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October 11, 2005

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

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

Subject: Additional Information Supporting the Request for License Amendment Related to Extending the Completion Time for Nuclear System Protection System Inverters

References:

1. Letter from Keith R. Jury (AmerGen Energy Company, LLC) to U. S. NRC, "Request for Technical Specification Change to Extend Completion Time for Nuclear System Protection System Inverters," dated April 26, 2004

2. Letter from Keith R. Jury (AmerGen Energy Company, LLC) to U. S. NRC, "Additional Information Supporting the Request for License Amendment Related to Extending the Completion Time for Nuclear System Protection System Inverters," dated April 18, 2005

In Reference 1, AmerGen Energy Company, LLC (AmerGen) requested an amendment to the facility operating license for Clinton Power Station (CPS), Unit 1. The proposed change is requested to revise the Completion Time for Required Action A.1 of Technical Specification (TS) 3.8.7, "Inverters - Operating," from the current 24 hours to 7 days for an inoperable Division 1 or 2 Nuclear System Protection System (NSPS) inverter. Reference 2 provided additional information requested by the NRC to support their review of Reference 1.

On January 10, 2005, the NRC requested that AmerGen provide additional information to support review of the proposed license amendment in the referenced letter. This request was provided electronically from Kahtan N. Jabbour (U. S. NRC) to Timothy A. Byam (AmerGen). Attachment 1 to this letter provides the requested information.

The regulatory commitments contained in this letter are documented in Attachment 2.

AmerGen has reviewed the information supporting a finding of no significant hazards consideration that was previously provided to the NRC in Reference 1. The supplemental information provided in this submittal does not affect the bases for concluding that the proposed license amendment does not involve a significant hazards consideration.

If you have any questions concerning this letter, please contact Mr. Timothy A. Byam at (630) 657-2804.

I declare under penalty of perjury that the foregoing is true and correct. Executed on the 11th day of October 2005.

Respectfully,

Keith R. Jury

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

Attachments:
1. Additional Information Supporting the Request for License Amendment Related to Extending the Completion Time for Nuclear System Protection System Inverters
2. Commitments

ATTACHMENT 1

Additional Information Supporting the Request for License Amendment Related to Extending the Completion Time for Nuclear System Protection System Inverters

Request 1:

Page 11 of attachment 1 presents the Tier 2 assessment. The Tier 2 assessment is limited to a qualitative statement that there is reasonable assurance that risk-significant equipment configurations will not occur with equipment out of service consistent with the proposed TS changes. The referenced CRMP program is more appropriately designated as a Tier 3 program that ensures that the risk impact of out-of-service equipment is evaluated prior to performing any maintenance activity. Provide a Tier 2 assessment and discuss the conclusions consistent with the guidance of Regulatory Guide 1.177. Include any compensatory measures, TS changes or procedures to be implemented based on the Tier 1 and Tier 2 evaluations as discussed below.

- *Page 5 of 20 of the submittal discusses the impact on the plant when alternate power is supplying a Nuclear System Protection System (NSPS) bus. With the alternate supply and an inoperable inverter, a Loss-of-offsite power event would cause a momentary loss of power to the NSPS bus until the associated diesel generator re-energizes the bus. The submittal states that there is no adverse impacts because no additional instrument channels in the opposite train are expected to be inoperable (except for routine maintenance).*

- *Section 4.3 of Attachment 4, "Technical Evaluation of Extending Division 1 and 2 Inverter Completion Time (CT)," Revision 1, dated August 8, 2004 states that certain additional items could be included in work planning to minimize any incremental risk. The additional items are identified in the submittal and are shown below.*

  - *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 addition, see Attachment 1, page 5, first paragraph of the amendment. Also see Attachment 4, section 7.3.1 which presents additional risk insights as follows.*

  - *The Division 1 diesel generator availability during inverter 1A on-line maintenance is critical to minimizing the configuration specific risk.*

  - *The offsite power availability including emergency reserve auxiliary transformer (ERAT) are critical to minimizing the configuration specific risk.*

Also, Attachment 4, Section 3.4, page 3-6 states that major overhauls of the inverter on-line within the extended CT will only occur at most once per inverter per fuel cycle.

Section 3.4 goes on to state that compensatory measures are included in the proposed plans. However, attachment 4, Section 3.4 does not list or discuss these compensatory measures.

Discuss any compensatory measures to limit DG or opposite train surveillance during inverter maintenance including the conditions/ limitations and/or regulatory commitments that are expected to be implemented as part of the Division 1 and 2 extended CT NSPS inverter request.

Response 1:
The purpose of Tier 2 as identified in Regulatory Guide (RG) 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," is to provide an assessment that evaluates "equipment according to its contribution to plant risk (or safety) while the equipment covered by the proposed AOT change is out of service." This purpose can be fulfilled by examining the plant risk increase (e.g., the change in core damage frequency (ΔCDF) and the change in large early release frequency (ΔLERF)) when the most risk significant combinations occur. Such an assessment is discussed below.

Tier 2 Assessment

AmerGen Energy Company, LLC (AmerGen) processes direct progressively more compensatory measures as the evaluated risk increases. These are reflected by the process of binning risk increase groups together and labeling these risk increase groups by colors.

Attachment 4 from Clinton Power Station (CPS) Procedure WC-AA-101, "Online Work Control", explains the required actions for each risk color. Voluntary entry into RED conditions is not allowed. Voluntary entry into ORANGE conditions requires senior management review and approval. Attachment 4 from WC-AA-101 is provided here as Table 1-1.

In addition, Step 4.1.4 of the same procedure directs the following:

> "When risk significant SSCs are made unavailable, actions shall be taken to protect redundant/diverse SSCs. SSCs needing protection shall be those SSCs which, if lost concurrent with other SSCs being unavailable for maintenance, would cause an unplanned entry into an orange or red risk configuration. Protection can be installed on any component at the discretion of the Shift Manager. Protective measures taken should be commensurate with the risk significance of the work being performed."

The CPS Configuration Risk Management Program (CRMP) process is useful in managing combinations of equipment that should receive special attention. Table 1-2 provides the resulting Remain-In-Service list for the Division 1 inverter out of service (OOS) configuration, as determined by the CPS CRMP assessment tool. This list shows the resulting plant risk color that would result if other equipment were made unavailable (i.e., either emergent failure or taken OOS for test or maintenance) coincident with the

Division 1 inverter OOS configuration. Only those configurations resulting in an ORANGE or RED risk color are listed in Table 1-2. As the risk impact associated with the Division 2 inverter OOS configuration is negligible, explicit quantitative assessment of risk significant OOS combination configurations is not performed.

Many of the ORANGE and RED risk color configurations in Table 1-2 are also present in the base "zero-maintenance" Remain in Service List. These configurations already result in an ORANGE or RED risk configuration regardless of the Division 1 inverter OOS configuration. The majority of these risk significant configurations are due to electrical distribution equipment unavailability (e.g., 4kV buses or MCCs). CPS internal processes already preclude taking major buses out of service for maintenance during power operation. In addition, bus failures are low likelihood events; and normal plant work practices and controls already exist that place a heightened awareness on electrical distribution equipment.

Considering the information in Table 1-2 for the Division 1 inverter OOS configuration and the recognition that major bus outages are effectively precluded during power operation, the following equipment warrants further consideration of compensatory actions.

- Shutdown Service Water pump 'C' (1SX01PC)
- 125V Division 3 DC charger (1E22S001E)
- High Pressure Core Spray pump (1E22C001)
- Emergency Reserve Auxiliary Transformer (0AP03E)
- Emergency Diesel Generator 'A'
- Emergency Diesel Generator 'B'
- Emergency Diesel Generator 'C'
- Shutdown Service Water pump 'B' (1SX01PB)
- Shutdown Service Water pump 'A' (1SX01PA)
- 125V Division 1 DC charger (1DC06E)
- 125V Division 2 DC charger (1DC07E)
- NSPS Division 1 regulating transformer

The risk impact associated with unavailability of the above equipment coincident with the Division 1 inverter OOS configuration is evaluated further here based on the "average maintenance" PRA model used to perform the CPS inverter completion time (CT) risk assessment. This approach is consistent with guidance in RG 1.177. Table 1-3 summarizes the ΔCDF_{AVE}, $\Delta LERF_{AVE}$, incremental conditional core damage probability (ICCDP), and incremental conditional large early release probability (ICLERP) risk metrics for each of these configurations. As can be seen from Table 1-3, eight of the identified configurations exceed the RG 1.177 or RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," risk significance thresholds. These configurations are indicated by the shaded cells in Table 1-3 and are as follows.

- Shutdown Service Water pump 'C' (1SX01PC)
- 125V Division 3 DC charger (1E22S001E)
- High Pressure Core Spray pump (1E22C001)

- Shutdown Service Water pump 'B' (1SX01PB)
- Shutdown Service Water pump 'A' (1SX01PA)
- 125V Division 1 DC charger (1DC06E)
- 125V Division 2 DC charger (1DC07E)
- Division 1 NSPS regulating transformer

AmerGen commits to take the following compensatory actions when the Division 1 NSPS inverter is unavailable.

- Entry into the extended inverter CT will not be planned concurrent with Shutdown Service Water maintenance.

- Entry into the extended inverter CT will not be planned concurrent with Division 3 (HPCS) maintenance including Division 3 battery or charger.

- Entry into the extended inverter CT will not be planned concurrent with maintenance unavailability of the Division 1 or 2 DC components (i.e., batteries or chargers).

- Entry into the extended inverter CT will not be planned concurrent with maintenance unavailability of the Division 1 NSPS regulating transformer.

In addition, to minimize the potential for a plant trip, AmerGen commits to take the following additional compensatory actions when either a Division 1 or 2 NSPS inverter is unavailable.

- Entry into the extended inverter CT will not be planned concurrent with planned maintenance on another Reactor Protection System (RPS) channel that could result in that channel being in a tripped condition.

These compensatory actions address all of the equipment configurations identified by the above sensitivity study that have high risk potential.

Summary

The CPS CRMP ensures that the risk impact of out of service equipment (e.g., maintenance on the Division 1 Inverter) is evaluated prior to performing any maintenance activity. As part of the CRMP for the proposed equipment out of service configuration, an evaluation of the systems, structures, and components (SSCs) to be maintained available is performed. This evaluation results in an SSC "Remain In Service" list. The "Remain In Service" list ranks the SSCs that have the most significant impact on risk if any single SSC becomes unavailable in addition to the proposed out of service configuration. The CPS CRMP (i.e., Tier 3) ensures that the inverter maintenance activities are managed in a risk-informed manner.

In addition, the specific compensatory action commitments listed above further aid in minimizing risk during inverter OOS configurations.

Table 1-1

ATTACHMENT 4
Configuration Risk Management Criteria
Page 1 of 2

Color	Risk Threshold[6]	Required Action
Green	CDF[1] - <2x Zero Maintenance CDF[2]; AND SFAT[3] - optimal defense in depth; AND PTAT[4] - no appreciable increase in initiating event frequency or decrease in mitigation capability; AND LERF[1] - <2x Zero Maintenance LERF[2]	No specific actions are required.
Yellow	CDF[1] - ≥2x Zero Maintenance CDF[2]; OR SFAT[3] - nominal defense in depth (key safety function with redundancy); OR PTAT[4] - acceptable increase in initiating event frequency or decrease in mitigation capability; OR LERF[1] - ≥2x Zero Maintenance LERF[2]	Limit the unavailability time by establishing a continuous work schedule or provide justification on Attachment 3. Protection of SSCs (if lost concurrent with other SSCs being unavailable for maintenance, would cause an event such as unplanned increase in the overall station risk greater than a yellow condition (orange or red)).
Orange	CDF[1] - ≥10x Zero Maintenance CDF[2]; OR SFAT[3] - marginal defense in depth (key safety function without redundancy); OR PTAT[4] - significant increase in initiating event frequency or decrease in mitigation capability; OR LERF[1] - ≥10x Zero Maintenance LERF[2];	Requires senior management review and approval prior to entering this condition. Compensatory measures shall be taken to reduce risk, including limiting unavailability time and establishing contingency plans for restoration and/or protection of SSCs relied upon to mitigate events. IF an emergent condition causes, or degradation may cause an unplanned entry into this condition, notify station duty manager.
Red	CDF[1] - ≥20x Zero Maintenance CDF[2] not to exceed $1E^{-3}$/yr (PWR or BWR Mk III) or $1E^{-4}$/yr (BWR Mk I or II); OR SFAT[3] - unacceptable defense in depth (loss of a key safety function); OR PTAT[4] - unacceptable increase in initiating event frequency or decrease in mitigation capability; OR LERF[1] - ≥20x Zero Maintenance LERF[2] not to exceed $1E^{-4}$/yr;	It is unacceptable to voluntarily enter this condition. IF an emergent condition causes, or degradation may cause an unplanned entry into this condition, immediate actions shall be taken to restore and/or protect SSCs relied upon to mitigate events, and to contact the station duty manager for direction and support.

Table 1-1 Continued

ATTACHMENT 4
Configuration Risk Management Criteria
Page 2 of 2

Note: Until a LERF model is deployed at the station, LERF criteria do **not** apply.

(1) Factor increase in CDF (or LERF) during the time the SSC is unavailable. This is a risk configuration state as a factor increase on a per year basis, **not** the average risk for a year.

(2) The Zero Maintenance CDF (or LERF) is obtained by assuming that all equipment modeled in the PRA is available.

(3) SFAT is the Safety Function Assessment Tree rating obtained using the ORAM-SENTINEL-PARAGON Code.

(4) PTAT is the Plant Transient Assessment Tree rating obtained using the ORAM-SENTINEL-PARAGON Code (trip/scram initiator should only be activated for an order of magnitude increase in the probability of a trip/scram).

(5) Risk is indeterminate if results are unavailable for all of the ORAM-SENTINEL-PARAGON modules (CDF/LERF, SFAT, PTAT). If PRA results (CDF/LERF) are unavailable, the overall risk color is the most limiting of the SFAT or PTAT results.

Table 1-2

REMAIN-IN-SERVICE LIST FOR DIVISION 1 INVERTER OOS CONFIGURATION

Remain-In-Service Item	Risk Color	Comment
AP - RESERVE AUX TRANSFORMER (1AP02E)	**RED**	CPS internal processes normally preclude taking the RAT out of service for maintenance during power operation. Failure of the RAT results in a RED condition even during zero maintenance conditions.
SX - SHUTDOWN SERVICE WTR PP C (1SX01PC)	**RED**	Failure or maintenance OOS of this component results in a YELLOW condition during zero maintenance conditions.
AP - 4160V BUS 1A1 (1AP07E)	**RED**	CPS internal processes already preclude taking this bus out of service for maintenance during power operation. Bus failures are low likelihood events; and normal plant work practices and controls are already in effect that place a heightened awareness on electrical distribution equipment. Failure of this particular bus results in a RED condition even during zero maintenance conditions.
AP - 4160V BUS 1B1 (1AP09E)	**RED**	CPS internal processes already preclude taking this bus out of service for maintenance during power operation. Bus failures are low likelihood events; and normal plant work practices and controls are already in effect that place a heightened awareness on electrical distribution equipment. Failure of this particular bus results in a RED condition even during zero maintenance conditions.
AP - 4160V BUS 1C1 (1E22-S004)	**RED**	CPS internal processes already preclude taking this bus out of service for maintenance during power operation. Bus failures are low likelihood events; and normal plant work practices and controls are already in effect that place a heightened awareness on electrical distribution equipment.
AP - 480V AUX BLDG UNIT SUB 1A (1AP11E)	**RED**	CPS internal processes already preclude taking this bus out of service for maintenance during power operation. Bus failures are low likelihood events; and normal plant work practices and controls are already in effect that place a heightened awareness on electrical distribution equipment.
AP - 480V AUX BLDG UNIT SUB 1B (1AP12E)	**RED**	CPS internal processes already preclude taking this bus out of service for maintenance during power operation. Bus failures are low likelihood events; and normal plant work practices and controls are already in effect that place a heightened awareness on electrical distribution equipment.

Table 1-2

REMAIN-IN-SERVICE LIST FOR DIVISION 1 INVERTER OOS CONFIGURATION

Remain-In-Service Item	Risk Color	Comment
AP - 480V AUX BLDG MCC 1C1 (1AP78E)	**RED**	CPS internal processes already preclude taking this bus out of service for maintenance during power operation. Bus failures are low likelihood events; and normal plant work practices and controls are already in effect that place a heightened awareness on electrical distribution equipment.
AP - 480V SSW MCC 1C (1AP31E)	**RED**	CPS internal processes already preclude taking this bus out of service for maintenance during power operation. Bus failures are low likelihood events; and normal plant work practices and controls are already in effect that place a heightened awareness on electrical distribution equipment.
DC - 125V DIV 3 DC CHARGER (1E22-S001E)	**RED**	Failure or maintenance OOS of this component results in an ORANGE condition during zero maintenance conditions.
DC - 125V DIV 3 DC MCC (1E22-S001C)	**RED**	CPS internal processes already preclude taking this bus out of service for maintenance during power operation. Bus failures are low likelihood events; and normal plant work practices and controls are already in effect that place a heightened awareness on electrical distribution equipment.
HP - HIGH PRESS CORE SPRAY PP (1E22C001)	**RED**	Failure or maintenance OOS of this component results in an ORANGE condition during zero maintenance conditions.
AP - EMERGENCY RESERVE AUX TRAN (0AP03E)	**ORANGE**	Failure or maintenance OOS of this component results in a YELLOW condition during zero maintenance conditions.
DG - EMERGENCY DIESEL GEN A (DIV 1)	**ORANGE**	Failure or maintenance OOS of this component results in a YELLOW condition during zero maintenance conditions.
DG - EMERGENCY DIESEL GEN B (DIV 2)	**ORANGE**	Failure or maintenance OOS of this component results in a YELLOW condition during zero maintenance conditions.
DG - EMERGENCY DIESEL GEN C (DIV 3)	**ORANGE**	Failure or maintenance OOS of this component results in a YELLOW condition during zero maintenance conditions.
SX - SHUTDOWN SERVICE WTR PP B (1SX01PB)	**ORANGE**	Failure or maintenance OOS of this component results in a YELLOW condition during zero maintenance conditions.
SX - SHUTDOWN SERVICE WTR PP A (1SX01PA)	**ORANGE**	Failure or maintenance OOS of this component results in a YELLOW condition during zero maintenance conditions.

Table 1-2

REMAIN-IN-SERVICE LIST FOR DIVISION 1 INVERTER OOS CONFIGURATION

Remain-In-Service Item	Risk Color	Comment
AP - 480V AUX BLDG MCC 1A1 (1AP72E)	**ORANGE**	CPS internal processes already preclude taking this bus out of service for maintenance during power operation. Bus failures are low likelihood events; and normal plant work practices and controls are already in effect that place a heightened awareness on electrical distribution equipment.
AP - 480V AUX BLDG MCC 1B1 (1AP75E)	**ORANGE**	CPS internal processes already preclude taking this bus out of service for maintenance during power operation. Bus failures are low likelihood events; and normal plant work practices and controls are already in effect that place a heightened awareness on electrical distribution equipment.
AP - 480V SSW MCC 1A (1AP29E)	**ORANGE**	CPS internal processes already preclude taking this bus out of service for maintenance during power operation. Bus failures are low likelihood events; and normal plant work practices and controls are already in effect that place a heightened awareness on electrical distribution equipment.
AP - 480V SSW MCC 1B (1AP30E)	**ORANGE**	CPS internal processes already preclude taking this bus out of service for maintenance during power operation. Bus failures are low likelihood events; and normal plant work practices and controls are already in effect that place a heightened awareness on electrical distribution equipment.
AP - 480V AUX BLDG MCC 1B2 (1AP76E)	**ORANGE**	CPS internal processes already preclude taking this bus out of service for maintenance during power operation. Bus failures are low likelihood events; and normal plant work practices and controls are already in effect that place a heightened awareness on electrical distribution equipment.
AP - 480V CONT BLDG MCC E1+E2 0AP54E-A&B	**ORANGE**	CPS internal processes already preclude taking this bus out of service for maintenance during power operation. Bus failures are low likelihood events; and normal plant work practices and controls are already in effect that place a heightened awareness on electrical distribution equipment.
AP - 480V CONT BLDG MCC F1+F2 0AP55E-A&B	**ORANGE**	CPS internal processes already preclude taking this bus out of service for maintenance during power operation. Bus failures are low likelihood events; and normal plant work practices and controls are already in effect that place a heightened awareness on electrical distribution equipment.

Table 1-2

REMAIN-IN-SERVICE LIST FOR DIVISION 1 INVERTER OOS CONFIGURATION

Remain-In-Service Item	Risk Color	Comment
AP - 480V CONT BLDG UNIT SUB 1A (0AP05E)	**ORANGE**	CPS internal processes already preclude taking this bus out of service for maintenance during power operation. Bus failures are low likelihood events; and normal plant work practices and controls are already in effect that place a heightened awareness on electrical distribution equipment.
AP - 480V CONT BLDG UNIT SUB 1B (0AP06E)	**ORANGE**	CPS internal processes already preclude taking this bus out of service for maintenance during power operation. Bus failures are low likelihood events; and normal plant work practices and controls are already in effect that place a heightened awareness on electrical distribution equipment.
DC - 125V DIV 1 DC BATTERY (1DC01E)	**ORANGE**	The short Technical Specification Allowable Completion Time effectively precludes taking batteries out of service for maintenance during power operation. Battery failures are low likelihood events; and normal plant work practices and controls are already in effect that place a heightened awareness on electrical distribution equipment.
DC - 125V DIV 2 DC BATTERY (1DC02E)	**ORANGE**	The short Technical Specification Allowable Completion Time effectively precludes taking batteries out of service for maintenance during power operation. Battery failures are low likelihood events; and normal plant work practices and controls are already in effect that place a heightened awareness on electrical distribution equipment.
DC - 125V DIV 3 DC BATTERY (1E22-S001D)	**ORANGE**	Batteries are rarely if ever taken out of service for maintenance during power operation. Battery failures are low likelihood events; and normal plant work practices and controls are already in effect that place a heightened awareness on electrical distribution equipment.
DC - 125V DIV 1 DC CHARGER (1DC06E)	**ORANGE**	Failure or maintenance OOS of this component results in an ORANGE condition even during zero maintenance conditions.
DC - 125V DIV 2 DC CHARGER (1DC07E)	**ORANGE**	Failure or maintenance OOS of this component results in an ORANGE condition even during zero maintenance conditions.
DC - 125V DIV 1 DC MCC (1DC13E)	**ORANGE**	CPS internal processes already preclude taking this bus out of service for maintenance during power operation. Bus failures are low likelihood events; and normal plant work practices and controls are already in effect that place a heightened awareness on electrical distribution equipment.

Table 1-2

REMAIN-IN-SERVICE LIST FOR DIVISION 1 INVERTER OOS CONFIGURATION

Remain-In-Service Item	Risk Color	Comment
DC - 125V DIV 2 DC MCC (1DC14E)	**ORANGE**	CPS internal processes already preclude taking this bus out of service for maintenance during power operation. Bus failures are low likelihood events; and normal plant work practices and controls are already in effect that place a heightened awareness on electrical distribution equipment.
DC - 125V DC MCC 1E (1DC16E)	**ORANGE**	CPS internal processes already preclude taking this bus out of service for maintenance during power operation. Bus failures are low likelihood events; and normal plant work practices and controls are already in effect that place a heightened awareness on electrical distribution equipment.
IP - NSPS DIV 1 REG TRANSFORMER	**ORANGE**	Failure or maintenance OOS of this component results in a GREEN condition during zero maintenance conditions. The Regulating Transformer becomes more critical when the inverter is out of Service, because the Regulating Transformer becomes the sole source of power for the bus.

Table 1-3

RISK IMPACTS FOR DIVISION 1 INVERTER OUT OF SERVICE (OOS) COINCIDENT WITH OTHER RISK SIGNIFICANT CONFIGURATIONS

Additional Equipment OOS	ΔCDF_{AVE}	$\Delta LERF_{AVE}$	ICCDP	ICLERP	Comment
NONE (Only the Div. 1 Inverter OOS)	3.0E-08	4.0E-09	1.0E-07	7.7E-09	Base Division 1 inverter OOS assessment.
SX - SHUTDOWN SERVICE WTR PP C (1SX01PC)	5.8E-07	1.4E-08	1.1E-06	2.7E-08	5E-7 ICCDP RG 1.177 risk significance threshold exceeded.
DC - 125V DIV 3 DC CHARGER (1E22S001E)	1.9E-06	2.0E-08	3.6E-06	3.8E-08	5E-7 ICCDP RG 1.177 and 1E-6 /yr delta CDF RG 1.174 risk significance thresholds exceeded.
HP - HIGH PRESS CORE SPRAY PP (1E22C001)	1.2E-06	1.5E-08	2.3E-06	2.8E-08	5E-7 ICCDP RG 1.177 and 1E-6 /yr delta CDF RG 1.174 risk significance thresholds exceeded.
AP - EMERGENCY RESERVE AUX TRAN (0AP03E)	2.0E-07	1.1E-08	3.8E-07	2.0E-08	All risk metrics remain below risk significance thresholds.
DG - EMERGENCY DIESEL GEN A (DIV 1)	1.7E-07	1.0E-08	3.3E-07	2.0E-08	All risk metrics remain below risk significance thresholds.
DG - EMERGENCY DIESEL GEN B (DIV 2)	1.5E-07	1.0E-08	2.9E-07	2.0E-08	All risk metrics remain below risk significance thresholds.
DG - EMERGENCY DIESEL GEN C (DIV 3)	2.4E-07	1.2E-08	4.7E-07	2.4E-08	All risk metrics remain below risk significance thresholds.
SX - SHUTDOWN SERVICE WTR PP B (1SX01PB)	6.4E-07	1.2E-08	1.2E-06	2.3E-08	5E-7 ICCDP RG 1.177 risk significance threshold exceeded.
SX - SHUTDOWN SERVICE WTR PP A (1SX01PA)	5.8E-07	1.2E-08	1.1E-06	2.2E-08	5E-7 ICCDP RG 1.177 risk significance threshold exceeded.
DC - 125V DIV 1 DC CHARGER (1DC06E)	1.3E-06	1.9E-08	2.5E-06	3.6E-08	5E-7 ICCDP RG 1.177 and 1E-6 /yr delta CDF RG 1.174 risk significance thresholds exceeded.
DC - 125V DIV 2 DC CHARGER (1DC07E)	1.2E-06	2.0E-08	2.2E-06	3.7E-08	5E-7 ICCDP RG 1.177 and 1E-6 /yr delta CDF RG 1.174 risk significance thresholds exceeded.
IP - NSPS DIV 1 REG TRANSFORMER	1.6E-06	9.0E-09	3.1E-06	1.7E-08	5E-7 ICCDP RG 1.177 and 1E-6 /yr delta CDF RG 1.174 risk significance thresholds exceeded.

Notes to Table 1-3:

1. Risk impact calculations are for the Division 1 inverter OOS in addition to the individual equipment item listed in the left-hand column.

2. Risk metrics are calculated consistent with the CPS inverter CT extension risk assessment (and consistent with RG 1.174 and RG 1.177). Refer to Attachment 4 of the CPS Inverter CT extension LAR submittal for details.

3. There are no criteria that combinations of equipment OOS meet NRC RG 1.177 or 1.174. These criteria are used here as convenient benchmarks. The RG 1.177 and 1.174 risk significance thresholds are as follows:

ΔCDF_{AVE}	<1.0E-6/yr	[RG 1.174]
$\Delta LERF_{AVE}$	<1.0E-7/yr	[RG 1.174]
ICCDP	<5.0E-7	[RG 1.177]
ICLERP	<5.0E-8	[RG 1.177]

4. Shaded cells indicate the risk metrics for those OOS configurations that exceed the RG 1.174 and RG 1.177 risk significance thresholds. There are no criteria that combinations of equipment OOS meet NRC RG 1.177 or 1.174. These criteria are used here as convenient benchmarks.

Request 2:
Attachment 1 page 11 discusses the Tier 3 program and states that for planned maintenance activities the assessment of the overall risk of the activity includes benefits to system reliability and performance. Provide a discussion on the applicability of including system reliability and performance benefits in the Tier 3 assessment.

Response 2:
A decision to perform maintenance on a component considers not only the risk associated with the out of service condition, but also the benefits to be gained by the maintenance activity. The risk associated with the out of service condition can be evaluated by the quantitative measures of the on-line risk assessment tool. Evaluation of the benefit of maintenance work is more subjective.

Preventive maintenance tasks are performed to maintain the reliability of components that are projected to degrade over time. For inverters, these routine preventive maintenance tasks are planned for plant shutdown conditions. The extended inverter completion time is not intended to perform routine preventive maintenance tasks. The extended completion time requested is intended to deal with emergent corrective maintenance situations involving the inverters. These include situations in which the inverter has failed or is degraded.

If the inverter has failed, the inverter is already unavailable and the risk associated with inverter unavailability has already been incurred. The only logical decision in this case is to repair or replace it. If the inverter is still functional, but in a degraded condition, station management must decide whether the inverter is still operable. If not in an operable status, the inverter must be brought back to an operable status similar to the case where it is unavailable. If the inverter is operable but degraded, the station may or may not elect to remove the inverter from service for corrective maintenance. Considerations in making this decision include whether the inverter degradation is getting worse or if the inverter is currently performing acceptably, but there is uncertainty in how the inverter would perform under accident conditions. These considerations may be reasons to impose an inverter outage to perform corrective maintenance including troubleshooting or inverter replacement. If station management elects to enter an inverter outage, they have, in effect, formed a qualitative judgment that potential improvements in inverter reliability are worth the incurred unavailability time.

However, this judgment is not part of the Configuration Risk Management Program. The CRMP assesses the risk associated with a piece of equipment being unavailable, but is not required to quantitatively assess the benefits to be gained in terms of long term reliability improvements from maintenance. The CRMP shows that taking a component out of service does not cause an unacceptable risk increment regardless of the reliability benefits to be gained from the maintenance.

Additional Information Supporting the Request for License Amendment Related to Extending the Completion Time for Nuclear System Protection System Inverters

Request 3:
Provide a description of the program for updating and the maintenance of the CPS PRA referencing the appropriate procedures/instructions.

Response 3
CPS utilizes a standardized Exelon wide approach for maintaining the CPS PRA in a condition that adequately represents the as-built, as-operated plant. Exelon Training and Reference Manual (T&RM) ER-AA-600-1015, "Full Power Internal Events PRA Model Update," is the guidance document for this process. Among the attributes to be reviewed for their potential impact on the PRA are the following.

- Design changes impacting PRA modeled systems as identified by the design process
- Plant procedure changes affecting PRA modeled systems or impacting accident mitigation
- Calculation revisions that could impact PRA modeling assumptions

Potential PRA modeling changes are identified and tracked for evaluation in PRA updates. The significance of the change is evaluated to determine whether the PRA model requires an immediate update or whether the issue can be resolved during the next periodic PRA model update.

Periodic PRA updates typically occur on a three-year interval. Periodic updates should consider the following changes in addition to those identified above and tracked through the updating process.

- TS Changes
- Component Failure Rates
- Component Maintenance Unavailabilities
- Initiating Event Frequencies
- Changes to PRA Technology
- Industry Experience
- Site Operating Experience

Following completion of a PRA update, the revised model and documentation is officially rolled-out for use by other plant departments as well as the Risk Management department.

The goal of the Risk Management Program is to assure the Risk Management tools and capabilities are adequate to support risk informed applications. Therefore, it is AmerGen's objective that in general the Full Power Internal Events PRA should target Grade Level 3 or higher when compared to the technical elements of the NEI PRA Peer Review Guidelines. When compared to the ASME PRA Standard, the Full Power Internal Events PRA targets ASME Capability Category II or higher. These goals are specified in Exelon T&RM ER-AA-600-1011, "Risk Management Program".

The CPS PRA revision used for the inverter CT extension risk assessment is the Revision 2003A PRA Update.

Request 4:
The submittal states that a spare inverter was obtained in 2001 to allow expedited replacement should an inverter fail in service. Describe preventive maintenance and/or storage practices that ensure the continued viability that the spare inverter is an available replacement for a failed plant inverter. Describe any credit taken in the inverter risk assessment based on the availability of the spare inverter with respect to maintenance/procedures/operator actions and assumed completion times.

Response 4:
The spare inverter, which was purchased new, was placed into service as a replacement for the Division 2 NSPS inverter in February 2004. The replaced Division 2 inverter, which was taken out of the plant, has been returned to the "stores" warehouse. This warehouse provides a clean, dry temperature controlled environment for the inverter. The inverter is scheduled for refurbishment, so that it will be placed in optimal condition should the need arise for it to be placed back in the plant as a replacement for one of the in-service NSPS inverters.

Preventive maintenance tasks performed on the inverters (including the spare inverter) are as follows.

- Cleaning and inspection of inverter components. This includes calibration of printed circuit boards.
- Replacement of components that degrade over time such as electrolytic capacitors.

The inverter risk assessment takes no credit for repair or recovery of an inverter, or use of a spare inverter, during accident mitigation. Because CPS has a spare inverter available for replacement of an installed inverter, the actual completion time for an inverter out of service condition is less than it otherwise would be to facilitate repairs of the installed inverter. During the time period the inverter would be unavailable during an inverter swap, the maintenance bypass of the inverter would be used, which is supplied with the regulating transformer source for the bus. This is the power source assumed in the risk analysis, so an inverter replacement does not result in any new assumptions for the risk analysis.

Request 5:
The submittal states that the CPS IPEEE fire models are currently archived. Discuss any differences the archived fire models may have with the current as-built, as operated plant and any impact that this would have on the proposed division 1 and 2 and extended NSPS inverter AOT and estimated fire PRA results.

Response 5:

The calculated incremental risk due to the proposed inverter CT extension is due almost entirely (>99%) to Station Blackout (SBO) scenarios and then only for Division 1 because it supports Reactor Core Isolation Cooling System operation. As such, this response is focused on addressing fire risk from areas that can impact fire-induced SBO scenarios. Because SBO events are a subset of Loss of Offsite Power (LOOP) events, fire scenarios of concern would be those that involve LOOP.

Based on the CPS IPEEE fire analysis and the subsequent risk evaluation for the CPS Emergency Diesel Generator (EDG) allowed outage time (AOT) extension license amendment request (LAR), reviewed and approved by the NRC in Reference 1, the following CPS fire areas have the potential for a fire-induced LOOP/SBO scenario.

- A-2k (Non-Safety Switchgear Room, Auxiliary Building 762' East Side)
- A-3d (Non-Safety Switchgear Room, Auxiliary Building 762' West Side)
- A-3f (Division II Safety Switchgear Room, Auxiliary Building 781' West Side)
- CB-1f (CCW Equipment Area, Control Building 762')
- CB-2 (Division II Cable Spreading Area, Control Building 781')
- CB-3a (DC/Uninterruptible Power Supply Area, Control Building 781')
- CB-4 (Division I Cable Spreading Area, Control Building 781')
- CB-6 (Main Control Room)
- R-1i (Southwest corner of general access corridor (R-S line), 737' Radwaste Building)
- R-1p (Radwaste Building 762', southwest corner of R-S line)
- R-1t (Radwaste Building 781' General Access Area)
- T-1f (Turbine Building 737', south end of R-S line)

These areas have changed little since the time of the IPEEE in those aspects that would adversely impact their associated fire risk, such as the following.

- Fire ignition frequencies – There have been only minor changes in equipment counts in these areas.
- Fire suppression systems – The suppression systems are essentially unchanged.
- Equipment locations – The locations of fixed ignition sources have changed little, the room sizes and shapes in these areas are the same, and cable routings support divisional separation in accordance with the Fire Protection Safe Shutdown analysis.

While the potential for fire induced LOOP in these areas is regarded as being small (i.e., much less than the LOOP initiating event frequency due to other causes), the IPEEE fire model did not quantify fire induced LOOP scenarios for all of these areas. Therefore, to address the unquantified fire risk contribution from all of these areas as it impacts the Inverter CT amendment request, AmerGen commits to compensatory measures to control the risk of fire induced LOOP in these areas. This is the same approach used to address fire induced LOOP for the Diesel Generator AOT extension as documented in Reference 6 and approved in Reference 1.

AmerGen commits to incorporate the following restrictions into the appropriate CPS procedure(s).

During Modes 1, 2 and 3, should the Division 1 NSPS inverter be removed from service for more than 24 hours, then, within 24 hours of removal from service the following will be performed.

- Conduct walkdowns in Fire Zones A-2k, A-3d, A-3f, CB-1f, CB-2, CB-3a, CB-4, R-1i (southwest corner of R-S line), R-1p (southwest corner of R-S line), R-1t, and T-1f (south end of R-S line), confirming that there are no unauthorized combustibles or other unusual fire hazards in these areas.
- Inspect Main Control Room panel 1H13-P870, confirming that there are no unauthorized combustibles or other unusual fire hazards in the cabinet.
- Ensure that the fire protection sprinklers are available for Fire Zones CB-2, CB-3a and CB-4.
- Hot work will not be permitted in the above areas during this extended maintenance period.

Request 6:
Provide a discussion on the cumulative impact of previous changes or additional planned risk-informed requests. In the discussion include the impact of the diesel generator CT extension and extended power uprate at Clinton Power Station Unit 1. See RG 1.174 Section 3.3.2.

Response 6:
The cumulative impact of previous CPS risk-informed plant changes are incorporated into the risk evaluation of the CPS inverter CT extension LAR.

The previous CPS risk-informed plant changes of note are as follows.

- Integrated Leak Rate Test (ILRT) Frequency Extension [one-time extension]
- EDG AOT Extension
- Extended Power Uprate (EPU)

These previous risk-informed plant changes are summarized in the table below along with the proposed inverter CT extension.

Additional Information Supporting the Request for License Amendment Related to Extending the Completion Time for Nuclear System Protection System Inverters

Risk-Informed Application	PRA Revision (Date)	Base CDF(1)	Application delta CDF(1)	Application delta LERF(1)
ILRT	Rev. 3 (06/00)	2.67E-5/yr	Note (2)	9E-8/yr
EDG AOT	Rev. 3A (12/00)	1.38E-5/yr	6E-7/yr	Negligible
EPU	Rev. 3A (12/00)	1.38E-5/yr	9E-7/yr	8E-9/yr
Inverter CT(3)	Rev. 2003A (08/03)	9.97E-6/yr	3E-8/yr	4E-9/yr

Notes to Table:
(1) Based on Internal Events CDF and LERF.
(2) ILRT frequency extension has no impact on CDF.
(3) Inverter LAR submittal incorporates PRA model changes to address the impact of EDG AOT and EPU LARs. Note that the CPS ILRT extension is a one-time extension with insignificant risk impacts (the 9E-8/yr delta LERF is a conservative calculation), thus explicit model changes are not incorporated into the base CPS PRA for the one time ILRT exemption.

It is noted that the change in risk metrics associated with the risk informed applications are significantly less than the change in risk metrics due to plant enhancements, modeling, and data changes typically incorporated in one PRA revision to another.

Note that delta CDF and delta LERF values summarized in the table above are not to be directly summed to obtain cumulative risk impacts due to past applications. The differing risk evaluations for the risk-informed applications include varying degrees of realistic, conservative, and bounding assessments that make such a summation inappropriate.

ILRT Frequency Extension

CPS performed a risk impact assessment in 2002 for a one-time extension request from 10 to 15 years of the test interval for the Type A containment integrated leak rate test (ILRT) and the drywell bypass leak rate test (DBLRT). One reason the DBLRT extension request was made in conjunction with the ILRT extension request is that the two tests share test equipment and system lineups. The NRC staff approved the CPS ILRT/DBLRT extension request in Reference 2.

The risk analysis was conducted according to the guidelines of NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J," and EPRI TR-104285, "Risk Impact Assessment of Revised Containment Leak Rate Testing Intervals." EPRI TR-104285 uses an analytical approach similar to that presented in NUREG-1493, "Performance-Based Containment Leak-Test Program." Previously, the risk contribution results from the representative plants analyzed in the EPRI TR-104285 guidance document confirmed the NUREG-1493 conclusion that a reduction in the frequency of Type A tests from three tests in 10 years to one test in 20

years leads to an "imperceptible" increase in risk. Nevertheless, a plant specific analysis was performed.

The CPS specific analysis confirmed the conclusions of NUREG-1493 and EPRI TR-104285. The risk impact due to internal events from extending the ILRT/DBLRT test intervals to 15 years falls within the RG 1.174 Region III (i.e., "Very Small") risk impact range.

The CPS ILRT/DBLRT extension is a one-time extension with non-significant risk impacts as analyzed in the risk application with a bounding analysis, thus explicit model changes are not incorporated into the base CPS PRA.

Emergency Diesel Generator AOT Extension

The EDG AOT extension LAR, which was approved in Reference 1, extended the allowable unavailability time for CPS Division 1 and 2 EDGs from 3 to 14 days. The actual long-term change in plant risk depends not so much on the allowed outage time for an EDG but rather on the total accumulated unavailability for an EDG over some fixed period of time. The CPS EDG AOT extension allows CPS to package maintenance work on the Division 1 and 2 EDGs in longer overhaul outages. As a result, more work can be done during the overall outage and long-term unavailability of the EDGs can be reduced because fewer outages are required.

The table below summarizes CPS actual diesel generator unavailability for Divisions 1 and 2 over the past three fuel cycles, based upon maintenance rule records. Note there has been an overall reduction in the total unavailability hours for the EDGs despite the change in TS AOT. The TS change occurred during Cycle 8 of operation. In addition, CPS also has transitioned from 18-month cycles to 24-month cycles, with last cycle (i.e., Cycle 9) being a transition cycle of about 22 months.

EDG Unavailability Summary

EDG TS Requirement	Cycle	Div 1 (hrs)	Div 2 (hrs)	Total of Div. 1 and 2 (hrs)
3 day AOT	7	168	222	390
Transition	8	91	247	338
14 day AOT	9	148	180	329

In summary, the risk impacts of the CPS EDG AOT extension risk-informed plant change on the PRA model are due to actual EDG unavailability hours. The EDG actual unavailability hours are incorporated into the CPS PRA during model updates. The impact of the EDG AOT extension from 3 to 14 days for Divisions 1 and 2, coupled with work practice changes, has resulted in a risk reduction for the plant in terms of lower EDG unavailability due to maintenance.

Additional Information Supporting the Request for License Amendment Related to Extending the Completion Time for Nuclear System Protection System Inverters

Extended Power Uprate (EPU)

The risk study in support of the EPU licensing change, examined expected changes in plant risk due to EPU. A summary of this risk study was provided in support of the EPU amendment request in Reference 3. This risk study found that PRA success criteria attributable to the EPU condition were essentially unchanged from the pre-EPU condition (i.e., the system trains that constituted success post EPU were the same as the pre EPU condition). The risk impact of EPU is primarily due to higher reactor power level and the corresponding increase in decay heat power which, in turn, reduces the time available for certain operator actions. EPU was approved in Reference 7.

The model used in the inverter risk study incorporates the impact of the post EPU condition (i.e., operator actions based on EPU timings). Other bounding assumptions included in the EPU LAR risk assessment (e.g., Turbine Trip initiating event frequency increases) are not incorporated into the CPS base model. The plant trip history in recent years has not deviated significantly from its long-term trend of one to two "transient without isolation" initiators per year. In the case of the assumed Turbine Trip initiating event frequency in the EPU LAR risk assessment, any actual impact on CPS transient initiating event frequency will be manifested in actual plant experience and incorporated into the model as such (i.e., via Bayesian statistical update to initiating event frequencies) during PRA updates.

Other Plant Changes

CPS has also made plant changes that have reduced plant risk (outside of the LAR process). For example, the Loss of Reserve Auxiliary Transformer (RAT) initiating event is significant at CPS because the RAT can supply power to all safety related systems and all Balance of Plant (BOP) systems such as Feedwater, Condensate, Condensate Booster, and Service Water. The plant experienced an event in 1996 in which the RAT was inadvertently deenergized because of switchyard activities. Deenergization of the RAT caused the safety related buses to transfer to the Emergency Reserve Auxiliary Transformer (ERAT). Because this transfer was a "break before make transfer", it resulted in the momentary deenergization of leak detection logic which in turn caused main steam isolation valve (MSIV) closure, reactor scram and turbine trip. The turbine trip caused loss of the Unit Auxiliary Transformer which is the normal source of power for the BOP loads during operating conditions. Because the RAT is the only backup source for the BOP loads, all BOP AC loads were lost.

Plant design changes have been subsequently implemented to power the affected leak detection logic from Uninterruptible Power Supply (UPS) sources. Thus, when a similar loss of RAT event occurred in 2001 due to switchyard configuration and a lightning strike on the transmission system, the safety related loads successfully transferred to the ERAT, but the leak detection logic remained powered from UPS sources so MSIV closure did not occur and the turbine and reactor remained on-line (i.e., no initiating event). The net result of this design change is a reduction of the Loss of RAT initiating event frequency, which has been incorporated in the CPS base PRA model used for the inverter CT extension risk assessment and has resulted in a decrease in overall plant risk.

In addition, Risk Informed Inservice Inspection (RI-ISI) has also been implemented at CPS. The RI-ISI program is implemented to use risk information for optimizing inspection activities as part of a risk-informed process. As part of the risk informed process for RI-ISI, calculated changes in plant risk were negligible.

Summary

In summary, the PRA updates make the CPS PRA model consistent with the latest as-built, as-operated plant. Therefore, the CPS PRA accurately reflects the cumulative impacts of plant changes, such that any future risk-informed plant changes will include the cumulative impact of past plant changes.

Request 7:
Attachment 1, page 10 of 20, states that the CDF contribution due to internal fires was estimated to be 3.26E-6/year. The staff review of the IPE references a CDF contribution from fire as 3.6E-6/year based on increased CDF contribution from dc/UPS equipment area fires. Reconcile these differences and possible impact on the proposed division 1 and 2 inverter 7-day CT.

Response 7:
This response assumes that the 3.6E-6/yr CDF referenced in this RAI refers to the 3.64E-6/yr value calculated in a sensitivity quantification to respond to an RAI on the CPS IPEEE that requested re-assessing certain electrical cabinet fires using higher heat release rates.

The fire analyses in the CPS IPEEE submittal used a heat release rate of 65 BTU/sec for electrical panel fires. In response to the NRC request for additional information on the CPS IPEEE submittal, electrical panel fires were re-performed assuming a heat release rate of 190 BTU/sec. This value was based on the EPRI document "Guidance for Development of Response to Generic Requests for Additional Information on Fire Individual Plant Examinations for External Events (IPEEE)" dated May 1999. The increased heat release rates resulted in increasing the total fire-induced CDF from 3.26E-6/yr (i.e., CPS IPEEE submittal value) to 3.64E-6/yr. The calculation of the 3.64E-6/yr value is documented in Reference 4.

Using the 3.64E-6/yr CDF value as representative of the CPS fire CDF, the calculated ICCDP from fire for the proposed CT extension is estimated at approximately 3.6E-9 (i.e., a slight increase from the ICCDP of 1E-9 estimated using the 3.26E-6/yr fire CDF). A revision to Table A-1 of the Inverter CT LAR (i.e., Reference 5) using the requested 3.64E-6/yr CDF is provided here as Table 7-1. The revised inputs to the calculation are shown in the bold outlined cells. These revisions to Table A-1 do not alter the response provided above to Request 5 (i.e., the fire SBO CDF is unchanged by these revisions).

ATTACHMENT 1

Additional Information Supporting the Request for License Amendment Related to Extending the Completion Time for Nuclear System Protection System Inverters

Table 7-1
REVISED TABLE A-1 OF SUBMITTAL USING 3.64E-6/YR FIRE CDF

ESTIMATE OF IMPACT ON FIRE CDF DUE TO INVERTER CT REQUEST
[Revised for RAI #7 on the Inverter Submittal]

Dominant Fire Scenarios Per CPS IPEEE:

Fire Area	Fire Area Description	Fire Area Fire-Induced CDF	Scenarios with Fire-Induced LOOP	Fire-Induced LOOP Scenario CDF	Fraction of Fire-Induced LOOP Scenario That is SBO	CDF of Fire SBO Scenarios
A-1a	Auxiliary Bldg - El. 707'6" Hallway	3.25E-10	<None>	0.00	0.00	0.00
A-1b	Auxiliary Bldg - El. 737' General Access	1.79E-10	<None>	0.00	0.00	0.00
A-2k	Auxiliary Bldg - Div. I Non-Safety SWGR	2.95E-07	All (assumed)	2.95E-07	0.01	2.95E-09
A-2n	Auxiliary Bldg - Div. I Safety SWGR	7.11E-07	<None>	0.00	0.00	0.00
A-3d	Auxiliary Bldg - Div. II Non-Safety SWGR	1.27E-07	All (assumed)	1.27E-07	0.01	1.27E-09
A-3f	Auxiliary Bldg - Div. II Safety SWGR	2.00E-07	All (assumed)	2.00E-07	0.10	2.00E-08
CB-1c	Control Bldg - El. 702'	2.04E-08	<None>	0.00	0.00	0.00
CB-1d	Control Bldg - Chemistry Lab Areas	5.36E-10	<None>	0.00	0.00	0.00
CB-1e	Control Bldg - Els. 737' & 751', Gen. Access & Lab HVA	1.14E-09	<None>	0.00	0.00	0.00
CB-1f	Control Bldg - CCW Equipment Area	6.85E-08	All (assumed)	6.85E-08	0.01	6.85E-10
CB-2	Control Bldg - Div. II Cable Spreading Area	3.97E-09	All (assumed)	3.97E-09	0.10	3.97E-10
CB-3a	Control Bldg - DC/UPS Area	4.84E-07	Scenario #6	7.81E-09	1.00	7.81E-09
			Scenario #8	8.46E-10	1.00	8.46E-10
			Scenario #9	8.70E-10	1.00	8.70E-10
			Scenario 1PL89JA	2.12E-09	negligible	negligible
CB-4	Control Bldg - Div. I Cable Spreading Area	1.39E-09	All (assumed)	1.39E-09	0.10	1.39E-10
CB-5a	Control Bldg - Div. III SWGR	1.36E-07	<None>	0.00	0.00	0.00
CB-6a	Control Bldg - Main Control Room	1.20E-06	Scenario 1H13-P870	7.73E-09	negligible	negligible
CB-6d	Control Bldg - Ops Kitchen/Restrooms/Storage	3.72E-08	<None>	0.00	0.00	0.00
F-1a	Fuel Bldg - El. 712' General Access	4.28E-10	<None>	0.00	0.00	0.00
F-1m	Fuel Bldg - El. 737' General Access	1.11E-08	<None>	0.00	0.00	0.00
F-1p	Fuel Bldg - Els. 755' & 781'	1.13E-09	<None>	0.00	0.00	0.00
M-2c	Screenhouse - Els. 678' & 699'	3.38E-07	<None>	0.00	0.00	0.00
R-1t	Radwaste - El. 781' General Access	4.75E-09	Scenario #2	3.50E-09	negligible	negligible
TOTALS:		3.64E-06				3.50E-08 (1.0%)
		This is taken as an approximation of the CPS fire CDF for the Inverter CT application				This is taken as an approximation of the CPS fire SBO scenario CDF for the Inverter CT application

Estimation of Change in CPS Fire Risk Due to Inverter CT Request:

Delta Fire CDF = [(.99% x 3.64e-6 x (1 + 0.01)) + (1% x 3.64e-6 x (2.6)) - 3.64e-6]
9.43E-08

Delta Fire CDF (%) = **2.59%**

ICCDP (fire) = **3.62E-09**

Where:
- The 99% term represents the fraction of the internal fires CDF due to non-SBO scenarios.
- The 0.01 term represents the <1% increase manifested in the internal events non-SBO CDF due to the Inverter CT request.
- The 1% term represents the fraction of the internal fires CDF due to SBO accidents.
- The 2.6 term represents the approximate 2.6 factor increase manifested in the internal events SBO CDF due to the Inverter CT request.
- The ICCDP is calculated as: [Delta Fire CDF x 14 days/365 days].
- For fire areas A-2k, A-3d, A-3f, CB-1f, CB-2 and CB-4, the fraction of fire scenario CDF that results in SBO CDF is based on information presented by CPS in responses to the second round of RAIs on the CPS EDG CT Extension request. For all other fire areas, the estimates are based on information presented by CPS in responses to the first round of RAIs on the CPS EDG CT Extension request.
- The dark bordered cells are revised CDFs based on the 1/28/00 round of CPS IPEEE responses (resulting in a revised fire CDF from 3.26E-6 to 3.64E-6).

Request 8:
Attachment 4, page 2-7. The CDF/average calculation assumes that each inverter is only taken out for maintenance once per fuel cycle and will use the full 7-day CT. Confirm that inverter maintenance history, reliability, and availability are consistent with the above assumptions. The submittal notes that CPS policy is to schedule inverter maintenance for half the CT (3.5 days). However, the proposed CT includes additional maintenance tasks including possible inverter replacement.

Response 8:
The CPS experience has been within the bounds of the above assumptions because inverter unavailability is rarely incurred with the plant on-line and never has exceeded the 24-hour allowable TS CT. As was stated in the LAR (i.e., Reference 5), this proposed extended CT is intended to address corrective maintenance conditions with the inverter, should the need arise. CPS replaced the Division 2 NSPS inverter during CPS's ninth refueling outage in February 2004. This inverter replacement occurred in the context of a Division 2 NSPS bus outage that lasted approximately 2 days, but included other work beyond the inverter replacement. This inverter outage was completed as a pre-planned evolution in a refueling outage. If an NSPS inverter had to be replaced on-line under corrective maintenance conditions, some time would be needed for initial troubleshooting, decision-making, and to gather the needed equipment and personnel to do the work. A seven day CT would allow this work to be completed without undue time pressure and would allow some time to deal with emergent problems during the inverter replacement.

Request 9:
The licensee states that they performed the quantification using a single top model (fault tree). This approach can result in subsuming (and thus elimination) of valid event sequences, if event sequence success branches are not included in the sequence logic that inputs to the single top event. Please describe your development approach of the single top fault tree (i.e., conversion from event tree logic structure to single top fault tree logic structure) and confirm that this approach does not subsume valid event sequences during the quantification process.

Response 9:
The CPS PRA model uses a single top model (fault tree) to quantify both CDF and LERF. It is understood that the single top fault tree methodology approach can result in subsuming (and thus eliminating) valid event sequences if sequence success branches are not included in the sequence logic input into the single top model.

The CPS PRA model used in the CPS inverter CT extension risk assessment was Revision 2003A. CPS PRA Revision 2003A was developed in 2003 as a conversion from the SETS software platform to the CAFTA software platform. As part of the conversion process, sequence success branch logic was not explicitly included to model the minimal event tree sequences (i.e., Boolean logic reduction eliminated the need to explicitly model all event tree sequences to obtain the minimum cutsets). Although this

methodology can result in subsuming valid event sequences (e.g., non-minimal loss of decay heat removal sequences), the single top model appropriately quantifies the minimal CDF and LERF cutsets. Based on experience with industry and other Exelon PRA models, explicitly including success branch logic in the development of single-top models produces a slightly lower (i.e., with respect to the single-top model developed without explicit incorporation of success branches) CDF/LERF point estimates due to the elimination of invalid cutsets. Therefore, not explicitly including success branch logic may result in a very minor increase in CDF and/or LERF but this potential conservatism is not judged to alter the conclusions of the inverter CT extension risk assessment.

Request 10:
For Table A-1, the last bullet on the bottom of page A-4 appears to have an incomplete reference for the fraction of the fire scenario attributed to station blackout.

Response 10:
This observation is correct. The bullet item in question in the notes to Table A-1 was erroneously truncated. The bullet item should read as follows in its entirety.

> "For fire areas A-2k, A-3d, A-3f, CB-1f, CB-2 and CB-4, the fraction of fire scenario CDF that results in SBO CDF is based on information presented by CPS in responses to the second round of RAIs on the CPS EDG CT Extension request. For all other fire areas, the estimates are based on information presented by CPS in responses to the first round of RAIs on the CPS EDG CT Extension request."

This revised bullet is reflected in Table 7-1 (i.e., the revised Table A-1) provided above in the response to Request 7.

Request 11:
Appendix D states that the 2003A Clinton Power Station Unit 1 LERF model incorporates a significant number of conservatisms. Appendix D credits operator action for the isolation for a pair of containment isolation valves that require AC power to close citing the availability of manual isolation valves. The valves as stated, are located where radiation levels could be high. The current PRA no longer incorporates the credit for manual valve isolation and the referenced human error probabilities (HEP) are not used. No justification is provided that the Appendix D change is considered valid and reviewed/approved for incorporating into the next revision of the PRA model. Based on the above, either present additional justification for this change to the model including the impact on Tier 2 and Tier 3 evaluations or, as an alternative, provide and confirm that the estimates for LERF, ΔLERF, and ICLERP without the revised HEP recovery factor are within the acceptance guidelines given in RG 1.174 and 1.177.

Confirm that baseline LERF, ΔLERF, and ICLERP with either division 1 or 2 inverters out-of-service incorporate the modified Appendix D reduction factor of .44 (credited recovery action) See table 1, Attachment 1, note 2, Equation 5, Attachment 4, page 2-8 equation 5, or page 2-9, equation 9.

Response 11:

(a) The CPS Revision 2003A PRA does not incorporate credit for the local manual operation of containment isolation valves. However, the risk-informed analysis submitted to support the CPS inverter CT extension has included credit for these crew actions.

The credit for manual isolation of containment isolation valves is appropriate in those accident sequences that involve available time before core damage or for those cases where access may still be available despite core damage.

For the SBO events that lead to core damage and containment isolation valves remaining open, there is substantial time available for crew action if the Reactor Core Isolation Cooling (RCIC) system operates. This credit was included in previous versions of the CPS PRA but has been removed in the 2003A PRA update and replaced with placeholder values until the crew interviews for the Level 2 PRA are performed in the next update.

Appendix D of Attachment 4 to Reference 5 identified the basis for the incorporation of the more realistic Human Error Probabilities (HEPs) in the risk metric calculations to support the extension of the inverter CT. Specific HEPs were calculated and approved within the AmerGen PRA process for incorporation in the next PRA update. These will be confirmed through operating staff interviews.

The Appendix D discussion states that:

- This local manual alignment action is a simple action directed by CPS procedure 4200.01, "Loss of AC Power," and is performed outside the control room, in the fuel building.
- This line also contains manually operated valves that would be accessible and could be shut.
- Access would be sufficient to allow local manual closure of one of the valves.
- At least 1.2 hours is available for this action to be completed.

The same HRA team that evaluated the remainder of the Level 1 HEPs for the 2003A model update has evaluated the HRA evaluation and model change.

(b) The NRC requested revised results of the risk metric calculations that remove the credit for the subject crew actions when comparing the results with the RG 1.177 and RG 1.174 acceptance guidelines. These comparisons are shown in Table 11-1.

Table 11-1

COMPARISON OF CALCULATED RISK METRICS WITH ACCEPTANCE GUIDELINES

Risk Metric	Risk Metric Value With Crew Isolation Credit	Risk Metric Value With Crew Isolation Actions Removed	Acceptance Guidelines	
			RG 1.174	RG 1.177
$LERF_{AVE}$	1.0E-7/yr	2.3E-7/yr	1E-5/yr	--
$\Delta LERF$	4.0E-9/yr	9.1E-9/yr	1E-7/yr	--
$ICLERP_{DIV1}$	7.7E-9	1.8E-8	--	5E-8
$ICLERP_{DIV2}$	ε	ε	ε	5E-8

As can be seen, with the credit removed for the operator actions, all of the risk metrics still meet the acceptance guidelines of both RG 1.174 and 1.177.

No change in the CDF or ICCDP risk metrics occur as a result of the incorporation of the more realistic HEP value for containment isolation in the Level 2 analysis.

The calculations performed assume:

- CT duration is 7 days
- The full CT is taken every fuel cycle for each inverter
  - 7 days for Division 1
  - 7 days for Division 2

  (See Attachment 4, Table 2.4-1 of Reference 5)

(c) The ΔLERF values for the inverter CT extension are modified by the conservative estimate of 0.44 credit for crew action to close the normally open containment isolation valves.

Table 1 of Attachment 1 to Reference 5 is correct and includes credit for crew action to isolate the normally open containment isolation valves.

Attachment 4, Tables 2.4-4 and 2.4-5 of Reference 5 show this calculation using values from Table 2.4-2, which already include the 0.44 credit in the LERF values. Tables 2.4-4 and 2.4-5 have footnotes that the LERF, ΔLERF, and ICLERP calculations include the factor of 0.44 in the values that are presented.

However, the Equations 5 and 9 of Attachment 4 to Reference 5 refer to $LERF_{AVE}$, $LERF_{BASE}$, and $LERF_{1\text{-}OOS}$. These values in Equations 5 and 9 should be referred to as the $LERF_{AVE}^{2003A}$, $LERF_{BASE}^{2003A}$, and $LERF_{1-OOS}^{2003A}$.

Nevertheless, the calculation used in the assessment properly accounts for the 0.44 credit by including it in the quoted LERF values. The credit of 0.44 is not then double counted when implementing Equations 5 and 9. Equations 5 and 9 should be re-written for clarity as:

$$\Delta \mathrm{LERF}_{AVE} = \left(LERF_{AVE}^{2003A} - LERF_{BASE}^{2003A}\right) * 0.44 \qquad [Eq.\ 5]$$

$$\Delta \mathrm{ICLERP}_{DIV1} = \left(LERF_{1-OOS}^{2003A} - LERF_{BASE}^{2003A}\right) * 0.44 * 1.92 \times 10^{-2}\ \mathrm{year} \qquad [Eq.\ 9]$$

Where,

$LERF_{AVE}^{2003A}$ is AVE LERF calculated directly from the model with the new inverter CT and no credit for the crew containment isolation action.

$LERF_{BASE}^{2003A}$ is the BASE LERF calculated directly from the 2003A model with the previous inverter CT and no credit for the crew containment isolation action.

$LERF_{1-OOS}^{2003A}$ is the LERF calculated directly from the 2003A model with the inverter Division 1 OOS and no credit for crew containment isolation action.

(d) Additional clarification on LERF usage

The LERF impact associated with the containment isolation failure is due to the assumption regarding LERF. LERF is defined the same as the ASME PRA Standard.

> *Large early release:* the rapid, unmitigated release of airborne fission products from the containment to the environment occurring before the effective implementation of off-site emergency response and protective actions such that there is a potential for early health effects.

However, the interpretation of the release timing for CPS is that any release within 6 hours of the general emergency declaration causes the time of release to be determined as "Early" even if the life threatening portion of the release does not occur until later (i.e., after the early period).

This results in the conservative inclusion of SBO events in the LERF determination.

Request 12:
Confirm that the referenced CPS CRMP meets the guidance for a Tier 3 program as outlined by Key Components 1, 2, 3 and 4 of a CRMP. RG 1.177 Section 2.3.7.2.

Response 12:
The key components of a CRMP from Section 2.3.7.2 of RG 1.177 are repeated below along with a discussion of the CPS CRMP as it relates to these key components.

RG 1.177 Key Component 1: Implementation of the CRMP

The intent of the CRMP is to implement Section a(3) of the Maintenance Rule (10 CFR 50.65) with respect to on-line maintenance for risk-informed TS, with the following additions and clarifications:

1. *The scope of structures, systems, and components (SSCs) to be included in the CRMP is all SSCs modeled in the licensee's plant PRA in addition to all SSC's considered high safety significant per Revision 2 of Regulatory Guide 1.160 that are not modeled in the PRA.*

2. *The CRMP assessment tool is PRA-informed and may be in the form of a risk matrix, an on-line assessment, or a direct PRA assessment.*

3. *The CRMP will be invoked as follows:*

   - *For pre-planned entrance into the plant configuration described by a TS action statement with a risk-informed AOT, a risk assessment, including, at a minimum, a search for risk-significant configurations, will be performed prior to entering the action statement.*

   - *For unplanned entrance into the plant configuration described by a TS action statement with a risk-informed AOT, a similar assessment will be performed in a time frame defined by the plant's Corrective Action Program (Criteria XVI of Appendix B to 10 CFR Part 50).*

   - *When in the plant configuration described by a TS action statement with a risk-informed AOT, if additional SSCs become inoperable or nonfunctional, a risk assessment, including at a minimum, a search for risk-significant configurations, will be performed in a time frame defined by the plant's Corrective Action Program (Criteria XVI of Appendix B to 10 CFR Part 50).*

4. *Tier 2 commitments apply only for planned maintenance, but should be evaluated as part of the Tier 3 assessment for unplanned occurrences.*

The CPS process for controlling on-line maintenance and equipment unavailability is delineated in Exelon Procedure WC-AA-101, "On-Line Work Control Process." Considerations in the process include meeting allowable TS Completion times, controlling unavailability hours on Maintenance Rule functions where unavailability monitoring is required, and assessing and managing configuration risk associated with actual equipment unavailability. SENTINEL is the computer-based tool used in the on-

line risk assessment process.[1] Characteristics of the tool and process are as follows:

1. SENTINEL utilizes a list of plant trains or components that can be "toggled" out of service to analyze the risk associated with a particular plant condition. The list of equipment trains or components that can be toggled out of service includes all the high safety significant Maintenance Rule functions that are in the PRA. The list encompasses the large majority of all the equipment trains modeled in the PRA. A few non risk significant SSCs in the PRA (e.g., plant chilled water chillers) have not been explicitly included in the CPS CRMP SSC list. This approach is generally consistent with the guidance in Exelon T&RM ER-AA-600-1023, "ORAM SENTINEL and PARAGON Model Capability," which states:

   > "SSCs in the PRA model that were determined by the Maintenance Rule Expert Panel to be Low Safety Significant may be excluded from the Sentinel model if the Risk Achievement Worth is very close to 1.0 (usually < 1.001)."

   The list also includes a number of functions that are not modeled in the PRA, but are assessed through other risk measures used within SENTINEL. For example, SENTINEL can be used to evaluate the availability of systems supporting secondary containment, even though secondary containment is not a PRA modeled function.

2. The risk assessment models used within SENTINEL use three primary risk measures. First, Safety Function Assessment Trees (SFATs) are used to measure the defense-in-depth available in Key Safety Functions such as High Pressure Injection, Low Pressure Injection or AC Power. A reduction in the number of trains capable of performing each Key Safety Function typically will result in an SFAT color change. Plant Transient Assessment Trees (PTATs) are the second type of risk measure used. PTATs as developed in the CPS Sentinel model are a measure of the availability of systems capable of responding to particular accident sequences. By keeping track of the number of systems available for responding to particular accident sequences, PTATs provide a measure of the protection the plant has against these accident sequences. The less protection available the more severe the PTAT color. The PRA model is used to provide the third risk measure used in SENTINEL. In this measure the PRA model is used to calculate the Core Damage Frequency (and Large Early Release Frequency) for the particular set of equipment unavailable at any one time. The result is expressed as Risk Increase Factors (RIF), one for CDF and one for LERF, over the baseline (i.e., all equipment in service) results. The higher the RIF the more severe the color associated with the PRA results. The overall "plant risk color" is the worst of the SFAT, PTAT or PRA risk colors.

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(1) CPS is in the process of switching from the SENTINEL software to the PARAGON software. The information presented here is based on use of the SENTINEL software. PARAGON will have essentially the same functionality as SENTINEL plus some additional features.

trains that have a significant impact on core damage risk are included. The SENTINEL tool makes provision for initiating events whose likelihood may or may not be under the plant's control. For example, Grid reliability, which the plant only has minimal control over, can be assessed by using a so-called High Risk Evolution for Loss of Offsite Power. This impacts the PTAT results, which are used to evaluate the protection provided by the plant against leading core damage sequences. There are plant features that are not addressed by the SENTINEL tool, (e.g. Control Room annunciator windows) but are left to the discretion of licensed operators to control. For example, for a typical annunciator window outage extra operators would be brought in to monitor process parameters, in effect compensating for the lack of annunciation.

In accordance with Exelon T&RM ER-AA-600-1042 and procedure WC-AA-101, Risk Management engineers advise Operations on plant configurations for which quantitative risk results are not directly obtainable from the SENTINEL tool.

RG 1.177 Key Component 3: Level 1 Risk-Informed Assessment

The CRMP assessment tool utilizes at least a Level 1, at-power, internal events PRA model. The CRMP assessment may use any combination of quantitative and qualitative input. CRMP assessments can include reference to a risk matrix, pre-existing calculations, or new PRA analyses.

1. *Quantitative assessments should be performed whenever necessary for sound decisionmaking.*

2. *When quantitative assessments are not necessary for sound decisionmaking, qualitative assessments can be performed. Qualitative assessments should consider applicable existing insights from previous quantitative assessments.*

The CPS CRMP addresses Key Component 3 as follows:

1. The risk measures used in the CPS risk assessment tool are described above under Key Component 1. The process includes both probabilistic and deterministic (i.e., defense in depth measures) considerations. SENTINEL has the capability to initiate new PRA model calculations to address the particular plant configuration encountered and therefore does not rely entirely on pre-solved PRA cases.

2. The blended approach used in the SENTINEL risk assessment tool utilizes both probabilistic and deterministic considerations in assessing risk through the use of the PRA, SFATs and PTATs. In accordance with Exelon T&RM ER-AA-600-1042 and procedure WC-AA-101, Risk Management engineers advise Operations on plant configurations for which quantitative risk results are not directly obtainable from the SENTINEL tool.

RG 1.177 Key Component 4: Level 2 Issues and External Events

External events and Level 2 issues are treated qualitatively or quantitatively, or both.

Key Component 4 is addressed in the CPS CRMP as follows:

The CPS SENTINEL model explicitly considers Level 2 PRA impacts by incorporation of a LERF model in the PRA model used as part of SENTINEL.

External hazards such as winds, rain and fire are typically assessed in a qualitative manner when performing on-line risk assessments. High winds (e.g. tornado warnings) can cause the operating shift to delay work that could impact on-site power reliability (e.g., EDGs). Heavy rain can prompt the plant staff to sandbag key plant structures related to keeping the unit on-line (e.g., the screen house). Safety-related Shutdown Service Water, whose pumps are also in the screen house, are protected by permanent flood barriers. Protection against fires is provided through strong spatial separation in the plant design. In addition, combustibles and ignition sources are kept at a minimum in key areas of the plant through the fire protection program. All three safety-related mechanical equipment divisions have been seismically qualified to a 0.25 g Safe Shutdown Earthquake. A Seismic Margins Assessment has been performed to demonstrate that the plant is capable of dealing with the NRC IPEEE Review Level Earthquake (RLE) of 0.3 g. Because the plant generally has a good design for dealing with these External Hazards they are not part of the SENTINEL on-line risk assessment tool, but are addressed through the judgment of the operating staff.

References:

1. Letter from U. S. NRC to Oliver D. Kingsley (Exelon Generation Company, LLC), "Clinton Power Station, Unit 1 – Issuance of Amendment (TAC No. MB0861)," dated November 8, 2001
2. Letter from U. S. NRC to John L. Skolds (AmerGen Energy Company, LLC), "Clinton Power Station, Unit 1 – Issuance of Amendment (TAC No. MB7675)," dated January 8, 2004
3. Letter from Kenneth A. Ainger (Exelon Generation Company, LLC), to U. S. NRC, "Supplemental Information Supporting the License Amendment Request to Permit Extended Power Uprate Operation at Clinton Power Station," dated September 28, 2001
4. Letter from Michael T. Coyle (Illinois Power) to U. S. NRC, "Clinton Power Station Response to Request for Additional Information Regarding Fire Questions for the Clinton Power Station Individual Plant Examination for External Events (IPEEE)," dated January 28, 2000
5. Letter from Keith R. Jury (AmerGen Energy Company, LLC) to U. S. NRC, "Request for Technical Specification Change to Extend Completion Time for Nuclear System Protection System Inverters," dated April 26, 2004
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 U. S. NRC to Oliver D. Kingsley (Exelon Generation Company, LLC), "Clinton Power Station, Unit 1 – Issuance of Amendment (TAC No. MB2210)," dated April 5, 2002

ATTACHMENT 2

Commitments

LIST OF COMMITMENTS

The following table identifies those actions committed to by AmerGen Energy Company, LLC (AmerGen), in this document. Any other statements in this submittal are provided for information purposes and are not to be considered commitments.

COMMITMENT	Due Date/Event
(1) During Modes 1,2 and 3, should the Division 1 NSPS inverter be removed from service for more than 24 hours, then, within 24 hours of removal from service the following will be performed. • Conduct walkdowns in Fire Zones A-2k, A-3d, A-3f, CB-1f, CB-2, CB-3a, CB-4, R-1i (southwest corner of R-S line), R-1p (southwest corner of R-S line), R-1t, and T-1f (south end of R-S line), confirming that there are no unauthorized combustibles or other unusual fire hazards in these areas. • Inspect Main Control Room panel 1H13-P870, confirming that there are no unauthorized combustibles or other unusual fire hazards in the cabinet. • Ensure that the fire protection sprinklers are available for Fire Zones CB-2, CB-3a and CB-4. • Hot work will not be permitted in the above areas during this extended maintenance period.	Upon implementation of the License Amendment

ATTACHMENT 2

Commitments

COMMITMENT	Due Date/Event
(2) When the Division 1 NSPS inverter is unavailable the following compensatory actions will be taken. • Entry into the extended inverter CT will not be planned concurrent with Shutdown Service Water maintenance. • Entry into the extended inverter CT will not be planned concurrent with Division 3 (HPCS) maintenance including Division 3 battery or charger. • Entry into the extended inverter CT will not be planned concurrent with maintenance unavailability of the Division 1 or 2 DC components (i.e., batteries or chargers). • Entry into the extended inverter CT will not be planned concurrent with maintenance unavailability of the Division 1 NSPS regulating transformer.	Upon implementation of the License Amendment
(3) When either Division 1 or 2 NSPS inverter is unavailable the following compensatory action will be taken. • Entry into the extended inverter CT will not be planned concurrent with planned maintenance on another Reactor Protection System (RPS) channel that could result in that channel being in a tripped condition.	Upon implementation of the License Amendment