UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

September 10, 2018

Mr. Ernest J. Kapopoulos, Jr.
Site Vice President
H. B. Robinson Steam Electric Plant
Duke Energy Progress, LLC
3581 West Entrance Road, RNPA01
Hartsville, SC 29550

SUBJECT: H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2 – ISSUANCE OF AMENDMENT NO. 261 TO ADD A SECOND QUALIFIED OFFSITE CIRCUIT AND FOR AUTOMATIC OPERATION OF LOAD TAP CHANGERS (CAC NO. MG0276; EPID L-2017-LLA-0308)

Dear Mr. Kapopoulos:

The U.S. Nuclear Regulatory Commission (the Commission) has issued the enclosed Amendment No. 261 to Renewed Facility Operating License No. DPR-23 for the H. B. Robinson Steam Electric Plant, Unit No. 2 (Robinson). This amendment is in response to your application dated September 27, 2017, as supplemented by letters dated May 16, July 11, and August 1, 2018.

The amendment revises the Technical Specifications to reflect the addition of a second qualified offsite power circuit. In addition, the amendment authorizes the modification of the Robinson Updated Final Safety Analysis Report to allow for the use of automatic load tap changers on the new (230 kilovolt (kV)) and the replacement (115 kV) startup transformers.

A copy of our related Safety Evaluation is also enclosed. Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,

Dennis J Galvin

Dennis J. Galvin, Project Manager
Plant Licensing Branch II-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-261

Enclosures:
1. Amendment No. 261 to DPR-23
2. Safety Evaluation

cc: Listserv

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

DUKE ENERGY PROGRESS, LLC

DOCKET NO. 50-261

H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 261
Renewed License No. DPR-23

1. The U.S. Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Duke Energy Progress, LLC (the licensee), dated September 27, 2017, as supplemented by letters dated May 16, July 11, and August 1, 2018, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

Enclosure 1

2. Accordingly, the license is amended by changes to the Technical Specifications, as indicated in the attachment to this license amendment. Paragraph 3.B. of Renewed Facility Operating License No. DPR-23 is hereby amended to read as follows:

    B. Technical Specifications

    The Technical Specifications contained in Appendix A, as revised through Amendment No. 261 are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

3. The license is amended to authorize revision to the Updated Final Safety Analysis Report (UFSAR) as set forth in the application dated September 27, 2017, as supplemented by letters dated May 16, July 11, and August 1, 2018. The licensee shall update the UFSAR to incorporate the changes as described in the licensee's application dated September 27, 2017, as supplemented by letters dated May 16, July 11, and August 1, 2018, and the NRC staff's safety evaluation attached to this amendment, and shall submit the revised description authorized by this amendment with the next update of the UFSAR.

4. This license amendment is effective as of its date of issuance and shall be implemented by the end of the next refueling outage.

FOR THE NUCLEAR REGULATORY COMMISSION

V. Booma

Booma Venkataraman, Acting Chief
Plant Licensing Branch II-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Renewed License
and Technical Specifications

Date of Issuance: September 10, 2018

ATTACHMENT TO LICENSE AMENDMENT NO. 261

H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2

RENEWED FACILITY OPERATING LICENSE NO. DPR-23

DOCKET NO. 50-261

Replace page 3 of Renewed Facility Operating License No. DPR-23 with the attached page 3.

Replace the following pages of the Appendix A Technical Specifications with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Remove Pages	Insert Pages
3.8-1	3.8-1
3.8-2	3.8-2
3.8-3	3.8-3
-------	3.8.3A
3.8-4	3.8-4
3.8-12	3.8-12

D. Pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess, and use in amounts as required any byproduct, source, or special nuclear material without restriction to chemical or physical form for sample analysis or instrument and equipment calibration or associated with radioactive apparatus or components;

E. Pursuant to the Act and 10 CFR Parts 30 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by operation of the facility.

3. This renewed license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations: 10 CFR Part 20, Section 30.34 of 10 CFR Part 30, Section 40.41 of 10 CFR Part 40, Section 50.54 and 50.59 of 10 CFR Part 50, and Section 70.32 of 10 CFR Part 70; and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

A. Maximum Power Level

The licensee is authorized to operate the facility at a steady state reactor core power level not in excess of 2339 megawatts thermal.

B. Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 261 are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

(1) For Surveillance Requirements (SRs) that are new in Amendment 176 to Final Operating License DPR-23, the first performance is due at the end of the first surveillance interval that begins at implementation of Amendment 176. For SRs that existed prior to Amendment 176, including SRs with modified acceptance criteria and SRs whose frequency of performance is being extended, the first performance is due at the end of the first surveillance interval that begins on the date the Surveillance was last performed prior to implementation of Amendment 176.

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 emergency AC Electrical Power Distribution System; and

b. Two diesel generators (DGs) capable of supplying the onsite emergency power distribution subsystem(s).

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

ACTIONS

-----NOTE-----
LCO 3.0.4.b is not applicable to DGs.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One offsite circuit inoperable.	A.1 Perform SR 3.8.1.1 for OPERABLE offsite circuit.	1 hour AND Once per 12 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	

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.3	Restore offsite circuit to OPERABLE status	72 hours AND 10 days from discovery of failure to meet LCO
B. One DG inoperable.	B.1	Perform SR 3.8.1.1 for the offsite circuit.	1 hour AND Once per 12 hours thereafter
	AND		
	B.2	Declare required feature(s) supported by the inoperable DG inoperable when its required redundant feature(s) is inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	AND		
	B.3.1	Perform SR 3.8.1.2 for OPERABLE DG	24 hours
	OR		
	B.3.2.1	Determine OPERABLE DG is not inoperable due to common cause failure. AND	24 hours
			(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	-----------------NOTE------------------ Not required to be performed when the cause of the inoperable DG is pre-planned maintenance and testing. --		
	B.3.2.2	Perform SR 3.8.1.2 for OPERABLE DG.	96 hours
	AND		
	B.4	Restore DG to OPERABLE status.	7 days AND 10 days from discovery of failure to meet LCO
C. Two offsite circuits inoperable.	C.1	Declare required feature(s) inoperable when its redundant required feature(s) is inoperable.	12 hours from discovery of Condition C concurrent with inoperability of redundant required features
	AND		
	C.2	Restore one offsite circuit to OPERABLE status.	24 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. One offsite circuit inoperable. AND One DG inoperable.	---------------NOTE--------------- Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems – Operating," when Condition D is entered with no AC power source to any train. ------------------------------------		
	D.1	Restore offsite circuit to OPERABLE status.	12 hours
	OR		
	D.2	Restore DG to OPERABLE status.	12 hours
E. Two DGs inoperable	E.1	Restore one DG to OPERABLE status.	2 hours
F. Required Action and associated Completion Time of Condition A, B, C, D, or E not met.	F.1	Be in MODE 3.	6 hours
	AND		
	F.2	Be in MODE 5.	36 hours
G. Three or more AC sources inoperable.	G.1	Enter LCO 3.0.3	Immediately

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each offsite circuit.	7 days
SR 3.8.1.2	-------------------------NOTES------------------------------- 1. Performance of SR 3.8.1.7 satisfies this SR. 2. All DG starts may be preceded by an engine prelube period and followed by a warmup period prior to loading. 3. A modified DG start involving idling and gradual acceleration to synchronous speed may be used for this SR as recommended by the manufacturer. When modified start procedures are not used, the time, voltage, and frequency tolerances of SR 3.8.1.7 must be met. --- Verify each DG starts from standby conditions and achieves steady state voltage ≥ 467 V and ≤ 493 V, and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	31 days

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.15 (continued)	5. supplies permanently connected and auto connected emergency loads for ≥ 5 minutes.	
SR 3.8.1.16	------------------------NOTE------------------------ 1. This Surveillance shall not be performed in MODE 1 or 2. 2. SR 3.8.1.16 is not required to be met if 4.160 kV bus 2 and 480 V Emergency Bus 1 power supply is from a start up transformer. --- Verify automatic transfer capability of the 4.160 kV bus 2 and the 480 V Emergency bus 1 loads from the Unit auxiliary transformer to a start up transformer.	24 months
SR 3.8.1.17	------------------------NOTE------------------------ All DG starts may be preceded by an engine prelube period. --- Verify when started simultaneously from standby condition, each DG achieves, in ≤ 10 seconds, voltage ≥ 467 V and frequency ≥ 58.8 Hz, and after steady state conditions are reached, maintains voltage ≥ 467 V and ≤ 493 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	10 years
SR 3.8.1.18	------------------------NOTE------------------------ This Surveillance shall not be performed in MODE 1 or 2. --- Verify manual transfer of AC power sources from the normal offsite circuit to each alternate offsite circuit.	24 months

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SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 261 TO

RENEWED FACILITY OPERATING LICENSE NO. DPR-23

DUKE ENERGY PROGRESS, LLC

H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2

DOCKET NO. 50-261

1.0 INTRODUCTION

By application dated September 27, 2017 (Reference 1), as supplemented by letters dated May 16 (Reference 2), July 11 (Reference 3), and August 1, 2018 (Reference 4), Duke Energy Progress, LLC (Duke Energy or the licensee), requested changes to the Technical Specifications (TSs) for the H. B. Robinson Steam Electric Plant, Unit No. 2 (Robinson). The proposed changes would revise (1) TS 3.8.1, "AC [Alternating Current] - Sources - Operating," related to addition of a second qualified offsite circuit with a 230 kilovolt (kV) startup transformer (SUT) and (2) the current licensing basis as reflected in the marked up pages of the Updated Final Safety Analysis Report (UFSAR) in the license amendment request (LAR), as supplemented, to allow use of new load tap changers (LTCs) as subcomponents on the new 230 kV SUT, as well as on the replacement 115 kV SUT in the automatic mode of operation.

The supplements dated May 16, July 11, and August 1, 2018, provided additional information that clarified the application, did not expand the scope of the application as originally noticed, and did not change the U.S. Nuclear Regulatory Commission (NRC or the Commission) staff's original proposed no significant hazards consideration determination as published in the *Federal Register* on December 5, 2017 (82 FR 57471).

2.0 REGULATORY EVALUATION

As discussed further below, Robinson was designed and licensed to meet proposed general design criteria (GDC) published by the Atomic Energy Commission (AEC) for public comment in the *Federal Register* (32 FR 10213) on July 11, 1967. At the time the offsite power connection to Robinson's safety buses through a single circuit was acceptable. Herein the licensee proposes to adopt TSs that recognize the addition of another offsite power circuit to power a safety bus that will be added via plant modifications to be completed during refueling outage RO31 that begins in September 2018. Following the modifications each safety bus will be powered via a separate physically independent circuit. The addition of a second offsite power circuit is a safety enhancement. The proposed TS modifications will recognize the second offsite circuit and afford the licensee additional remedial actions that recognize the enhancement.

The NRC staff considered the following regulatory requirements related to this application:

Title 10 of the *Code of Federal Regulations* (10 CFR) Section 50.36(c)(2), "Limiting conditions for operation [LCOs]," states, in part, that LCOs are the lowest functional capability or performance levels of equipment required for safe operation of the facility. 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 TSs until the condition can be met.

Section 50.36(c)(3) of 10 CFR, "Surveillance requirements [SRs]," states that SRs are requirements relating to test, calibration, or inspection to assure that the necessary quality of systems and components is maintained, the facility operation will be within safety limits, and that the LCOs will be met.

Robinson received its construction permit in 1967 and was licensed for operation in July 1970. The plant's design approval for the construction phase was based on the proposed GDC (hereinafter referred to as the "draft GDC"). On February 20, 1971, the AEC published in the *Federal Register* (36 FR 3255) a final rule that added Appendix A to 10 CFR Part 50, "General Design Criteria for Nuclear Power Plants" (hereinafter referred to as the "final GDC"). Differences between the draft GDC and final GDC included a consolidation from 70 to 64 criteria. As discussed in the NRC Staff Requirements Memorandum for SECY-92-223, "Resolution of Deviations Identified during the Systematic Evaluation Program," dated September 18, 1992, the Commission decided not to apply the final GDC to plants with construction permits issued prior to May 21, 1971.

Based on a review of the Robinson UFSAR (Reference 5), Section 3.1, "Conformance with General Design Criteria," the NRC staff identified the following draft GDC as being applicable to the proposed amendment:

The Robinson UFSAR, Section 3.1.2.39, "Emergency Power" (GDC 39), states that:

> An emergency power source shall be provided and designed with adequate independency, redundancy, capacity, and testability to permit the functioning of the engineered safety features [ESFs] and protection systems required to avoid undue risk to the health and safety of the public. This power source shall provide this capacity assuming a failure of a single active component.

The NRC staff also considered the following regulatory guidance related to this application. NUREG-1431, "Standard Technical Specifications (STS), Westinghouse Plants," Revision 4.0, (Reference 6), provides the current version of improved STS for Westinghouse Plants. The improved STS were developed based on the criteria in the Final Commission Policy Statement on Technical Specifications Improvements for Nuclear Power Reactors, dated July 22, 1993 (58 FR 39132), which was subsequently codified by changes to 10 CFR 50.36 (60 FR 36953). The abstract for NUREG-1431 states, in part, that licensees are encouraged to upgrade their TSs consistent with the criteria and conforming, to the practical extent, to Revision 4.0 to the improved STS. In the Policy Statement licensees were encouraged to adopt the STS. TS 3.8.1 of STS is written to recognize two separate and physically independent offsite power lines.

3.0 TECHNICAL EVALUATION

The licensee requested NRC approval of the following changes in the LAR:

1. Robinson will increase the number of qualified offsite circuits from one to two. Specifically, a second SUT will be connected to the 230 kV switchyard. The additional SUT will result in a second qualified circuit between the offsite transmission network and the onsite emergency AC Electrical Power Distribution System. TS 3.8.1, "AC Sources - Operating," will be changed to reflect the addition of a second qualified offsite circuit. The addition of a second offsite circuit in TS 3.8.1 results in the Robinson TSs being more consistent with NUREG-1431 and other Westinghouse plants.

2. The proposed changes will also revise the Robinson current design basis as reflected in the UFSAR to allow for the use of LTCs in the automatic mode of operation. The licensee will be installing LTCs at Robinson as subcomponents on the new 230 kV SUT, as well as on the replacement for the existing 115 kV SUT. There are no changes to the Robinson TSs associated with the request to use LTCs in the automatic mode of operation.

3.1 Addition of Second Qualified Circuit Technical Specification Changes

The licensee proposed 11 TS changes associated with the addition of a second qualified circuit. The current and proposed TSs are identified for each change, and then the proposed change is evaluated.

3.1.1 TS 3.8.1 LCO 3.8.1.a Revision (Change 1)

The current TS 3.8.1 LCO 3.8.1.a reads as:

> LCO 3.8.1.a The qualified circuit between the offsite transmission network and the onsite emergency AC Electrical Power Distribution System; and

The proposed TS 3.8.1 LCO 3.8.1.a would read as:

> LCO 3.8.1.a Two qualified circuits between the offsite transmission network and the onsite emergency AC Electrical Power Distribution System; and

Evaluation of LCO 3.8.1.a

In the LAR, the licensee identified offsite circuit #1 as 115 kV SUT (including the LTC in the automatic or manual mode of operation), which is supplied from the 115 kV switchyard and is fed through 4.16 kV breaker 52-36 powering station service transformer 2F, which in turn, powers engineered safety feature (ESF) bus E1 through its normal feeder breaker. Offsite circuit #2 consists of the 230 kV SUT (including the LTC in the automatic or manual mode of operation), which is supplied from the 230 kV switchyard and is fed through 4.16 kV breaker 52-47 powering station service transformer 2G, which in turn, powers ESF bus E2 through its normal feeder breaker. In instances where the main generator output is connected to the transmission system with one offsite circuit (SUT) out of service, the LTC for the operable offsite circuit (SUT) must remain in automatic.

The licensee stated in the LAR that each offsite circuit is capable of maintaining rated frequency and voltage within acceptable limits and accepting required loads during a design-basis accident (DBA), while connected to the ESF buses.

The LAR is proposing to credit qualified offsite circuit #2 at Robinson. The licensee is proposing to update TS LCO 3.8.1.a to identify two qualified offsite circuits at Robinson.

Section 50.36(c)(2)(ii)(C) of 10 CFR states that a TS LCO must be established for:

> A structure, system, or component that is part of the primary success path and which functions or actuates to mitigate a design basis accident or transient that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.

In the LAR, the licensee stated that addition of a second qualified circuit and SUT will result in increased availability of required power to shut down the reactor and maintain in a safe shutdown condition after a postulated DBA. The two immediately available offsite power sources will be totally independent of and electrically isolated from each other to the extent practical in order to minimize the likelihood of a single event causing loss of both offsite circuits. The 115 kV and 230 kV SUTs will be physically separated from each other in order to minimize simultaneous failure. The NRC staff finds that the licensee's proposed LCO for two credited qualified offsite circuits, which will be independent and electrically isolated and will be part of the primary success path to mitigate a DBA or transient that may present a challenge to the integrity of a containment assuming a single failure, is acceptable.

The NRC staff reviewed the proposed TS LCO 3.8.1.a and found that the proposed TS LCO recognizes the second offsite power circuit and is consistent with NUREG-1431 and is, therefore, acceptable. The NRC staff finds that the proposed revision to the LCO 3.8.1.a represents the lowest functional capability or performance levels of equipment required for safe operation of the facility and therefore meets the 10 CFR 50.36(c)(2)(1) requirements for an LCO, and, therefore, is acceptable.

3.1.2 TS 3.8.1 Condition A Revision (Change 2)

The licensee proposed to revise TS 3.8.1 Condition A by adding a new Required Action A.1, renumbering the current Required Actions A.1 and A.2 to A.2 and A.3, and revising the associated completion times (CTs).

The current TS 3.8.1 Condition A reads as:

CONDITION A	The qualified offsite circuit inoperable.
REQUIRED ACTION A.1	Declare required feature(s) with no offsite power available inoperable when its redundant required feature(s) is inoperable.
	<u>AND</u>
REQUIRED ACTION A.2	Restore offsite circuit to OPERABLE status.

CT for REQUIRED ACTION A.1	12 hours from discovery of no offsite power to one train concurrent with inoperability of redundant required feature(s),
CT for REQUIRED ACTION A.2	24 hours <u>AND</u> 8 days from discovery of failure to meet LCO

The proposed Unit No. 2 TS 3.8.1 Condition A would read as:

CONDITION A	One offsite circuit inoperable.
REQUIRED ACTION A.1	Perform SR 3.8.1.1 for OPERABLE offsite circuit.
	<u>AND</u>
REQUIRED ACTION A.2	Declare required feature(s) with no offsite power available inoperable when its redundant required feature(s) is inoperable.
	<u>AND</u>
REQUIRED ACTION A.3	Restore offsite circuit to OPERABLE status.

CT for REQUIRED ACTION A.1	1 hour AND Once per 12 hours thereafter
CT for REQUIRED ACTION A.2	24 hours from discovery of no offsite power to one train concurrent with inoperability of redundant required feature(s)
CT for REQUIRED ACTION A.3	72 hours AND 10 days from discovery of failure to meet LCO.

3.1.2.1 Evaluation of TS 3.8.1 Condition A Revision

The licensee is adding a new second qualified circuit with a 230 kV transmission line, 230 kV SUT with LTC to the 4.16 kV safety-related buses. This will ensure that one redundant and independent offsite circuit will be available in case the other offsite circuit is inoperable for any reason.

3.1.2.1.1 Required Action A.1 and Associated Completion Time Changes

In the LAR, the licensee stated that to ensure a highly reliable power source remains with one offsite circuit inoperable, it is necessary to verify the operability of the remaining qualified offsite circuit by performing SR 3.8.1.1 on a more frequent basis. However, if a second required circuit fails SR 3.8.1.1, Condition C for two offsite circuits inoperable will be entered.

The LAR states that the proposed CT for Required Action A.1 is "1 hour <u>AND</u> once per 12 hours thereafter." The licensee stated in the LAR that verifying the operability of the remaining required offsite circuit with one offsite circuit inoperable would be done once per 12 hours, which corresponds to once per shift. The licensee determined that the proposed CT of "Once per

12 hours thereafter" (i.e., once per shift) provides a reasonable time interval to perform a reevaluation of the operability of the remaining offsite circuit and to perform SR 3.8.1.1. This timeframe is also based on the CT (once per 12 hours thereafter) for the current Required Action B.1 to perform SR 3.8.1.1.

Based on the above discussion, the NRC staff finds that the proposed changes to Required Action A.1 to perform SR 3.8.1.1 for the operable offsite circuit with a CT of 1 hour and "once per 12 hours thereafter" is consistent with the current CT for Required Action B.1 to perform the same SR 3.8.1.1. Therefore, the NRC staff finds the revised Required Action A.1 acceptable.

3.1.2.1.2 Required Action A.2 and Associated Completion Time Changes

Required Action A.2, which applies if offsite source is not available to one train, is intended to provide assurance that this event, coincident with a single failure of the associated diesel generator (DG), will not result in a complete loss of safety function of critical redundant required features such as motor driven auxiliary feedwater pumps.

In the LAR, the licensee stated that the 24-hour CT for Required Action A.2 is intended to allow the operator time to evaluate and repair any discovered inoperability. This CT also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this required action, the CT only begins on discovery that both: (a) one train has no offsite power supplying its loads and (b) a required feature on the other train is inoperable. If at any time during the existence of Condition A (one offsite circuit inoperable) a redundant required feature subsequently becomes inoperable, this CT begins to be tracked. The 24-hour CT is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown. The remaining operable offsite circuit and DGs are adequate to supply electrical power to Train A and Train B of the onsite Class 1E Distribution System. Additionally, the 24-hour CT takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period. Based on the forgoing, the NRC staff finds the 24-hour CT for Required Action A.2 reasonable and, therefore, acceptable.

3.1.2.1.3 Required Action A.3 and Associated Completion Time Changes

The NRC staff's review of Required Action A.3 of the LAR indicated that the restoration of the one inoperable circuit is required within 72 hours. With one offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased with the potential for a challenge to the unit safety systems. In this condition, however, the remaining operable offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System. The 72-hour CT takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

The licensee has also proposed to extend the maximum CT in Required Action A.3 from 8 days to 10 days. The licensee stated that the maximum CT of 10-day limits the total time that LCO 3.8.1 is not met, while concurrently or simultaneously entering and exiting Condition A ("One offsite circuit inoperable") and Condition B ("One DG inoperable"). In addition, the licensee stated that the maximum CT of 10 days is based on the sum of the proposed CT (72 hours, which is 3 days) for the proposed Required Action A.3 to restore offsite circuit to operable status and the current CT (7 days) for Required Action B.4 to restore DG to operable status.

The NRC staff concludes that the proposed 10-day CT provides an appropriate maximum limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently or simultaneously. The "AND" connector between the 72-hour CT and 10-day CT means that both CT apply simultaneously, and the most restrictive CT must be met. The staff finds the 72-hour CT and 10-day CT for Required Action A.3 reasonable and, therefore, acceptable.

Based on the above, the NRC staff finds that collectively the proposed changes to TS 3.8.1 Condition A; Required Actions A.1, A.2, and A.3; and associated CTs; are consistent with NUREG-1431 and are acceptable remedial actions in accordance with 10 CFR 50.36(c)(2)(i) for the condition of one offsite circuit inoperable with the remaining operable offsite circuit and DGs available.

3.1.3 TS 3.8.1 Required Action B.4 Completion Time Revision (Change 3)

The current TS 3.8.1 Required Action B.4 CT reads as:

CT for REQUIRED ACTION B.4	7 days <u>AND</u> 8 days from discovery of failure to meet LCO

The proposed TS 3.8.1 Required Action B.4 CT would read as:

CT for REQUIRED ACTION B.4	7 days <u>AND</u> 10 days from discovery of failure to meet LCO

<u>Evaluation of Required Action B.4 and Associated CT Change</u>

The NRC staff's review of Required Action A.3 indicated that operation may continue in Condition B (one DG inoperable) for a period that should not exceed 7 days. In Condition B, the remaining operable DG and offsite circuits are adequate to supply electrical power to the onsite Distribution System. The 7-day CT takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period. The second CT "10 days" for Required Action B.4 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any one occurrence of failing to meet the LCO.

In the LAR, the licensee proposed a CT of "10 days from discovery of failure to meet LCO" limit, which is based on sum of the proposed current CT (7 days) for Required Action B.4 to restore DG to operable status and proposed CT (72 hours, which is 3 days) for Required Action A.3 to restore offsite circuit to operable status.

Since the NRC staff found the proposed CT for Required Action A3 acceptable, the NRC staff finds the proposed 10-day limit reasonable for situations in which Conditions A and B are entered concurrently and is, therefore, acceptable. The "AND" connector between the 7-day CT and 10-day CT means that both CTs apply simultaneously.

3.1.4 TS 3.8.1 New Condition C (Change 4)

The proposed TS 3.8.1 new Condition C would read as:

CONDITION C	Two offsite circuits inoperable.
REQUIRED ACTION C.1	Declare required feature(s) inoperable when its redundant required feature(s) is inoperable.
	<u>AND</u>
REQUIRED ACTION C.2	Restore one offsite circuit to OPERABLE status.
CT for REQUIRED ACTION C.1	12 hours from discovery of CONDITION C concurrent with inoperability of redundant required feature(s).
CT for REQUIRED ACTION C.2	24 hours.

<u>Evaluation of New Condition C, Required Actions C.1 and C.2, and Associated CTs</u>

The NRC staff's review of Required Action C.1 and associated CTs indicated that the Required Action C.1, which applies when two offsite circuits are inoperable, is intended to provide assurance that an event with a coincident single failure will not result in a complete loss of redundant required safety functions. The CT for this failure of redundant required features is reduced to 12 hours from that allowed for one train without offsite power (Required Action A.2). Required Action C.1 matches existing Required Action A.1 in the current TSs for the same applicable Condition (no operable offsite sources). Since that is true it is appropriate for the CTs (12 hours) to match.

Required Action C.2 essentially matches current TSs Required Action A.2. Although the wording is not identical both apply with no offsite circuits operable. The proposed CT of 24 hours also matches CT Required Action A.2.

The NRC staff finds that the proposed TS 3.8.1 Condition C, Required Actions C.1, C.2, and associated CTs are consistent with the current TSs and NUREG-1431.

Based on the above, the NRC staff finds that the proposed TS 3.8.1 Condition C, Required Actions C.1, C.2, and associated CTs meet the requirements of 10 CFR 50.36(c)(2)(i) as acceptable remedial actions for an LCO condition by ensuring that the necessary systems and components remain operable and are, therefore, acceptable.

3.1.5 TS 3.8.1 New Condition D (Change 5)

The proposed TS 3.8.1 new Condition D would read as:

CONDITION D	One offsite circuit inoperable. <u>AND</u> One DG inoperable.
REQUIRED ACTION	-----------------------------NOTE---------------------------- Enter applicable Conditions and Required Actions of LCO 3.8.9. "Distribution Systems – Operating." When CONDITION D is entered with no AC power source to any train. ---
REQUIRED ACTION D.1	Restore AC power to OPERABLE status. <u>OR</u>
REQUIRED ACTION D.2	Restore DG to OPERABLE status.
CT for REQUIRED ACTION D.1	12 hours.
CT for REQUIRED ACTION D.2	12 hours.

<u>Evaluation of New Condition D, Required Actions D.1 and D.2, and Associated CTs</u>

The NRC staff's review of Condition D, Required Actions D.1 and D.2, and associated CTs indicated that the required actions of Condition D are modified by a note to indicate that when Condition D is entered with no AC source to any train, the conditions and required actions for LCO 3.8.9, "Distribution Systems - Operating," must also be taken. LCO 3.0.6 makes inclusion of the note necessary since without the required actions of LCO 3.8.9 might not otherwise be taken. The power system redundancy is provided by two diverse sources of power. The reliability of the power systems with one offsite circuit and one DG inoperable may appear higher than that in Condition C (loss of both required offsite circuits). This difference in reliability is offset by the susceptibility to a single bus or switching failure of this power system configuration of one offsite circuit and one DG inoperable. The 12-hour CTs for Required Action D.1 to restore the offsite circuit and Required Action D.2 to restore the DG take into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

The NRC staff finds that TS 3.8.1 proposed Condition D, Required Actions D.1 and D.2, and associated CTs are consistent with NUREG-1431.

Based on the above, the NRC staff finds that TS 3.8.1 proposed Condition D, Required Actions D.1 and D.2, and associated CTs meet the requirements of 10 CFR 50.36(c)(2)(i) as appropriate remedial actions for an LCO condition by ensuring that the necessary systems and components remain operable and are, therefore, acceptable.

3.1.6 TS 3.8.1 New Condition E (Change 6)

The proposed TS 3.8.1 new Condition E would read as:

CONDITION E	Two DGs inoperable.
REQUIRED ACTION E.1	Restore one DG to OPERABLE status.
CT for REQUIRED ACTION E.1	2 hours.

<u>Evaluation of New Condition E, Required Action E.1, and Associated CT</u>

The NRC staff's review indicated that with Train A and Train B DGs inoperable, there are no remaining standby AC sources. Thus, with an assumed loss of offsite electrical power, insufficient standby AC sources are available to power the minimum required ESF functions. Since the offsite electrical power system is the only source of AC power for this level of degradation, the risk associated with continued operation for a very short time could be less than that associated with an immediate controlled shutdown (the immediate shutdown could cause grid instability, which could result in a total loss of AC power). Since any inadvertent generator trip could also result in a total loss of offsite AC power, however, the time allowed for continued operation is severely restricted.

The NRC staff finds the proposed addition of TS 3.8.1 Condition E, Required Action E.1, and the associated CT of 2 hours is consistent with NUREG-1431.

Based on the above, the NRC staff finds that TS 3.8.1 proposed Condition E, Required Action E.1, and the associated CT meet requirements of 10 CFR 50.36(c)(2)(i) as appropriate remedial actions for an LCO condition by ensuring that the necessary systems and components remain operable and are, therefore, acceptable.

3.1.7 TS 3.8.1 Renumbered and Revised Condition F (Change 7)

The licensee proposed to renumber the existing Condition C to Condition F, add new Conditions C, D, and E to Condition F, and renumber Required Actions C.1 to F.1 and C.2 to F.2.

The current TS 3.8.1 Condition C reads as:

CONDITION C	Required Action and associated Completion Time of Condition A or B not met.
REQUIRED ACTION C.1	Be in MODE 3.
	<u>AND</u>
REQUIRED ACTION C.2	Be in MODE 5.
CT for REQUIRED ACTION C.1	6 hours.
CT for REQUIRED ACTION C.2	36 hours.

The proposed TS 3.8.1 new renumbered and revised Condition F would read as:

CONDITION F	Required Action and associated Completion Time of Condition A, B, C, D, or E not met.
REQUIRED ACTION F.1	Be in MODE 3.
	<u>AND</u>
REQUIRED ACTION F.2	Be in MODE 5.
CT for REQUIRED ACTION F.1	6 hours.
CT for REQUIRED ACTION F.2	36 hours

<u>Evaluation of Proposed TS 3.8.1 Renumbered and Revised Condition F</u>

The NRC staff's review of Condition F indicated that if the inoperable AC electric power sources cannot be restored to operable status within the required CT, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least Mode 3 within 6 hours and to Mode 5 within 36 hours. The revision to Condition F reflects the new Conditions C, D, and E. The allowed CTs are reasonable based on operating experience to reach the required unit conditions from full power conditions in an orderly manner without challenging plant systems.

The NRC staff finds that the changes to the renumbered Condition F, Required Actions F.1 and F.2, and associated CTs are consistent with NUREG-1431.

Based on the above, the NRC staff finds that the proposed changes meet the requirements of 10 CFR 50.36(c)(2)(i) as appropriate remedial actions for an LCO condition by ensuring unit is shutdown and are, therefore, acceptable.

3.1.8 TS 3.8.1 Renumbered and Revised Condition G (Change 8)

The licensee proposed to renumber the existing Condition D to Condition G, revise Condition G, remove the note from the required action, and renumber the Required Action D.1 to G.1.

The current TS 3.8.1 Condition D reads as:

CONDITION D	Two or more AC sources inoperable.
REQUIRED ACTION	-------------------------------- NOTE ------------------------ Entry into this Required Action may be delayed for no greater than 2 hours during performance of Required Action B.3.1 and Required Action B.3.2.2. ---
REQUIRED ACTION D.1	Enter LCO 3.0.3.
CT for REQUIRED ACTION D.1	Immediately

The proposed TS 3.8.1 new renumbered and revised Condition G would read as:

CONDITION G	Three or more AC sources inoperable.
REQUIRED ACTION G.1	Enter LCO 3.0.3.
CT for REQUIRED ACTION G.1	Immediately

Evaluation of Proposed TS 3.8.1 Renumbered and Revised Condition G

The NRC staff's review indicated that the licensee has renumbered and relocated current Condition D to a new Condition G and current Required Action D.1 to a new G.1 and the associated CT. The licensee also deleted the note of the current Required Action D.1. Condition G is modified to reflect three or more AC sources inoperable to reflect that Robinson will have two qualified offsite circuits installed and one backfeed power supply through main transformer and unit auxiliary transform from 230 kV switchyard (by disconnecting main generator).

The NRC staff finds that the changes to the renumbered Condition G, Required Action G.1, and the associated CT are consistent with NUREG-1431.

Based on the above, the NRC staff finds that the proposed changes to TS 3.8.1 Condition G, Required Action G.1, and the associated CT meet the requirements of 10 CFR 50.36(c)(2(i) as appropriate remedial actions for this condition by ensuring that the unit is shutdown and are, therefore, acceptable.

3.1.9 TS 3.8.1 SR 3.8.1.1 Revision (Change 9)

The current TS 3.8.1 SR 3.8.1.1 reads as:

SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for the offsite circuit.
FREQUENCY	7 days.

The proposed TS 3.8.1 SR 3.8.1.1 would read as:

SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each offsite circuit.
FREQUENCY	7 days.

Evaluation of TS 3.8.1 SR 3.8.1.1 Revision

The NRC staff's review of TS 3.8.1 SR 3.8.1.1 indicated that the SR is being changed to reflect more than one offsite circuit. This SR ensures proper circuit continuity for the offsite AC electrical power supplies to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its correct position to ensure that distribution buses and loads are connected to their preferred power source, and that appropriate independence of offsite circuits is maintained. The 7-day frequency is adequate since breaker position is not likely to change without the operator being aware of it.

The NRC staff finds that the proposed change to this SR is consistent with the guidance in NUREG-1431.

Based on the above, the NRC staff concludes that the proposed change to SR 3.8.1.1 meets the requirements of 10 CFR 50.36(c)(3) by ensuring that the necessary quality of systems and components is maintained and that the LCOs will be met and is, therefore, acceptable.

3.1.10 TS 3.8.1 SR 3.8.1.16 Revision (Change 10)

The proposed revision to TS 3.8.1 SR 3.8.1.16 was described in the letter dated July 11, 2018.

The current TS 3.8.1 SR 3.8.1.16 reads as:

SR 3.8.1.16

-------------------------------------NOTE----------------------------

1. This Surveillance shall not be performed in MODE 1 or 2.

2. SR 3.8.1.16 is not required to be met if 4.160 kV bus 2 and 480 V Emergency Bus 1 power supply is from the start up transformer.

Verify automatic transfer capability of the 4.160 kV bus 2 and the 480 V Emergency Bus 1 loads from the Unit auxiliary transformer to the start up transformer.

The proposed TS 3.8.1 SR 3.8.1.16 would read as:

SR 3.8.1.16

-------------------------------------NOTE-----------------------------

1. This Surveillance shall not be performed in MODE 1 or 2.

2. SR 3.8.1.16 is not required to be met if 4.160 kV bus 2 and 480 V Emergency Bus 1 power supply is from a startup transformer.

Verify automatic transfer capability of the 4.160 kV bus 2 and the 480 V Emergency Bus 1 loads from the Unit auxiliary transformer to a startup transformer.

<u>Evaluation of TS 3.8.1 SR 3.8.1.16 Revision</u>

The NRC staff's review of TS 3.8.1 SR 3.8.1.16 indicated that this SR demonstrates the operability of the offsite circuit network to power shutdown loads by transferring the 4.16 kV bus 2 power supply from the unit auxiliary transformer to a startup transformer.

Note 2 and the SR are being changed to reflect that the function being tested can be accomplished with either the new 230 kV startup transformer or the new 115 kV startup transformer. The NRC staff finds that the proposed changes address the functions being tested by either of the two new startup transformers.

Based on the above, the NRC staff finds that the new SR 3.8.1.18 and the associated frequency meets the requirements of 10 CFR 50.36(c)(3) by ensuring that the necessary quality of systems and components is maintained, and that the LCOs will be met, and are, therefore, acceptable.

3.1.11 TS 3.8.1 New SR 3.8.1.18 (Change 11)

The new TS 3.8.1 SR 3.8.1.18 was described in the LAR and modified by letter dated July 11, 2018.

The proposed TS 3.8.1 SR 3.8.1.18 would read as:

SR 3.8.1.18	---------------------------------NOTE------------------------------ This Surveillance shall not be performed in MODE 1 or 2. -- Verify manual transfer of AC power sources from the normal offsite circuit to each alternate offsite circuit.
FREQUENCY	24 months.

Evaluation of New SR 3.8.1.18 and Associated Frequency

The NRC staff's review of the current and proposed SR 3.8.1.18 indicated that transfer of the 480 volt (V) ESF bus E1 power supply from the 4.16 kV bus 6 to the 4.16 kV bus 2 and transfer of the ESF bus E2 power supply from the 4.16 kV bus 9 to the 4.16 kV bus 3 demonstrates the operability of the alternate circuit distribution network to power shutdown loads. The NRC staff's review indicated that new SR 3.8.1.18 is consistent with SR 3.8.1.8 in NUREG-1431.

In the LAR, the licensee proposed modifying this SR by a note stating, "This Surveillance shall not be performed in MODE 1 or 2." In NUREG-1431, the comparable SR is SR 3.8.1.8, which has a note that states, in part, "This Surveillance shall not normally be performed in MODE 1 or 2." The reason for the note is that performing the surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. As the proposed SR is consistent or more restrictive than the guidance in NUREG-1431, the NRC staff finds the note acceptable.

In the LAR, the licensee requested an 18-month SR frequency of the SR based on engineering judgment, taking into consideration the unit conditions required to perform the surveillance, and consistent with the then Robinson fuel cycle length of 18-months. By letter dated May 25, 2018, the NRC issued Robinson Operating License Amendment No. 258 (Reference 7), which revised the frequency of certain SRs to support operations with 24-month fuel cycles. By letter dated July 11, 2018, the licensee proposed changing the frequency of SR 3.8.1.18 from 18 months to 24 months based on engineering judgment, the unit conditions required to perform the surveillance, and to support operations with 24-month fuel cycles. NUREG-1431 regarding SR frequency states that frequency should take into consideration unit conditions required to perform the surveillance and is intended to be consistent with expected fuel cycle lengths. The

NRC staff finds that the proposed 24-month frequency to perform SR 3.8.1.18 is consistent with the guidance in NUREG-1431 and is acceptable.

Based on the above, the NRC staff finds that the new SR 3.8.1.18 and the associated frequency meet the requirements of 10 CFR 50.36(c)(3) by ensuring that the necessary quality of systems and components is maintained, and that the LCOs will be met, and is, therefore, acceptable.

3.2 Use of Load Tap Changers in Automatic Mode of Operation

3.2.1 Description of Operation of Load Tap Changers

The licensee proposed to replace the existing 115 kV SUT with the new replacement 115 kV SUT provided with an LTC, and to add a second 230 kV qualified offsite circuit with a new 230 kV SUT provided with an LTC. The new LTCs on both SUTs will operate in automatic mode. The new LTCs will be located in a separate enclosure mounted to the transformer tanks. The tap changer mechanism can be operated in manual or automatic mode. However, the proposed amendment only requests NRC approval to operate the LTCs in the automatic mode of operation.

The licensee plans to use a primary and a backup microcontroller, separate for each SUT, to control the LTC mechanism. In the automatic mode of operation, the primary microcontroller would monitor load voltages to create a signal based on the sensed secondary voltage of its associated SUT. Each SUT has two output windings, designated the "X" and "Y" windings. During normal operation, the 115 kV SUT "X" winding provides power to emergency bus E1, and the 230 kV SUT "Y" winding provides power to emergency bus E2. Therefore, the LTC microcontroller senses the 115 kV SUT "X" winding and the 230 kV SUT "Y" winding voltages. The primary microcontroller sends the signal to the LTC mechanism, which changes the tap setting when required so that voltage is controlled to within the desired range. Figure 1 of the LAR shows the desired voltage range symbolized by the "Voltage Control Band – Primary Microcontroller" and includes the "Upper Band Limit" and the "Lower Band Limit." The primary microcontroller also has programmable overvoltage detection and undervoltage blocking settings available. Furthermore, the primary controller has the ability to be configured to operate in both steady state voltage control definite time delay and fast voltage recovery mode. The licensee stated in the LAR that the fast voltage recovery mode (sensing time of half a second and operation time of 2 seconds) provides acceptable voltage response for the worst case grid transients and plant trips.

In the LAR, the licensee stated that for added reliability, a backup microcontroller is installed that prevents a defective primary LTC microcontroller from adjusting the voltage outside the established upper and lower limits. Figure 1 of the LAR shows the desired voltage limit band symbolized by the "Voltage Limit Band - Backup Controller" and includes the "Undervoltage Limit (Backup Controller - Block Lower Limit)" and the "Overvoltage Limit (Backup Controller - Block Raise Limit)." The backup controller senses voltage at the same bus level as the primary controller with a separate drawer mounted potential transformer. This allows for proper isolation between the primary and backup controllers. The backup controller functions to provide an "inhibit band," which is a separate control band set just outside the normal control band. Should the sensed voltage vary outside of this band, the backup controller prevents the primary controller from issuing a raise or lower command. Additionally, the backup controller is configured with an adjustable deadband and the ability to issue a lower command to the LTC to bring the voltage back into normal operating range, should voltage continue to rise. The backup microcontroller time delay is adjustable from 1 to 30 seconds (the licensee chose 5 seconds to create the desired backup controller response). If voltage remains above the maximum voltage by the selected deadband, the controller will issue a lower command to the tap changer to lower the voltage.

The LAR states that the new LTCs on both SUTs provide a range of voltage regulation from -12.4% to +12.4% at rated secondary voltage in 16 steps (plus the nominal tap position). By providing automatic voltage regulation based on the onsite 4.16 kV buses voltage from both the 115 kV SUT LTC and the 230 kV SUT LTC, both LTCs can compensate for the range of 115 kV and/or 230 kV system operating voltages. The nominal secondary voltage is set at 4,160 V and the operating band is maintained between 4,095.7 V and 4,224.3 V by the primary microcontroller. In case of a malfunction of the primary controller, a backup microcontroller maintains control within the maximum allowable band of 4,030 V and 4,290 V. In the LAR, the licensee stated that a local and remote alarm and annunciation will be actuated if sustained operation outside the allowable band is detected. Robinson will install the following voltage alarms in the offsite power system of the transmission system:

1. Annunciator APP-036-E3 for the 115 kV SUT or 230 kV SUT over/under voltage. The annunciator will be located on the high side of the SUTs, indicating high or low voltage conditions by the grid.

2. 480 V emergency bus E1 or E2 supply over/under voltage alarms. The 480 V emergency bus E1 or E2 supply over/under voltage alarms will be installed on the low side of the transformers SST 2F and SST 2G respectively.

3.2.2 Failure Mode Analysis of Load Tap Changers

The following summarizes the failure mode analysis of the LTCs as described by the licensee:

a) Failure Mode that Increases Voltage: The licensee analyzed the failure mode of LTC that could result in increasing voltage at the 4 kV and 480 V buses and loads downstream of the affected LTC to experience higher than design-level voltages. When this failure mode occurs, one or both of the 480 V emergency buses are affected. Damage from an overvoltage condition is only expected if the condition is sustained for an extended period of time. This condition will not be sustained over an extended period of time due to the ability to quickly detect the failure and administer protective actions to correct the condition.

b) Failure Mode that Decreases Voltage: The licensee analyzed the failure of an LTC that could result in decreasing voltage, causing the 4 kV and 480 V buses and loads downstream of the affected LTC to experience lower than design-level voltages. When this failure mode occurs, one or both of the 480 V emergency buses are affected. At the LTC highest tap setting, the undervoltage conditions on the affected 480 V emergency bus will cause the supply breaker to trip and the bus to isolate and align with its associated emergency diesel generator (EDG). Prior to reaching the degraded or undervoltage conditions on the emergency buses, operators will be notified of the low voltage condition by the E1/E2 voltage monitors and main control room annunciation.

c) LTC Fails in Place: In the LAR, the licensee stated that failure of the LTC to change the tap setting when required could create an overvoltage or an undervoltage condition if the grid voltage changes by a sufficiently large amount subsequent to a failure. A failure of the LTC to change the tap setting when required is not immediately detectable in some instances. However, there are alarms that will indicate high or low voltage from the grid and at the 480 V emergency buses that will provide sufficient detection once failure effects are present. Operator attention to voltages during tap changes will also provide an indication of tap position (or failure to change position). Procedurally controlled operator actions will be implemented quickly following detection and will return the system voltage to acceptable levels.

3.2.3 Evaluation of the Load Tap Changers

The NRC staff reviewed the use of LTCs and failure modes of LTCs as described in the LAR.

In the LAR, the licensee stated that the proposed change will also allow operation of the LTCs on the 115 kV and 230 kV SUTs in automatic mode. The inputs or assumptions of any of the analyses that demonstrate the integrity of the fuel cladding, reactor coolant system, or containment during accident conditions are unaffected by this proposed change. The allowable values for the degraded voltage protection function are unchanged and will continue to ensure that the degraded voltage protection function actuates when required, but does not actuate prematurely to unnecessarily transfer safety-related loads from offsite power to the EDGs. The staff finds that automatic operation of the LTCs will increase the margin of safety by reducing the potential for transferring loads to the EDGs during an undervoltage or overvoltage event on the offsite power sources.

The NRC staff reviewed the markup of Section 8.2.2 of the UFSAR as provided in the LAR to reflect the use of LTCs to automatically control the 4.16 kV bus voltages within desirable voltage band. By letter dated May 16, 2018, the licensee provided additional discussion regarding the minimum switchyard voltage profile for Robinson 115 kV and 230 kV switchyards considered for the design of SUTs, which will be added to the UFSAR, Section 8.2.2.

Based on the above discussion, the NRC staff finds the operation of LTCs in automatic mode is acceptable. Therefore, the incorporation of the proposed changes to the Robinson UFSAR to allow the use of LTCs in automatic mode is acceptable.

3.3 Evaluation of Additional Supporting Technical Information

In the LAR and supplements, the licensee provided summary evaluations and results of transient analyses (summarized from the licensee calculation RNP-E-8.066, "RNP-E-8.002 Interim," Revision 0) for various plant alignments and the new SUT LTC in automatic position. The licensee performed the transient analyses to determine if the voltage excursions will have any adverse impact on the current degraded grid voltage relay (DGVR) and loss of voltage (LVR) setpoints or on any safety equipment operation.

3.3.1 Grid Voltage Profile Summary

In the LAR, the licensee stated that each SUT will be capable of providing sufficient power to serve 100% of the plant auxiliary loads necessary to achieve and maintain safe shutdown conditions (i.e., emergency buses E1 and E2 may be fed from either SUT, either separately or together, on the same SUT).

In the LAR, the licensee stated that after installation of the two SUTs with automatic LTCs, the Duke Energy Transmission System Operator will begin managing the transmission system to ensure that adequate Robinson switchyard voltage is maintained as per the Minimum Required

Switchyard Voltage Profile Bounding Graph shown in Figure 3 of the LAR. The voltage profile graph of Figure 3 of the LAR represents the worst case post-trip bounding values. After installation of the new Robinson SUTs, the licensee will revise the plant voltage support and coordination procedure to reflect the bounding voltages as shown in Figure 3 of the LAR. The Minimum Required Switchyard Voltage Profile Bounding Graph is expected to conservatively represent anticipated transmission system performance through the planning period (10 years).

In EEOB RAI-2, dated April 18, 2018 (Reference 8), the NRC staff requested the licensee to clarify whether information in Figure 3 of the LAR or its equivalent will be included in the Robinson UFSAR or explain why such information is not appropriately included in the UFSAR, since Figure 3 represents part of the design basis of the offsite power system, and thus it or equivalent information should be included in the UFSAR. By letter dated May 16, 2018 (Reference 2), the licensee confirmed that Figure 3 of the LAR contains part of the design-basis information, and the Robinson UFSAR would be updated to include information equivalent to Figure 3 of the LAR. The licensee provided additional information that will be added to Section 8.2.2 of the UFSAR to reflect the design basis of the Robinson Unit No. 2 offsite power system discussed in the LAR. The NRC staff finds that the proposed updates to Section 8.2.2 of the UFSAR will reflect part of the design basis of the Robinson offsite power system and is acceptable.

3.3.2 Steady State Load Flow and Short Circuit Analysis

3.3.2.1 Normal Bus Alignments

For the new SUT rated capacity, the licensee evaluated the maximum loading and margin. By letter dated July 11, 2018, the licensee stated that the loading and margin values of the new SUTs were originally taken from configuration N5 (100% Power on the Unit Auxiliary Transformer (UAT) and the 115kV SUT Out of Service (OOS)) and N6. However, N6 was later eliminated as a valid operating configuration. In the July 11, 2018, letter, based on an updated bus configuration and correct values for configuration N5, the licensee updated the load flow analyses (i.e., licensee calculation RNP-E-8.066, "RNP-E-8.002 Interim," Revision 0). In the July 11, 2018, letter the licensee also provided an updated summary evaluation of analyses regarding the adequacy of the new SUTs' rating, expected loading, and capacity margin. The licensee's summary evaluation showed that the replacement 115 kV SUT will have 50.4 MVA rated capacity for an estimated 22.16 Megavolt Ampere (MVA) maximum calculated load (i.e., 56.0% additional margin in capacity). Similarly, new 230 KV SUT will have 50.4 MVA rated capacity for an estimated maximum load of 46.65 MVA (i.e., 7.5% additional margin in capacity). Based on the above, the NRC staff concludes that there will be no adverse impact on equipment voltage rating, no adverse bus overloading conditions, and the new replacement 115 kV SUT and 230 kV SUT with LTC in automatic mode will have sufficient capacity with additional margin to support the worst case loading and is acceptable.

3.3.2.2 Short Circuit

In the LAR, the licensee provided a summary evaluation of the short circuit fault current analysis. The licensee concluded as follows:

- In the normal or shutdown bus alignments and when EDG A or EDG B are running in parallel with an offsite power source for surveillance testing, the momentary short circuit ratings of E1/E2 switchgear, respectively, are exceeded. Robinson will implement changes to procedures prior to implementation of the transmission upgrade modifications in order to limit loads on the applicable emergency bus. Limiting loads on the applicable emergency bus will bring the fault current within the duty cycle.

- In normal bus alignments, when the dedicated shutdown diesel generator (DSDG) is running in parallel with an offsite power source for surveillance testing, the interrupting duty ratings of multiple breakers on the 480 V DS bus and bus 3 are exceeded. However, the DSDG is only operated in parallel with the offsite power system during testing conditions. When the DSDG design function is required to operate, the system will operate independent of the offsite power supply. Therefore, the subject condition does not exist when the DSDG is required for design function operation.

The NRC staff reviewed the licensee's summary of the short circuit fault current analysis and equipment momentary duty ratings for the normal bus alignments and concluded that the equipment momentary duty ratings were within the required limits for all other alignments except the above two cases. The LAR states that Robinson will implement changes to procedures for the above alignments where momentary rating of the E1 and E2 switchgears were exceeded prior to implementation of the transmission upgrade modification to limit loads on the applicable emergency bus that will decrease the fault current with the duty cycle.

Based on above, the NRC staff finds that the short circuit fault current analysis and equipment momentary duty ratings are reasonable and are, therefore, acceptable.

3.3.3 Transient Load Flow Summary

In the LAR, and by letter dated July 11, 2018, the licensee provided a summary evaluation of the transient load flow analysis for the following:

1. Bus Transients – Pump Starts
2. Grid transient – LOCA [Loss of Coolant Accident] 100% Power Bus Alignments
3. Grid transient response – LOCA with Plant in Backfeed
4. Grid transient response – Plant Trip with Fast Bus Transfers

In addition, an analysis was performed to show that the revised Robinson transmission system can react to the worst case grid transients without timing out the E1/E2 DGVR and LVR relays.

The transient analysis was performed for the following bus alignment descriptions:

- N1 - 100% Power Normal Alignment
- N2 - 100% Power 115 kV SUT OOS
- N3 - 100% Power 230 kV SUT OOS
- N4 - 100% Power UAT OOS
- N5 - 100% Power UAT and 115 kV SUT OOS
- N7 - Plant Trip/Normal Shutdown Alignment
- N5N7 - Plant Trip 115 kV SUT OOS
- N6N7 - Plant Trip 230 kV SUT OOS
- B2 - Backfeed

By letters dated May 16, 2018, and July 11, 2018, the licensee stated that configuration N6 mentioned in the original LAR, Section 3.3.3, was eliminated as a valid operating configuration, and as a result, the transient analysis was revised. However, the revision to the transient analysis (in the July 11, 2018, letter) did not change the conclusion of the analyses. The licensee performed a revision to transient voltage analysis to ensure that during large motor starts, plant transients, and grid transients, the plant equipment has sufficient voltage to "ride through" and remain running following the transient. In addition, the revised analyses show that the revised Robinson transmission system can react to the worst case grid transients without timing out the E1/E2 DGVR and LVR relays.

In the LAR, the licensee stated that for the E1/E2 buses, the maximum DGVR pickup voltage, adjusted for instrument uncertainty of 437 V (91.04% of the nominal 480 V bus voltage) for the minimum relay time delay of 9.5 seconds, was used as the acceptance criteria in the revised transient analysis (RNP-E-8.066, Revision 0), which is higher than the Robinson current TS SR 3.3.5.2.b DGVR trip setpoint of 430 V± 4 V with a time delay of 10±0.5 seconds. The DGVR pickup voltage is the voltage to which bus voltage must recover after the DGVR trip setpoint (430 V ± 4 V) is reached and before the relay times out to stop the timer and reset the DGVR.

Additionally, for the E1/E2 buses, the licensee revised the maximum LVR pickup voltage from 352.V to 360.8 V (75.2% of 480 V nominal bus voltage) with a minimum relay time delay of 0.712 seconds as the acceptance criteria, which is higher than the allowable range (328 V ± 10%) with a time delay of ≤ 1 second (at zero voltage) of current TS Section 3.3.5.2.a.

Based on above discussion, the NRC staff finds that the licensee used higher acceptance criteria than the current Robinson TS 3.3.5.2 DGVR and LVR setpoints, providing a small margin. Therefore, the NRC staff finds the use of the acceptance criteria for the transient analysis acceptable.

3.3.3.1 Bus Transients – Reactor Coolant Pump Starts Scenario

The licensee performed the transient analysis to ensure that a worst case reactor coolant pump (RCP) start does not result in unacceptable voltages at the E1/E2 or 4 kV buses. The licensee stated in the LAR that an Electrical Power System Analysis Software's ETAP model for the transient analysis was used to analyze RCP pump starts in the different operating and shutdown bus alignments and evaluated the effects on the bus voltages. The licensee used an acceptance criterion of 73% of nominal 4.16 kV for RCP starts, and there were no cases where the 4 kV buses fell below the acceptance criterion of 73% of nominal 4.16 kV during any RCP starts. The lowest transient voltage level on the 4 kV buses for any RCP start was approximately 80%. The minimum transient value of 80% is well above the 66.9% 4 kV bus undervoltage relay setpoint.

Based on the above discussion, the NRC staff concludes that voltages at the 4 kV safety buses are expected to remain above the minimum (73%) criterion during the RCP starts, and the lowest transient voltage on the 4 kV safety buses is expected to remain higher than the 4 kV bus undervoltage relay setpoint. Therefore, the NRC staff finds the evaluation of bus transients for RCP starts acceptable.

3.3.3.2 Grid Transient Response – LOCA 100% Power Bus Alignments (N1, N2, N3, N4, and N5)

The licensee's summary evaluation of the transient analyses with SUT LTC in automatic operation for each bus 100% power alignment study showed the following:

- Buses E1/E2 voltage excursions did not result in the DGVR timing out during the system response (based on the example study with the SUT LTC in automatic operation). The analysis also demonstrates that no voltage excursion resulted in the voltage falling below the maximum DGVR time delay pickup value greater than the relay's 9.5 seconds time delay. Additionally, the E1/E2 bus voltage excursion did not approach the TS maximum LVR relay pickup value of 360.8 V (328 V + 10%) limit.

- The example study showed that the voltage on the 4 kV buses 1, 2, and 4 dropped below the undervoltage relay's setpoint for no more than 0.1 seconds. Since the 4 kV buses 1, 2, and 4 undervoltage relays have a time delay setting of 0.692 seconds, which is higher than 0.1 seconds, the 4 kV bus 1, 2, and 4 undervoltage relays did not pick up during this grid transient condition.

- The 4 kV motors and bus E1/E2 motors 150 horsepower (HP) and greater remained running and did not stall or trip based on their respective instantaneous and/or time overcurrent trip settings.

Based on above discussion, the NRC staff concludes that the voltage excursion is not expected to result in the voltage falling below the maximum DGVR or LVR setpoints; the 4 kV bus 1, 2, and 4 undervoltage relays are not expected to pick up during this grid transient condition; and the 4 kV motors and bus E1/E2 motors (150 HP and greater) are expected to remain running and expected not to stall or trip based on their respective instantaneous and/or time overcurrent trip settings. Therefore, the NRC staff finds the licensee's evaluation of the grid transient response for the applicable alignments acceptable.

3.3.3.3 Grid Transient Response – LOCA with Plant in Backfeed (B2 Alignment)

In the LAR, the licensee stated that in the B2 alignment, the LOCA transient did not result in the bus E1/E2 bus voltage excursion timing out the DGVR. The 4 kV buses 1, 2, and 4 undervoltage relays did not time out and the bus E1/E2 motors (150 HP and greater) remained running during and after the transient.

The NRC staff reviewed the transient response and concludes that in the B2 bus alignment, the voltage excursion is not expected to result in the voltage falling below the maximum DGVR or LVR setpoints; 4 kV bus 1, 2, and 4 undervoltage relays are not expected to pick up during this grid transient condition; and the 4 kV motors and bus E1/E2 motors (150 HP and greater) are expected to remain running and expected not to stall or trip based on their respective instantaneous and/or time overcurrent trip settings. Therefore, the NRC staff finds the licensee's evaluation of the grid transient response for the B2 alignment acceptable.

3.3.3.4 Grid Transient – Plant trip with Fast Bus Transfer

In LAR Section 3.3.3, and by letters dated July 12, 2018, and August 1, 2018, the licensee provided summaries of the transient voltage analyses for bus alignments (N1, N2, N3, N4, and N5). One case of the licensee's transient voltage analyses was with the LTC in the automatic position. The transient analysis performed with the LTC in automatic position used an initial time delay of half a second and an operating time delay of 2 seconds.

By letter dated August 1, 2018, the licensee stated that the transient analyses for the plant in bus alignments (N1, N2, N3, N4, and N5) with the new LTCs in the automatic position for the "Grid Transient – Plant Trip with Fast Bus transfer" scenario did not show any adverse impact on the DGVR and the LVR setpoints and any safety equipment used for operations.

Based on the above discussion, the NRC staff concludes that the expected voltage excursions during the proposed operation of the SUT LTC in automatic mode (with N1, N2, N3, N4, or N5 bus alignments during the Grid Transient – Plant Trip with Fast Bus transfer scenario) will not adversely impact the current setpoints in TS SR 3.3.5.2 for the DGVR, or LVR relays. The NRC further concludes that the 4 kV motors and bus E1/E2 motors (150 HP and greater) are expected to remain running and are not expected to stall or trip based on their respective instantaneous and/or time overcurrent trip settings. Therefore, the NRC staff finds the licensee's evaluation of the grid transient of the plant trip with a fast bus transfer acceptable.

3.3.4 Breaker Coordination Summary and Equipment Protection Summary

In the LAR, the licensee provided a summary of the evaluation of Robinson to Transmission Engineering Resource and Project Management (TERPM) relay coordination to ensure that the TERPM SUT high and low 487E protective relay setpoints will provide coordination with downstream plant relaying and to ensure additional relay interlocking is not necessary. Relay interlocking allows the breaker closest to the faults (or large motor start) to react first while inhibiting or time delaying the response of the upstream breakers. The licensee's analysis of relay coordination determined that adequate time difference exists between the furthest upstream plant relay and the first upstream TERPM relay to allow for the Robinson breaker to clear a fault prior to resulting in the TERPM relaying actuation.

In the LAR, the licensee also stated that the new protective relay settings would provide complete instantaneous and time overcurrent protection for the 115 kV SUT, 230 kV SUT, and the associated cable bus and non-segregated bus duct.

The NRC staff reviewed the licensee's evaluation of the breaker coordination and finds that the licensee has adequately evaluated the breaker coordination between Robinson 4 kV relaying and upstream TERPM relaying, and the new protective relay settings would provide complete, instantaneous, and time overcurrent protection for the 115 kV SUT, 230 kV SUT, and the associated cable bus and non-segregated bus duct. Therefore, the NRC staff finds the licensee's evaluation of breaker coordination acceptable.

3.4 Technical Conclusion

The NRC staff's evaluation finds the proposed changes to TS 3.8.1 for LCO due to the addition of a second qualified offsite circuit are consistent with NUREG-1431, Revision 4.0. Additionally, the proposed plant modification to add a new second offsite circuit and revise the current licensing basis to allow use of new LTCs (as subcomponents on the new 230 kV SUT, as well as on the replacement 115 kV SUT) in the automatic position will not adversely impact the current DGVR and LVR setpoints in Robinson TS 3.3.5.2 and safety equipment operation and protection.

The NRC staff concludes that the proposed changes to the Robinson TS 3.8.1 licensing basis due to addition of an offsite power circuit and to allow operation of SUT LTCs in automatic mode acceptable. The modifications provide reasonable assurance of the continued availability of the required offsite electrical power to shut down the reactor and to maintain the reactor in a safe condition after an anticipated operational occurrence or a postulated DBA. The staff concludes that the proposed changes meet the requirements of 10 CFR 50.36(c)(2)(ii)(C), and continue to meet the draft GDC 39. Therefore, the NRC staff finds the proposed changes in the LAR, as supplemented, acceptable.

4.0 STATE CONSULTATION

In accordance with the Commission's regulations, the State of South Carolina official was notified of the proposed issuance of the amendment on August 15, 2018. The State official had no comments.

5.0 ENVIRONMENTAL CONSIDERATION

The amendment changes a requirement with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20 and changes SRs. The NRC staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendment involves no significant hazards consideration, and there has been no public comment on such finding published in the *Federal Register* on December 5, 2017 (82 FR 57471). Accordingly, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendment.

6.0 CONCLUSION

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

7.0 REFERENCES

1. Kapopoulos, E. J., Duke Energy Progress, LLC, letter to U.S. Nuclear Regulatory Commission, "License Amendment Request Proposing to Add a Qualified Offsite Circuit to Technical Specification 3.8.1, 'AC Sources-Operating' and the Use of Load Tap Changers in the Automatic Mode of Operation on the Startup Transformers," dated September 27, 2017 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML17270A041).

2. Kapopoulos, E. J., Duke Energy Progress, LLC, letter to U.S. Nuclear Regulatory Commission, "Response to Request for Additional Information (RAI) Regarding License Amendment Request Proposing to Add a Qualified Offsite Circuit to Technical Specification 3.8.1, 'AC Sources – Operating' and the Use of Load Tap Changers in the Automatic Mode of Operation on the Startup Transformers," dated May 16, 2018 (ADAMS Accession No. ML18137A353).

3. Kapopoulos, E. J., Duke Energy Progress, LLC, letter to U.S. Nuclear Regulatory Commission, "Supplement to License Amendment Request Proposing to Add a Qualified Offsite Circuit to Technical Specification 3.8.1, 'AC Sources – Operating' and the Use of Load Tap Changers in the Automatic Mode of Operation on the Startup Transformers," dated July 11, 2018 (ADAMS Accession No. ML18192C179).

4. Kapopoulos, E. J., Duke Energy Progress, LLC, letter to U.S. Nuclear Regulatory Commission, "Response to Supplemental Request for Additional Information Regarding License Amendment Request Proposing to Add a Qualified Offsite Circuit to Technical Specification 3.8.1, 'AC Sources – Operating' and the Use of Load Tap Changers in the Automatic Mode of Operation on the Startup Transformers," dated August 1, 2018 (ADAMS Accession No. ML18214A167).

5. Kapopoulos, E. J., Duke Energy Progress, LLC, letter to the U.S. Nuclear Regulatory Commission, "Submittal of Updated Final Safety Analysis Report, Revision No. 27," dated September 25, 2017 (ADAMS Accession No. ML17298A847).

6. U.S. Nuclear Regulatory Commission, NUREG 1431, "Standard Technical Specifications, Westinghouse Plants," Revision 4.0, Volume 1, Specifications," dated April 2012 (ADAMS Accession No. ML12100A222).

7. Galvin, D. J., U.S. Nuclear Regulatory Commission, letter to E. J. Kapopoulos, Duke Energy Progress, LLC, "H. B. Robinson Steam Electric Plant, Unit No. 2 - Issuance of Amendment 258 Regarding Request to Revise Technical Specification Surveillance Requirement Frequencies to Support 24-Month Fuel Cycles (CAC No. MF9544; EPID L-2017-LLA-0206)," dated May 25, 2018 (ADAMS Accession No. ML18115A150).

8. Galvin, D. J., U.S. Nuclear Regulatory Commission, email to K. M. Ellis, Duke Energy Progress, LLC, "Robinson RAIs – LAR to Revise TS to Add a 2nd Qualified Offsite Power Circuit and Revise UFSAR to Operate LTCs in Automatic Mode (CAC No. MG0276; L-2017-LLA-0308)," dated April 18, 2018 (ADAMS Accession No. ML18108A759).

Principal Contributors: Prem Sahay
Pete Snyder

Date: September 10, 2018

SUBJECT: H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2 – ISSUANCE OF AMENDMENT NO. 261 TO ADD A SECOND QUALIFIED OFFSITE CIRCUIT AND FOR AUTOMATIC OPERATION OF LOAD TAP CHANGERS (CAC NO. MG0276; EPID L-2017-LLA-0308) DATED SEPTEMBER 10, 2018

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