Southern Nuclear

Southern Nuclear
Operating Company, Inc.
3535 Colonnade Parkway
Birmingham, AL 35243

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ND-22-0881
10 CFR 50.90

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

Vogtle Electric Generating Plant Units 3 and 4
Docket Nos.: 52-025 & 52-026

Subject: License Amendment Request for Technical Specification 3.8.3, Inverters – Operating, Completion Time Extension (LAR-22-002)

Ladies and Gentlemen:

Pursuant to 10 CFR 52.98(c) and in accordance with 10 CFR 50.90, Southern Nuclear Operating Company (SNC) requests an amendment to the combined licenses (COLs) for Vogtle Electric Generating Plant (VEGP) Units 3 and 4 (License Numbers NPF-91 and NPF-92, respectively). The requested amendment proposes changes to COL Appendix A, Technical Specifications (TS) 3.8.3, Inverters – Operating, to extend the Completion time for Required Action A.1.

These changes were previously discussed with the NRC Staff at a public presubmittal conference call on November 10, 2022 (ADAMS Accession Number ML22307A061).

The Enclosure provides the description, technical evaluation, regulatory evaluation (including the Significant Hazards Consideration Determination) and environmental considerations for the proposed changes.

Attachments 1 and 2 provide markups depicting the requested changes and final typed changes, respectively, to the VEGP Units 3 and 4 TS.

Attachment 3 provides the information-only changes to the VEGP Units 3 and 4 TS Bases document.

This letter contains no regulatory commitments. This letter has been reviewed and determined not to contain security-related information.

SNC requests NRC staff review and approval of this LAR no later than 12 months from acceptance. Delayed approval of this license amendment could put the plant at increased risk of a TS required shutdown upon discovery of an inoperable inverter. SNC expects to implement the proposed amendment within 30 days of approval of the LAR.

In accordance with 10 CFR 50.91, SNC is notifying the State of Georgia by transmitting a copy of this letter and its enclosure to the designated State Official.

Should you have any questions, please contact Amy Chamberlain at (205) 992-6361.

I declare under penalty of perjury that the foregoing is true and correct. Executed on the 3rd of January 2023.

Respectfully submitted,

Amy C. Chamberlain
Licensing Manager
Southern Nuclear Operating Company

Enclosure: Vogtle Electric Generating Plant (VEGP) Units 3 and 4 – Request for License Amendment: Technical Specification 3.8.3, Inverters – Operating, Completion Time Extension (LAR-22-002)

Attachments:

1. Technical Specification Marked-up Pages
2. Revised Technical Specification Pages
3. Technical Specification Bases Marked-up Pages (for information only)

cc:

Regional Administrator, Region II
VPO Project Manager
Senior Resident Inspector – Vogtle 3 & 4
Director, Environmental Protection Division - State of Georgia
Document Services RTYPE: VND.LI.L00
File AR.01.02.06

Vogtle Electric Generating Plant (VEGP) Units 3 and 4

License Amendment Request for Technical Specification 3.8.3, Inverters – Operating, Completion Time Extension

Enclosure

Basis for Proposed Change

1 SUMMARY DESCRIPTION

Pursuant to 10 CFR 52.98(c) and in accordance with 10 CFR 50.90, Southern Nuclear Operating Company (SNC) hereby requests an amendment to Combined License (COL) Nos. NPF-91 and NPF-92 for Vogtle Electric Generating Plant (VEGP) Units 3 and 4, respectively.

The proposed change would revise COL Appendix A, Technical Specifications (TS) 3.8.3, Inverters – Operating, to extend the Completion time for Required Action A.1 from 24 hours to 14 days.

Additionally, TS 3.3.9, Engineered Safety Feature Actuation System (ESFAS) Manual Initiation, Condition C proposed change would replace misspelled "Requried" with "Required."

2 DETAILED DESCRIPTION

2.1 System Design and Operation

The Class 1E 250 VDC and Uninterruptable Power Supply System (IDS) consists of the Class 1E 250 DC subsystem and the Uninterruptable Power Supply (UPS) subsystem.

The Class 1E 250 VDC subsystem is divided into four independent Divisions (A, B, C, and D). Each of these divisions is supplied from dedicated batteries and battery chargers. Divisions A and D battery banks and one of the battery banks in Divisions B and C are designated as 24-hour battery banks (two 60-cell strings in series) and provide power to the loads required for the first 24 hours following a loss of all AC power event or a design basis accident (DBA). The second battery bank in Divisions B and C, designated as the 72-hour battery bank (two 60-cell strings in series), is used for those loads requiring power for 72 hours following the same event. A single spare battery bank with spare battery charger is provided for the Class 1E 250 VDC subsystem.

The Class 1E UPS subsystem provides power at 208 Y/120 VAC to four independent divisions of Class 1E instrument and control power buses. Divisions A and D each consist of one Class 1E inverter associated with an instrument and control distribution panel and a backup voltage regulating transformer with a distribution panel. The inverter is powered from the respective 24-hour battery bank switchboard. Divisions B and C each consist of two inverters, two instrument and control distribution panels, and a voltage regulating transformer (which can be supplied by an ancillary diesel generator) with a distribution panel. One inverter is powered by the 24-hour battery bank switchboard and the other, by the 72-hour battery bank switchboard.

The four divisions are independent, located in separate rooms, cannot be interconnected, and their circuits are routed in dedicated, physically separated raceways. This level of electrical and physical separation prevents the failure or unavailability of a single battery, battery charger, or inverter from adversely affecting a redundant division.

An IDS spare battery bank (IDSS-DB-1A and IDSS-DB-1B) with a spare charger (IDSS-DC-1) is provided for the Class 1E battery system. In order to preserve independence of each Class 1E DC system division, plug-in locking type disconnects are permanently installed to prevent connection of more than one battery bank to the spare. In addition, kirk-key interlock switches are provided to prevent transfer operation of more than one switchboard at a time. The spare battery bank is located in a separate room and is capable of supplying power to the required loads on any battery being temporarily replaced with the spare.

The inverters are the preferred source of power for the Class 1E AC instrument and control buses because of the stability and reliability they achieve. Divisions A and D, each consist of one Class 1E inverter. Divisions B and C, each consist of two inverters. The function of the inverter is to convert Class 1E DC electrical power to AC electrical power, thus providing an uninterruptible power source for the instrumentation and controls for the Protection and Safety Monitoring System (PMS). The inverters are powered from the Class 1E 250 VDC battery sources.

Under normal operation, a Class 1E inverter supplies power to the Class 1E AC instrument and control bus. If the inverter is inoperable or the Class 1E 250 VDC input to the inverter is unavailable, the Class 1E AC instrument and control bus is powered from the backup source associated with the same division via a static transfer switch featuring a make-before-break contact arrangement. In addition, a manual mechanical bypass switch can be used to provide power from the backup source to the Class 1E AC instrument and control bus when the inverter is removed from service. The backup source is a Class 1E 480-208/120 volt voltage regulating transformer providing a regulated output to the Class 1E AC instrument and control bus through a static transfer switch or a manual bypass switch. This backup source can be supplied by the standby diesel generator during a loss of offsite power (LOOP). Additionally, for Divisions B and C the ancillary diesel generator can also provide a source of backup power.

2.2 Current Technical Specifications Requirements

TS 3.8.3, Inverters – Operating, Condition A is for “One or two inverter(s) within one division inoperable.” The associated Required Action A.1 requires “Restore inverter(s) to OPERABLE status” within a Completion Time of “24 hours.”

TS 3.8.3 Required Action A.1 also is provided a Note stating: “Enter applicable Conditions and Required Actions of LCO 3.8.5 “Distribution Systems – Operating” with any instrument and control bus de-energized.” With any instrument and control bus de-energized, TS 3.8.5 Required Action A.1 requires restoring power to the instrument and control bus within a Completion Time of 6 hours.

TS 3.3.9, Engineered Safety Feature Actuation System (ESFAS) Manual Initiation, Condition C has a misspelling “Requried” instead of “Required.”

2.3 Reason for the Proposed Change

The TS 3.8.3 Required Action A.1 24-hour Completion Time is based upon engineering judgement, taking into consideration the time required to repair an inverter and the additional risk to which the unit is exposed because of the inverter inoperability. The proposed change provides greater operational flexibility for online repair or replacement of an inoperable inverter. The proposed change would avert an unplanned shutdown of the unit if an inverter were inoperable for longer than 24 hours and a repair or replacement and retest of the inoperable inverter could not be completed during this time.

Extending the Completion Time for an inoperable inverter to 14 days provides the following potential benefits:

- Provide additional time to complete repairs and necessary retesting when components fail with the unit in the Applicability of TS 3.8.3 (i.e., Modes 1, 2, 3 and 4) thereby avoiding an unnecessary unplanned shutdown of the unit, which could challenge safety systems.
- Reducing the potential administrative burden of requesting a notice of enforcement discretion or emergency license amendment.
- Provide additional time to troubleshoot and complete inverter repair in a more controlled environment, which will enhance equipment and personnel safety.

Correcting misspelling in TS 3.3.9 Condition C is an editorial enhancement.

2.4 Description of the Proposed Change

TS 3.8.3, Inverters – Operating, Required Action A.1 Completion Time is proposed to be revised to “14 days.”

TS 3.3.9 Condition C is proposed to replace “Requried” with “Required.”

3 TECHNICAL EVALUATION

The proposed change to TS 3.3.9 Condition C to replace “Requried” with “Required” is an editorial correction with no technical impact. The remainder of the Technical Evaluation will address the proposed TS 3.8.3 Completion Time change.

Regulatory Guide (RG) 1.177, Revision 2, “An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications,” identifies that evaluations should consider integrated decision making consistent with RG 1.174, Revision 3, “An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis.” As described in RG 1.174, Revision 3, decisions concerning proposed changes are expected to be reached in an integrated fashion, considering traditional engineering and risk information, and may be based on qualitative factors as well as quantitative analyses and information. Therefore, a deterministic evaluation and a probabilistic risk assessment (PRA) have been included to support the proposed changes.

The deterministic evaluation discusses the design of the Class 1E 250 VDC and UPS System (IDS) and the associated defense-in-depth (DID) design features, the function of the inverters within the IDS during normal operation, accident mitigating steps included in the abnormal operating procedures related to the inverters, an assessment of continued compliance with applicable safety analyses, and risk management measures to be taken during the extended Completion Time. The PRA subsection discusses the quantitative analyses and risk information.

Deterministic Evaluation

Electrical System Design and Defense-in-Depth Features

The Vogtle Electric Generating Plant (VEGP) Units 3&4 plant design provides appropriate electrical systems and DID to permit functioning of plant structures, systems, and components (SSCs) during all plant states. These systems include:

- Normal power supply system
    - Normal source (AC power from Turbine Generator)
        - The normal ac power supply to the main ac power system is provided from the station main generator.
- Off-site power supply system
    - Preferred source (AC power from grid)
        - When the main generator is not available, plant auxiliary power is provided from the switchyard by backfeeding through the main stepup and unit auxiliary transformers.
    - Secondary/Maintenance source (AC Power from grid)
        - When neither the normal or the preferred power source is available due to an electrical fault, fast bus transfer is initiated to transfer the loads to the reserve auxiliary transformers powered by maintenance/secondary source.
- Emergency electric power system
    - Battery source, from Class 1E DC and UPS power systems.

VEGP also has the following additional power sources: non-Class 1E DC and UPS power system, non-Class 1E onsite standby diesel generator system, and the non-Class 1E ancillary diesel generator.

The emergency electric supply design incorporates additional levels of DID:

- The Class 1E DC and UPS system has sufficient capacity to achieve and maintain safe shutdown of the plant for 72 hours following a complete loss of all AC power sources without requiring load shedding for the first 24 hours.
- The Class 1E DC and UPS system is divided into four independent divisions. Any three out of four divisions can shut down the plant safely and maintain it in a safe shutdown condition.
- Each Class 1E division includes a voltage regulating transformer with a distribution panel capable of providing a regulated output to the Class 1E AC instrument and control bus through a static transfer switch or a manual bypass switch in the event of an inverter failure.
- Two ancillary diesel generators provide AC power for Class 1E post-accident monitoring, MCR lighting, MCR and instrumentation and control (I&C) room ventilation, and power to refill the passive containment cooling water storage tank and spent fuel pool if no other sources of power are available to Divisions B and C.

- The onsite standby power system supplies ac power to the selected permanent nonsafety loads in the event of a main generator trip concurrent with the loss of preferred power source and maintenance power source when under fast bus transfer conditions. The onsite standby diesel generators are automatically connected to the associated 6.9 kV buses upon loss of bus voltage only after the generator rated voltage and frequency is established.

Extending IDS Inverter Completion Time from 24 hours to 14 days does not impact the layers of DID inherent to the VEGP Units 3&4 electrical systems or the IDS. There are no changes to the offsite and normal power supplies. There are no changes to the diesel generator backed Class 1E voltage regulating transformer. There are no changes to the redundancy inherent in the IDS design. The safety-related IDS batteries continue to provide necessary electrical power for the safety-related valves and instrumentation credited for design basis events. Therefore, the VEGP Units 3&4 design provides reasonable assurance of the continued availability of the required power to shut down the reactor and to maintain the reactor in a safe condition after an anticipated operational occurrence or a postulated design-basis accident.

<u>Normal Operation</u>

The Main AC Power System (ECS) system is part of a three tier design supporting normal operation. The first tier consists of the AC power distribution systems feeding non-safety loads required exclusively for unit operation. The second tier includes the AC and DC power distribution systems supplying power to permanent non-safety loads. These are non-safety loads that, due to their specific functions, are generally required to remain operational at all times including when the unit is shut down. The third tier consists of the redundant Class 1E DC and Uninterruptible Power Supply (UPS) power distribution systems feeding safety related loads.

To provide normal power to the plant auxiliary and service loads during normal operation, the station generated power is transmitted to the offsite transmission system and includes a tap to the two Unit Auxiliary Transformers (UATs). A second AC power supply from the utility grid is provided through the two Reserve Auxiliary Transformers (RATs) supplied by two overhead lines from a 230 kV switchyard with a ring bus configuration. The capacity and the secondary voltage ratings of the UATs and the RATs are identical.

When AC power is available at the plant from the on-site or off-site sources, the IDS provides Class 1E 250 VDC and Class 1E 208Y/120V AC UPS power for distribution through the Class 1E battery chargers. The Class 1E battery chargers receive 480 VAC input power from the on-site standby diesel generator backed MCCs and supply 250 VDC output power to the DC buses and to the associated Class 1E inverters as input power. The Class 1E inverter supplies 208Y/120V AC UPS output power to the instrument and control buses. The spare battery charger supplies 250 VDC output power to the spare fused transfer switch box bus and the spare termination box.

Abnormal Operation

An abnormal system condition may occur as a result of component failures within the IDS or as the result of a fire. Potential component failures and sources of component unavailability include battery charger failure, battery failure, off-line battery recharging, inverter failure, inverter maintenance, I&C room fires, and electrical equipment room fires. In each case, operator responses and actions have been developed and included in advanced operating procedures.

If an inverter is inoperable or the Class 1E 250 VDC input to the inverter is unavailable, the power is transferred automatically to the backup AC source by a static transfer switch featuring a make-before-break contact arrangement. The backup power is received from the diesel generator backed non-Class 1E 480 VAC bus through the Class 1E voltage-regulating transformer. Additionally, two ancillary diesel generators provide another source of backup AC power for Divisions B and C.

Upon the unlikely failure of the DC bus or the inverter and the backup AC power supply (voltage regulating transformer, or upstream equipment / source), the associated instrument and control power bus(es) will de-energize. TS 3.8.3 Required Action A.1 includes a Note providing more limiting actions in the event the instrument and control bus is de-energized by requiring the entry into the applicable Conditions and Required Actions of LCO 3.8.5, Distribution Systems – Operating. These Required Actions required that each affected instrument and control bus is promptly re-energized (i.e., within 6 hours) as required by LCO 3.8.5 Required Action A.1.

Applicable Safety Analyses and Safety Margin Evaluation

The initial conditions of DBA and transient analyses in UFSAR Chapter 6 and UFSAR Chapter 15, assume engineered safety features are OPERABLE. The inverters are designed to provide the required capacity, capability, redundancy, and reliability to maintain the availability of necessary power to the PMS instrumentation and controls so that the fuel, reactor coolant system (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Technical Specifications 3.2 (Power Distribution Limits), 3.4 (Reactor Coolant System), and 3.6 (Containment Systems).

The operability of the inverters is consistent with the initial assumptions of the accident analyses and is based on meeting the design basis of the unit. This includes maintaining at least three of the four Divisions of AC instrument and control buses operable during accident conditions in the event of:

a) An assumed loss of all offsite and onsite AC power source; and
b) A worst case single failure.

During operation with an inoperable inverter division governed by the associated TS 3.8.3 Action Completion Time, and additional single failure is not assumed. In this condition the minimum required UPS divisions are operable to support the assumption of the safety analysis. As such, with one of the required Class 1E UPS divisions being powered from the voltage regulating transformer, which is backed up by a diesel generator, there is no significant reduction in the margin of safety.

In the event of a LOOP with an IDS division aligned to the backup power source, the power is received from a standby diesel generator backed non-Class 1E 480 VAC bus through the voltage regulating transformer. For divisions B and C, the voltage-regulating transformers can also be connected to the ancillary AC diesel generator. The simultaneous failure of an inverter, or inverter removed from service for maintenance, followed by a standby diesel generator failure (and for Division B or C an ancillary diesel generator followed by a standby diesel generator failure (and for Division B or C an ancillary diesel generator failure) concurrent with a LOOP is extremely unlikely. Nonetheless, a failure of an IDS division following a LOOP has no impact on the ability on safety-related functions since any three out of four divisions can shut down the plant safely and maintain it in a safe shutdown condition. Furthermore, TS 3.8.5 limits the time for this deenergized bus to 6 hours.

Industry Experience Related to Inverter Maintenance

VEGP Units 3&4 do not currently have direct operating experience related to maintenance on the specific VEGP inverter. The Class 1E Inverters are Gutor system type WDW 3015-250/208-EAN, which utilize components similar to components typically used in other Nuclear Power Plant applications. The exact model of inverter however does not currently have industry operating experience available.

Despite not having direct operating experience, general industry operating experience for inverter maintenance supports the proposed extension of the 24 hour allowed outage time. Previous license amendment requests for Vital AC inverter allowed outage time were submitted by Palo Verde Nuclear Generating Station, North Anna Power Station, Clinton Power Station, and Byron and Braidwood Stations. Each request identified inverter maintenance scenarios exceeding the 24 hour Completion Time. More recent industry operating experience is also available demonstrating instances when 24 hours (and in some case 7 days) was insufficient to complete inverter maintenance. Table 1 provides examples of industry operating experience supporting extension of the Completion Time from 24 hours. Unavailability of personnel or replacement equipment to support the repairs could extend these completion times.

Table 1: Industry Operating Experience Supporting Completion Time Extension

Location	Inverter Maintenance Description	Reference
North Anna	Once every refueling outage the inverters at North Anna Power Station, Units 1 and 2, have been out of service for approximately 24 hours for maintenance activities	ADAMS Accession No. ML041380438
North Anna	The normal preventative maintenance that occurs every six refueling outages can typically be performed within 48 hours	ADAMS Accession No. ML041380438
North Anna	During power operation the replacement of a failed constant voltage transformer, which is a component of the inverter, would take 5 to 7 days.	ADAMS Accession No. ML041380438
Clinton	Inverters have had an extensive history of maintenance and operational issues since they were installed in 1986. A review of the corrective maintenance and elective maintenance records was performed to identify work performed on Division 1, 2, 3, and 4 NSPS inverters. This review indicated that 37 emergent	ADAMS Accession No. ML061160181

Location	Inverter Maintenance Description	Reference
	work activities have been completed since installation of the CPS NSPS inverters. The most significant failures occurred during refueling outages, when no generation capability was lost. Of these failures, the longest duration to repair an inverter was 174 hours (7.25 days). This occurred in August 1998 during CPS's extended sixth refueling outage.	
Clinton	There have been 7 emergent work activities completed on the regulating transformers since they were installed but none of the failures occurred during power operation. The longest repair duration was 3 days, which occurred in 1997.	ADAMS Accession No. ML061160181
Byron/Braidwood	The inverters have been out-of-service for approximately 2 to 3 days during outages for maintenance activities.	ADAMS Accession No. ML032830455
Byron/Braidwood	It is expected that additional maintenance activities will be needed, with major rebuilds of each inverter that would take a maximum of 4 to 7 days to perform corrective maintenance.	ADAMS Accession No. ML032830455
Palo Verde	In response to request for information, Palo Verde Nuclear Station provided typical inverter corrective maintenance schedule information which details a hypothetical inverter corrective maintenance scenario and provides a postulated timeline. The postulated timeline found that it may take between 5.5 days and 7.5 days to reenergize an inverter.	ADAMS Accession No. ML102720481
Millstone Unit 3	On May 4, 2019, while Millstone Unit 3 was in Mode 6 Refueling Shutdown, operators received intermittent alarms concurrent with a loss of Safety Related 120 Volts AC distribution panel (Vital Inverter AC 4 or VIAC 4). VIAC 4 swapped to its alternate source and then back to its normal alignment multiple times and was declared inoperable. Troubleshooting identified visible degradation and measured a temperature gradient on a fuse block for the main fuses of the distribution panel on the output of the inverter. The distribution panel was de-energized and the degraded fuse block and associated fuses were replaced. The affected distribution panel was restored and the inverter was restored to operable on May 6, 2019. There was no impact to the outage schedule	INPO IRIS Report No. 460389
Salem Unit 2	On April 02, 2018, the Control Room received an Over Head alarm identifying the Vital Instrument Bus Inverter Failure. A walkdown discovered that the inverter temporarily swapped from primary to alternate source (unlatched transfer) with no abnormal conditions noted. Operators manually transferred the load to the AC Line Regulator. Maintenance entered complex troubleshooting and upon adjustment of a tuning potentiometer, a fuse was identified to be blown, which is characteristic of a faulty Modulation Index Control (MIC) card. The MIC card was replaced and the inverter was restored on April 04, 2018.	INPO IRIS Report No. 436327

Risk Management Measures

The VEGP Units 3&4 Maintenance Rule program monitors the reliability and availability of the IDS inverters and confirms that appropriate management attention and goal setting are applied based on pre-established performance criteria. The VEGP Units 3&4 configuration risk management program (CRMP) is consistent with 10 CFR 50.65(a)(4) (Maintenance Rule) and is managed to prevent entering risk-significant plant configurations for planned maintenance activities, and to take appropriate actions should unforeseen events place the plant in a risk-significant configuration during the IDS inverter Completion Time.

Planned maintenance is screened for impacts related to nuclear safety. Examples include consideration of maintenance that results in entry into Technical Specifications Required Action Statements, inability to control a critical safety function (e.g., power to Class 1E instrument and control power buses), and inability to perform an Emergency Operating Procedure. Planned maintenance also bundles work to minimize plant risk and to minimize out of service time. Operations is the final authority for determining if work is done on-line or in an outage.

Operational Risk Awareness procedures also screen emergent, as well as planned maintenance. These activities are classified as either medium or high risk. The associated risk management plans identify work activities that pose risk to personnel, plant equipment, or the environment are clearly identified, and an appropriate mitigation plan(s) developed to minimize or eliminate the likelihood of an unacceptable event.

10 CFR 50.65 requires that preventive maintenance activities must be sufficient to provide reasonable assurance that SSCs are capable of fulfilling their intended functions. As it pertains to the proposed IDS inverter Completion Time extension, 10 CFR 50.65(a)(4) requires the assessment and management of the increase in risk that result from proposed maintenance activities. The VEGP Units 3&4 Maintenance Rule program monitors the reliability and availability of the IDS inverters and confirms that appropriate management attention and goal setting are applied based on pre-established performance criteria. The VEGP Units 3&4 configuration risk management program (CRMP) is consistent with 10 CFR 50.65(a)(4) (Maintenance Rule) and is managed to prevent entering risk-significant plant configurations for planned maintenance activities, and to take appropriate actions should unforeseen events place the plant in a risk-significant configuration during the extended IDS inverter Completion Time. Therefore, the proposed extension of the vital AC inverter Completion Time from 24 hours to 14 days, and the planned vital AC inverter on-line maintenance that this extension will permit, are not anticipated to result in exceeding the current established Maintenance Rule criteria for the IDS inverters.

Probabilistic Risk Assessment

Regulatory Guide 1.177 provides guidance for both permanent and one-time only Completion Time changes to Technical Specifications. This guidance was used to assess the impact of a permanent Completion Time extension from 24 hours to 14 days.

Based on Guidance from Regulatory Guide 1.177, an Incremental Conditional Core Damage Probability (ICCDP) of less than 1.0E-06 is considered a small quantitative impact on plant risk. An Incremental Conditional Large Early Release Probability (ICLERP) of less than 1.0E-07 is also considered a small quantitative impact on plant risk. Plant risk assuming a single IDS inverter is inoperable and assuming both IDS inverters in the same division are unavailable (limited to Division B and C) for 14 days has been estimated to demonstrate that the quantitative impact is small, based on the Regulatory Guide 1.177 thresholds.

Table 2 outlines the basic events associated with the IDS inverters that are explicitly addressed within the PRA Model. Note that the PRA only addresses failures of the 24 hour battery banks to support the indication and control function of the IDS batteries. The 72-hour battery banks provide longer term indications (e.g., PAMS) and other support functions. The PAMS function is not explicitly addressed or credited to mitigate CDF or LERF in the PRA model. The 72-hour battery banks have limited credit in the PRA. This includes power supports for the 120 VAC UPS distribution panel IDSB-EA-3 (supported by inverter APP-IDSB-DU-2) and the AC UPS distribution panel IDSC-EA-3 (supported by inverter APP-IDSC-DU-2) electric power dependencies are included in the PRA if the identified PRA equipment requires power for the given PRA function. The electric power dependency is then addressed in the model based on the associated distribution panel/bus identified by the electrical load list.

The IDS inverters static switch is an important component that adds to the reliability of the UPS and, as such, is modeled separately from the inverter. If an inverter is inoperable or the Class 1E 250 VDC input to the inverter is unavailable (i.e., the TS 3.8.3 Actions entered), the power is transferred automatically to the backup AC source by a static transfer switch featuring a make-before-break contact arrangement. The backup power is received from normal non-Class 1E 480V AC bus through the Class 1E voltage-regulating transformer. The impact of an inoperable inverter is only explicitly addressed in the unavailability of the inverter function. Unavailability of the inverter function is not a direct loss of I&C loads (e.g., IDSA-EA-1). That would only occur if it was coupled with a failure of the transfer switch or AC power supply. In the event that backup power is not supplying the instrument and control power bus, the TS 3.8.5 Action A applies limiting continued operation to 6 hours.

Table 2: IDS Inverter Associated Basic Events

Bus	Component	Tag	Related Basic Event(s)
IDSA	Inverter	APP-IDSA-DU-1	IDS-INV-FOP-DU1/A
	Transfer Switch	APP-IDSA-DU-1	IDS-ABT-FOP-DU1STS/A
IDSB	Inverter	APP-IDSB-DU-1	IDS-INV-FOP-DU1/B
	Inverter	APP-IDSB-DU-2	IDS-INV-FOP-DU2/B
	Transfer Switch	APP-IDSB-DU-1	IDS-ABT-FOP-DU1STS/B
	Transfer Switch	APP-IDSB-DU-2	IDS-ABT-FOP-DU2STS/B
IDSC	Inverter	APP-IDSC-DU-1	DS-INV-FOP-DU1/C
	Inverter	APP-IDSC-DU-2	IDS-INV-FOP-DU2/C
	Transfer Switch	APP-IDSC-DU-1	IDS-ABT-FOP-DU1STS/C
	Transfer Switch	APP-IDSC-DU-2	IDS-ABT-FOP-DU2STS/C
IDSD	Inverter	APP-IDSD-DU-1	IDS-INV-FOP-DU1/D
	Transfer Switch	APP-IDSD-DU-1	IDS-ABT-FOP-DU1STS/D

The estimated risk impacts are generated by setting the representative events to true in the associated internal events or hazards baseline results cutset file post-processing. Table 3 outlines the baseline cutset files and associated baseline frequencies for the at-power Vogtle Units 3 and 4 PRA.

Table 3: Baseline CDF and LERF Results

Hazards	Result	Baseline CDF & LERF Cutset File	Frequency (per reactor year)
Internal Events	CDF	CDF-ALL.CUT	3.94E-07
	LERF	L2-ALL-LERF.CUT	3.83E-08
Internal Flooding	CDF	CDF-ALL_E-14.CUT	2.17E-07
	LERF	L2-ALL-LERF_E-14.CUT	8.40E-08
Internal Fire	CDF	CDF_1E-14.GROUP.CUT	8.54E-07
	LERF	LERF_5E-15.GROUP.CUT	3.37E-07(1)
Seismic	CDF	ALL-SCENARIOS-CDF.CUT	9.30E-08(2)
	LERF	ALL-SCENARIOS-LERF.CUT	5.16E-08(2)

Notes:
(1) Result based on the FRANX results for truncation level of 1E-15. The grouped cutset file for Internal Fire LERF was limited to 5E-15 truncation due to computing limitation. The Fire LERF value of 3.37E-07/reactor year is used for this assessment based on the 5E-15 truncation results. Given the small difference between the 1E-15 and 5E-15 LERF values (~5E-09) this small difference is not anticipated to have any notable impact the ICLERP assessment results.
(2) All results are based on the CAFTA Minimal Cutset Upper Bound (MCUB) results and not the ACUBE post processing results.

Based on the results in Table 3, the total baseline CDF is 1.56E-06 and the total baseline LERF is 5.11E-07. The baseline cutset files outlined in Table 3 are used to support the conditional CDF and LERF values for each of the inverter basic events presented in Table 2. The results of this evaluation are outlined in Table 4. Each inverter basic event identified in the representative event column was set to true to obtain the corresponding conditional CDF and LERF. Conditional values were obtained for each inverter individually and two cases were assessed with both inverters in the same division set to true at the same time (limited to Division B and C). The results provide the individual risk impact of each inverter or division individually, consistent with the conditions reflected by TS 3.8.3 Action A.

The estimated risk impacts are generated by setting the representative events to true in the associated hazards baseline results cutset file post-processing, utilizing the baseline truncation values. This was selected over re-quantification due to the computing limitation associated with FRANX (used to quantify fire and seismic) and the large cutset file generated to support the LERF results. The impact of the representative basic event(s) set to true was observed in each of the total conditional CDF and LERF resulting values when compared to individual hazard results where impact may not be observed due to the representative basic event(s) not being in the baseline cutset file (below truncation). These subset of cases with the representative basic event(s) not in the baseline cutset file (below truncation) are identified in bold text in Table 4. This treatment is deemed sufficient, and impact is anticipated to be negligible since impact is observed in the total conditional CDF and LERF values for each inverter case and representative basic event(s) not in the baseline cutset file (below truncation) is an indication of lower importance to CDF and LERF.

Table 5 utilizes the conditional CDF and LERF values from Table 4 to assess the impact of different Completion Times. The resulting ICCDP and ICLERP are calculated on a per entry basis, with the TS entry duration being the full proposed duration of the allowed Completion Time identified for each column.

The final baseline seismic CDF and LERF results were based on the ACUBE post-processing results over the CAFTA MCUB results utilized for the conditional CDF and LERF values and baseline values in Tables 4 and 3. Utilizing the MCUB results over the ACUBE results is anticipated to have no meaningful impact on the resulting ICCDP and ICLERP values since the delta from the condition CDF and LERF values to the baseline values CDF and LERF values are small (less than 6E-8/year for CDF and less than 5E-9/year for LERF) when compared to the other hazard groups.

Risk impact was assessed using the VEGP 3&4 specific PRA. Impacts on other external hazards and low power or shutdown operation were qualitatively assessed and described in further detail below. There is a small quantitative impact on plant risk due to the extension of the IDS Inverter extended Completion Time as shown above in Table 5. Note that, the 30-day Completion Time results shown above in Table 5 also indicate a small quantitative impact on plant risk providing additional confidence in the minimal impact at a 14-day Completion Time. Therefore, it is concluded that increasing the Completion Time for an IDS inverter from 24 hours to 14 days meets the acceptance guidelines of RG 1.177.

<u>Consideration of Impact on External Hazards</u>

Based on the conclusions of the at-power External Hazards Assessment, the identified external hazards (excluding Internal Flooding, Seismic, and Internal Fire) were screened out. Qualitative and quantitative screening of external hazards was performed consistent with the requirements of ASME/ANS-RA-Sa 2009, “Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications” for this external events analysis. These assessments conclude that other external hazards are individually screened with CDFs between 1E-09 per year to approximately 1E-14 per year. Extension of the IDS TS Completion Time from the current 24 hours to 14 days increases the single component outage risk associated CDP due to “other” (i.e., screened external hazards) to the range of 2E-11 to 2E-16 per entry. Given the low probability (contribution) of “other” external hazards they may be screened from the impact for this test Interval extension. These contributions are insignificant, particularly when compared to the impact on Internal Events, Internal Flooding, Internal Fire and Seismic.

Table 4: Conditional CDF and LERF Results for At-Power Internal Events and Hazards

Representative Event	Internal Events		Internal Flooding		Internal Fire		Seismic		Total		CCDF and CLERF (CDF Baseline 1.56E-06 LERF Baseline 5.11E-07)	
Basic Event(s) for sensitivities	**Conditional CDF**	**Conditional LERF**	**Conditional CDF**	**Conditional LERF**	**Conditional CDF**	**Conditional LERF**	**Conditional CDF**	**Conditional LERF**	**Conditional CDF**	**Conditional LERF**	**CCDF (Total – Baseline)**	**CLERF (Total – Baseline)**
IDS-INV-FOP-DU1/A	4.33E-07	***3.83E-08***	1.67E-06	1.02E-07	2.18E-06	5.83E-07	***9.30E-08***	5.65E-08	4.38E-06	7.80E-07	2.82E-06	2.69E-07
IDS-INV-FOP-DU1/B	4.06E-07	***3.83E-08***	2.48E-07	***8.40E-08***	1.45E-06	3.95E-07	9.91E-08	***5.16E-08***	2.20E-06	5.69E-07	6.45E-07	5.80E-08
IDS-INV-FOP-DU2/B	1.31E-06	1.10E-07	1.89E-06	6.89E-07	4.58E-06	1.82E-06	9.91E-08	5.16E-08	7.88E-06	2.67E-06	6.32E-06	2.16E-06
IDS-INV-FOP-DU1/C	4.13E-07	***3.83E-08***	2.98E-07	***8.40E-08***	1.64E-06	3.48E-07	1.19E-07	***5.16E-08***	2.47E-06	5.22E-07	9.12E-07	1.10E-08
IDS-INV-FOP-DU2/C	4.13E-07	***3.83E-08***	3.00E-07	8.50E-08	1.64E-06	3.49E-07	1.19E-07	5.16E-08	2.47E-06	5.24E-07	9.14E-07	1.30E-08
IDS-INV-FOP-DU1/D	1.23E-06	1.10E-07	5.92E-07	2.99E-07	3.39E-06	1.65E-06	9.91E-08	5.17E-08	5.31E-06	2.11E-06	3.75E-06	1.60E-06
IDS-INV-FOP-DU1/B & IDS-INV-FOP-DU2/B	1.33E-06	1.10E-07	1.92E-06	6.89E-07	5.17E-06	1.88E-06	1.05E-07	5.16E-08	8.53E-06	2.73E-06	6.97E-06	2.22E-06
IDS-INV-FOP-DU1/C & IDS-INV-FOP-DU2/C	4.32E-07	***3.83E-08***	3.81E-07	8.50E-08	2.43E-06	3.59E-07	1.44E-07	5.16E-08	3.39E-06	5.34E-07	1.83E-06	2.30E-08
Notes: (1) ***BOLD*** text signifies that the inverter basic event is not in the baseline cutset file (below truncation) therefore the conditional CDF and conditional LERF is set at the baseline CDF or LERF value.												

Table 5: ICCDP and ICLERF Results For LCO 3.8.3 Completion Time Extensions for At-Power Internal Events and Hazards

Basic Event(s) for sensitivities	24 Hour ICCDP	24 Hours ICLERP	14 days ICCDP	14 days ICLERP	30 days ICCDP	30 days ICLERP
IDS-INV-FOP-DU1/A	7.72E-09	7.37E-10	1.08E-07	1.03E-08	2.32E-07	2.21E-08
IDS-INV-FOP-DU1/B	1.77E-09	1.59E-10	2.47E-08	2.22E-09	5.30E-08	4.77E-09
IDS-INV-FOP-DU2/B	1.73E-08	5.92E-09	2.42E-07	8.28E-08	5.20E-07	1.78E-07
IDS-INV-FOP-DU1/C	2.50E-09	3.01E-11	3.50E-08	4.22E-10	7.50E-08	9.04E-10
IDS-INV-FOP-DU2/C	2.50E-09	3.56E-11	3.51E-08	4.99E-10	7.51E-08	1.07E-09
IDS-INV-FOP-DU1/D	1.03E-08	4.38E-09	1.44E-07	6.14E-08	3.08E-07	1.31E-07
IDS-INV-FOP-DU1/B & IDS-INV-FOP-DU2/B	1.91E-08	6.08E-09	2.67E-07	8.51E-08	5.73E-07	1.82E-07
IDS-INV-FOP-DU1/C & IDS-INV-FOP-DU2/C	5.01E-09	6.30E-11	7.02E-08	8.82E-10	1.50E-07	1.89E-09

Consideration of Impact During Low Power and Shutdown

TS 3.8.3 Action A is applicable from Mode 1 through Mode 4. As the plant configuration is the same for Modes 1 through 3 with minor exceptions, the insights from at-power PRA are applicable for Modes 1, 2 and 3. The primary differences among these modes from at-power operation (Mode 1) is that Mode 2 limits power operation to ≤ 5% and that the Mode 3 configuration has control rods inserted with potentially lower plant temperatures/pressures. Therefore, Mode 3 is not subject to anticipated transients without scram (ATWS) and would likely have lower loss of coolant accident (LOCA) frequencies and lower decay heat conditions. As a result, should an initiating event occur, the initial conditions of lower power and decay heat in Mode 2 and Mode 3 that result in initiating events that provide more time for operator responses.

Mode 4 maintains the plant in hot shutdown with an intact RCS. During Mode 4 operation, prior to placing Normal Residual Heat Removal System (RNS) in service, the plant decay heat removal defenses are not reduced when compared to the at-power level of defenses. For example, steam generators (SGs), passive residual heat removal and in-containment refueling water storage tank (injection and passive recirculation cooling methods are available to support decay heat removal. Therefore, in lieu of developing quantitative impacts, it is conservative to use the at-power PRA model to bound the risk impact of Mode 4 operation prior to placing RNS in service.

During Mode 4 operation with RNS in service, the plant has the same safety-related decay heat removal defense as Mode 1, as well as the non-safety related steam generators providing decay heat removal. Core Makeup Tanks (CMTs), Passive Residual Heat Removal Heat Exchanger (PRHR HX), and In-Containment Refueling Water Storage Tank (IRWST) injection/passive recirculation cooling methods continue to be available during Mode 4 regardless of RNS providing decay heat removal.

In the event that RNS is lost during Mode 4 operation with RNS in service, the operators utilize the Loss of Normal Residual Heat Removal procedure to address the cause with the intent of restoring RNS for decay heat removal. If RNS cannot be restored, operators establish cooling using a secondary heat sink consisting of at least one intact SG, a means to add feedwater (main or startup feedwater pumps), and a means to dump steam in a controlled manner. If a secondary heat sink cannot be established, then PRHR HX cooling is initiated. If no means of RCS cooling can be established, then passive feed and bleed is established by actuation of Safeguards and transitioning to the Emergency Operation Procedures. Unless a heat sink is established that directs reactor decay heat outside containment using the RNS system or a SG, the PRHR HX is used to transfer heat to the IRWST. Heat is then transferred to the containment atmosphere by allowing the IRWST to heat up and boil. The IRWST can be cooled by the spent fuel pool cooling system if available. Potential actions to cool the containment atmosphere include operation of the containment fan coolers.

Additionally, lines of defense that are independent from IDS are available. This includes DAS actuation of PRHR and IRWST injection/passive recirculation cooling. RNS operation is also independent from IDS after RNS is placed in service.

Also, as discussed in UFSAR Section 17.4 risk significant non-safety systems, structures, and components (including RNS as shown in UFSAR Table 17.4-1) are included in the Operational

Phase Reliability Assurance Activities. These reliability assurance and investment protection programs include:

- Maintenance Rule Program
- Quality Assurance Program
- Inservice Testing Program
- Inservice Inspection Programs
- Investment Protection Short Term Availability Control
- Site Maintenance Program

There is no change to the Regulatory Treatment of Non-Safety Systems evaluation as a result of the risk impact estimates for the proposed changes to TS 3.8.3.

Safety-related normal decay heat removal is provided by the Passive Core Cooling System (PXS). The requirements for Mode 4 operation of the PXS are provided in TS Section 3.5, Passive Core Cooling System. Specifically, TS 3.5.3, "CMTs – Shutdown, RCS Intact", and TS 3.5.5, "PRHR HX - Shutdown, RCS Intact", address the PXS component operability required when in Mode 4 with the RCS cooling provided by the RNS to provide the availability of safety-related decay heat removal in the event RNS is lost. TS 3.5.6, "IRWST – Operating", addresses the operability requirements for the IRWST in Mode 4.

The multiple lines of defense that are independent from IDS and the longer time window available for recovery typically observed during lower mode operation, the contribution of the lower power and shutdown modes are judged to be very small compared to the at-power PRA risks and does not impact the assessment of overall risk insights.

<u>Status of Vogtle AP1000 Plant PRA</u>

VEGP Unit 3&4 COL condition 2.D(12)(g)6 requires a review of the differences between the as-built plant and the design used as the basis for the AP1000 seismic margin analysis, including verification walkdowns, evaluation of differences, seismic margin analysis, and high confidence, low probability of failures (HCLPFs) evaluations. VEGP Units 3&4 COL condition 2.D(12)(g)8 requires a review of the differences between the as-built plant and the design used as the basis for the AP1000 internal fire and internal flood analysis. The differences between the plant-specific PRA-based insights and the design for internal fire and internal flood have been evaluated.

Each of these activities is complete and satisfied based on the as-built activities for VEGP Unit 3 and assumed to be representative of VEGP Unit 4 since each activity must also be complete for Vogtle Unit 4 to satisfy the COL Conditions. Any significant deviations at that time must be reconciled to complete the COL Conditions for Unit 4.

The plant specific PRA model has been modified as necessary to account for the plant-specific design and any design changes or departures from the design certified in Revision 19 of the AP1000 Design Certification Document. None of the plant-specific differences identified during performance of walkdowns or model changes as a result of design changes resulted in changes to the risk insights from the VEGP Unit 3 PRA. No model changes as a result of design changes have resulted in changes to risk insights from the VEGP Unit 4 PRA.

The CDF and LERF are calculated for internal events. Selected internal hazard events are also quantitatively assessed to derive plant insights and plant risk conclusions. Seismic events are assessed using a detailed site-specific PRA approach. Other external hazards are evaluated with a qualitative approach.

The models have been updated to reflect plant-specific design and as-built conditions following standards and methodologies applicable to preparing a PRA model for operations including:

- ASME/ANS-RA-Sa 2009, "Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications," American Society of Mechanical Engineers.
- US NRC Regulatory Guide 1.200, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk Informed Activities," Revision 2.
- NUREG/CR-6928, "Industry-Average Performance for Components and Initiating Events at U.S. Commercial Nuclear Power Plants."
- EPRI 1019194, "Guidelines for Performance of Internal Flooding Probabilistic Risk Assessment," Electric Power Research Institute."
- US NRC NUREG/CR-6850, "EPRI/NRC–RES Fire PRA Methodology for Nuclear Power Facilities."
- ANSI/ANS 58.21-2007, "External Events PRA Methodology."

The models have been peer reviewed following appropriate guidance including:

- NEI 00-02, Probabilistic Risk Assessment (PRA) Peer Review Process Guidance.
- NEI 05-04, Process for Performing Internal Events PRA Peer Reviews Using the ASME/ANS PRA Standard.
- NEI 07-12, Fire Probabilistic Risk Assessment (FPRA) Peer Review Process Guidelines.
- NEI 12-13, "External Hazards PRA Peer Review Process Guidelines".
- EPRI 3002012994, "Seismic Fragility and Seismic Margin Guidance for Seismic Probabilistic Risk Assessment," September 2018

Therefore, the technical adequacy of the VEGP site-specific PRA, and the risk evaluations performed to support this proposed change, are sufficient to provide confidence in the results such that the PRA can be used in regulatory decision-making.

Discussion of Findings & Observations

The At-Power Internal Events PRA was peer reviewed against Part 2 of ASME/ANS RA-Sa-2009 in 2013. Since the 2013 peer review, the Vogtle Units 3&4 plant At-Power Internal Events PRA has been updated to address several peer review findings & observations (F&Os), to the extent possible for a pre-operational plant.

The At-Power Internal Flooding PRA was peer reviewed against Part 3 of ASME/ANS RA-Sa-2009 in 2013. Since the 2013 peer review the Vogtle Units 3&4 plant At-Power Internal Flooding PRA has been updated to address peer review F&Os, to the extent possible for a pre-operational plant. In 2020, an independent F&O closure assessment was performed in accordance with Appendix X of NEI 05-04, Process for Performing Internal Events PRA Peer Reviews. Due to the pre-operational/construction stage of the plant some of the Supporting Requirements (SRs) were marked as "Met Intent, Not Achievable." The remaining Internal Flooding PRA open F&Os are related to the pre-operational/construction stage of the plant.

The At-Power Fire PRA was peer reviewed against Part 4 of ASME/ANS RA-Sa-2009 in 2020. Since the 2020 peer review, the Vogtle Units 3&4 plant At-Power Fire PRA has been updated to address several peer review F&Os, to the extent possible for a pre-operational plant.

The At-Power Seismic PRA was peer reviewed against Part 5 of ASME/ANS RA-Sa-2009 in 2017. In 2020 an independent F&O closure assessment and focused-scope peer review was performed in accordance with Appendix X of NEI 12-13, External Hazards PRA Peer Review Process Guidelines. Since the 2020 F&O independent assessment and focused-scope peer review, the Vogtle Units 3&4 plant At-Power Seismic PRA has been updated to address several peer review F&Os, to the extent possible for a pre-operational plant.

The At-Power External Events analysis was peer reviewed against Part 6 of ASME/ANS RA-Sa-2009 in 2016. Since the 2016 peer review, the Vogtle Units 3&4 plant At-Power external events PRA has been updated to address peer review F&Os.

Status of Unit 3 Walkdown

Walkdowns have been performed that confirm the assumptions used in the PRA represent the Vogtle Unit 3 as-built plant conditions. The walkdown teams followed industry guidance outlined in walkdown notebooks. Walkdowns of the plant were conducted in the August 2020 to April 2021 timeframe when the plant construction was approximately 98% complete. Results of these walkdowns, including as-built observations, are documented in walkdown notebooks. Since the plant construction was not complete at the time of the walkdowns, as-found conditions were evaluated for potential risk-significance and determination of if necessary for incorporation into the models. Results of the as-built walkdown evaluations and observations were incorporated into the plant-specific PRA models as necessary. Observations identified with potential risk-significant impact to the PRA were incorporated into the model, while observations and as-found conditions identified with low impact (not risk significant) were dispositioned and are tracked via the model maintenance process for future incorporation.

None of the plant-specific differences identified during performance of walkdowns or model changes as a result of design changes resulted in changes to the risk insights from the Vogtle Unit 3 PRA or a risk-significant impact to the Vogtle Unit 3 PRA. The walkdown observations and walkdown open items were reviewed. No walkdown observations or walkdown open items were identified for possible impact to this application.

PRA Maintenance and Update Procedure

The Vogtle Units 3&4 PRA model reflects the design reference point of August 2018 ("model freeze date"). The changes to the design up to the model freeze date for the Vogtle Unit 3 have been incorporated in the PRA model. For the design changes or departures from the certified design that would have occurred after August 2018, a model maintenance process was used to identify, collect, and screen them for any necessary model update. Subsequent design changes were reviewed for possible impact on this application. No design changes were identified for possible impact to this application.

Review of Self-Assessment

A self-assessment was performed against Part 2 of ASME/ANS RA-Sa-2009 for Internal Events, Internal Flooding, Internal Fire, Seismic, and External Events. Due to the pre-operational / construction stage of the plant at the time of the self-assessment, some of the Supporting Requirements (SRs) were marked as “Met Intent, Not Achievable.” No internal events SR is identified for possible impact to this application.

LOOP Sensitivity

LOOP was identified as a potential source of uncertainty impacting this application. A sensitivity study was performed by reducing the LOOP frequency in the base and condition cases for internal events.

The VEGP Units 3&4 Internal Events PRA conservatively assumes no recovery from LOOP. A sensitivity was performed by decreasing the LOOP initiating event frequency by 50%. The baseline values (CDF and LERF) and conditional CDF and LERF values for IDS-INV-FOP-DU1/B & IDS-INV-FOP-DU2/B were generated to assess the impact of this assumption for this application. This sensitivity is limited to internal events since no credit or limited credit for LOOP recovery would be expected during an internal flood, internal fire or seismic events. For example, no credit for equipment recovery is included for fire-induced and flood-induced loss of Electric Power Distribution System equipment leading to a LOOP. Conditional CDF and LERF values for IDS-INV-FOP-DU1/B & IDS-INV-FOP-DU2/B were selected for the sensitivity since they have the largest delta risk from Table 4.

The loss of offsite power initiating event frequency is currently 3.59E-02/per reactor year. To estimate the potential impact of crediting loss of offsite power recovery the offsite power initiating event frequency was reduced by 50% resulting in an updated LOOP frequency of 1.80E-02/per reactor year. LOOP frequency was updated from its baseline frequency 3.59E-02 to the revised sensitivity value of 1.80E-02.

The “baseline” CDF and LERF values in Table 6 are directly from Table 3. The “Baseline + LOOP Update” results utilized the baseline cutset files CDF-ALL.CUT and L2-ALL-LERF.CUT from Table 3. The LOOP frequency (%LOOP) was then updated to 1.80E-02/per reactor operating state year in the cutset file. The updated CDF and LERF results are then presented in Table 6. As expected, a small decrease in CDF and LERF results is observed.

Table 6: Internal Events Baseline Cases

Baseline Case	CDF	LERF
Baseline (From Table 3)	3.94E-07	3.83E-08
Baseline + LOOP Update	3.83E-07	3.59E-08

The "IDS-INV-FOP-DU1/B & IDS-INV-FOP-DU2/B Baseline (from Table 4)" Conditional CDF and LERF values in Table 7 below are directly from Table 4. The "IDS-INV-FOP-DU1/B & IDS-INV-FOP-DU2/B + LOOP Update" results utilized the cutset files CDF-ALL-IDS-INV-FOP-DU1_B_and_IDS-INV-FOP-DU2_B - LOOP.cut and L2-ALL-LERF-IDS-INV-FOP-DU2_B - LOOP.CUT that support the conditional results in Table 4. The LOOP frequency was then updated to 1.80E-02 per reactor operating state year in each cutset file. The updated conditional CDF and LERF results are presented in Table 7. The CCDF and CLERF values were calculated by subtracting the baseline value (Table 6) from the corresponding conditional value. The resulting CCDF and CLERF values in Table 7 demonstrate that this assumption is conservative for this application.

Table 7: Conditional CDF and LERF Results for At-Power Internal Events and Hazards

	Internal Events		**CCDF and CLERF**	
Sensitivity Conditional Case	**Conditional CDF**	**Conditional LERF**	**CCDF (Conditional –Baseline)**	**CLERF (Conditional – Baseline)**
IDS-INV-FOP-DU1/B & IDS-INV-FOP-DU2/B Baseline (from Table 4)	1.33E-06	1.10E-07	9.36E-07	7.17E-08
IDS-INV-FOP-DU1/B & IDS-INV-FOP-DU2/B + LOOP Update	9.35E-07	7.49E-08	5.52E-07	3.90E-08

The results indicate that the current treatment of LOOP recovery in the PRA model is conservative for this application.

<u>RAW Value of Unavailability Basic Events Comparison</u>

A review of the unavailable basic events with risk assessment worth (RAW) for the conditional internal events CDF and LERF results. They are then compared to the baseline results RAW values. The risk-significant unavailable basic events with a notable increase in RAW, identified during this review, each support the backup sources to the Class 1E AC instrument and control buses. Cutset reviews were performed for the cutsets containing the identified risk-significant unavailable basic events with a notable increase in RAW. The cutset reviews of the unavailable basic events with a notable RAW increase all included an initiating event independent from one inverter division being unavailable, coupled with a system failure independent from IDS or two systems independent from IDS and each other. This demonstrates that DID is maintained for events with one inverter division being unavailable, and therefore demonstrates that no additional compensatory measures (beyond the current procedurally controlled risk management plans and Maintenance Rule program) are necessary.

4 REGULATORY EVALUATION

4.1 Applicable Regulatory Requirements/Criteria

A review of the pertinent regulations and industry guidance was performed and found that compliance with 10 CFR Sections 50.36, 50.63, 50.65, Part 50 Appendix A General Design Criteria (GDC) 17, 18, and Regulatory Guides (RGs) 1.174 and 1.177 is maintained by extending the IDS Inverter Completion Time from 24 hours to 14 days. A description of the pertinent requirements and guidance as well as a disposition for continued compliance are provided below.

<u>10 CFR Section 50.36, "Technical Specifications"</u>

10 CFR 50.36 requires that operating licenses for nuclear reactors must include TS that specify LCOs for equipment required for safe operation. The proposed change in the IDS Inverter Completion Time has no impact on the continued conformance with the requirements of 10 CFR 50.36. Specifically, the inverters are part of the electrical power distribution systems, and as such, satisfy criterion 3 of 10 CFR 50.36(c)(2)(ii). The distribution system for which the inverters are included, are a primary success path, and function or actuate 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 and continues to perform as intended and consistent with the accident analyses.

<u>10 CFR 50, Appendix A, GDC 17 – "Electrical Power Systems"</u>

GDC 17 requires, in part, that nuclear power plants have onsite and offsite electric power systems to permit the functions of SSCs that are important to safety. The onsite system must have sufficient independence, redundancy, and testability to perform its safety function, assuming a single failure. The offsite power system must be supplied by two physically independent circuits that are designed and located so as to minimize, to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. In addition, this criterion requires provisions to minimize the probability of losing electric power from the remaining electric power supplies as a result of a loss of power from the unit, the offsite transmission network, or the onsite power supplies. The proposed change continues to provide sufficient independence, redundancy, and testability, and minimizes the probability of losing power as a result of a loss of power from the unit, the offsite transmission network, or the onsite power supplies.

The VEGP Units 3&4 plant design continues to provide appropriate electrical systems and Defense-in-Depth (DID) to permit functioning of plant SSCs during all plant states. These systems include:

- Normal power supply system
  - Normal source (AC power from Turbine Generator)
    - The normal ac power supply to the main ac power system is provided from the station main generator.
- Off-site power supply system
  - Preferred source (AC power from grid)
    - When the main generator is not available, plant auxiliary power is provided from the switchyard by backfeeding through the main stepup and unit auxiliary transformers.

- Secondary/Maintenance source (AC Power from grid)
  - When neither the normal or the preferred power supply is available due to an electrical fault, fast bus transfer is initiated to transfer the loads to the reserve auxiliary transformers powered by maintenance sources of power
- Emergency electric power system
  - Battery source, from Class 1E DC and UPS power systems.

The VEGP Units 3&4 plants also have the following additional power sources: non-Class 1E DC and UPS power system, non-Class 1E onsite standby diesel generator system, and the non-Class 1E ancillary diesel generator.

The safety-related IDS batteries continue to provide the necessary electrical power for the safety-related valves and instrumentation credited for design basis events. There are no changes to other plant electrical systems or the DID design. Therefore, implementation of the proposed Completion Time extension will have no impact on the VEGP Units 3&4 GDC 17 licensing basis.

10 CFR 50, Appendix A, GDC 18, "Inspection and Testing of Electric Power Systems,"

GDC 18 requires that electric power systems that are important to safety must be designed to permit appropriate periodic inspection and testing. The extended IDS Inverter Completion Time from 24 hours to 14 days does not impact the testing or inspection of the inverters. Therefore, implementation of the proposed Completion Time extension will have no impact on the VEGP Units 3&4 GDC 18 licensing basis.

10 CFR Section 50.63, "Loss of All Alternating Current Power"

10 CFR Section 50.63 requires that nuclear power plants must be able to withstand a loss of all AC power for an established period of time and recover from a station blackout.

During a loss of all AC power sources including the on-site standby diesel generators, the IDS provides power from the IDS batteries without interruption for a period of 24 and 72 hours to the required safety-related loads.

Divisions A and D battery banks and one of the battery banks in Divisions B and C are designated as 24-hour battery banks (two 60-cell strings in series) and provide power to the loads required for the first 24 hours following a loss of all AC power event or a DBA. The second battery bank in Divisions B and C, designated as the 72-hour battery bank (two 60-cell strings in series) is used for those loads requiring power for 72 hours following the same event. A spare battery bank with spare battery charger is provided for the Class 1E DC and UPS system. The voltage-regulating transformers provide the availability of AC power to the UPS loads in case of failure or unavailability of the inverters.

Including the extended IDS Inverter Completion Time from 24 hours to 14 days, the IDS continues to provide sufficient levels of redundancy and DID to provide the necessary electrical power for the safety-related valves and instrumentation credited for design basis events. Therefore, the proposed extension of the IDS Inverter Completion time from 24 hours to 14 days has no significant impact on the ability to withstand a loss of all AC power and recover from a station blackout.

<u>10 CFR 50.65, Requirements for monitoring the effectiveness of maintenance at nuclear power plants</u>

10 CFR 50.65 requires that preventive maintenance activities must be sufficient to provide reasonable assurance that SSCs are capable of fulfilling their intended functions. As it pertains to the proposed IDS inverter Completion Time extension, 10 CFR 50.65(a)(4) requires the assessment and management of the increase in risk that result from proposed maintenance activities. The VEGP Units 3&4 Maintenance Rule program monitors the reliability and availability of the IDS inverters and confirms that appropriate management attention and goal setting are applied based on pre-established performance criteria. The VEGP Units 3&4 configuration risk management program (CRMP) is consistent with 10 CFR 50.65(a)(4) (Maintenance Rule) and is managed to prevent entering risk-significant plant configurations for planned maintenance activities, and to take appropriate actions should unforeseen events place the plant in a risk-significant configuration during the extended IDS inverter Completion Time. Therefore, the proposed extension of the vital AC inverter Completion Time from 24 hours to 14 days, and the planned vital AC inverter on-line maintenance that this extension will permit, are not anticipated to result in exceeding the current established Maintenance Rule criteria for the IDS inverters.

<u>Regulatory Guides (RG)</u>

RG 1.177 states that a risk-informed application should be evaluated to confirm that the proposed change meet the following five key principles:

1) The proposed change meets the current regulations unless it is explicitly related to a requested exemption, i.e., a "specific exemption" under 10 CFR 50.12.

2) The proposed change is consistent with the DID philosophy.

3) The proposed change maintains sufficient safety margins.

4) When proposed changes result in an increase in CDF or risk, the increases should be small and consistent with the intent of the Commission's Safety Goal Policy Statement.

5) The impact of the proposed change should be monitored using performance measurement strategies.

The NRC's safety Goal Policy Statement and PRA Policy Statement are implemented in part via RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis" and RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications". RG 1.174 describes a risk-informed approach, acceptable to the NRC, for assessing the nature and impact of proposed licensing basis changes by considering engineering issues and applying risk insights. RG 1.177 identifies an acceptable risk-informed approach, including additional guidance geared toward the assessment of proposed TS Completion Time changes.

RG 1.200, "An Approach For Determining The Technical Adequacy Of Probabilistic Risk Assessment Results For Risk-Informed Activities," Revision 2, provide guidance to licensees for use in determining the technical adequacy of the base PRA used in a risk-informed regulatory activity. RG 1.200 endorses standards and industry guidance that address risk-informed activities and is a supporting document to other NRC regulatory guides that address risk-informed activities, including RG 1.174 and RG 1.177 described above. The VEGP Units 3&4 Probabilistic Risk Assessment has been developed in accordance with Regulatory Guide 1.200 Revision 2 and the endorsed standards and industry guidance, and therefore is adequate for use in risk-informed regulatory activity.

The VEGP Units 3&4 assessment of potential risk impacts associated with the IDS Inverter Completion Time extension from 24 hours to 14 days was performed in a manner consistent with the guidance and criteria described above. This assessment confirms that applicable regulatory requirements continue to be met, adequate DID is maintained, sufficient safety margins are maintained, and any increase in risk is small and consistent with the NRC's Safety Goal Policy Statement. The ICCDP and ICLERP for each IDS Inverter meet the regulatory guidelines such that the impact on plant risk is considered small.

The risk impact of the extended IDS Inverter Completion Time from 24 hours to 14 days as estimated by ICCDP and ICLERP, is consistent with the acceptance guidelines specified in RG 1.174 and RG 1.177.

4.2 Precedents

- Byron & Braidwood, Units 1 and 2, Package, Re Completion Time from 24 Hours to 7 Days for One Inoperable Instrument Bus Inverter, dated November 19, 2003 [ML032830455]
- North Anna, Units 1 and 2, License Amendments 235 & 217 regarding Extended Inverter Allowed Outage Time, dated May 12, 2004 [ML041380438]
- Clinton, License Amendment, TS Change to Extend Completion Time for Nuclear System Protection System Inverters, dated May 26, 2006 [ML061160181]
- Palo Verde, Units 1, 2, and 3 - Issuance of Amendment Nos. 180, 180, and 180, Revise TS 3.8.7, "Inverters - Operating," to Extend Completion Time for Restoration of an Inoperable Inverter (TAC Nos. ME2337, ME2338, and ME2339), dated September 29, 2010 [ML102670352]

4.3 Significant Hazards Consideration

Southern Nuclear Operating Company (SNC) is requesting an amendment to Combined License (COL) Nos. NPF-91 and NPF-92 for Vogtle Electric Generating Plant (VEGP) Units 3 and 4, respectively. The license amendment request (LAR) proposes changes to COL Appendix A, Technical Specifications (TS) 3.8.3, Inverters – Operating, to extend the Completion time for restoring the inoperability of one or two inverters one division to 14 days. An additional editorial change corrects the spelling of “Required” in TS 3.3.9, Engineered Safety Feature Actuation System (ESFAS) Manual Initiation, Condition C.

4.3.1 Does the proposed amendment involve a significant increase in the probability or consequences of an accident previously evaluated?

Response: No.

The proposed changes do not adversely affect the operation of any structures, systems, or components (SSCs) associated with an accident initiator or initiating sequence of events. The proposed change does not affect the design of the vital AC inverters, the operational characteristics or function of the inverters, the interfaces between the inverters and other plant systems, or the reliability of the inverters. An inoperable vital AC inverter is not considered an initiator of an analyzed event. In addition, Required Actions and the associated Completion Times are not initiators of previously evaluated accidents. Extending the Completion Time for an inoperable vital AC inverter would not have a significant impact on the frequency of occurrence of an accident previously evaluated.

The proposed changes continue to maintain the initial conditions and operating limits assumed during normal operation, assumed by the accident analysis, and assumed in anticipated operational occurrences. Therefore, the proposed changes do not result in any increase in probability of an analyzed accident occurring.

The proposed changes do not involve a change to any mitigation sequence or the predicted radiological releases due to postulated accident conditions. Thus, the consequences of the accidents previously evaluated are not adversely affected.

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

4.3.2 Does the proposed amendment create the possibility of a new or different kind of accident from any accident previously evaluated?

Response: No.

The proposed changes do not involve physical alteration, and do not impact the required functional capability of the safety systems for previously evaluated accidents and anticipated operational occurrences. No new equipment is being introduced, and installed equipment is not being operated in a new or different manner. The proposed revisions do not change the function of the related systems, and thus, the changes do not introduce a new failure mode, malfunction or sequence of events that could adversely affect safety or safety-related equipment.

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

4.3.3 Does the proposed amendment involve a significant reduction in a margin of safety?

Response: No.

Margins of safety are established in the design of components, the configuration of components to meet certain performance parameters, and in the establishment of setpoints to initiate alarms or actions. The proposed amendment does not alter the design or configuration of the vital AC inverters. The proposed changes continue to provide the required functional capability of the safety systems for previously evaluated accidents and anticipated operational occurrences. The proposed changes do not change the function of the related systems nor significantly affect the margins provided by the systems. No safety analysis or design basis acceptance limit/criterion is challenged or exceeded by the requested changes. Applicable regulatory requirements will continue to be met, adequate defense-in-depth will be maintained, sufficient safety margins will be maintained, and any increases in risk are consistent with the NRC Safety Goals.

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

Based on the above, it is concluded that the proposed amendment does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of “no significant hazards consideration” is justified.

4.4 Conclusions

Based on the considerations discussed above, (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission’s regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public. Therefore, it is concluded that the requested amendment does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of “no significant hazards consideration” is justified.

5 ENVIRONMENTAL CONSIDERATIONS

The proposed changes to the Technical Specifications (TS) are described in Section 2.4 of this Enclosure.

A review has determined that the proposed changes require an amendment to the COL. A review of the anticipated construction and operational effects of the requested amendment has determined that the requested amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9), in that:

(i) *There is no significant hazards consideration.*

As documented in Section 4.3, Significant Hazards Consideration, of this license amendment request, an evaluation was completed to determine whether or not a significant hazards consideration is involved by focusing on the three standards set forth in 10 CFR 50.92, “Issuance of amendment.” The Significant Hazards Consideration evaluation determined that (1) the proposed amendment does not involve a significant increase in the probability or consequences of an accident previously evaluated; (2) the proposed amendment does not create the possibility of a new or different kind of accident from any accident previously evaluated; and (3) the proposed amendment does not involve a significant reduction in a margin of safety. Therefore, it is concluded that the proposed amendment does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and accordingly, a finding of "no significant hazards consideration" is justified.

(ii) *There is no significant change in the types or significant increase in the amounts of any effluents that may be released offsite.*

The proposed changes are unrelated to any aspect of plant construction or operation that would introduce any change to effluent types (e.g., effluents containing chemicals or biocides, sanitary system effluents, and other effluents) or affect any plant radiological or non-radiological effluent release quantities. Furthermore, the proposed changes do not affect any effluent release path or diminish the functionality of any design or operational features that are credited with controlling the release of effluents during plant operation. Therefore, it is concluded that the proposed amendment does not involve a significant change in the types or a significant increase in the amounts of any effluents that may be released offsite.

(iii) *There is no significant increase in individual or cumulative occupational radiation exposure.*

The proposed change in the requested amendment does not affect the shielding capability of, or alter any walls, floors, or other structures that provide shielding. Plant radiation zones and controls under 10 CFR 20 preclude a significant increase in occupational radiation exposure. Therefore, the proposed amendment does not involve a significant increase in individual or cumulative occupational radiation exposure.

Based on the above review of the proposed amendment, it has been determined that anticipated construction and operational effects of the proposed amendment does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluents that may be released offsite, or (iii) a significant increase in the individual or cumulative occupational radiation exposure. Accordingly, the proposed amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendment.

6 REFERENCES

None.

Vogtle Electric Generating Plant (VEGP) Units 3 and 4

License Amendment Request for Technical Specification 3.8.3, Inverters – Operating, Completion Time Extension

Attachment 1

Technical Specification Marked Up Pages

Insertions Denoted by Blue Underline **and Deletions by** ~~Red Strikethrough~~
Omitted text is identified by three asterisks (* * *)

(Attachment 1 consists of three pages, including this cover page.)

Technical Specification 3.8.3, Inverters – Operating:

* * *

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or two inverter(s) within one division inoperable.	A.1 ------------------------------------ **- NOTE -** Enter applicable Conditions and Required Actions of LCO 3.8.5 “Distribution Systems – Operating” with any instrument and control bus de-energized. ------------------------------------ Restore inverter(s) to OPERABLE status.	~~24 hours~~14 days
B. * * *	* * *	

* * *

Technical Specification 3.3.9, Engineered Safety Feature Actuation System (ESFAS) Manual Initiation:

* * *

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
* * *		
C. ~~Requried~~ Required Action and associated Completion Time of Condition A or B not met. OR One or more Functions with two channels inoperable.	* * *	
* * *		

* * *

Vogtle Electric Generating Plant (VEGP) Units 3 and 4

License Amendment Request for Technical Specification 3.8.3, Inverters – Operating, Completion Time Extension

Attachment 2

Technical Specification Revised Pages

(Attachment 2 consists of three pages, including this cover page.)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition A or B not met. <u>OR</u> One or more Functions with two channels inoperable.	C.1 Enter the Condition referenced in Table 3.3.9-1 for the channel(s).	Immediately
D. As required by Required Action C.1 and referenced in Table 3.3.9-1.	D.1 Be in MODE 3. <u>AND</u> D.2 Be in MODE 4 with the Reactor Coolant System (RCS) cooling provided by the Normal Residual Heat Removal System (RNS).	6 hours 24 hours
E. As required by Required Action C.1 and referenced in Table 3.3.9-1.	E.1 Be in MODE 3. <u>AND</u> E.2 Be in MODE 5.	6 hours 36 hours
F. As required by Required Action C.1 and referenced in Table 3.3.9-1.	F.1 Declare affected isolation valve(s) inoperable.	Immediately
G. As required by Required Action C.1 and referenced in Table 3.3.9-1.	G.1 Be in MODE 5. <u>AND</u> G.2 Initiate action to establish RCS VENTED.	12 hours 12 hours

3.8 ELECTRICAL POWER SYSTEMS

3.8.3 Inverters – Operating

LCO 3.8.3 The Division A, B, C, and D inverters shall be OPERABLE.

- NOTES -

One inverter may be disconnected from its associated DC bus for ≤ 72 hours to perform an equalizing charge on its associated battery, providing:

1. The associated instrument and control bus is energized from its Class 1E voltage regulating transformer; and

2. All other AC instrument and control buses are energized from their associated OPERABLE inverters.

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

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or two inverter(s) within one division inoperable.	A.1	-------------------- **- NOTE -** Enter applicable Conditions and Required Actions of LCO 3.8.5 “Distribution Systems – Operating” with any instrument and control bus de-energized. -------------------- Restore inverter(s) to OPERABLE status.	14 days
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	B.2	Be in MODE 5.	36 hours

Vogtle Electric Generating Plant (VEGP) Units 3 and 4

License Amendment Request for Technical Specification 3.8.3, Inverters – Operating, Completion Time Extension

Attachment 3

Technical Specification Bases Marked Up Pages
(For Information Only)

Insertions Denoted by Blue Underline and Deletions by ~~Red Strikethrough~~
Omitted text is identified by three asterisks (* * *)

(Attachment 3 consists of two pages, including this cover page.)

Technical Specifications Bases B 3.8.3, Inverters – Operating

* * *

BASES

ACTIONS

A.1

* * *

Required Action A.1 allows ~~24 hours~~ 14 days to fix each inoperable inverter and return it to service. The ~~24 hours~~ 14 day time limit is ~~based on engineering judgment~~ a risk-informed Completion Time based on site-specific risk analysis, taking into consideration the time required to repair an inverter and the additional risk to which the unit is exposed because of the inverter inoperability. This has to be balanced against the risk of an immediate shutdown, along with the potential challenges to safety systems such a shutdown might entail. When the AC instrument and control bus is powered from its voltage regulating transformer, it is relying upon interruptible AC electrical power sources (offsite and onsite). The uninterruptible inverter source to the AC instrument and control buses is the preferred source for powering instrumentation trip setpoint devices.

* * *