 36 hours
~~H~~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 source inoperable.	~~H~~J.1 Enter LCO 3.0.3.	Immediately