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

Clinton Power Station, Unit 1
Facility Operating License No. NPF-62
NRC Docket No. 50-461

Subject: Request for Technical Specification Change to Extend Completion Time for Nuclear System Protection System Inverters

Pursuant to 10 CFR 50.90, "Application for amendment of license or construction permit.", AmerGen Energy Company (AmerGen), LLC hereby requests an amendment to Appendix A, Technical Specifications (TS), of Facility Operating License No. NPF-62 for Clinton Power Station, Unit 1. The proposed change revises the Completion Time for Required Action A.1 of TS 3.8.7, "Inverters – Operating," from the current 24 hours for a Division 1 or 2 Nuclear System Protection System (NSPS) inverter inoperable to 7 days.

The change is being proposed to support on-line corrective maintenance of the NSPS inverters and will have a negligible impact on plant safety. The current Completion Time for restoration of an inoperable Division 1 or 2 NSPS inverter is insufficient to support on-line corrective maintenance and post-maintenance testing. Implementation of this proposed Completion Time extension will provide operational flexibility, allowing more efficient application of plant resources to safety significant activities. The change will allow performance of periodic NSPS inverter maintenance and post-maintenance testing on-line, reducing plant refueling outage duration, and improving NSPS inverter availability during shutdown. The proposed change is not required for Divisions 3 and 4 since the current completion time for restoration of an inoperable Division 3 or 4 inverter is of sufficient duration to support on-line corrective maintenance and post-maintenance testing.

The justification for extending the Completion Time for an inoperable Division 1 or 2 NSPS inverter is based upon a risk-informed and a deterministic evaluation incorporating two main elements: 1) the availability of a separate transformer powering each instrument bus, and 2) the application of the Configuration Risk Management Program while the NSPS inverter is inoperable for planned maintenance. These elements provide high assurance of the capability to provide power to the instrument buses during the NSPS inverter extended Completion Time.

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The risk impact of this extension of the Completion Time associated with TS 3.8.7 Required Action A.1 was evaluated using the upgraded CPS Probabilistic Risk Assessment (PRA) model. The Incremental Conditional Core Damage Probability (ICCDP) and Incremental Conditional Large Early Release Probability (ICLERP) for each inverter division are sufficiently below the guidelines of < 5.0E-07 and < 5.0E-08, respectively, to be able to call the risk change small. Hence, the guidelines of Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," for the increased inverter Completion Time have been met. Furthermore, the evaluation of changes in Core Damage Frequency (CDF) and Large Early Release Frequency (LERF) due to the expected increased inverter unavailability have been shown to meet the risk significance criteria of Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," with substantial margin. This evaluation supports the increase in the Division 1 and 2 inverter Completion Time from a quantitative risk-informed perspective consistent with the plant operational and maintenance practices. Therefore, this Completion Time revision is considered non-risk significant.

This request is subdivided as follows:

1. Attachment 1 gives a description and safety analysis of the proposed change.
2. Attachment 2 includes the marked-up TS pages for the proposed change.
3. Attachment 3 includes the associated marked-up TS Bases pages for information only.
4. Attachment 4 provides the risk assessment supporting the proposed changes.

This proposed change has been reviewed by the CPS Plant Operations Review Committee and approved by the Nuclear Safety Review Board in accordance with the requirements of the Quality Assurance Program.

AmerGen is notifying the State of Illinois of this application for amendment by transmitting a copy of this letter and its attachments to the designated State Official.

AmerGen is requesting approval of the proposed change by April 30, 2005. Once approved, the amendment will be implemented within 60 days.

Should you have any questions related to this information, please contact Mr. Timothy Byam at (630) 657-2804.

I declare under penalty of perjury that the foregoing is true and correct.

Respectfully,

April 26, 2004
Executed on

Keith R. Jury
Keith R. Jury
Director – Licensing and Regulatory Affairs
AmerGen Energy Company, LLC

Attachments:
1. Evaluation of Proposed Changes
2. Markup of Proposed Technical Specification Page Changes
3. Markup of Proposed Bases Page Changes (For Information Only)
4. Technical Evaluation of Extending Division 1 and 2 Inverter Completion Time

cc: Regional Administrator – NRC Region III
NRC Senior Resident Inspector – Clinton Power Station
Office of Nuclear Facility Safety – IEMA Division of Nuclear Safety

Subject: Request for Technical Specification Change to Extend Completion Time for Nuclear System Protection System Inverters

1.0 DESCRIPTION

This is a request from AmerGen Energy Company (AmerGen), LLC to amend Appendix A, Technical Specifications (TS), of Facility Operating License No. NPF-62 for Clinton Power Station (CPS). The proposed change revises the Completion Time for Required Action A.1 of TS 3.8.7, "Inverters – Operating," from the current 24 hours for a Division 1 or 2 Nuclear System Protection System (NSPS) inverter inoperable to 7 days.

The change is being proposed to support on-line corrective maintenance of the NSPS inverters. The current Completion Time for restoration of an inoperable Division 1 or 2 NSPS inverter is insufficient to support on-line corrective maintenance and post-maintenance testing. The proposed change is not required for Divisions 3 and 4 since the current completion time for restoration of an inoperable Division 3 or 4 inverter is of sufficient duration to support on-line corrective maintenance and post-maintenance testing.

Implementation of this proposed Completion Time extension will provide operational flexibility, allowing more efficient application of plant resources to safety significant activities. The change will allow performance of periodic NSPS inverter maintenance and post-maintenance testing on-line, reducing plant refueling outage duration, and improving NSPS inverter availability during shutdown.

2.0 PROPOSED CHANGES

The proposed change revises the Completion Time for Required Action A.1 of TS 3.8.7, "Inverters – Operating," from the current 24 hours for a Division 1 or 2 NSPS inverter inoperable to 7 days.

In addition to the above, the TS Bases will be revised to document the basis for the proposed completion time.

3.0 BACKGROUND

The NSPS inverters are the preferred source of power for the uninterruptible 120 VAC buses because of the stability and reliability they demonstrate. There is one inverter per uninterruptible AC bus, making a total of four divisional inverters. The function of the inverter is to provide AC electrical power to these buses.

The four safety-related 120 VAC inverter buses support the NSPS instruments. Each NSPS bus has its own inverter supplied from a separate and independent, divisional DC bus. There is an alternate supply to each of these NSPS buses from a safety-related 480 VAC bus. Each inverter contains a solid-state transfer switch to select the NSPS bus supply. The DC bus through the inverter is the normal supply. However, the solid-state transfer switch will shift to the alternate AC source automatically if the inverter detects abnormal conditions, such as an internal inverter component failure or for handling fault clearing or inrush current demands. The transfer of the divisional inverters to their alternate source will occur if the alternate source is either energized or deenergized. In addition, the inverter contains a manual bypass switch to the alternate AC source that is used during maintenance alignments or can be used if the solid-state transfer switch fails. The DC source provides an uninterruptible power source for the instrumentation and controls for the Reactor Protection System (RPS), the Emergency Core Cooling Systems (ECCS) initiation, and miscellaneous isolations.

The inverters are required to be operable in Modes 1, 2, and 3 to ensure that:

- Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of anticipated operational occurrences (AOOs) or abnormal transients; and
- Adequate core cooling is provided, and containment operability and other vital functions are maintained in the event of a postulated design basis accident (DBA).

The inverters ensure the availability of AC electrical power for the instrumentation for the systems required to shut down the reactor and maintain it in a safe condition after an AOO or a postulated DBA.

Maintaining the required inverters operable ensures that the redundancy incorporated into the design of the RPS and ECCS instrumentation and controls is maintained. The four battery powered divisional inverters ensure an uninterruptible supply of AC electrical power to the uninterruptible AC buses even if the 4.16 kV safety buses are deenergized. Operable NSPS inverters require that the associated bus is powered by the inverter via inverted DC voltage from the required Class 1E DC bus, with the output within the design voltage and frequency tolerances.

TS 3.8.7, Action A.1, currently allows only 24 hours to repair an inoperable Division 1 or 2 inverter and return it to service. The 24 hour limit was based upon engineering judgment, taking into consideration the time required to repair an inverter and the additional risk to which the plant is exposed because of the inverter inoperability. TS 3.8.7, Action B.1, requires that with one or more Division 3 or 4 inverters inoperable, the associated Division 3 ECCS subsystem be declared inoperable. Since the Division 3 and 4 inverters support operation of the Division 3 ECCS, inoperability of one or more Division 3 or 4 inverters may result in the associated Division 3 ECCS subsystem (i.e., High Pressure Core Spray) being incapable of performing its intended function. Therefore, Action B.1 requires that High Pressure Core Spray (HPCS) be declared inoperable immediately. HPCS must be restored to operable within 14 days. This effectively results in a 14-day completion time for the Division 3 and 4 inverters. This provides sufficient time for on-line maintenance and post-maintenance testing should it be required for Division 3 or 4. The same is not true for Division 1 or 2.

The proposed change to the TS will extend the allowable Completion Time for the Required Action associated with restoration of an inoperable Division 1 or 2 inverter. The current Completion Time for restoration of an inoperable Division 1 or 2 inverter is insufficient in some cases to support on-line corrective maintenance and post-maintenance testing while CPS is at power. Implementation of this proposed Completion Time extension will provide the following benefits.

- Allow increased flexibility in the scheduling and performance of preventive maintenance.
- Allow better control and allocation of resources. Allowing on-line preventive maintenance, provides the flexibility to focus more quality resources on any required or elective NSPS inverter maintenance.
- Avert unplanned plant shutdowns and minimize the potential need for requests for Notice of Enforcement Discretion (NOED).
- Improve inverter bus availability during shutdown Modes or Conditions. This will reduce the shutdown risk associated with inverter maintenance and the synergistic effects on risk due to inverter unavailability occurring at the same time as other various activities and equipment outages that occur during a refueling outage.
- Permit scheduling of inverter maintenance within the requested 7 day period.

4.0 TECHNICAL ANALYSIS

As noted above, the NSPS inverters are the preferred source of power for the NSPS instrument buses because of their inherent stability and reliability. The divisional portion of the NSPS includes four independent Class 1E 120 VAC uninterruptible power supplies (UPS) and their respective power buses. Each UPS consists of a battery charger, a station battery, an inverter, and a solid-state transfer switch. Each of the four AC instrument buses is normally supplied AC electrical power by the dedicated NSPS inverter. The NSPS inverters are powered from an associated 125 VDC battery. The battery provides an uninterruptible power source for the instrumentation. In addition, alternate power is available to each of the NSPS buses from a safety-related AC bus, step-down transformer, and isolation transformer.

The initial conditions of DBA and transient analyses in the CPS Updated Safety Analysis Report (USAR), Chapter 6, "Engineered Safety Features," and Chapter 15, "Accident Analyses," assume Engineered Safety Features (ESF) Systems are operable. The NSPS inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the RPS and ECCS instrumentation and controls so that the fuel, reactor coolant system (RCS), and containment design limits are not exceeded. The operability of the NSPS inverters is consistent with the initial assumptions of the accident analyses and is based on meeting the design basis of CPS. This includes maintaining required AC instrument buses operable during accident conditions in the event of an assumed loss of all offsite AC power or all onsite AC power sources, and a worst-case single failure.

With a required inverter inoperable, its associated uninterruptible AC bus is inoperable if not energized. The alternate power supply provides an interruptible source of power to the NSPS instrument buses. A loss of offsite power (LOOP) with an inoperable NSPS inverter (i.e., instrument bus being powered by the alternate power supply) will result in a loss of power to the associated instrument bus. The alternate power is provided from a Class 1E power supply; therefore, upon a LOOP with an inoperable NSPS inverter, power would be restored to the affected instrument bus once the associated diesel generator (DG) re-energizes the Class 1E 480 VAC bus. Following restoration of the 480 VAC bus, all instruments supplied by the instrument bus would be restored with no adverse impact to CPS because no other instrument channels in the opposite train would be expected to be inoperable or in a tripped condition during this time, with the exception of routine surveillances. That is, the inverters would be available in the divisions not powered by the alternate AC source. In order for the instrument bus to remain de-energized, the associated DG would have to fail, there would have to be a failure to re-energize the alternate 480 VAC bus powering the instrument bus, or the alternate source would have to fail to energize the instrument bus (i.e., failure of the step-down transformer or isolation transformer).

Based on the above, it has been demonstrated that in the event of a failure to re-energize the 480 VAC bus or of a transformer failure, the most significant impact on the unit is the failure of one train of ESF equipment to actuate. In this condition, the redundant train of ESF equipment will automatically actuate to mitigate the accident, and the unit would remain within the bounds of the accident analyses. In addition, there would be no adverse impact to the unit because no other instrument channels in the opposite train would be expected to be inoperable or in a tripped condition during this time, with the exception of routine surveillances. Since the probability of these events occurring simultaneously during a planned maintenance window is low, there is minimal safety impact due to the requested extended Completion Time. Therefore, the safety functions associated with the NSPS instrument buses will continue to be met with the power supplied by the alternate AC power source.

The CPS Division 1, 2, 3, and 4 NSPS inverters have an extensive history of maintenance and operational issues since installation. In 1994, the Instrument Power (IP) System, which includes the NSPS inverters, was classified as Maintenance Rule category (a)1 as a direct result of frequent and repetitive NSPS inverter fuse failures. A condition report was written to document these failures and the focus of the corrective actions associated with that condition report was to improve inverter performance by correcting the NSPS inverter material conditions that resulted in frequent fuse failures. The fuse failure issues were subsequently resolved during NSPS inverter refurbishment. In 1998, the IP system was classified once again as Maintenance Rule category (a)1 due to a spurious Division 2 NSPS inverter transfer to the alternate source. Several condition reports were written to document the failures associated with the NSPS inverters. A root cause investigation was performed and poor inverter performance was determined to be the result of incorrect and insufficient inverter maintenance. Since the corrective actions taken to correct reliability issues associated with the NSPS inverters have been completed, performance of the inverters has improved. Establishment of an adequate maintenance program and refurbishment of the inverters in the 1998 – 1999 time frame have resolved inverter reliability issues satisfactorily. In 2000, the IP system Maintenance Rule classification was upgraded to category (a)2. In addition to improving reliability of the inverters, CPS obtained a spare NSPS inverter in 2001. This was done to allow rapid response to any future catastrophic failure of a divisional NSPS inverter.

While the reliability of the NSPS inverters has improved, as a result of having only 24 hours to fix an inoperable NSPS inverter, catastrophic and emergent events associated with the NSPS inverters may necessitate preparation of a NOED at CPS. Use of the spare inverter would reduce the time required to repair a failed NSPS inverter, however, this spare may not be able to be installed and tested in 24 hours. The spare inverter provides CPS with a means of making repairs in a much more timely manner and would result in a quicker return to power if the plant has been shut down.

Evaluation of Risk Impact

The proposed changes are evaluated to determine that current regulations and applicable requirements continue to be met, that adequate defense-in-depth and sufficient safety margins are maintained, and that any increase in core damage frequency (CDF) or large early release frequency (LERF) is small and consistent with the NRC Safety Goal Policy Statement, USNRC, "Use of Probabilistic Risk Assessment Methods in Nuclear Activities: Final Policy Statement," Federal Register, Volume 60, p.42622, August 16, 1995.

Risk informed input for this change is based on the latest CPS probabilistic risk assessment (PRA) update (Revision 2003A) for full power internal events. The PRA is used to quantify the change in Core Damage Frequency (CDF) and Large Early Release Frequency (LERF) produced by the increased Completion Time for the Inverters. Other deterministic techniques are being implemented to minimize any risk impact. These deterministic techniques include: (1) implementation of a Configuration Risk Management Program (CRMP) to control performance of other high risk tasks during the inverter outage; and, (2) consideration of specific compensatory measures to minimize risk.

The risk impact of the proposed NSPS divisional inverter Completion Time change has been evaluated and found to be acceptable. The calculated risk increases are very small as characterized by Regulatory Guide (RG) 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," (Reference 1).

The effect on risk of the requested increase in Completion Time for restoration of an inoperable inverter has been evaluated using NRC's three-tier approach suggested in RG 1.177, "An Approach for Plant-Specific Risk-Informed Decisionmaking: Technical Specifications," (Reference 2):

Tier 1: PRA Capability and Insights

Tier 2: Avoidance of Risk-Significant Plant Configurations

Tier 3: Risk-Informed Configuration Risk Management

Tier 1: PRA Capability and Insights

Risk-informed support for the proposed change is based on PRA calculations performed to quantify the change in CDF and LERF resulting from the increased Completion Time for the NSPS inverter.

The CPS PRA model and documentation has been maintained current and is routinely updated to reflect the current plant configuration following refueling outages and to reflect the accumulation of additional plant operating history and component failure data. The Level 1 and Level 2 CPS PRA analyses were originally developed and submitted to the NRC in September, 1992 as the Clinton Power Station Individual Plant Examination (IPE) Submittal (Reference 3). The CPS PRA has been updated several times since the original IPE.

The latest PRA update (Revision 2003A) includes the incorporation of all the "A" PRA Peer Review Fact and Observations (F&Os) and the risk significant "B" F&Os. The PRA Peer Review is discussed in Appendix B of Attachment 4. The latest PRA update also includes the effects of a full Extended Power Uprate of 20%.

In addition to incorporating recent advances in PRA technology across all elements of the PRA, a special effort was made to ensure that those aspects of the PRA that are potentially sensitive to changes in inverter maintenance unavailability are adequate to evaluate the risk impacts of the increased Completion Time for the inverters. These elements include the proper characterization of initiating events involving loss of offsite power, treatment of time dependent offsite power recovery, treatment of operator actions to implement emergency operating procedures, and data analysis of key parameters such as diesel generator failure rates, maintenance unavailabilities, and common cause failure probabilities.

For the Level 2 analysis (i.e., the containment analysis), LERF was calculated using an approach based on a detailed containment event tree. This approach to LERF evaluation supports a realistic quantification of contributions to containment failure and radionuclide release.

To determine the effect of the proposed 7-day Completion Time[1] for an inverter, the guidance suggested in References 1 and 2 was used. Thus, the following risk metrics were used to evaluate the risk impacts of extending the inverter Completion Time from 24 hours to 7 days.

$\Delta\ CDF_{AVE}$ = change in the annual average CDF due to any increased on-line maintenance unavailability of inverters that could result from the increased Completion Time. This risk metric is used to compare against the criteria of Reference 1 to determine whether a change in CDF is regarded as risk significant. These criteria are a function of the baseline annual average core damage frequency, CDF_{BASE}.

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(1) The evaluation of the Completion Time conservatively assumed that each inverter would be unavailable for 7 days per fuel cycle.

Δ $LERF_{AVE}$ = change in the annual average LERF due to any increased on-line maintenance unavailability of inverters that could result from the increased Completion Time. Reference 1 criteria were also applied to judge the significance of changes in this risk metric.

ICCDP{Inverter Y} = incremental conditional core damage probability with inverter Y out-of-service for an interval of time equal to the proposed new Completion Time (i.e., 7 days). This risk metric is used as suggested in Reference 2 to determine whether a proposed increase in Completion Time has an acceptable risk impact.

ICLERP{Inverter Y} = incremental conditional large early release probability with inverter Y out-of-service for an interval of time equal to the proposed new Completion Time (i.e., 7 days). Reference 2 criteria were also applied to judge the significance of changes in this risk metric.

The evaluation of the above risk metrics was performed assuming that each divisional inverter undergoes a planned maintenance outage of the full 7 days each fuel cycle. The analysis assumes that CPS is on a 24-month fuel cycle. The details of this analysis are provided in Section 2.3 of Attachment 4.

The intermediate results of the risk evaluation are presented in Table 1, "PRA Model Results and Inverter Maintenance Unavailabilities for the Risk Metric Calculations." This table shows the results for each train dependent calculation of risk metrics. The base CDF value for CPS is 9.97E-06/year based on the average unavailability of the NSPS inverters consistent with the current inverter Completion Time. The base LERF is 9.86E-8/year.

Table 1

PRA MODEL RESULTS AND INVERTER MAINTENANCE UNAVAILABILITIES FOR THE RISK METRIC CALCULATIONS

CDF	Frequency (Per Rx Yr)(1)	LERF	Frequency (Per Rx Yr)(2)
$CDF_{1\text{-}OOS}$	1.52E-5(3)	$LERF_{1\text{-}OOS}$	5.02E-7(2)
$CDF_{2\text{-}OOS}$	9.97E-6(3), (4)	$LERF_{2\text{-}OOS}$	9.86E-8(2)
CDF_{BASE}	9.97E-6(3)	$LERF_{BASE}$	9.86E-8(2)

(1) All CDF estimates based on Single Top model at a truncation of 3E-11/yr.

(2) All LERF estimates based on Single Top model at a truncation of 5E-11/yr (as modified by Appendix D to Attachment 4 to remove excess conservatisms).

(3) The asymmetry between $CDF_{1\text{-}OOS}$ (i.e., Division 1 out of service) and $CDF_{2\text{-}OOS}$ (i.e., Division 2 out of service) is due to a plant design asymmetry. The Division 1 inverter supports RCIC. RCIC tends to be a mitigation system in Station Blackout (SBO)

related events such that the impact of the Division 1 inverter is greater than Division 2.

(4) $CDF_{2\text{-}OOS}$ is reported as the same value as CDF_{BASE}. Model quantification shows the difference between $CDF_{2\text{-}OOS}$ and CDF_{BASE} to be less than 3.1E-10/yr.

The results of the risk evaluation are compared in Table 2, "Results of Risk Evaluation for Clinton Inverter Completion Time Extension," with risk significance criteria from Reference 1 for changes in the annual average CDF and LERF and from Reference 2 for ICCDP and ICLERP.

Table 2

RESULTS OF RISK EVALUATION FOR CLINTON INVERTER COMPLETION TIME EXTENSION

Risk Metric	Risk Significance Guideline	Risk Metric Results	Guideline Met
ΔCDF_{AVE}	< 1.0E-06/yr	3.0E-8/yr	Yes
$\Delta LERF_{AVE}$	< 1.0E-07/yr.	4.0E-9/yr	Yes
$ICCDP_{DIV1}$	< 5.0E-07	1.0E-7	Yes
$ICLERP_{DIV1}$	< 5.0E-08	7.7E-9	Yes
$ICCDP_{DIV2}$	< 5.0E-07	Negligible	Yes
$ICLERP_{DIV2}$	< 5.0E-08	Negligible	Yes

The base CDF is 9.97E-6/yr while the calculated increase in CDF associated with the Completion Time extension is 3.0E-8/yr. As defined in Reference 1, this combination of results places the proposed plant TS change in Region III. RG 1.174 describes Region III as:

- Very small changes in the CDF risk metric
- More flexibility with respect to the Baseline CDF

The conclusion is that the Reference 1 guidance for CDF is met with substantial margin.

The base LERF is 9.86E-8/yr while the calculated increase in LERF associated with the Completion Time extension is 4.0E-9/yr. As defined in Reference 1, this combination of results places the proposed plant TS change in Region III. RG 1.174 describes Region III as:

- Very small changes in the LERF risk metric

- More flexibility with respect to the Baseline LERF

The conclusion is that the Reference 1 guidance on LERF is met with substantial margin.

The ICCDP and ICLERP guideline values demonstrate that the proposed inverter Completion Time change has only a small quantitative impact on plant risk. Table 2 demonstrates the following.

- For the Division 2 inverter, the Reference 2 guidelines for ICCDP and ICLERP are both met with substantial margin.
- For the Division 1 inverter, the calculated ICCDP and ICLERP are well below the guideline. Therefore, the quantitative impact on plant risk is "small" consistent with the Reference 2 guidance.

The results indicate that the individual inverter ICCDP and ICLERP are within the Reference 2 guidelines. In addition, the Reference 1 acceptance guidelines (Region III: very small risk changes) are met with approximately an order of magnitude margin.

The CPS plant risk due to internal fires was evaluated in 1995 as part of the CPS Individual Plant Examination of External Events (IPEEE) Submittal (Reference 4). EPRI Fire Induced Vulnerability Evaluation (FIVE) Methodology and Fire PRA Implementation Guide screening approaches and data were used to perform the CPS IPEEE fire PRA study. The CDF contribution due to internal fires was calculated at 3.26E-6/yr.

The results of the fire PRA evaluation are documented in Appendix A to Attachment 4. As the CPS internal fire PRA models are currently archived, the IPEEE documentation for the fire induced core damage scenarios and the associated frequency results were reviewed in support of this assessment. This estimate was performed as follows:

- The dominant fire scenarios from the CPS IPEEE fire analysis are used to represent the CPS fire risk profile. These scenarios are summarized in Figure 4.24, "Fire Zone Contribution to Core Damage Frequency", of Reference 4.
- Based on the internal events risk impact results of this risk assessment, it was determined that the inverter Completion Time extension only impacts SBO scenarios, all other accident types are negligibly impacted. As such, based on References 5 and 6, the CPS fire IPEEE quantitative results were reviewed to determine the breakdown of the fire CDF into SBO and non-SBO accidents.
- The results of the inverter Completion Time base case quantification (in terms of CDF increase as a function of SBO vs. non-SBO accidents) were applied to the CPS fire scenarios. The CPS Completion Time base quantification cutsets were compared with the CPS base PRA cutsets to make this determination. The sum of SBO cutsets increased by approximately a factor of 1.6 for the Completion Time case over the base case; and, the sum of the non-SBO cutsets increased insignificantly (i.e., < 1%).

The fire impact calculation estimate is summarized in Appendix A to Attachment 4. As can be seen from Table A-1 in Attachment 4, it is estimated that the CPS fire IPEEE CDF would increase by 1-2% due to the inverter Completion Time extension request. The ICCDP is estimated at approximately 1.0E-9.

Based on a review of the CPS IPEEE and the key general conclusions identified earlier in this assessment, the conclusions of the seismic margins analysis are judged to be unaffected by the Completion Time extension for the NSPS Division 1 and 2 inverters. The inverter Completion Time extension has no impact on the seismic qualifications of the structures, systems, and components (SSCs).

The CPS IPEEE analysis of high winds, tornadoes, external floods, transportation accidents, nearby facility accidents, and other external hazards was accomplished by reviewing the plant environs against regulatory requirements regarding these hazards. Based upon this review, it was concluded that CPS meets the applicable Standard Review Plan requirements and therefore has an acceptably low risk with respect to these hazards. Similar to the conclusions related to the seismic assessment, the inverter Completion Time extension does not impact the conclusions of the assessment for these external hazards.

Tier 2: Avoidance of Risk-Significant Plant Configurations

There is reasonable assurance that risk-significant plant equipment configurations will not occur when specific plant equipment is out-of-service consistent with the proposed TS changes. This conclusion is based on the following considerations:

- LCO 3.0.3 must be entered if one or more additional inverters are inoperable.
- Increases in risk posed by potential combinations of equipment out-of-service will be managed under the CRMP.

Tier 3: Risk-Informed Configuration Risk Management

CPS follows procedure WC-AA-101, "On-Line Work Control Process," to ensure that the risk impact of equipment out of service is appropriately evaluated prior to performing any maintenance activity. This process requires an integrated review (i.e., both probabilistic and deterministic) to identify risk-significant plant equipment outage configurations in a timely manner both during the work management process and for emergent conditions during normal plant operation. Appropriate consideration is given to equipment unavailability, operational activities like testing, and weather conditions. This process includes provisions for performing a configuration dependent assessment of the overall impact on risk of proposed plant configurations prior to, and during, the performance of maintenance activities that remove equipment from service. Risk is re-assessed if equipment failure/malfunction or emergent conditions produce a plant configuration that has not been previously assessed.

For planned maintenance activities, an assessment of the overall risk of the activity on plant safety, including benefits to system reliability and performance, is currently performed prior to scheduled work. The assessment includes the following considerations.

- Maintenance activities that affect redundant and diverse SSCs that provide backup for the same function are minimized.
- The potential for planned activities to cause a plant transient are reviewed and work on SSCs that would be required to mitigate the transient are avoided.
- Work is not scheduled that has a potential to exceed a TS Completion Time requiring a plant shutdown. Planning for on-line equipment outages typically provides for a 100% contingency time within the TS Completion Time.
- For Maintenance Rule Program High Risk Significant SSCs, the impact of the planned activity on the unavailability performance criteria is evaluated.
- As a final check, a quantitative risk assessment is performed to ensure that the activity does not pose any unacceptable risk. This evaluation is performed using the Level 1 PRA model. The results of the risk assessment are classified by a color code based on the increased risk of the activity as follows.

Color	Level of Risk	Plant Impact and Required Action
Green	Minimal Risk	Little or no impact on Plant Risk. No specific actions are required.
Yellow	Acceptable Risk	More than minimal impact on Plant Risk. Requires only increased awareness of affected safety function by plant personnel.
Orange	High-Risk	Significant impact on Plant Risk. Requires written contingency planning and Plant Manager's approval prior to entry. Continuous monitoring and on-line risk assessment required for duration of work.
Red	Unacceptable Risk	No planned evolutions shall be scheduled that will result in this risk level. Unplanned entry requires immediate site wide response to reduce the risk level.

Emergent work is reviewed by Operations Shift Management to ensure that the work does not invalidate the assumptions made during the work management process. Prior to starting any work, the work scope and schedule are critically reviewed to assure that nuclear safety and plant operations are consistent with the expectations of management. Individual work activities that potentially have an impact to plant risk shall be evaluated by the use of system impact matrices, work document job details, plant drawings, or additional means to effectively determine the overall impact to plant risk levels.

As part of the risk management program the following types of items may be considered in work planning to minimize any incremental risk.

- Evaluate simultaneous switchyard maintenance and reliability.
- Evaluate concurrent maintenance or inoperable status of any of the remaining three instrument bus inverters for the unit.
- Evaluate simultaneous emergency diesel generator maintenance.
- Perform simultaneous with RCIC work window to minimize overall integrated risk.

In accordance with NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," the inverters are considered risk significant and therefore the reliability and unavailability of the inverters are monitored to demonstrate that their performance is adequate.

The reliability and availability of the affected NSPS inverters are monitored under the CPS Maintenance Rule program. If the pre-established reliability or availability performance criteria are exceeded for the NSPS inverters, consideration must be given to 10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants," paragraph (a)(1) actions, including increased management attention and goal setting in order to restore their performance (i.e., reliability and availability) to an acceptable level. The performance criteria are risk based and, therefore, are a means to manage the overall risk profile of the plant. An accumulation of large core damage probabilities over time is precluded by the performance criteria.

The NSPS inverters are all currently in the 10 CFR 50.65 (a)(2) Maintenance Rule category (i.e., the NSPS inverters are meeting established performance goals). Performance of the NSPS inverter on-line maintenance is not anticipated to result in exceeding the current established Maintenance Rule criteria for the NSPS inverters.

The actual NSPS inverter reliability and availability will be monitored and periodically evaluated to assess the effect of the proposed extended Completion Time upon plant performance in relationship to the Maintenance Rule goals.

To ensure the TS Completion Time does not degrade operational safety over time, the Maintenance Rule program will be used, as discussed above, to identify and correct adverse trends. Compliance with the Maintenance Rule not only optimizes reliability and availability of important equipment, it also results in management of the risk when equipment is taken out of service for testing or maintenance per 10 CFR 50.65(a)(4).

As stated previously, CPS has developed a CRMP consistent with 10 CFR 50.65(a)(4). The goals of this program are to ensure that risk-significant plant configurations will not be entered for planned maintenance activities, and appropriate actions will be taken should unforeseen events place the plant in a risk-significant configuration during the proposed extended NSPS inverter Completion Time.

Conclusion

The justification for the use of a Division 1 and 2 inverter extended Completion Time is based upon risk informed and deterministic evaluations consisting of three main elements.

1. The availability of the alternate power source to the inverter bus
2. Verification that the opposite division is operable, and
3. Implementation of the CRMP while an inverter is in an extended Completion Time. The CRMP is used for all work and helps ensure that there is no significant increase in the risk of a severe accident while any inverter maintenance is performed.

The evaluations concluded that the proposed changes are consistent with the defense-in-depth philosophy and that sufficient safety margins are maintained. Together these analyses provide high assurance of the capability to provide power to the ESF buses to support instrument bus reliability during the proposed 7-day NSPS inverter Completion Time.

The proposed change results in a very small increase in CDF and LERF, but the small increase in plant risk is consistent with the intent of the NRC Safety Goal Policy Statement. The impact of the proposed change will be monitored using performance measures to ensure actual reliability and availability is consistent with the values used in the PRA.

AmerGen shall continue to minimize the time periods to complete any unplanned maintenance. Plant configuration changes for planned and unplanned maintenance of the inverters as well as the maintenance of equipment having risk significance is managed by the CRMP. The CRMP helps ensure that these maintenance activities are carried out with no significant increase in the risk of a severe accident.

Maintenance during power operation should improve overall NSPS inverter availability which, in turn, should result in reducing shutdown risk by increasing the availability of the inverters during refueling outages. The proposed changes in Division 1 and Division 2 inverter Completion Times, in conjunction with the availability of an alternate power supply and use of a CRMP consistent with 10CFR50.65(a)(4) during the proposed extended inverter Completion Time, will provide adequate assurance of the capability to provide power to the associated instrument buses. The equipment required to mitigate design basis events will not be reduced below the required level by performance of the inverter on-line maintenance.

The proposed changes are consistent with the applicable regulatory requirements and guidelines. The resultant very small increases in CDF and LERF have been shown to meet the risk significance criteria of Reference 1. The ICCDP and ICLERP for each inverter for the increased Completion Time are sufficiently below the Reference 2 guidelines to be able to call the risk change small. Finally, the impact of the proposed changes will be monitored using performance measures to ensure actual reliability and availability is consistent with the values used in the PRA.

5.0 REGULATORY ANALYSIS

5.1 No Significant Hazards Consideration

AmerGen Energy Company (AmerGen), LLC is requesting a revision to the Facility Operating License No. NPF-62 for Clinton Power Station (CPS), Unit 1. The proposed change revises the Completion Time for Required Action A.1 of Technical Specification (TS) 3.8.7, "Inverters – Operating," from the current 24 hours for a Division 1 or 2 Nuclear System Protection System (NSPS) inverter inoperable to 7 days.

The change is being proposed to support on-line corrective maintenance of the NSPS inverters and will have a negligible impact on plant safety. The current Completion Time for restoration of an inoperable Division 1 or 2 NSPS inverter is insufficient to support on-line corrective maintenance and post-maintenance testing. The proposed change is not required for Divisions 3 and 4 since the current completion time for restoration of an inoperable Division 3 or 4 inverter is of sufficient duration to support on-line corrective maintenance and post-maintenance testing.

Implementation of this proposed Completion Time extension will provide operational flexibility, allowing more efficient application of plant resources to safety significant activities. The change will allow performance of periodic NSPS inverter maintenance and post-maintenance testing on-line, potentially reducing plant refueling outage duration, and improving NSPS inverter availability during shutdown.

AmerGen has evaluated whether or not a significant hazards consideration is involved with the proposed amendment by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below.

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

Response: No.

The proposed TS change revises the Completion Time for Required Action A.1 associated with the Division 1 and 2 NSPS inverters. Specifically, the proposed action allows continued unit operation, for up to 7 days, with an inoperable Division 1 or 2 NSPS inverter.

The proposed change does not affect the design of the NSPS 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 NSPS inverter is not considered as an initiator of any analyzed event. In addition, Required Actions and the associated Completion Times are not initiators of any previously evaluated accidents. Extending the Completion Time for an inoperable NSPS inverter would not have a significant impact on the frequency of occurrence for any accident previously evaluated. The proposed change will not result in changes to the plant activities associated with NSPS inverter maintenance, but rather will allow increased flexibility in the scheduling and performance of preventive maintenance. Therefore, this change will not significantly increase the probability of occurrence of any event previously analyzed.

The consequences of a previously analyzed event are dependent on the initial conditions assumed in the analysis, the availability and successful functioning of equipment assumed to operate in response to the analyzed event, and the setpoints at which these actions are initiated. With an NSPS inverter inoperable, the affected instrument bus is capable of being fed from its dedicated safety-related alternate power supply, which is powered from a Class 1E 480 VAC bus through a step-down transformer and an isolation transformer. In the event of a Loss of Offsite Power (LOOP), the affected instrument bus will experience a momentary loss of power until the associated diesel generator (DG) re-energizes the 480 VAC bus. A LOOP with an inoperable NSPS inverter (i.e., instrument bus being powered by its alternate power supply) will result in a loss of power to the associated instrument bus until the associated DG re-energizes the Class 1E 480 VAC bus. All instruments supplied by the instrument bus would be restored with no adverse impact to the unit because no other instrument channels in the opposite train would be expected to be inoperable or in a tripped condition during this time, with the exception of routine surveillances. In the event of a failure to re-energize the 480 VAC bus or of a transformer failure, the most significant impact on the unit is the failure of one train of Engineered Safety Feature (ESF) equipment to actuate. In this condition, the redundant train of ESF equipment will automatically actuate to mitigate the accident, and the affected unit would remain within the bounds of the accident analyses. In addition, there would be no adverse impact to the unit because no other instrument channels in the opposite train would be expected to be inoperable or in a tripped condition during this time, with the exception of routine surveillances.

To fully evaluate the effect of the proposed NSPS inverter Completion Time extension, probabilistic risk assessment (PRA) methods and a deterministic analysis were utilized. The Incremental Conditional Core Damage Probability (ICCDP) and Incremental Conditional Large Early Release Probability (ICLERP) for each inverter division are sufficiently below the regulatory guidelines to be able to call the risk change small. Hence, the guidelines of Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decision-Making: Technical Specifications," for the increased inverter Completion Time have been met. Furthermore, the evaluation of changes in Core Damage Frequency (CDF) and Large Early Release Frequency (LERF) due to the expected increased inverter unavailability, as mitigated by the compensating measures assumed in the analysis, have been shown to meet the risk significance criteria of Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," with substantial margin. This calculation supports the increase in the Division 1 and 2 inverter Completion Times from a quantitative risk-informed perspective consistent with the plant operational and maintenance practices. Therefore, the request for extending the Completion Time will not significantly increase the consequences of an accident previously evaluated.

In summary, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

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 action does not involve physical alteration of the station. No new equipment is being introduced, and installed equipment is not being operated in a new or different manner. There is no change being made to the parameters within which CPS is operated. There are no setpoints at which protective or mitigative actions are initiated that are affected by this proposed action. The use of the alternate Class 1E power source for the instrument bus is consistent with the CPS plant design. The change does not alter assumptions made in the safety analysis. This proposed action will not alter the manner in which equipment operation is initiated, nor will the function demands on credited equipment be changed. No alteration in the procedures, which ensure the unit remains within analyzed limits, is proposed, and no change is being made to procedures relied upon to respond to an off-normal event. As such, no new failure modes are being introduced.

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

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. There is no change in the design of the affected systems, no alteration of the setpoints at which alarms or actions are initiated, and no change in plant configuration from original design. With one of the required instrument buses being powered from the alternate Class 1E power supply, there is no significant reduction in the margin of safety. Testing of the DGs and associated electrical distribution equipment provides confidence that the DGs will start and provide power to the associated equipment in the unlikely event of a LOOP during the extended 7-day Completion Time.

- 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 small and consistent with the NRC Safety Goal Policy Statement (Federal Register, Vol.51, p. 30028 (51 FR 30028), August 4, 1986, as interpreted by NRC Regulatory

Guides 1.174 and 1.177). Furthermore, increases in risk posed by potential combinations of equipment out of service during the proposed NSPS inverter extended Completion Time will be managed under a configuration risk management program (CRMP) consistent with 10CFR50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants.", paragraph (a)(4).

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

Conclusion

Based on the above, AmerGen concludes that the proposed amendment presents no significant hazards consideration under the standards set forth in 10 CFR 50.92, paragraph (c), and, accordingly, a finding of no significant hazards consideration is justified.

5.2 Applicable Regulatory Requirements/Criteria

The proposed change has been evaluated to determine whether applicable regulations and requirements continue to be met. To fully evaluate the effect of the proposed NSPS inverter Completion Time extension, PRA methods and a deterministic analysis were utilized. AmerGen has determined that the proposed change does not require any exemptions or relief from regulatory requirements, other than the Technical Specifications, and does not affect conformance with any General Design Criteria (GDC) differently than described in the CPS USAR.

Applicable regulatory requirements will continue to be met, adequate defense-in-depth will be maintained, sufficient safety margins will be maintained, and any increase in plant risk is small and consistent with the NRC "Safety Goals for the Operations of Nuclear Power Plants; Policy Statement," Federal Register, Vol.51, p.30028 (51 FR 30028), August 4, 1986, as interpreted by NRC 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 Decision-Making: Technical Specifications." The ICCDP and ICLERP for each inverter division are sufficiently below the regulatory guidelines to be able to call the risk change small. Hence, the guidelines of RG 1.177 for the increased inverter Completion Time have been met. Furthermore, the evaluation of changes in CDF and LERF due to the expected increased inverter unavailability, as mitigated by the compensating measures assumed in the analysis, have been shown to meet the risk significance criteria of Regulatory Guide 1.174 with substantial margin.

CPS utilizes a CRMP consistent with 10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants.", paragraph (a)(4). The goals of this program are to ensure that risk-significant plant configurations will not be entered for planned maintenance activities, and appropriate actions will be taken should unforeseen events place the plant in a risk-significant configuration during the proposed extended NSPS inverter

Completion Time. To ensure the TS Completion Time does not degrade operational safety over time, the Maintenance Rule program will be used, as discussed above, to identify and correct adverse trends. Compliance with the Maintenance Rule not only optimizes reliability and availability of important equipment, it also results in management of the risk when equipment is taken out of service for testing or maintenance per 10 CFR 50.65(a)(4).

In conclusion, 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 NRC 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.

The proposed amendment is similar to the amendment request submitted for North Anna Power Station Units 1 and 2 (References 7 and 8) and the approved amendments for the Braidwood and Byron Stations (Reference 9).

6.0 ENVIRONMENTAL CONSIDERATION

A review has determined that the proposed amendment would change a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, "Standards for Protection Against Radiation," or would change an inspection or surveillance requirement. However, 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 effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed amendment meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22, "Criterion for categorical exclusion; identification of licensing and regulatory actions eligible for categorical exclusion or otherwise not requiring environmental review.", Paragraph (c)(9). Therefore, pursuant to 10 CFR 51.22, Paragraph (b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendment.

7.0 REFERENCES

1. Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," Revision 1, November 2002.

2. Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decision-Making: Technical Specifications," August 1998.

3. Letter from J. S. Perry (Illinois Power Company) to U.S. NRC, "Response to Generic Letter 88-20, Supplement 1," dated September 23, 1992.

4. Illinois Power Company, "Clinton Power Station Individual Plant Examination for External Events (IPEEE) Submittal," Final Report, September 1995.

5. Letter from J. M. Heffley (AmerGen Energy Company, LLC) to U. S. NRC, "Response to Request for Additional Information," dated March 22, 2001.

6. Letter from J. M. Heffley (AmerGen Energy Company, LLC) to U. S. NRC, "Response to Second Request for Additional Information," dated July 27, 2001.

7. Letter from L. N. Hartz (Virginia Electric and Power Company) to U. S. NRC, "Proposed Risk-Informed Technical Specifications Change Extended Inverter Allowed Outage Time," dated December 13, 2002.

8. Letter from L. N. Hartz (Virginia Electric and Power Company) to U. S. NRC, "Revised Required Action Completion Time for Proposed Risk-Informed Technical Specifications Change Extended Inverter Allowed Outage Time," dated December 17, 2003.

9. Letter from U. S. NRC to J. L. Skolds (Exelon Generation Company, LLC), "Issuance of Amendments (TAC Nos. MB6569, MB6570, MB6571, and MB6572)," dated November 19, 2003.

ATTACHMENT 2
Markup of Proposed Technical Specification Page Changes

Revised TS Page

3.8-34

3.8 ELECTRICAL POWER SYSTEMS

3.8.7 Inverters—Operating

LCO 3.8.7 The Division 1, 2, 3, and 4 inverters, and A and B RPS solenoid bus inverters shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

------------------------------------NOTE------------------------------------
Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems—Operating," with any uninterruptible AC bus de-energized.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Division 1 or 2 inverter inoperable.	A.1 Restore Division 1 and 2 inverters to OPERABLE status.	~~24 hours~~ 7 days
B. One or more Division 3 or 4 inverters inoperable.	B.1 Declare High Pressure Core Spray System inoperable.	Immediately
C. One RPS solenoid bus inverter inoperable.	C.1.1 Transfer RPS bus to alternate power source. AND C.1.2 Verify RPS bus supply frequency $\geq$ 57 Hz. OR C.2 De-energize RPS bus.	1 hour Once per 8 hours thereafter 1 hour

(continued)

ATTACHMENT 3
Markup of Proposed Bases Page Changes

Revised Bases Page
(Provided For Information Only)

B 3.8-71

BASES

APPLICABILITY (continued)

Inverter requirements for MODES 4 and 5 are covered in the Bases for LCO 3.8.8, "Inverters—Shutdown."

ACTIONS

With a required inverter inoperable, its associated uninterruptible AC bus is inoperable if not energized. LCO 3.8.9 addresses this action; however, pursuant to LCO 3.0.6, these actions would not be entered even if the uninterruptible AC bus were de-energized. Therefore, the ACTIONS are modified by a Note stating that ACTIONS for LCO 3.8.9 must be entered immediately. This ensures the uninterruptible bus is re-energized within 8 hours.

A.1

Required Action A.1 allows ~~24 hours~~ 7 days to fix the inoperable inverter and return it to service. The ~~24 hour~~ 7 day limit is ~~based upon engineering judgment, taking into consideration the time required to repair an inverter and the additional risk to which the plant is exposed because of the inverter inoperability.~~ a risk-informed Completion Time based on a plant-specific risk analysis performed to establish this Completion Time for the Division 1 and 2 inverters. This risk has to be balanced against the risk of an immediate shutdown, along with the potential challenges to safety systems that such a shutdown might entail. When the uninterruptible AC bus is powered from its constant voltage source, it is relying upon interruptible AC electrical power sources (offsite and onsite). The uninterruptible inverter source to the uninterruptible AC buses is the preferred source for powering instrumentation trip setpoint devices.

B.1

With one or more Division 3 or 4 inverters inoperable, the associated Division 3 ECCS subsystem may be incapable of performing intended function and must be immediately declared inoperable. This also requires entry into applicable Conditions and Required Actions for LCO 3.5.1, "ECCS—Operating."

C.1.1, C.1.2, and C.2

With one RPS solenoid bus inverter inoperable it may be incapable of providing voltage and frequency regulated power

(continued)

ATTACHMENT 4

Technical Evaluation of Extending
Division 1 and 2 Inverter Completion Time