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January 31, 2007

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

Braidwood Station, Units 1 and 2
Facility Operating License Nos. NPF-72 and NPF-77
<u>NRC Docket Nos. STN 50-456 and STN 50-457</u>

Byron Station, Units 1 and 2
Facility Operating License Nos. NPF-37 and NPF-66
<u>NRC Docket Nos. STN 50-454 and STN 50-455</u>

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

Dresden Nuclear Power Station, Units 2 and 3
Renewed Facility Operating License Nos. DPR-19 and DPR-25
<u>NRC Docket Nos. 50-237 and 50-249</u>

LaSalle County Station, Units 1 and 2
Facility Operating License Nos. NPF-11 and NPF-18
<u>NRC Docket Nos. STN 50-373 and STN 50-374</u>

Limerick Generating Station, Units 1 and 2
Facility Operating License Nos. NPF-39 and NPF-85
<u>NRC Docket Nos. 50-352 and 50-353</u>

Oyster Creek Generating Station
Facility Operating License No. DPR-16
<u>NRC Docket No. 50-219</u>

Peach Bottom Atomic Power Station, Units 2 and 3
Renewed Facility Operating License Nos. DPR-44 and DPR-56
NRC Docket Nos. 50-277 and 50-278

Quad Cities Nuclear Power Station, Units 1 and 2
Renewed Facility Operating License Nos. DPR-29 and DPR-30
NRC Docket Nos. 50-254 and 50-265

Three Mile Island Nuclear Station, Unit 1
Facility Operating License No. DPR-50
NRC Docket No. 50-289

Subject: EGC/AmerGen Response to the Request for Additional Information Regarding Resolution of NRC Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power"

References:

1. Letter from Christopher Grimes (U.S. NRC) to Addressees, "NRC Generic Letter 2006-02: Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated February 1, 2006

2. Letter from K. R. Jury (Exelon Generation Company, LLC/AmerGen Energy Company, LLC) to U.S. NRC, "EGC/AmerGen 60-Day Response to NRC Generic Letter 2006-02: Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated April 3, 2006

3. Letter from C. Haney (U.S. NRC) to Addressees, "Request for Additional Information Regarding Resolution of Generic Letter 2006-02, Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated December 5, 2006

On February 1, 2006 NRC Generic Letter (GL) 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," (i.e., Reference 1) was issued. The GL requested that all holders of operating licenses submit a written response within 60 days in accordance with 10 CFR 50.54, "Conditions of licenses," paragraph (f). The GL requested information in the following four areas in order to determine if regulatory compliance is being maintained:

(1) use of protocols between the nuclear power plant (NPP) and the transmission system operator (TSO), independent system operator (ISO), or reliability coordinator/authority (RC/RA) and the use of transmission load flow analysis tools (analysis tools) by TSOs to assist NPPs in monitoring grid conditions to determine the operability of offsite power systems under plant technical specifications (TSs). (The TSO, ISO, or RA/RC is responsible for preserving the reliability of the local transmission system. In this GL the term TSO is used to denote these entities);

(2) use of NPP/TSO protocols and analysis tools by TSOs to assist NPPs in monitoring grid conditions for consideration in maintenance risk assessments;

(3) offsite power restoration procedures in accordance with Section 2 of NRC Regulatory Guide (RG) 1.155, "Station Blackout," and

(4) losses of offsite power caused by grid failures at a frequency equal to or greater than once in 20 site-years in accordance with RG 1.155.

Reference 2 provided the Exelon Generation Company, LLC (EGC) and AmerGen Energy Company, LLC (AmerGen) 60-day response to the requested information for Braidwood Station, Byron Station, Clinton Power Station, Dresden Nuclear Power Station, LaSalle County Station, Limerick Generating Station, Oyster Creek Generating Station, Peach Bottom Atomic Power Station, Three Mile Island Nuclear Station Unit 1, and Quad Cities Nuclear Power Station.

In Reference 3, the NRC requested additional information to complete its review of the GL. Attachments 1 through 10 provide the EGC and AmerGen responses to the requested information for the applicable plants.

Some of the questions in this request seek information about analyses, procedures, and activities concerning grid reliability. This information was provided by a third party and is outside the control of EGC and AmerGen. As such, the accuracy and completeness of this information cannot be validated by EGC and AmerGen.

Certain values (e.g., voltages) documented in this response were obtained from current calculations of record and are subject to change as calculations may be revised to address specific plant configuration changes or changes to the analysis methodologies.

There are no regulatory commitments contained in this letter. Should you have any questions concerning this letter, please contact Ms. Alison Mackellar at (630) 657-2817.

I declare under penalty of perjury that the foregoing is true and correct. Executed on the 31st day of January 2007.

Respectfully,

Keith R. Jury

Keith R. Jury
Director - Licensing and Regulatory Affairs
Exelon Generation Company, LLC
AmerGen Energy Company, LLC

Attachment 1: Response to RAI related to GL 2006-02, Braidwood Station

Attachment 2: Response to RAI related to GL 2006-02, Byron Station

Attachment 3: Response to RAI related to GL 2006-02, Clinton Power Station

Attachment 4: Response to RAI related to GL 2006-02, Dresden Nuclear Power Station

Attachment 5: Response to RAI related to GL 2006-02, LaSalle County Station

Attachment 6: Response to RAI related to GL 2006-02, Limerick Generating Station

Attachment 7: Response to RAI related to GL 2006-02, Oyster Creek Generating Station

Attachment 8: Response to RAI related to GL 2006-02, Peach Bottom Atomic Power Station

Attachment 9: Response to RAI related to GL 2006-02, Quad Cities Nuclear Power Station

Attachment 10: Response to RAI related to GL 2006-02, Three Mile Island Nuclear Station Unit 1

cc: Regional Administrator - NRC Region I
Regional Administrator - NRC Region III
NRC Project Manager, NRR - Braidwood Station
NRC Project Manager, NRR - Byron Station
NRC Project Manager, NRR - Clinton Power Station
NRC Project Manager, NRR - Dresden Nuclear Power Station
NRC Project Manager, NRR - LaSalle County Station
NRC Project Manager, NRR - Limerick Generating Station
NRC Project Manager, NRR - Oyster Creek Generating Station
NRC Project Manager, NRR - Peach Bottom Atomic Power Station
NRC Project Manager, NRR - Quad Cities Nuclear Power Station
NRC Project Manager, NRR - Three Mile Island Nuclear Station Unit 1
NRC Senior Resident Inspector - Braidwood Station
NRC Senior Resident Inspector - Byron Station
NRC Senior Resident Inspector - Clinton Power Station
NRC Senior Resident Inspector - Dresden Nuclear Power Station
NRC Senior Resident Inspector - LaSalle County Station
NRC Senior Resident Inspector - Limerick Generating Station
NRC Senior Resident Inspector - Oyster Creek Generating Station
NRC Senior Resident Inspector - Peach Bottom Atomic Power Station
NRC Senior Resident Inspector - Three Mile Island Nuclear Station Unit 1
NRC Senior Resident Inspector - Quad Cities Nuclear Power Station
Illinois Emergency Management Agency - Division of Nuclear Safety
Director, Bureau of Radiation Protection - Pennsylvania Department of Environmental Resources
Director, Bureau of Nuclear Engineering, New Jersey Department of Environmental Protection
Chairman, Board of County Commissioners of Dauphin County, PA
Chairman, Board of Supervisors of Londonderry Township, PA
Mayor of Lacey Township, Forked River, NJ
R. I. McLean, State of Maryland
R. R. Janati, Commonwealth of Pennsylvania

ATTACHMENT 1

Response to Request for Additional Information
Related to GL 2006-02

BRAIDWOOD STATION, Units 1 and 2

Facility Operating License Nos. NPF-72 and NPF-77

ATTACHMENT 1
Response to Request for Additional Information
Related to GL 2006-02
BRAIDWOOD STATION, Units 1 and 2

As stated in Reference 2, Braidwood Station is located in the service territory of PJM Interconnection, LLC (PJM). PJM is the Transmission System Operator (TSO) for Braidwood Station. The Transmission Owner (TO) providing interconnection services for Braidwood Station is Commonwealth Edison Company (ComEd). Exelon Generation Company, LLC (EGC) and ComEd are both members of PJM. As requested in Reference 3, only questions 4, 5, and 6 apply to Braidwood Station.

Offsite Power Operability

Question No. 4

Identification of Applicable Single Contingencies

In response to question 3(a) you did not identify the loss of other critical transmission elements that may cause the offsite power system (OSP) to degrade, other than the loss of the nuclear unit. If it is possible for specific critical transmission elements (such as other generators, critical transmission line, transformers, capacitor banks, voltage regulators, etc.) to degrade the OSP such that inadequate post-trip voltage could result, have these elements been included in your N-1 contingency analysis? When these elements are included in your GO's contingency analysis model and failure of one of these transmission elements could result in actuation of your degraded voltage grid relay, is the offsite power declared inoperable? If not, what is your basis for not declaring the offsite power inoperable?

Response

Critical transmission elements are included in both the transmission studies and the real time contingency analysis used for predicting switchyard voltage. The N-1 contingency analysis is performed by the TSO (i.e., PJM).

As stated in Reference 2, predicted contingency voltages following the loss of a transmission facility other than the nuclear unit (e.g., the loss of the most critical transmission line or the largest supply to the grid) are not used as the basis for offsite source operability determinations.

Nuclear units (i.e., Braidwood Station Units 1 and 2) are reviewed for anticipated operational occurrences and postulated accidents. Various anticipated plant process disturbances, equipment malfunctions, potential operator actions or errors and component failures are examined to evaluate the nuclear unit's capability to control or accommodate these failures and malfunctions. The Braidwood Station UFSAR, Section 15 describes the plant's response to these anticipated operational occurrences and postulated accidents. Since several of these operational transients and postulated accidents could result in a unit trip following the event, the effects of post trip contingency voltages resulting from the tripping of the unit need to be addressed in the operability determinations of the offsite power sources. None of the operational transients or postulated accidents can be shown to cause the loss of other specific critical transmission elements. Since there is no identified causality associated with the design basis anticipated operational occurrences and postulated accidents and the loss of other transmission elements, there is no operational basis to consider the offsite sources inoperable based solely upon a transmission element post trip contingency voltage value.

Up until the time that a transmission system contingency (e.g., loss of a non nuclear unit) were to occur, the offsite power systems would be in compliance with the requirements of General Design Criterion (GDC) 17, "Electrical power systems," of 10 CFR Part 50 Appendix A, "General Design Criteria for Nuclear Power Plants." The offsite power system would provide sufficient capacity and capability to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary were not exceeded as a result of anticipated operational occurrences, and the core was cooled and containment integrity and other vital functions were maintained in the event of postulated accidents.

Maintenance Rule

Question No. 5

Seasonal Variation in Grid Stress (Reliability and Loss-of-offsite Power (LOOP) Probability)

Certain regions during certain times of the year (seasonal variations) experience higher grid stress as indicated in Electrical Power Research Institute (EPRI) Report 1011759, Table 4-7, Grid LOOP Adjustment Factor, and NRC NUREG/CR-6890. Do you adjust the base LOOP frequency in your probabilistic risk assessment (PRA) and Maintenance Rule evaluations for various seasons? If you do not consider seasonal variations in base LOOP frequency in your PRA and Maintenance Rule evaluations, explain why it is acceptable not to do so.

Response

The Braidwood Station base probabilistic risk assessment (PRA) represents an annual estimate of core damage frequency (CDF). As such, there is no seasonal variation included in the base PRA. The annual average Loss of Offsite Power (LOOP) frequency is the appropriate parameter to use for the base PRA calculation of an annual average CDF.

As stated in the response to Question 5(c) submitted in Reference 2, PJM provided the following information to EGC regarding stress on the grid in a letter from PJM to all PJM nuclear owners (i.e., Reference 4):

> "Stress on the grid is manifested in a number of ways. Stress can represent the loading levels on individual facilities, overall demand levels, the degree of facilities out of service for maintenance, occurrence of severe weather, etc. Each aspect creates a level of stress on the grid and challenges for the system operators."

Braidwood Station has an on-line risk management program consistent with 10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants," (i.e., the Maintenance Rule) and focused on the risk impact of the plant configuration, the grid integrity, and environmental conditions at the time of the on-line work window. Assessment of risk on the basis of current, rather than average, or adjusted average, plant configuration, weather, and grid conditions is judged to be the most appropriate input to safe, risk-informed work control and is therefore the most appropriate technical approach for managing risk.

The EGC method of on-line maintenance risk management uses a blended approach of quantitative and qualitative analyses. Due to substantial uncertainties in the factors that

contribute to grid stress and their impacts at any given time, a seasonal quantitative adjustment in the LOOP frequency is not used. Rather, to account for the configuration specific effects of degraded grid conditions or adverse environmental conditions, a qualitative "high risk evolution" override process is included that both provides awareness of the condition and triggers compensatory measures or procedural limitations on the on-line work as appropriate. One of the noted strengths of the EGC approach to configuration risk management is that it does not require a set "number" to trigger actions. It is a risk-informed approach that considers risk calculations, defense-in-depth, and other qualitative inputs such as grid conditions.

The seasonal LOOP frequency adjustment approach, as suggested in EPRI technical report TR1011759, "Frequency Determination Method for Cascading Grid Events," (i.e., Reference 5) has been reviewed by EGC; however, the particular implementation and conclusions in Reference 5 are not considered appropriate because of the following:

- The approach may actually underestimate the specific conditions that exist during the work-week for non-peak seasons (e.g., low grid margin or severe weather).
- The approach is not risk-informed in that it may result in the unnecessary deferral of some work that could have been performed during the "higher LOOP frequency season" but for the arbitrary global assignment of higher risk of LOOP.

The concept that the grid is "seasonal" in susceptibility to stress is in essence a different form of averaging over a shorter time interval. Even during the summer months, when there are periods of time when the grid is highly stressed there are also long periods where it is less stressed. Given this, the actual likelihood of high grid stress could vary substantially, even within a season. Attempting to reflect this concept through a quantitative "seasonal-average" approach could actually over-estimate risk during lower stress periods, or under-estimate it during high stress periods.

To address factors that could affect the likelihood of a LOOP, at any time during the year, the EGC work management procedure, WC-AA-101, "On-Line Work Control Process," (i.e., Reference 6) incorporates such measures as:

- Evaluation of maintenance activities based upon conditions, such as current power grid stability information from the system operator, the weather forecast (including information obtained from day ahead forecasts), and the current plant system and component (SSC) status. If severe weather (e.g., high wind, severe thunderstorm warning, tornado watch/warning) or conditions that are potential high risk evolutions (HREs) for loss of offsite power are expected, then planned unavailability of electrical power sources is deferred.

- Declaring an HRE, and appropriately managing the plant configuration, when such conditions as the following exist or are predicted to occur:

    - Unexpected repeated station power line trips due to area environmental conditions such as icing, wind, or storms.
    - Sustained winds above the site sustained high winds procedure entry level.
    - Declaration by the TSO of a maximum emergency generation action.

- Actual switchyard voltage alarms or notifications indicating voltage below that required for offsite source Technical Specification operability limits.
- Predicted unit trip contingency switchyard voltage below minimum required switchyard voltage.
- Notification that at the current time a condition exists such that if a transmission line or other transmission facility were to trip, then the site would be below voltage operability limits.

- Restoring availability, as soon as possible, of systems required to mitigate the loss of offsite power if an offsite power source becomes unavailable or degraded, or if the risk of losing offsite power significantly increases due to severe weather.

The EGC on-line risk management program focuses on identifying compensatory measures to cope with potential grid stress conditions, regardless of season, to support effective risk management given the current conditions within a work week window. In addition, EGC augments the on-line risk management process with guidelines that specify the planning of switchyard on-line maintenance to avoid scheduling such activities during the summer period, when peak generation periods normally occur.

The above risk-informed process ensures that potential impacts of variations in factors affecting grid reliability are evaluated on a continuing basis throughout the year and that appropriate risk management actions are taken when necessary.

<u>Question No. 6</u>

<u>Interface With Transmission System Operator During Extended Plant Maintenance</u>

How do you interface with your GO when on-going maintenance at the nuclear power plant, that has been previously coordinated with your GO for a definite time frame, gets extended past that planned time frame?

<u>Response</u>

As stated in the response to Question 6(e) in Reference 2, planned transmission outages are coordinated in accordance with a process detailed in PJM Manual 03, "Transmission Operations," Section 4 (i.e., Reference 7). This process requires advanced notice and subsequent PJM approval for all outages to ensure grid reliability. Once the equipment is switched out of service, grid status is continually monitored and evaluated by both the TO and the TSO.

The nuclear power plant (NPP) (i.e., Braidwood Station) coordinates maintenance activities that can have an impact on the transmission system with the TSO/TO. EGC formal interface procedure, WC-AA-8000, "Interface Procedure between Exelon Energy Delivery (ComEd/PECO) and Exelon Generation (Nuclear/Power) for Construction and Maintenance Activities," (i.e., Reference 8) specifies that scheduled plant equipment outages that may restrict transmission system configuration changes or outages (e.g., scheduled diesel generator outages) should be communicated and coordinated between the EGC Nuclear Duty Officer (NDO) and the TSO/TO.

In addition, EGC will clarify and enhance procedure(s) (e.g., WC-AA-8000) to specify that any extension to equipment outages or maintenance activities that could have mutual impact are appropriately communicated to the TSO/TO. These actions have been entered into the EGC Corrective Action Program.

References

1. Letter from Christopher Grimes (U.S. NRC) to Addressees, "NRC Generic Letter 2006-02: Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated February 1, 2006

2. Letter from K. R. Jury (Exelon Generation Company, LLC/AmerGen Energy Company, LLC) to U.S. NRC, "EGC/AmerGen 60-Day Response to NRC Generic Letter 2006-02: Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated April 3, 2006

3. Letter from C. Haney (U.S. NRC) to Addressees, "Request for Additional Information Regarding Resolution of Generic Letter 2006-02, Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated December 5, 2006

4. Letter from F. J. Koza (PJM Interconnection, LLC) to PJM nuclear owners, "PJM Information to Support Utilities Response to Generic Letter 2006-02, 'Grid Reliability and the Impact on Plant Risk and Operability of Offsite Power, dated February 1, 2006,'" dated February 23, 2006

5. EPRI Report 1011759, "Frequency Determination Method for Cascading Grid Events," dated December, 2005

6. EGC procedure WC-AA-101, "On-Line Work Control Process," Revision 13

7. PJM Manual 03, "Transmission Operations," Revision 22, effective October 25, 2006

8. EGC procedure WC-AA-8000, "Interface Procedure between Exelon Energy Delivery (ComEd/PECO) and Exelon Generation (Nuclear/Power) for Construction and Maintenance Activities," Revision 1

ATTACHMENT 2

Response to Request for Additional Information
Related to GL 2006-02

BYRON STATION, Units 1 and 2

Facility Operating License Nos. NPF-37 and NPF-66

ATTACHMENT 2
Response to Request for Additional Information
Related to GL 2006-02
BYRON STATION, Units 1 and 2

As stated in Reference 2, Byron Station is located in the service territory of PJM Interconnection, LLC (PJM). PJM is the Transmission System Operator (TSO) for Byron Station. The Transmission Owner (TO) providing interconnection services for Byron Station is Commonwealth Edison Company (ComEd). Exelon Generation Company, LLC (EGC) and ComEd are both members of PJM. As requested in Reference 3, only questions 4, 5, and 6 apply to Byron Station.

Offsite Power Operability

Question No. 4

Identification of Applicable Single Contingencies

In response to question 3(a) you did not identify the loss of other critical transmission elements that may cause the offsite power system (OSP) to degrade, other than the loss of the nuclear unit. If it is possible for specific critical transmission elements (such as other generators, critical transmission line, transformers, capacitor banks, voltage regulators, etc.) to degrade the OSP such that inadequate post-trip voltage could result, have these elements been included in your N-1 contingency analysis? When these elements are included in your GO's contingency analysis model and failure of one of these transmission elements could result in actuation of your degraded voltage grid relay, is the offsite power declared inoperable? If not, what is your basis for not declaring the offsite power inoperable?

Response

Critical transmission elements are included in both the transmission studies and the real time contingency analysis used for predicting switchyard voltage. The N-1 contingency analysis is performed by the TSO (i.e., PJM).

As stated in Reference 2, predicted contingency voltages following the loss of a transmission facility other than the nuclear unit (e.g., the loss of the most critical transmission line or the largest supply to the grid) are not used as the basis for offsite source operability determinations.

Nuclear units (i.e., Byron Station Units 1 and 2) are reviewed for anticipated operational occurrences and postulated accidents. Various anticipated plant process disturbances, equipment malfunctions, potential operator actions or errors and component failures are examined to evaluate the nuclear unit's capability to control or accommodate these failures and malfunctions. The Byron UFSAR, Section 15 describes the plant's response to these anticipated operational occurrences and postulated accidents. Since several of these operational transients and postulated accidents could result in a unit trip following the event, the effects of post trip contingency voltages resulting from the tripping of the unit need to be addressed in the operability determinations of the offsite power sources. None of the operational transients or postulated accidents can be shown to cause the loss of other specific critical transmission elements. Since there is no identified causality associated with the design basis anticipated operational occurrences and postulated accidents and the loss of other transmission elements, there is no operational basis to consider the offsite sources inoperable based solely upon a transmission element post trip contingency voltage value.

Up until the time that a transmission system contingency (e.g., loss of a non nuclear unit) were to occur, the offsite power systems would be in compliance with the requirements of General Design Criterion (GDC) 17, "Electrical power systems," of 10 CFR Part 50 Appendix A, "General Design Criteria for Nuclear Power Plants." The offsite power system would provide sufficient capacity and capability to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary were not exceeded as a result of anticipated operational occurrences, and the core was cooled and containment integrity and other vital functions were maintained in the event of postulated accidents.

Maintenance Rule

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Response

The Byron Station base probabilistic risk assessment (PRA) represents an annual estimate of core damage frequency (CDF). As such, there is no seasonal variation included in the base PRA. The annual average Loss of Offsite Power (LOOP) frequency is the appropriate parameter to use for the base PRA calculation of an annual average CDF.

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> "Stress on the grid is manifested in a number of ways. Stress can represent the loading levels on individual facilities, overall demand levels, the degree of facilities out of service for maintenance, occurrence of severe weather, etc. Each aspect creates a level of stress on the grid and challenges for the system operators."

Byron Station has an on-line risk management program consistent with 10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants," (i.e., the Maintenance Rule) and focused on the risk impact of the plant configuration, the grid integrity, and environmental conditions at the time of the on-line work window. Assessment of risk on the basis of current, rather than average, or adjusted average, plant configuration, weather, and grid conditions is judged to be the most appropriate input to safe, risk-informed work control and is therefore the most appropriate technical approach for managing risk.

The EGC method of on-line maintenance risk management uses a blended approach of quantitative and qualitative analyses. Due to substantial uncertainties in the factors that

contribute to grid stress and their impacts at any given time, a seasonal quantitative adjustment in the LOOP frequency is not used. Rather, to account for the configuration specific effects of degraded grid conditions or adverse environmental conditions, a qualitative "high risk evolution" override process is included that both provides awareness of the condition and triggers compensatory measures or procedural limitations on the on-line work as appropriate. One of the noted strengths of the EGC approach to configuration risk management is that it does not require a set "number" to trigger actions. It is a risk-informed approach that considers risk calculations, defense-in-depth, and other qualitative inputs such as grid conditions.

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The above risk-informed process ensures that potential impacts of variations in factors affecting grid reliability are evaluated on a continuing basis throughout the year and that appropriate risk management actions are taken when necessary.

Question No. 6

Interface With Transmission System Operator During Extended Plant Maintenance

How do you interface with your GO when on-going maintenance at the nuclear power plant, that has been previously coordinated with your GO for a definite time frame, gets extended past that planned time frame?

Response

As stated in the response to Question 6(e) in Reference 2, planned transmission outages are coordinated in accordance with a process detailed in PJM Manual 03, "Transmission Operations," Section 4 (i.e., Reference 7). This process requires advanced notice and subsequent PJM approval for all outages to ensure grid reliability. Once the equipment is switched out of service, grid status is continually monitored and evaluated by both the TO and the TSO.

The nuclear power plant (NPP) (i.e., Byron Station) coordinates maintenance activities that can have an impact on the transmission system with the TSO/TO. EGC formal interface procedure, WC-AA-8000, "Interface Procedure between Exelon Energy Delivery (ComEd/PECO) and Exelon Generation (Nuclear/Power) for Construction and Maintenance Activities," (i.e., Reference 8) specifies that scheduled plant equipment outages that may restrict transmission system configuration changes or outages (e.g., scheduled diesel generator outages) should be communicated and coordinated between the EGC Nuclear Duty Officer (NDO) and the TSO/TO.

In addition, EGC will clarify and enhance procedure(s) (e.g., WC-AA-8000) to specify that any extension to equipment outages or maintenance activities that could have mutual impact are appropriately communicated to the TSO/TO. These actions have been entered into the EGC Corrective Action Program.

References

1. Letter from Christopher Grimes (U.S. NRC) to Addressees, "NRC Generic Letter 2006-02: Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated February 1, 2006

2. Letter from K. R. Jury (Exelon Generation Company, LLC/AmerGen Energy Company, LLC) to U.S. NRC, "EGC/AmerGen 60-Day Response to NRC Generic Letter 2006-02: Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated April 3, 2006

3. Letter from C. Haney (U.S. NRC) to Addressees, "Request for Additional Information Regarding Resolution of Generic Letter 2006-02, Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated December 5, 2006

4. Letter from F. J. Koza (PJM Interconnection, LLC) to PJM nuclear owners, "PJM Information to Support Utilities Response to Generic Letter 2006-02, 'Grid Reliability and the Impact on Plant Risk and Operability of Offsite Power, dated February 1, 2006,'" dated February 23, 2006

5. EPRI Report 1011759, "Frequency Determination Method for Cascading Grid Events," dated December, 2005

6. EGC procedure WC-AA-101, "On-Line Work Control Process," Revision 13

7. PJM Manual 03, "Transmission Operations," Revision 22, effective October 25, 2006

8. EGC procedure WC-AA-8000, "Interface Procedure between Exelon Energy Delivery (ComEd/PECO) and Exelon Generation (Nuclear/Power) for Construction and Maintenance Activities," Revision 1

ATTACHMENT 3

Response to Request for Additional Information
Related to GL 2006-02

CLINTON POWER STATION, Unit 1

Facility Operating License No. NPF-62

ATTACHMENT 3
Response to Request for Additional Information
Related to GL 2006-02
CLINTON POWER STATION

Clinton Power Station (CPS) has entered into a Nuclear Plant Operating Agreement (NPOA) with AmerenIP and the Midwest Independent Transmission System Operator (Midwest ISO), (i.e., Reference 7). AmerenIP is the Transmission System Owner/Operator (TSO) for CPS and provides interconnection services for CPS. Midwest ISO is the Transmission Provider and Reliability Coordinator. As requested in Reference 3, only questions 4, 5, and 6 apply to CPS.

Offsite Power Operability

Question No. 4

Identification of Applicable Single Contingencies

In response to question 3(a) you did not identify the loss of other critical transmission elements that may cause the offsite power system (OSP) to degrade, other than the loss of the nuclear unit. If it is possible for specific critical transmission elements (such as other generators, critical transmission line, transformers, capacitor banks, voltage regulators, etc.) to degrade the OSP such that inadequate post-trip voltage could result, have these elements been included in your N-1 contingency analysis? When these elements are included in your GO's contingency analysis model and failure of one of these transmission elements could result in actuation of your degraded voltage grid relay, is the offsite power declared inoperable? If not, what is your basis for not declaring the offsite power inoperable?

Response

Critical transmission elements are included in both the transmission studies and the real time contingency analysis used for predicting switchyard voltage. The N-1 contingency analysis is performed by the TSO (i.e., AmerenIP).

As stated in Reference 2, predicted contingency voltages following the loss of a transmission facility other than the nuclear unit (e.g., the loss of the most critical transmission line or the largest supply to the grid) are not used as the basis for offsite source operability determinations.

Nuclear units (i.e., CPS) are reviewed for anticipated operational occurrences and postulated accidents. Various anticipated plant process disturbances, equipment malfunctions, potential operator actions or errors and component failures are examined to evaluate the nuclear unit's capability to control or accommodate these failures and malfunctions. The CPS USAR Chapter 15, "Accident Analysis," describe the plant's response to these anticipated operational occurrences and postulated accidents. Since several of these operational transients and postulated accidents could result in a unit trip following the event, the effects of post trip contingency voltages resulting from the tripping of the unit need to be addressed in the operability determinations of the offsite power sources. None of the operational transients or postulated accidents can be shown to cause the loss of other specific critical transmission elements. Since there is no identified causality associated with the design basis anticipated operational occurrences and postulated accidents and the loss of other transmission elements, there is no operational basis to consider the offsite sources inoperable based solely upon a transmission element post trip contingency voltage value.

Up until the time that a transmission system contingency (e.g., loss of a non nuclear unit) were to occur, the offsite power systems would be in compliance with the requirements of General

Design Criterion (GDC) 17, "Electrical power systems," of 10 CFR Part 50 Appendix A, "General Design Criteria for Nuclear Power Plants." The offsite power system would provide sufficient capacity and capability to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary were not exceeded as a result of anticipated operational occurrences, and the core was cooled and containment integrity and other vital functions were maintained in the event of postulated accidents.

Maintenance Rule

Question No. 5

Seasonal Variation in Grid Stress (Reliability and Loss-of-offsite Power (LOOP) Probability)

Certain regions during certain times of the year (seasonal variations) experience higher grid stress as indicated in Electrical Power Research Institute (EPRI) Report 1011759, Table 4-7, Grid LOOP Adjustment Factor, and NRC NUREG/CR-6890. Do you adjust the base LOOP frequency in your probabilistic risk assessment (PRA) and Maintenance Rule evaluations for various seasons? If you do not consider seasonal variations in base LOOP frequency in your PRA and Maintenance Rule evaluations, explain why it is acceptable not to do so.

Response

The CPS base probabilistic risk assessment (PRA) represents an annual estimate of core damage frequency (CDF). As such, there is no seasonal variation included in the base PRA. The annual average Loss of Offsite Power (LOOP) frequency is the appropriate parameter to use for the base PRA calculation of an annual average CDF.

CPS has an on-line risk management program consistent with 10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants," (i.e., the Maintenance Rule) and focused on the risk impact of the plant configuration, the grid integrity, and environmental conditions at the time of the on-line work window. Assessment of risk on the basis of current, rather than average, or adjusted average, plant configuration, weather, and grid conditions is judged to be the most appropriate input to safe, risk-informed work control and is therefore the most appropriate technical approach for managing risk.

The AmerGen method of on-line maintenance risk management uses a blended approach of quantitative and qualitative analyses. Due to substantial uncertainties in the factors that contribute to grid stress and their impacts at any given time, a seasonal quantitative adjustment in the LOOP frequency is not used. Rather, to account for the configuration specific effects of degraded grid conditions or adverse environmental conditions, a qualitative "high risk evolution" override process is included that both provides awareness of the condition and triggers compensatory measures or procedural limitations on the on-line work as appropriate. One of the noted strengths of the AmerGen approach to configuration risk management is that it does not require a set "number" to trigger actions. It is a risk-informed approach that considers risk calculations, defense-in-depth, and other qualitative inputs such as grid conditions.

The seasonal LOOP frequency adjustment approach, as suggested in EPRI technical report TR1011759, "Frequency Determination Method for Cascading Grid Events," (i.e., Reference 4) has been reviewed by AmerGen; however, the particular implementation and conclusions in Reference 4 are not considered appropriate because of the following:

- The approach may actually underestimate the specific conditions that exist during the work-week for non-peak seasons (e.g., low grid margin or severe weather).
- The approach is not risk-informed in that it may result in the unnecessary deferral of some work that could have been performed during the "higher LOOP frequency season" but for the arbitrary global assignment of higher risk of LOOP.

The concept that the grid is "seasonal" in susceptibility to stress is in essence a different form of averaging over a shorter time interval. Even during the summer months, when there are periods of time when the grid is highly stressed there are also long periods where it is less stressed. Given this, the actual likelihood of high grid stress could vary substantially, even within a season. Attempting to reflect this concept through a quantitative "seasonal-average" approach could actually over-estimate risk during lower stress periods, or under-estimate it during high stress periods.

To address factors that could affect the likelihood of a LOOP, at any time during the year, the Exelon Generation Company, LLC (EGC) work management procedure, WC-AA-101, "On-Line Work Control Process," (i.e., Reference 5) is applicable to CPS and incorporates such measures as:

- Evaluation of maintenance activities based upon conditions, such as current power grid stability information from the system operator, the weather forecast (including information obtained from day ahead forecasts), and the current plant system and component (SSC) status. If severe weather (e.g., high wind, severe thunderstorm warning, tornado watch/warning) or conditions that are potential high risk evolutions (HREs) for loss of offsite power are expected, then planned unavailability of electrical power sources is deferred.

- Declaring an HRE, and appropriately managing the plant configuration, when such conditions as the following exist or are predicted to occur:

    - Unexpected repeated station power line trips due to area environmental conditions such as icing, wind, or storms.
    - Sustained winds above the site sustained high winds procedure entry level.
    - Declaration by the TSO of a maximum emergency generation action.
    - Actual switchyard voltage alarms or notifications indicating voltage below that required for offsite source Technical Specification operability limits.
    - Predicted unit trip contingency switchyard voltage below minimum required switchyard voltage.
    - Notification that at the current time a condition exists such that if a transmission line or other transmission facility were to trip, then the site would be below voltage operability limits.

- Restoring availability, as soon as possible, of systems required to mitigate the loss of offsite power if an offsite power source becomes unavailable or degraded, or if the risk of losing offsite power significantly increases due to severe weather.

The AmerGen on-line risk management program focuses on identifying compensatory measures to cope with potential grid stress conditions, regardless of season, to support effective risk management given the current conditions within a work week window. In addition, AmerGen augments the on-line risk management process with guidelines that specify the planning of switchyard on-line maintenance to avoid scheduling such activities during the summer period, when peak generation periods normally occur.

The above risk-informed process ensures that potential impacts of variations in factors affecting grid reliability are evaluated on a continuing basis throughout the year and that appropriate risk management actions are taken when necessary.

Question No. 6

Interface With Transmission System Operator During Extended Plant Maintenance

How do you interface with your GO when on-going maintenance at the nuclear power plant, that has been previously coordinated with your GO for a definite time frame, gets extended past that planned time frame?

Response

As stated in the response to Question 6(e) in Reference 2, planned transmission outages are coordinated through Midwest ISO and their governing procedures. The process requires advanced notice and subsequent Midwest ISO approval for all outages to ensure grid reliability. On the outage start day; Midwest ISO analyzes the system again before permitting the equipment to be switched out of service.

The nuclear power plant (NPP) (i.e., CPS) coordinates maintenance activities that can have an impact on the transmission system with the TSO/TO. Coordination of maintenance activities is discussed in article 5 of the Interconnection Agreement between CPS and AmerenIP (i.e., Reference 7)

In addition, AmerGen will clarify and enhance procedure(s) (e.g., OP-CL-108-107-1001, "Interface Between AmerenIP and Clinton Power Station for Switchyard Operations and Maintenance," (i.e., Reference 6)) to specify that any extension to equipment outages or maintenance activities that could have mutual impact are appropriately communicated to the TSO/TO. These actions have been entered into the EGC Corrective Action Program and are applicable to CPS.

References

1. Letter from Christopher Grimes (U.S. NRC) to Addressees, "NRC Generic Letter 2006-02: Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated February 1, 2006

2. Letter from K. R. Jury (Exelon Generation Company, LLC/AmerGen Energy Company, LLC) to U.S. NRC, "EGC/AmerGen 60-Day Response to NRC Generic Letter 2006-02: Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated April 3, 2006

3. Letter from C. Haney (U.S. NRC) to Addressees, "Request for Additional Information Regarding Resolution of Generic Letter 2006-02, Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated December 5, 2006

4. EPRI Report 1011759, "Frequency Determination Method for Cascading Grid Events," dated December, 2005

5. EGC procedure WC-AA-101, "On-Line Work Control Process," Revision 13

6. OP-CL-108-107-1001, "Interface Between AmerenIP and Clinton Power Station for Switchyard Operations and Maintenance," Revision 5

7. "Nuclear Plant Operating Agreement for Clinton Power Station," between Midwest Independent Transmission System Operator, Inc., AmerGen Energy Company, LLC, and Illinois Power Company, d/b/a AmerenIP, dated February 24, 2006

8. First Revised Interconnection Agreement by and among AmerGen Energy Company, LLC, and Illinois Power Company for the Clinton Power Station," revised February 15, 2002

ATTACHMENT 4

Response to Request for Additional Information
Related to GL 2006-02

DRESDEN NUCLEAR POWER STATION, Units 2 and 3

Renewed Facility Operating License Nos. DPR-19 and DPR-25

ATTACHMENT 4
Response to Request for Additional Information
Related to GL 2006-02
DRESDEN NUCLEAR POWER STATION, Units 2 and 3

As stated in Reference 2, Dresden Nuclear Power Station (DNPS) is located in the service territory of PJM Interconnection, LLC (PJM). PJM is the Transmission System Operator (TSO) for DNPS. The Transmission Owner (TO) providing interconnection services for DNPS is Commonwealth Edison Company (ComEd). Exelon Generation Company, LLC (EGC) and ComEd are both members of PJM. As requested in Reference 3, only questions 4, 5, and 6 apply to DNPS.

Offsite Power Operability

Question No. 4

Identification of Applicable Single Contingencies

In response to question 3(a) you did not identify the loss of other critical transmission elements that may cause the offsite power system (OSP) to degrade, other than the loss of the nuclear unit. If it is possible for specific critical transmission elements (such as other generators, critical transmission line, transformers, capacitor banks, voltage regulators, etc.) to degrade the OSP such that inadequate post-trip voltage could result, have these elements been included in your N-1 contingency analysis? When these elements are included in your GO's contingency analysis model and failure of one of these transmission elements could result in actuation of your degraded voltage grid relay, is the offsite power declared inoperable? If not, what is your basis for not declaring the offsite power inoperable?

Response

Critical transmission elements are included in both the transmission studies and the real time contingency analysis used for predicting switchyard voltage. The N-1 contingency analysis is performed by the TSO (i.e., PJM).

As stated in Reference 2, predicted contingency voltages following the loss of a transmission facility other than the nuclear unit (e.g., the loss of the most critical transmission line or the largest supply to the grid) are not used as the basis for offsite source operability determinations.

Nuclear units (i.e., DNPS Units 2 and 3) are reviewed for anticipated operational occurrences and postulated accidents. Various anticipated plant process disturbances, equipment malfunctions, potential operator actions or errors and component failures are examined to evaluate the nuclear unit's capability to control or accommodate these failures and malfunctions. The DNPS UFSAR, Chapter 15, "Accident and Transient Analysis," describes the plant's response to these anticipated operational occurrences and postulated accidents. Since several of these operational transients and postulated accidents could result in a unit trip following the event, the effects of post trip contingency voltages resulting from the tripping of the unit need to be addressed in the operability determinations of the offsite power sources. None of the operational transients or postulated accidents can be shown to cause the loss of other specific critical transmission elements. Since there is no identified causality associated with the design basis anticipated operational occurrences and postulated accidents and the loss of other transmission elements, there is no operational basis to consider the offsite sources inoperable based solely upon a transmission element post trip contingency voltage value.

Up until the time that a transmission system contingency (e.g., loss of a non nuclear unit) were to occur, the offsite power systems would be in compliance with the requirements of General Design Criterion (GDC) 17, "Electrical power systems," of 10 CFR Part 50 Appendix A, "General Design Criteria for Nuclear Power Plants." The offsite power system would provide sufficient capacity and capability to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary were not exceeded as a result of anticipated operational occurrences, and the core was cooled and containment integrity and other vital functions were maintained in the event of postulated accidents.

Maintenance Rule

Question No. 5

Seasonal Variation in Grid Stress (Reliability and Loss-of-offsite Power (LOOP) Probability)

Certain regions during certain times of the year (seasonal variations) experience higher grid stress as indicated in Electrical Power Research Institute (EPRI) Report 1011759, Table 4-7, Grid LOOP Adjustment Factor, and NRC NUREG/CR-6890. Do you adjust the base LOOP frequency in your probabilistic risk assessment (PRA) and Maintenance Rule evaluations for various seasons? If you do not consider seasonal variations in base LOOP frequency in your PRA and Maintenance Rule evaluations, explain why it is acceptable not to do so.

Response

The DNPS base probabilistic risk assessment (PRA) represents an annual estimate of core damage frequency (CDF). As such, there is no seasonal variation included in the base PRA. The annual average Loss of Offsite Power (LOOP) frequency is the appropriate parameter to use for the base PRA calculation of an annual average CDF.

As stated in the response to Question 5(c) submitted in Reference 2, PJM provided the following information to EGC regarding stress on the grid in a letter from PJM to all PJM nuclear owners (i.e., Reference 4):

> "Stress on the grid is manifested in a number of ways. Stress can represent the loading levels on individual facilities, overall demand levels, the degree of facilities out of service for maintenance, occurrence of severe weather, etc. Each aspect creates a level of stress on the grid and challenges for the system operators."

DNPS has an on-line risk management program consistent with 10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants," (i.e., the Maintenance Rule) and focused on the risk impact of the plant configuration, the grid integrity, and environmental conditions at the time of the on-line work window. Assessment of risk on the basis of current, rather than average, or adjusted average, plant configuration, weather, and grid conditions is judged to be the most appropriate input to safe, risk-informed work control and is therefore the most appropriate technical approach for managing risk.

The EGC method of on-line maintenance risk management uses a blended approach of quantitative and qualitative analyses. Due to substantial uncertainties in the factors that

contribute to grid stress and their impacts at any given time, a seasonal quantitative adjustment in the LOOP frequency is not used. Rather, to account for the configuration specific effects of degraded grid conditions or adverse environmental conditions, a qualitative "high risk evolution" override process is included that both provides awareness of the condition and triggers compensatory measures or procedural limitations on the on-line work as appropriate. One of the noted strengths of the EGC approach to configuration risk management is that it does not require a set "number" to trigger actions. It is a risk-informed approach that considers risk calculations, defense-in-depth, and other qualitative inputs such as grid conditions.

The seasonal LOOP frequency adjustment approach, as suggested in EPRI technical report TR1011759, "Frequency Determination Method for Cascading Grid Events," (i.e., Reference 5) has been reviewed by EGC; however, the particular implementation and conclusions in Reference 5 are not considered appropriate because of the following:

- The approach may actually underestimate the specific conditions that exist during the work-week for non-peak seasons (e.g., low grid margin or severe weather).
- The approach is not risk-informed in that it may result in the unnecessary deferral of some work that could have been performed during the "higher LOOP frequency season" but for the arbitrary global assignment of higher risk of LOOP.

The concept that the grid is "seasonal" in susceptibility to stress is in essence a different form of averaging over a shorter time interval. Even during the summer months, when there are periods of time when the grid is highly stressed there are also long periods where it is less stressed. Given this, the actual likelihood of high grid stress could vary substantially, even within a season. Attempting to reflect this concept through a quantitative "seasonal-average" approach could actually over-estimate risk during lower stress periods, or under-estimate it during high stress periods.

To address factors that could affect the likelihood of a LOOP, at any time during the year, the EGC work management procedure, WC-AA-101, "On-Line Work Control Process," (i.e., Reference 6) incorporates such measures as:

- Evaluation of maintenance activities based upon conditions, such as current power grid stability information from the system operator, the weather forecast (including information obtained from day ahead forecasts), and the current plant system and component (SSC) status. If severe weather (e.g., high wind, severe thunderstorm warning, tornado watch/warning) or conditions that are potential high risk evolutions (HREs) for loss of offsite power are expected, then planned unavailability of electrical power sources is deferred.

- Declaring an HRE, and appropriately managing the plant configuration, when such conditions as the following exist or are predicted to occur:

    - Unexpected repeated station power line trips due to area environmental conditions such as icing, wind, or storms.
    - Sustained winds above the site sustained high winds procedure entry level.
    - Declaration by the TSO of a maximum emergency generation action.

- Actual switchyard voltage alarms or notifications indicating voltage below that required for offsite source Technical Specification operability limits.
- Predicted unit trip contingency switchyard voltage below minimum required switchyard voltage.
- Notification that at the current time a condition exists such that if a transmission line or other transmission facility were to trip, then the site would be below voltage operability limits.

- Restoring availability, as soon as possible, of systems required to mitigate the loss of offsite power if an offsite power source becomes unavailable or degraded, or if the risk of losing offsite power significantly increases due to severe weather.

The EGC on-line risk management program focuses on identifying compensatory measures to cope with potential grid stress conditions, regardless of season, to support effective risk management given the current conditions within a work week window. In addition, EGC augments the on-line risk management process with guidelines that specify the planning of switchyard on-line maintenance to avoid scheduling such activities during the summer period, when peak generation periods normally occur.

The above risk-informed process ensures that potential impacts of variations in factors affecting grid reliability are evaluated on a continuing basis throughout the year and that appropriate risk management actions are taken when necessary.

Question No. 6

Interface With Transmission System Operator During Extended Plant Maintenance

How do you interface with your GO when on-going maintenance at the nuclear power plant, that has been previously coordinated with your GO for a definite time frame, gets extended past that planned time frame?

Response

As stated in the response to Question 6(e) in Reference 2, planned transmission outages are coordinated in accordance with a process detailed in PJM Manual 03, "Transmission Operations," Section 4 (i.e., Reference 7). This process requires advanced notice and subsequent PJM approval for all outages to ensure grid reliability. Once the equipment is switched out of service, grid status is continually monitored and evaluated by both the TO and the TSO.

The nuclear power plant (NPP) (i.e., DNPS) coordinates maintenance activities that can have an impact on the transmission system with the TSO/TO. EGC formal interface procedure, WC-AA-8000, "Interface Procedure between Exelon Energy Delivery (ComEd/PECO) and Exelon Generation (Nuclear/Power) for Construction and Maintenance Activities," (i.e., Reference 8) specifies that scheduled plant equipment outages that may restrict transmission system configuration changes or outages (e.g., scheduled diesel generator outages) should be communicated and coordinated between the EGC Nuclear Duty Officer (NDO) and the TSO/TO.

In addition, EGC will clarify and enhance procedure(s) (e.g., WC-AA-8000) to specify that any extension to equipment outages or maintenance activities that could have mutual impact are appropriately communicated to the TSO/TO. These actions have been entered into the EGC Corrective Action Program.

References

1. Letter from Christopher Grimes (U.S. NRC) to Addressees, "NRC Generic Letter 2006-02: Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated February 1, 2006

2. Letter from K. R. Jury (Exelon Generation Company, LLC/AmerGen Energy Company, LLC) to U.S. NRC, "EGC/AmerGen 60-Day Response to NRC Generic Letter 2006-02: Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated April 3, 2006

3. Letter from C. Haney (U.S. NRC) to Addressees, "Request for Additional Information Regarding Resolution of Generic Letter 2006-02, Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated December 5, 2006

4. Letter from F. J. Koza (PJM Interconnection, LLC) to PJM nuclear owners, "PJM Information to Support Utilities Response to Generic Letter 2006-02, 'Grid Reliability and the Impact on Plant Risk and Operability of Offsite Power, dated February 1, 2006,'" dated February 23, 2006

5. EPRI Report 1011759, "Frequency Determination Method for Cascading Grid Events," dated December, 2005

6. EGC procedure WC-AA-101, "On-Line Work Control Process," Revision 13

7. PJM Manual 03, "Transmission Operations," Revision 22, effective October 25, 2006

8. EGC procedure WC-AA-8000, "Interface Procedure between Exelon Energy Delivery (ComEd/PECO) and Exelon Generation (Nuclear/Power) for Construction and Maintenance Activities," Revision 1

ATTACHMENT 5

Response to Request for Additional Information
Related to GL 2006-02

LASALLE COUNTY STATION, Units 1 and 2

Facility Operating License Nos. NPF-11 and NPF-18

ATTACHMENT 5
Response to Request for Additional Information
Related to GL 2006-02
LASALLE COUNTY STATION, Units 1 and 2

As stated in Reference 2, LaSalle County Station (LSCS) is located in the service territory of PJM Interconnection, LLC (PJM). PJM is the Transmission System Operator (TSO) for LSCS. The Transmission Owner (TO) providing interconnection services for LSCS is Commonwealth Edison Company (ComEd). Exelon Generation Company, LLC (EGC) and ComEd are both members of PJM. As requested in Reference 3, only questions 4, 5, and 6 apply to LSCS.

Offsite Power Operability

Question No. 4

Identification of Applicable Single Contingencies

In response to question 3(a) you did not identify the loss of other critical transmission elements that may cause the offsite power system (OSP) to degrade, other than the loss of the nuclear unit. If it is possible for specific critical transmission elements (such as other generators, critical transmission line, transformers, capacitor banks, voltage regulators, etc.) to degrade the OSP such that inadequate post-trip voltage could result, have these elements been included in your N-1 contingency analysis? When these elements are included in your GO's contingency analysis model and failure of one of these transmission elements could result in actuation of your degraded voltage grid relay, is the offsite power declared inoperable? If not, what is your basis for not declaring the offsite power inoperable?

Response

Critical transmission elements are included in both the transmission studies and the real time contingency analysis used for predicting switchyard voltage. The N-1 contingency analysis is performed by the TSO (i.e., PJM).

As stated in Reference 2, predicted contingency voltages following the loss of a transmission facility other than the nuclear unit (e.g., the loss of the most critical transmission line or the largest supply to the grid) are not used as the basis for offsite source operability determinations.

Nuclear units (i.e., LSCS Units 1 and 2) are reviewed for anticipated operational occurrences and postulated accidents. Various anticipated plant process disturbances, equipment malfunctions, potential operator actions or errors and component failures are examined to evaluate the nuclear unit's capability to control or accommodate these failures and malfunctions. The LSCS UFSAR, Section 15 describes the plant's response to these anticipated operational occurrences and postulated accidents. Since several of these operational transients and postulated accidents could result in a unit trip following the event, the effects of post trip contingency voltages resulting from the tripping of the unit need to be addressed in the operability determinations of the offsite power sources. None of the operational transients or postulated accidents can be shown to cause the loss of other specific critical transmission elements. Since there is no identified causality associated with the design basis anticipated operational occurrences and postulated accidents and the loss of other transmission elements, there is no operational basis to consider the offsite sources inoperable based solely upon a transmission element post trip contingency voltage value.

Up until the time that a transmission system contingency (e.g., loss of a non nuclear unit) were to occur, the offsite power systems would be in compliance with the requirements of General

Design Criterion (GDC) 17, "Electrical power systems," of 10 CFR Part 50 Appendix A, "General Design Criteria for Nuclear Power Plants." The offsite power system would provide sufficient capacity and capability to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary were not exceeded as a result of anticipated operational occurrences, and the core was cooled and containment integrity and other vital functions were maintained in the event of postulated accidents.

Maintenance Rule

Question No. 5

Seasonal Variation in Grid Stress (Reliability and Loss-of-offsite Power (LOOP) Probability)

Certain regions during certain times of the year (seasonal variations) experience higher grid stress as indicated in Electrical Power Research Institute (EPRI) Report 1011759, Table 4-7, Grid LOOP Adjustment Factor, and NRC NUREG/CR-6890. Do you adjust the base LOOP frequency in your probabilistic risk assessment (PRA) and Maintenance Rule evaluations for various seasons? If you do not consider seasonal variations in base LOOP frequency in your PRA and Maintenance Rule evaluations, explain why it is acceptable not to do so.

Response

The LSCS base probabilistic risk assessment (PRA) represents an annual estimate of core damage frequency (CDF). As such, there is no seasonal variation included in the base PRA. The annual average Loss of Offsite Power (LOOP) frequency is the appropriate parameter to use for the base PRA calculation of an annual average CDF.

As stated in the response to Question 5(c) submitted in Reference 2, PJM provided the following information to EGC regarding stress on the grid in a letter from PJM to all PJM nuclear owners (i.e., Reference 4):

> "Stress on the grid is manifested in a number of ways. Stress can represent the loading levels on individual facilities, overall demand levels, the degree of facilities out of service for maintenance, occurrence of severe weather, etc. Each aspect creates a level of stress on the grid and challenges for the system operators."

LSCS has an on-line risk management program consistent with 10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants," (i.e., the Maintenance Rule) and focused on the risk impact of the plant configuration, the grid integrity, and environmental conditions at the time of the on-line work window. Assessment of risk on the basis of current, rather than average, or adjusted average, plant configuration, weather, and grid conditions is judged to be the most appropriate input to safe, risk-informed work control and is therefore the most appropriate technical approach for managing risk.

The EGC method of on-line maintenance risk management uses a blended approach of quantitative and qualitative analyses. Due to substantial uncertainties in the factors that contribute to grid stress and their impacts at any given time, a seasonal quantitative adjustment in the LOOP frequency is not used. Rather, to account for the configuration specific effects of degraded grid conditions or adverse environmental conditions, a qualitative "high risk evolution" override process is included that both provides awareness of the condition and triggers compensatory measures or procedural limitations on the on-line work as appropriate. One of the noted strengths of the EGC approach to configuration risk management is that it does not require a set "number" to trigger actions. It is a risk-informed approach that considers risk calculations, defense-in-depth, and other qualitative inputs such as grid conditions.

The seasonal LOOP frequency adjustment approach, as suggested in EPRI technical report TR1011759, "Frequency Determination Method for Cascading Grid Events," (i.e., Reference 5) has been reviewed by EGC; however, the particular implementation and conclusions in Reference 5 are not considered appropriate because of the following:

- The approach may actually underestimate the specific conditions that exist during the work-week for non-peak seasons (e.g., low grid margin or severe weather).
- The approach is not risk-informed in that it may result in the unnecessary deferral of some work that could have been performed during the "higher LOOP frequency season" but for the arbitrary global assignment of higher risk of LOOP.

The concept that the grid is "seasonal" in susceptibility to stress is in essence a different form of averaging over a shorter time interval. Even during the summer months, when there are periods of time when the grid is highly stressed there are also long periods where it is less stressed. Given this, the actual likelihood of high grid stress could vary substantially, even within a season. Attempting to reflect this concept through a quantitative "seasonal-average" approach could actually over-estimate risk during lower stress periods, or under-estimate it during high stress periods.

To address factors that could affect the likelihood of a LOOP, at any time during the year, the EGC work management procedure, WC-AA-101, "On-Line Work Control Process," (i.e., Reference 6) incorporates such measures as:

- Evaluation of maintenance activities based upon conditions, such as current power grid stability information from the system operator, the weather forecast (including information obtained from day ahead forecasts), and the current plant system and component (SSC) status. If severe weather (e.g., high wind, severe thunderstorm warning, tornado watch/warning) or conditions that are potential high risk evolutions (HREs) for loss of offsite power are expected, then planned unavailability of electrical power sources is deferred.

- Declaring an HRE, and appropriately managing the plant configuration, when such conditions as the following exist or are predicted to occur:

  - Unexpected repeated station power line trips due to area environmental conditions such as icing, wind, or storms.
  - Sustained winds above the site sustained high winds procedure entry level.
  - Declaration by the TSO of a maximum emergency generation action.
  - Actual switchyard voltage alarms or notifications indicating voltage below that required for offsite source Technical Specification operability limits.

- Predicted unit trip contingency switchyard voltage below minimum required switchyard voltage.
- Notification that at the current time a condition exists such that if a transmission line or other transmission facility were to trip, then the site would be below voltage operability limits.

- Restoring availability, as soon as possible, of systems required to mitigate the loss of offsite power if an offsite power source becomes unavailable or degraded, or if the risk of losing offsite power significantly increases due to severe weather.

The EGC on-line risk management program focuses on identifying compensatory measures to cope with potential grid stress conditions, regardless of season, to support effective risk management given the current conditions within a work week window. In addition, EGC augments the on-line risk management process with guidelines that specify the planning of switchyard on-line maintenance to avoid scheduling such activities during the summer period, when peak generation periods normally occur.

The above risk-informed process ensures that potential impacts of variations in factors affecting grid reliability are evaluated on a continuing basis throughout the year and that appropriate risk management actions are taken when necessary.

Question No. 6

Interface With Transmission System Operator During Extended Plant Maintenance

How do you interface with your GO when on-going maintenance at the nuclear power plant, that has been previously coordinated with your GO for a definite time frame, gets extended past that planned time frame?

Response

As stated in the response to Question 6(e) in Reference 2, planned transmission outages are coordinated in accordance with a process detailed in PJM Manual 03, "Transmission Operations," Section 4 (i.e., Reference 7). This process requires advanced notice and subsequent PJM approval for all outages to ensure grid reliability. Once the equipment is switched out of service, grid status is continually monitored and evaluated by both the TO and the TSO.

The nuclear power plant (NPP) (i.e., LSCS) coordinates maintenance activities that can have an impact on the transmission system with the TSO/TO. EGC formal interface procedure, WC-AA-8000, "Interface Procedure between Exelon Energy Delivery (ComEd/PECO) and Exelon Generation (Nuclear/Power) for Construction and Maintenance Activities," (i.e., Reference 8) specifies that scheduled plant equipment outages that may restrict transmission system configuration changes or outages (e.g., scheduled diesel generator outages) should be communicated and coordinated between the EGC Nuclear Duty Officer (NDO) and the TSO/TO.

In addition, EGC will clarify and enhance procedure(s) (e.g., WC-AA-8000) to specify that any extension to equipment outages or maintenance activities that could have mutual impact are appropriately communicated to the TSO/TO. These actions have been entered into the EGC Corrective Action Program.

References

1. Letter from Christopher Grimes (U.S. NRC) to Addressees, "NRC Generic Letter 2006-02: Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated February 1, 2006

2. Letter from K. R. Jury (Exelon Generation Company, LLC/AmerGen Energy Company, LLC) to U.S. NRC, "EGC/AmerGen 60-Day Response to NRC Generic Letter 2006-02: Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated April 3, 2006

3. Letter from C. Haney (U.S. NRC) to Addressees, "Request for Additional Information Regarding Resolution of Generic Letter 2006-02, Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated December 5, 2006

4. Letter from F. J. Koza (PJM Interconnection, LLC) to PJM nuclear owners, "PJM Information to Support Utilities Response to Generic Letter 2006-02, 'Grid Reliability and the Impact on Plant Risk and Operability of Offsite Power, dated February 1, 2006,'" dated February 23, 2006

5. EPRI Report 1011759, "Frequency Determination Method for Cascading Grid Events," dated December, 2005

6. EGC procedure WC-AA-101, "On-Line Work Control Process," Revision 13

7. PJM Manual 03, "Transmission Operations," Revision 22, effective October 25, 2006

8. EGC procedure WC-AA-8000, "Interface Procedure between Exelon Energy Delivery (ComEd/PECO) and Exelon Generation (Nuclear/Power) for Construction and Maintenance Activities," Revision 1

ATTACHMENT 6

Response to Request for Additional Information
Related to GL 2006-02

LIMERICK GENERATING STATION, Units 1 and 2

Facility Operating License Nos. NPF-39 and NPF-85

ATTACHMENT 6
Response to Request for Additional Information
Related to GL 2006-02
LIMERICK GENERATING STATION, Units 1 and 2

As stated in Reference 2, Limerick Generating Station (LGS) is located in the service territory of PJM Interconnection, LLC (PJM). PJM is the Transmission System Operator (TSO) for LGS. The Transmission Owner (TO) providing interconnection services for LGS is PECO Energy Company (PECO). Exelon Generation Company, LLC (EGC) and PECO are both members of PJM. As requested in Reference 3, only questions 4, 5, and 6 apply to LGS.

Offsite Power Operability

Question No. 4

Identification of Applicable Single Contingencies

In response to question 3(a) you did not identify the loss of other critical transmission elements that may cause the offsite power system (OSP) to degrade, other than the loss of the nuclear unit. If it is possible for specific critical transmission elements (such as other generators, critical transmission line, transformers, capacitor banks, voltage regulators, etc.) to degrade the OSP such that inadequate post-trip voltage could result, have these elements been included in your N-1 contingency analysis? When these elements are included in your GO's contingency analysis model and failure of one of these transmission elements could result in actuation of your degraded voltage grid relay, is the offsite power declared inoperable? If not, what is your basis for not declaring the offsite power inoperable?

Response

Critical transmission elements are included in both the transmission studies and the real time contingency analysis used for predicting switchyard voltage. The N-1 contingency analysis is performed by the TSO (i.e., PJM).

As stated in Reference 2, predicted contingency voltages following the loss of a transmission facility other than the nuclear unit (e.g., the loss of the most critical transmission line or the largest supply to the grid) are not used as the basis for offsite source operability determinations.

Nuclear units (i.e., LGS Units 1 and 2) are reviewed for anticipated operational occurrences and postulated accidents. Various anticipated plant process disturbances, equipment malfunctions, potential operator actions or errors and component failures are examined to evaluate the nuclear unit's capability to control or accommodate these failures and malfunctions. The LGS UFSAR, Section 15 describes the plant's response to these anticipated operational occurrences and postulated accidents. Since several of these operational transients and postulated accidents could result in a unit trip following the event, the effects of post trip contingency voltages resulting from the tripping of the unit need to be addressed in the operability determinations of the offsite power sources. None of the operational transients or postulated accidents can be shown to cause the loss of other specific critical transmission elements. Since there is no identified causality associated with the design basis anticipated operational occurrences and postulated accidents and the loss of other transmission elements, there is no operational basis to consider the offsite sources inoperable based solely upon a transmission element post trip contingency voltage value.

Up until the time that a transmission system contingency (e.g., loss of a non nuclear unit) were to occur, the offsite power systems would be in compliance with the requirements of General

Design Criterion (GDC) 17, "Electrical power systems," of 10 CFR Part 50 Appendix A, "General Design Criteria for Nuclear Power Plants." The offsite power system would provide sufficient capacity and capability to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary were not exceeded as a result of anticipated operational occurrences, and the core was cooled and containment integrity and other vital functions were maintained in the event of postulated accidents.

Maintenance Rule

Question No. 5

Seasonal Variation in Grid Stress (Reliability and Loss-of-offsite Power (LOOP) Probability)

Certain regions during certain times of the year (seasonal variations) experience higher grid stress as indicated in Electrical Power Research Institute (EPRI) Report 1011759, Table 4-7, Grid LOOP Adjustment Factor, and NRC NUREG/CR-6890. Do you adjust the base LOOP frequency in your probabilistic risk assessment (PRA) and Maintenance Rule evaluations for various seasons? If you do not consider seasonal variations in base LOOP frequency in your PRA and Maintenance Rule evaluations, explain why it is acceptable not to do so.

Response

The LGS base probabilistic risk assessment (PRA) represents an annual estimate of core damage frequency (CDF). As such, there is no seasonal variation included in the base PRA. The annual average Loss of Offsite Power (LOOP) frequency is the appropriate parameter to use for the base PRA calculation of an annual average CDF.

As stated in the response to Question 5(c) submitted in Reference 2, PJM provided the following information to EGC regarding stress on the grid in a letter from PJM to all PJM nuclear owners (i.e., Reference 4):

> "Stress on the grid is manifested in a number of ways. Stress can represent the loading levels on individual facilities, overall demand levels, the degree of facilities out of service for maintenance, occurrence of severe weather, etc. Each aspect creates a level of stress on the grid and challenges for the system operators."

LGS has an on-line risk management program consistent with 10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants," (i.e., the Maintenance Rule) and focused on the risk impact of the plant configuration, the grid integrity, and environmental conditions at the time of the on-line work window. Assessment of risk on the basis of current, rather than average, or adjusted average, plant configuration, weather, and grid conditions is judged to be the most appropriate input to safe, risk-informed work control and is therefore the most appropriate technical approach for managing risk.

The EGC method of on-line maintenance risk management uses a blended approach of quantitative and qualitative analyses. Due to substantial uncertainties in the factors that contribute to grid stress and their impacts at any given time, a seasonal quantitative adjustment in the LOOP frequency is not used. Rather, to account for the configuration specific effects of degraded grid conditions or adverse environmental conditions, a qualitative "high risk evolution" override process is included that both provides awareness of the condition and triggers compensatory measures or procedural limitations on the on-line work as appropriate. One of the noted strengths of the EGC approach to configuration risk management is that it does not require a set "number" to trigger actions. It is a risk-informed approach that considers risk calculations, defense-in-depth, and other qualitative inputs such as grid conditions.

The seasonal LOOP frequency adjustment approach, as suggested in EPRI technical report TR1011759, "Frequency Determination Method for Cascading Grid Events," (i.e., Reference 5) has been reviewed by EGC; however, the particular implementation and conclusions in Reference 5 are not considered appropriate because of the following:

- The approach may actually underestimate the specific conditions that exist during the work-week for non-peak seasons (e.g., low grid margin or severe weather).
- The approach is not risk-informed in that it may result in the unnecessary deferral of some work that could have been performed during the "higher LOOP frequency season" but for the arbitrary global assignment of higher risk of LOOP.

The concept that the grid is "seasonal" in susceptibility to stress is in essence a different form of averaging over a shorter time interval. Even during the summer months, when there are periods of time when the grid is highly stressed there are also long periods where it is less stressed. Given this, the actual likelihood of high grid stress could vary substantially, even within a season. Attempting to reflect this concept through a quantitative "seasonal-average" approach could actually over-estimate risk during lower stress periods, or under-estimate it during high stress periods.

To address factors that could affect the likelihood of a LOOP, at any time during the year, the EGC work management procedure, WC-AA-101, "On-Line Work Control Process," (i.e., Reference 6) incorporates such measures as:

- Evaluation of maintenance activities based upon conditions, such as current power grid stability information from the system operator, the weather forecast (including information obtained from day ahead forecasts), and the current plant system and component (SSC) status. If severe weather (e.g., high wind, severe thunderstorm warning, tornado watch/warning) or conditions that are potential high risk evolutions (HREs) for loss of offsite power are expected, then planned unavailability of electrical power sources is deferred.

- Declaring an HRE, and appropriately managing the plant configuration, when such conditions as the following exist or are predicted to occur:

    - Unexpected repeated station power line trips due to area environmental conditions such as icing, wind, or storms.
    - Sustained winds above the site sustained high winds procedure entry level.
    - Declaration by the TSO of a maximum emergency generation action.
    - Actual switchyard voltage alarms or notifications indicating voltage below that required for offsite source Technical Specification operability limits.

  - Predicted unit trip contingency switchyard voltage below minimum required switchyard voltage.
  - Notification that at the current time a condition exists such that if a transmission line or other transmission facility were to trip, then the site would be below voltage operability limits.

- Restoring availability, as soon as possible, of systems required to mitigate the loss of offsite power if an offsite power source becomes unavailable or degraded, or if the risk of losing offsite power significantly increases due to severe weather.

The EGC on-line risk management program focuses on identifying compensatory measures to cope with potential grid stress conditions, regardless of season, to support effective risk management given the current conditions within a work week window. In addition, EGC augments the on-line risk management process with guidelines that specify the planning of switchyard on-line maintenance to avoid scheduling such activities during the summer period, when peak generation periods normally occur.

The above risk-informed process ensures that potential impacts of variations in factors affecting grid reliability are evaluated on a continuing basis throughout the year and that appropriate risk management actions are taken when necessary.

Question No. 6

Interface With Transmission System Operator During Extended Plant Maintenance

How do you interface with your GO when on-going maintenance at the nuclear power plant, that has been previously coordinated with your GO for a definite time frame, gets extended past that planned time frame?

Response

As stated in the response to Question 6(e) in Reference 2, planned transmission outages are coordinated in accordance with a process detailed in PJM Manual 03, "Transmission Operations," Section 4 (i.e., Reference 7). This process requires advanced notice and subsequent PJM approval for all outages to ensure grid reliability. Once the equipment is switched out of service, grid status is continually monitored and evaluated by both the TO and the TSO.

The nuclear power plant (NPP) (i.e., LGS) coordinates maintenance activities that can have an impact on the transmission system with the TSO/TO. EGC formal interface procedure, WC-AA-8000, "Interface Procedure between Exelon Energy Delivery (ComEd/PECO) and Exelon Generation (Nuclear/Power) for Construction and Maintenance Activities," (i.e., Reference 8) specifies that scheduled plant equipment outages that may restrict transmission system configuration changes or outages (e.g., scheduled diesel generator outages) should be communicated and coordinated between the EGC Nuclear Duty Officer (NDO) and the TSO/TO.

In addition, EGC will clarify and enhance procedure(s) (e.g., WC-AA-8000) to specify that any extension to equipment outages or maintenance activities that could have mutual impact are appropriately communicated to the TSO/TO. These actions have been entered into the EGC Corrective Action Program.

References

1. Letter from Christopher Grimes (U.S. NRC) to Addressees, "NRC Generic Letter 2006-02: Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated February 1, 2006

2. Letter from K. R. Jury (Exelon Generation Company, LLC/AmerGen Energy Company, LLC) to U.S. NRC, "EGC/AmerGen 60-Day Response to NRC Generic Letter 2006-02: Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated April 3, 2006

3. Letter from C. Haney (U.S. NRC) to Addressees, "Request for Additional Information Regarding Resolution of Generic Letter 2006-02, Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated December 5, 2006

4. Letter from F. J. Koza (PJM Interconnection, LLC) to PJM nuclear owners, "PJM Information to Support Utilities Response to Generic Letter 2006-02, 'Grid Reliability and the Impact on Plant Risk and Operability of Offsite Power, dated February 1, 2006,'" dated February 23, 2006

5. EPRI Report 1011759, "Frequency Determination Method for Cascading Grid Events," dated December, 2005

6. EGC procedure WC-AA-101, "On-Line Work Control Process," Revision 13

7. PJM Manual 03, "Transmission Operations," Revision 22, effective October 25, 2006

8. EGC procedure WC-AA-8000, "Interface Procedure between Exelon Energy Delivery (ComEd/PECO) and Exelon Generation (Nuclear/Power) for Construction and Maintenance Activities," Revision 1

ATTACHMENT 7

**Response to Request for Additional Information
Related to GL 2006-02**

OYSTER CREEK GENERATING STATION

Facility Operating License No. DPR-16

ATTACHMENT 7
Response to Request for Additional Information
Related to GL 2006-02
OYSTER CREEK GENERATING STATION

As stated in Reference 2, Oyster Creek Generating Station (OCGS) is located in the service territory of PJM Interconnection, LLC (PJM). PJM is the Transmission System Operator (TSO) for OCGS. The Transmission Owner (TO) providing interconnection services for OCGS is FirstEnergy Corporation (FirstEnergy). AmerGen Energy Company, LLC (AmerGen) and FirstEnergy are both members of PJM. As requested in Reference 3, only questions 4, 5, and 6 apply to OCGS.

Offsite Power Operability

Question No. 4

Identification of Applicable Single Contingencies

In response to question 3(a) you did not identify the loss of other critical transmission elements that may cause the offsite power system (OSP) to degrade, other than the loss of the nuclear unit. If it is possible for specific critical transmission elements (such as other generators, critical transmission line, transformers, capacitor banks, voltage regulators, etc.) to degrade the OSP such that inadequate post-trip voltage could result, have these elements been included in your N-1 contingency analysis? When these elements are included in your GO's contingency analysis model and failure of one of these transmission elements could result in actuation of your degraded voltage grid relay, is the offsite power declared inoperable? If not, what is your basis for not declaring the offsite power inoperable?

Response

Critical transmission elements are included in both the transmission studies and the real time contingency analysis used for predicting switchyard voltage. The N-1 contingency analysis is performed by the TSO (i.e., PJM).

As stated in Reference 2, predicted contingency voltages following the loss of a transmission facility other than the nuclear unit (e.g., the loss of the most critical transmission line or the largest supply to the grid) are not used as the basis for offsite source operability determinations.

Nuclear units (i.e., OCGS) are reviewed for anticipated operational occurrences and postulated accidents. Various anticipated plant process disturbances, equipment malfunctions, potential operator actions or errors and component failures are examined to evaluate the nuclear unit's capability to control or accommodate these failures and malfunctions. The OCGS UFSAR, Section 15 describes the plant's response to these anticipated operational occurrences and postulated accidents. Since several of these operational transients and postulated accidents could result in a unit trip following the event, the effects of post trip contingency voltages resulting from the tripping of the unit need to be addressed in the operability determinations of the offsite power sources. None of the operational transients or postulated accidents can be shown to cause the loss of other specific critical transmission elements. Since there is no identified causality associated with the design basis anticipated operational occurrences and postulated accidents and the loss of other transmission elements, there is no operational basis to consider the offsite sources inoperable based solely upon a transmission element post trip contingency voltage value.

Up until the time that a transmission system contingency (e.g., loss of a non nuclear unit) were to occur, the offsite power systems would be in compliance with the requirements of General Design Criterion (GDC) 17, "Electrical power systems," of 10 CFR Part 50 Appendix A, "General Design Criteria for Nuclear Power Plants." The offsite power system would provide sufficient capacity and capability to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary were not exceeded as a result of anticipated operational occurrences, and the core was cooled and containment integrity and other vital functions were maintained in the event of postulated accidents.

Maintenance Rule

Question No. 5

Seasonal Variation in Grid Stress (Reliability and Loss-of-offsite Power (LOOP) Probability)

Certain regions during certain times of the year (seasonal variations) experience higher grid stress as indicated in Electrical Power Research Institute (EPRI) Report 1011759, Table 4-7, Grid LOOP Adjustment Factor, and NRC NUREG/CR-6890. Do you adjust the base LOOP frequency in your probabilistic risk assessment (PRA) and Maintenance Rule evaluations for various seasons? If you do not consider seasonal variations in base LOOP frequency in your PRA and Maintenance Rule evaluations, explain why it is acceptable not to do so.

Response

The OCGS base probabilistic risk assessment (PRA) represents an annual estimate of core damage frequency (CDF). As such, there is no seasonal variation included in the base PRA. The annual average Loss of Offsite Power (LOOP) frequency is the appropriate parameter to use for the base PRA calculation of an annual average CDF.

As stated in the response to Question 5(c) submitted in Reference 2, PJM provided the following information to AmerGen regarding stress on the grid in a letter from PJM to all PJM nuclear owners (i.e., Reference 4):

> "Stress on the grid is manifested in a number of ways. Stress can represent the loading levels on individual facilities, overall demand levels, the degree of facilities out of service for maintenance, occurrence of severe weather, etc. Each aspect creates a level of stress on the grid and challenges for the system operators."

OCGS has an on-line risk management program consistent with 10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants," (i.e., the Maintenance Rule) and focused on the risk impact of the plant configuration, the grid integrity, and environmental conditions at the time of the on-line work window. Assessment of risk on the basis of current, rather than average, or adjusted average, plant configuration, weather, and grid conditions is judged to be the most appropriate input to safe, risk-informed work control and is therefore the most appropriate technical approach for managing risk.

The AmerGen method of on-line maintenance risk management uses a blended approach of quantitative and qualitative analyses. Due to substantial uncertainties in the factors that contribute to grid stress and their impacts at any given time, a seasonal quantitative adjustment in the LOOP frequency is not used. Rather, to account for the configuration specific effects of degraded grid conditions or adverse environmental conditions, a qualitative "high risk evolution" override process is included that both provides awareness of the condition and triggers compensatory measures or procedural limitations on the on-line work as appropriate. One of the noted strengths of the AmerGen approach to configuration risk management is that it does not require a set "number" to trigger actions. It is a risk-informed approach that considers risk calculations, defense-in-depth, and other qualitative inputs such as grid conditions.

The seasonal LOOP frequency adjustment approach, as suggested in EPRI technical report TR1011759, "Frequency Determination Method for Cascading Grid Events," (i.e., Reference 5) has been reviewed by AmerGen; however, the particular implementation and conclusions in Reference 5 are not considered appropriate because of the following:

- The approach may actually underestimate the specific conditions that exist during the work-week for non-peak seasons (e.g., low grid margin or severe weather).
- The approach is not risk-informed in that it may result in the unnecessary deferral of some work that could have been performed during the "higher LOOP frequency season" but for the arbitrary global assignment of higher risk of LOOP.

The concept that the grid is "seasonal" in susceptibility to stress is in essence a different form of averaging over a shorter time interval. Even during the summer months, when there are periods of time when the grid is highly stressed there are also long periods where it is less stressed. Given this, the actual likelihood of high grid stress could vary substantially, even within a season. Attempting to reflect this concept through a quantitative "seasonal-average" approach could actually over-estimate risk during lower stress periods, or under-estimate it during high stress periods.

To address factors that could affect the likelihood of a LOOP, at any time during the year, the Exelon Generation Company, LLC (EGC) work management procedure, WC-AA-101, "On-Line Work Control Process," (i.e., Reference 6) is applicable to OCGS and incorporates such measures as:

- Evaluation of maintenance activities based upon conditions, such as current power grid stability information from the system operator, the weather forecast (including information obtained from day ahead forecasts), and the current plant system and component (SSC) status. If severe weather (e.g., high wind, severe thunderstorm warning, tornado watch/warning) or conditions that are potential high risk evolutions (HREs) for loss of offsite power are expected, then planned unavailability of electrical power sources is deferred.

- Declaring an HRE, and appropriately managing the plant configuration, when such conditions as the following exist or are predicted to occur:

  - Unexpected repeated station power line trips due to area environmental conditions such as icing, wind, or storms.
  - Sustained winds above the site sustained high winds procedure entry level.

- Declaration by the TSO of a maximum emergency generation action.
- Actual switchyard voltage alarms or notifications indicating voltage below that required for offsite source Technical Specification operability limits.
- Predicted unit trip contingency switchyard voltage below minimum required switchyard voltage.
- Notification that at the current time a condition exists such that if a transmission line or other transmission facility were to trip, then the site would be below voltage operability limits.

- Restoring availability, as soon as possible, of systems required to mitigate the loss of offsite power if an offsite power source becomes unavailable or degraded, or if the risk of losing offsite power significantly increases due to severe weather.

The AmerGen on-line risk management program focuses on identifying compensatory measures to cope with potential grid stress conditions, regardless of season, to support effective risk management given the current conditions within a work week window. In addition, AmerGen augments the on-line risk management process with guidelines that specify the planning of switchyard on-line maintenance to avoid scheduling such activities during the summer period, when peak generation periods normally occur.

The above risk-informed process ensures that potential impacts of variations in factors affecting grid reliability are evaluated on a continuing basis throughout the year and that appropriate risk management actions are taken when necessary.

Question No. 6

Interface With Transmission System Operator During Extended Plant Maintenance

How do you interface with your GO when on-going maintenance at the nuclear power plant, that has been previously coordinated with your GO for a definite time frame, gets extended past that planned time frame?

Response

As stated in the response to Question 6(e) in Reference 2, planned transmission outages are coordinated in accordance with a process detailed in PJM Manual 03, "Transmission Operations," Section 4 (i.e., Reference 7). This process requires advanced notice and subsequent PJM approval for all outages to ensure grid reliability. Once the equipment is switched out of service, grid status is continually monitored and evaluated by both the TO and the TSO.

The nuclear power plant (NPP) (i.e., OCGS) coordinates maintenance activities that can have an impact on the transmission system with the TSO/TO. As further stated in the response to Question 6(e) in Reference 2, interface with the TO (i.e., FirstEnergy) is identified in accordance with an OCGS site specific procedure, OP-OC-108-107-1002, "Interface Between FirstEnergy, JCP&L and Exelon Generation for OC Switchyard Operations," (i.e., Reference 8).

In addition, AmerGen will clarify and enhance procedure(s) (e.g., OP-OC-108-107-1002) to specify that any extension to equipment outages or maintenance activities that could have mutual impact are appropriately communicated to the TSO/TO. These actions have been entered into the EGC Corrective Action Program and are applicable to OCGS.

References

1. Letter from Christopher Grimes (U.S. NRC) to Addressees, "NRC Generic Letter 2006-02: Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated February 1, 2006

2. Letter from K. R. Jury (Exelon Generation Company, LLC/AmerGen Energy Company, LLC) to U.S. NRC, "EGC/AmerGen 60-Day Response to NRC Generic Letter 2006-02: Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated April 3, 2006

3. Letter from C. Haney (U.S. NRC) to Addressees, "Request for Additional Information Regarding Resolution of Generic Letter 2006-02, Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated December 5, 2006

4. Letter from F. J. Koza (PJM Interconnection, LLC) to PJM nuclear owners, "PJM Information to Support Utilities Response to Generic Letter 2006-02, 'Grid Reliability and the Impact on Plant Risk and Operability of Offsite Power, dated February 1, 2006,'" dated February 23, 2006

5. EPRI Report 1011759, "Frequency Determination Method for Cascading Grid Events," dated December, 2005

6. EGC procedure WC-AA-101, "On-Line Work Control Process," Revision 13

7. PJM Manual 03, "Transmission Operations," Revision 22, effective October 25, 2006

8. OCGS procedure OP-OC-108-107-1002, "Interface Between FirstEnergy, JCP&L and Exelon Generation for OC Switchyard Operations"

ATTACHMENT 8

Response to Request for Additional Information
Related to GL 2006-02

PEACH BOTTOM ATOMIC POWER STATION, Units 2 and 3

Renewed Facility Operating License Nos. DPR-44 and DPR-56

ATTACHMENT 8
Response to Request for Additional Information
Related to GL 2006-02
PEACH BOTTOM ATOMIC POWER STATION, Units 2 and 3

As stated in Reference 2, Peach Bottom Atomic Power Station (PBAPS) is located in the service territory of PJM Interconnection, LLC (PJM). PJM is the Transmission System Operator (TSO) for PBAPS. The Transmission Owner (TO) providing interconnection services for PBAPS is PECO Energy Company (PECO). Exelon Generation Company, LLC (EGC) and PECO are both members of PJM. As requested in Reference 3, only questions 3, 4, 5, and 6 apply to PBAPS.

Offsite Power Operability

Question No. 3

Verification of RTCA Predicted Post-Trip Voltage

Your response to question 2(g) indicates that you have not verified by procedure the voltages predicted by the online grid analysis tool (software program) with actual real plant trip voltage values. It is important that the programs used for predicting post-trip voltage be verified to be reasonably accurate and conservative. What is the range of accuracy for your [grid operators] GO's contingency analysis program? Why are you confident that the post-trip voltages calculated by the GO's contingency analysis program (that you are using to determine operability of the offsite power system) are reasonably accurate and conservative? What is your standard of acceptance?

Response

What is the range of accuracy for your [grid operators] GO's contingency analysis program?

There is no established numerical range of accuracy for the TSO's (i.e., PJM) contingency analysis program. However, state estimation and real time contingency analysis have been used for many years by PJM to aid in evaluating and maintaining transmission system reliability and are proven tools for analyzing transmission system contingencies.

Why are you confident that the post-trip voltages calculated by the GO's contingency analysis program (that you are using to determine operability of the offsite power system) are reasonably accurate and conservative?

State estimation is a mathematical process by which the state of an electric power system is extracted from a set of measurements. Traditionally, the analog inputs to the state estimator are measurements of voltage and real and reactive power flows. Discrete measurements such as switch position, breaker status and transformer tap positions, are also provided to the state estimator. These measurements are combined with the model of the system (e.g., impedances, topology) to determine the state of the entire system.

The state estimator solution provides a best estimate of the system state based on the available measurements and on the system model. The system state (e.g., voltages, line power flows) is passed on to energy management system (EMS) application functions such as the real time contingency analysis (RTCA) program. The contingency analysis program calculates system voltages and power flows for the postulated loss of transmission system elements. Contingency calculations are performed individually for a large set of transmission elements including lines, generators and transformers.

Field telemetry data inherently has a degree of error and one of the primary reasons for using a state estimator is that its solution minimizes these errors across the entire system. The state estimator acts as a filter between the raw measurements received from the remote terminal units and the application functions (e.g., RTCA) that require the most reliable database for the current state of the system.

Typically more measurements are taken than the number of state variables to be determined. This redundancy permits the state estimator to determine the best estimate for the state variables given identified errors in the telemetry data. The state estimator includes measurement error-processing algorithms that provide for detection of both gross and bias errors.

PJM provided the following information to EGC regarding the periodic update of the state estimator and the real time coordination between PJM and the PJM member transmission owners (i.e., Reference 9):

"Description of State Estimation and Relation to Real Time Contingency Analysis (RTCA)

State estimation is an advanced application that is used to ensure that power system analysis that relies on complete power system models can be performed even when incomplete or conflicting data is received from the sensing devices in the field. Basically, the state estimator (SE) compares actual field data to an expected value based on the power system model resident in the application. If the actual data is unavailable or out of its expected range, the SE will calculate a value and substitute it into the power system model, creating a SE solution, so that other applications can provide reasonable results.

The relevance of the SE to the post-contingency voltage calculation discussion is that the SE results are used as the input to the real time contingency analysis (RTCA). The RTCA takes the SE solution and calculates post-contingency flows, voltages and voltage drops for each contingency in the contingency list (in PJM's case, the RTCA analyzes about 4, 000 contingencies, approximately every 2 minutes). However, without a valid SE solution, the RTCA is not possible.

On rare occasions, the SE is not able to provide a valid solution due to the magnitude of missing, conflicting, or inaccurate data. Normally, such events are caused by communications or equipment failure in the field. In these cases, PJM is required to notify the transmission owners (TOs) that PJM's capability to calculate the necessary nuclear plant post-contingency voltages is temporarily unavailable and that PJM will be deferring to the TO's RTCA results. (Refer to PJM Manual M-01 Control Center, Section 2, pg 14.) If both PJM and the TO lose the capability to perform RTCA, the impacted nuclear power plants are notified.

Advanced applications, like the SE and the RTCA, are critical to executing PJM's tasks as a Reliability Coordinator. All Reliability Coordinators are required to have such tools to be in compliance with NERC Standard IRO-002, Reliability Coordination--Facilities. Requirements addressing the accuracy and capability of field sensors and communications systems that feed the SE are covered in PJM Manual M-01, Control Center Requirements, and are necessary to be compliant with NERC Standard TOP-006, Monitoring System Conditions.

<u>Issues related to SE accuracy</u>

Input Data Accuracy
Continuous and accurate input data is critical to the proper functioning of the SE. An accurate representation of the configuration of the grid components that actually exist in the field is essential. The data coming in from the sensors in the field must be accurately mapped to the correct elements in the SE model.

Model Scope and Level of Detail
The other key factor to ensuring accurate SE solutions is the scope and level of detail of the model. The model must contain sufficient monitoring capability of its surrounding Reliability Coordinator areas to ensure that potential, actual operating limits are not violated.

<u>Steps taken by PJM to assure SE "accuracy"</u>

Given the issues stated above, PJM and its members take steps to ensure that the SE runs as accurately as possible, including the following:

Overlapping coverage of PJM and member company state estimators
In addition to PJM, the TOs have their own SEs running in parallel with the PJM SE. The respective models are different from a scope and level of detail standpoint, but the results obtained generally are close. If discrepancies between the two SEs are identified, PJM and the TO work together to correct the problem. During the interim period, the more conservative limit becomes the operational limit.

PJM works closely with the TOs and the generation owners to ensure the accuracy of the PJM data model. PJM builds the updated model and verifies its accuracy in a test environment before installing the updated model in the production system. Model updates are performed on a quarterly basis.

Review of post-contingency parameters prior to switching
Prior to switching transmission equipment out of service, the PJM operator is required to calculate the post-switching system parameters in the vicinity of the switching using RTCA. This step is taken to ensure that the switching will not result in a reliability problem. Once the switching has been done, the operator monitors the post-switching parameters, providing a near real time comparison to what RTCA predicted. Seldom does that comparison yield an unexpected result, attesting to the accuracy of the SE and RTCA solution. Any case that does yield an unexpected result is investigated and understood. Corrective actions are taken as appropriate."

Based on the state estimator and contingency analysis attributes described above and the proven use of the state estimator and contingency analysis programs for transmission system reliability evaluations, EGC is confident that the post trip voltages calculated are reasonably accurate and that the state estimator and contingency analysis programs are currently the best approach to predict unit post trip contingency voltages.

What is your standard of acceptance?

EGC relies on the TSO (i.e., PJM) to operate a state estimator and a RTCA program to evaluate the nuclear power plant contingency voltages. The state estimator and contingency analysis program are utilized by the TSO (i.e., PJM) as tools for evaluating and maintaining the reliability of the transmission system. PJM utilizes these tools as a means to satisfy their responsibilities as a North American Electric Reliability Council (NERC) Reliability Coordinator as delineated in NERC Standards IRO-002 (i.e., Reference 10) and TOP-006 (i.e., Reference 11). These NERC Standards provide the standard of acceptance with which the TSO (i.e., PJM) must comply.

Question No. 4

Identification of Applicable Single Contingencies

In response to question 3(a) you did not identify the loss of other critical transmission elements that may cause the offsite power system (OSP) to degrade, other than the loss of the nuclear unit. If it is possible for specific critical transmission elements (such as other generators, critical transmission line, transformers, capacitor banks, voltage regulators, etc.) to degrade the OSP such that inadequate post-trip voltage could result, have these elements been included in your N-1 contingency analysis? When these elements are included in your GO's contingency analysis model and failure of one of these transmission elements could result in actuation of your degraded voltage grid relay, is the offsite power declared inoperable? If not, what is your basis for not declaring the offsite power inoperable?

Response

Critical transmission elements are included in both the transmission studies and the real time contingency analysis used for predicting switchyard voltage. The N-1 contingency analysis is performed by the TSO (i.e., PJM).

As stated in Reference 2, predicted contingency voltages following the loss of a transmission facility other than the nuclear unit (e.g., the loss of the most critical transmission line or the largest supply to the grid) are not used as the basis for offsite source operability determinations.

Nuclear units (i.e., PBAPS Units 2 and 3) are reviewed for anticipated operational occurrences and postulated accidents. Various anticipated plant process disturbances, equipment malfunctions, potential operator actions or errors and component failures are examined to evaluate the nuclear unit's capability to control or accommodate these failures and malfunctions. The PBAPS UFSAR, Section 14 describes the plant's response to these anticipated operational occurrences and postulated accidents. Since several of these operational transients and postulated accidents could result in a unit trip following the event, the effects of post trip contingency voltages resulting from the tripping of the unit need to be addressed in the operability determinations of the offsite power sources. None of the operational transients or postulated accidents can be shown to cause the loss of other specific critical transmission elements. Since there is no identified causality associated with the design basis anticipated operational occurrences and postulated accidents and the loss of other transmission elements, there is no operational basis to consider the offsite sources inoperable based solely upon a transmission element post trip contingency voltage value.

Up until the time that a transmission system contingency (e.g., loss of a non nuclear unit) were to occur, the offsite power systems would be in compliance with the requirements of General Design Criterion (GDC) 17, "Electrical power systems," of 10 CFR Part 50 Appendix A, "General Design Criteria for Nuclear Power Plants." The offsite power system would provide sufficient capacity and capability to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary were not exceeded as a result of anticipated operational occurrences, and the core was cooled and containment integrity and other vital functions were maintained in the event of postulated accidents.

Maintenance Rule

Question No. 5

Seasonal Variation in Grid Stress (Reliability and Loss-of-offsite Power (LOOP) Probability)

Certain regions during certain times of the year (seasonal variations) experience higher grid stress as indicated in Electrical Power Research Institute (EPRI) Report 1011759, Table 4-7, Grid LOOP Adjustment Factor, and NRC NUREG/CR-6890. Do you adjust the base LOOP frequency in your probabilistic risk assessment (PRA) and Maintenance Rule evaluations for various seasons? If you do not consider seasonal variations in base LOOP frequency in your PRA and Maintenance Rule evaluations, explain why it is acceptable not to do so.

Response

The PBAPS base probabilistic risk assessment (PRA) represents an annual estimate of core damage frequency (CDF). As such, there is no seasonal variation included in the base PRA. The annual average Loss of Offsite Power (LOOP) frequency is the appropriate parameter to use for the base PRA calculation of an annual average CDF.

As stated in the response to Question 5(c) submitted in Reference 2, PJM provided the following information to EGC regarding stress on the grid in a letter from PJM to all PJM nuclear owners (i.e., Reference 4):

> "Stress on the grid is manifested in a number of ways. Stress can represent the loading levels on individual facilities, overall demand levels, the degree of facilities out of service for maintenance, occurrence of severe weather, etc. Each aspect creates a level of stress on the grid and challenges for the system operators."

PBAPS has an on-line risk management program consistent with 10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants," (i.e., the Maintenance Rule) and focused on the risk impact of the plant configuration, the grid integrity, and environmental conditions at the time of the on-line work window. Assessment of risk on the basis of current, rather than average, or adjusted average, plant configuration, weather, and grid conditions is judged to be the most appropriate input to safe, risk-informed work control and is therefore the most appropriate technical approach for managing risk.

The EGC method of on-line maintenance risk management uses a blended approach of quantitative and qualitative analyses. Due to substantial uncertainties in the factors that

contribute to grid stress and their impacts at any given time, a seasonal quantitative adjustment in the LOOP frequency is not used. Rather, to account for the configuration specific effects of degraded grid conditions or adverse environmental conditions, a qualitative "high risk evolution" override process is included that both provides awareness of the condition and triggers compensatory measures or procedural limitations on the on-line work as appropriate. One of the noted strengths of the EGC approach to configuration risk management is that it does not require a set "number" to trigger actions. It is a risk-informed approach that considers risk calculations, defense-in-depth, and other qualitative inputs such as grid conditions.

The seasonal LOOP frequency adjustment approach, as suggested in EPRI technical report TR1011759, "Frequency Determination Method for Cascading Grid Events," (i.e., Reference 5) has been reviewed by EGC; however, the particular implementation and conclusions in Reference 5 are not considered appropriate because of the following:

- The approach may actually underestimate the specific conditions that exist during the work-week for non-peak seasons (e.g., low grid margin or severe weather).
- The approach is not risk-informed in that it may result in the unnecessary deferral of some work that could have been performed during the "higher LOOP frequency season" but for the arbitrary global assignment of higher risk of LOOP.

The concept that the grid is "seasonal" in susceptibility to stress is in essence a different form of averaging over a shorter time interval. Even during the summer months, when there are periods of time when the grid is highly stressed there are also long periods where it is less stressed. Given this, the actual likelihood of high grid stress could vary substantially, even within a season. Attempting to reflect this concept through a quantitative "seasonal-average" approach could actually over-estimate risk during lower stress periods, or under-estimate it during high stress periods.

To address factors that could affect the likelihood of a LOOP, at any time during the year, the EGC work management procedure, WC-AA-101, "On-Line Work Control Process," (i.e., Reference 6) incorporates such measures as:

- Evaluation of maintenance activities based upon conditions, such as current power grid stability information from the system operator, the weather forecast (including information obtained from day ahead forecasts), and the current plant system and component (SSC) status. If severe weather (e.g., high wind, severe thunderstorm warning, tornado watch/warning) or conditions that are potential high risk evolutions (HREs) for loss of offsite power are expected, then planned unavailability of electrical power sources is deferred.

- Declaring an HRE, and appropriately managing the plant configuration, when such conditions as the following exist or are predicted to occur:

    - Unexpected repeated station power line trips due to area environmental conditions such as icing, wind, or storms.
    - Sustained winds above the site sustained high winds procedure entry level.
    - Declaration by the TSO of a maximum emergency generation action.

- Actual switchyard voltage alarms or notifications indicating voltage below that required for offsite source Technical Specification operability limits.
- Predicted unit trip contingency switchyard voltage below minimum required switchyard voltage.
- Notification that at the current time a condition exists such that if a transmission line or other transmission facility were to trip, then the site would be below voltage operability limits.

- Restoring availability, as soon as possible, of systems required to mitigate the loss of offsite power if an offsite power source becomes unavailable or degraded, or if the risk of losing offsite power significantly increases due to severe weather.

The EGC on-line risk management program focuses on identifying compensatory measures to cope with potential grid stress conditions, regardless of season, to support effective risk management given the current conditions within a work week window. In addition, EGC augments the on-line risk management process with guidelines that specify the planning of switchyard on-line maintenance to avoid scheduling such activities during the summer period, when peak generation periods normally occur.

The above risk-informed process ensures that potential impacts of variations in factors affecting grid reliability are evaluated on a continuing basis throughout the year and that appropriate risk management actions are taken when necessary.

Question No. 6

Interface With Transmission System Operator During Extended Plant Maintenance

How do you interface with your GO when on-going maintenance at the nuclear power plant, that has been previously coordinated with your GO for a definite time frame, gets extended past that planned time frame?

Response

As stated in the response to Question 6(e) in Reference 2, planned transmission outages are coordinated in accordance with a process detailed in PJM Manual 03, "Transmission Operations," Section 4 (i.e., Reference 7). This process requires advanced notice and subsequent PJM approval for all outages to ensure grid reliability. Once the equipment is switched out of service, grid status is continually monitored and evaluated by both the TO and the TSO.

The nuclear power plant (NPP) (i.e., PBAPS) coordinates maintenance activities that can have an impact on the transmission system with the TSO/TO. EGC formal interface procedure, WC-AA-8000, “Interface Procedure between Exelon Energy Delivery (ComEd/PECO) and Exelon Generation (Nuclear/Power) for Construction and Maintenance Activities,” (i.e., Reference 8) specifies that scheduled plant equipment outages that may restrict transmission system configuration changes or outages (e.g., scheduled diesel generator outages) should be communicated and coordinated between the EGC Nuclear Duty Officer (NDO) and the TSO/TO.

In addition, EGC will clarify and enhance procedure(s) (e.g., WC-AA-8000) to specify that any extension to equipment outages or maintenance activities that could have mutual impact are appropriately communicated to the TSO/TO. These actions have been entered into the EGC Corrective Action Program.

References

1. Letter from Christopher Grimes (U.S. NRC) to Addressees, "NRC Generic Letter 2006-02: Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated February 1, 2006

2. Letter from K. R. Jury (Exelon Generation Company, LLC/AmerGen Energy Company, LLC) to U.S. NRC, "EGC/AmerGen 60-Day Response to NRC Generic Letter 2006-02: Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated April 3, 2006

3. Letter from C. Haney (U.S. NRC) to Addressees, "Request for Additional Information Regarding Resolution of Generic Letter 2006-02, Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated December 5, 2006

4. Letter from F. J. Koza (PJM Interconnection, LLC) to PJM nuclear owners, "PJM Information to Support Utilities Response to Generic Letter 2006-02, 'Grid Reliability and the Impact on Plant Risk and Operability of Offsite Power, dated February 1, 2006,'" dated February 23, 2006

5. EPRI Report 1011759, "Frequency Determination Method for Cascading Grid Events," dated December, 2005

6. EGC procedure WC-AA-101, "On-Line Work Control Process," Revision 13

7. PJM Manual 03, "Transmission Operations," Revision 22, effective October 25, 2006

8. EGC procedure WC-AA-8000, "Interface Procedure between Exelon Energy Delivery (ComEd/PECO) and Exelon Generation (Nuclear/Power) for Construction and Maintenance Activities," Revision 1

9. F.J. Koza, Executive Director, System Operations (PJM Interconnection, LLC), "RAI Question #3 Final Version," email to all PJM nuclear owners regarding accuracy of post-contingency voltage calculations, (January 12, 2007)

10. NERC Standard IRO-002, "Reliability Coordination – Facilities"

11. NERC Standard TOP-006, "Monitoring System Conditions"

ATTACHMENT 9

Response to Request for Additional Information
Related to GL 2006-02

QUAD CITIES NUCLEAR POWER STATION, Units 1 and 2

Renewed Facility Operating License Nos. DPR-29 and DPR-30

As stated in Reference 2, Quad Cities Nuclear Power Station (QCNPS) is located in the service territory of PJM Interconnection, LLC (PJM). PJM is the Transmission System Operator (TSO) for QCNPS. The Transmission Owner (TO) providing interconnection services for QCNPS is Commonwealth Edison Company (ComEd). Exelon Generation Company, LLC (EGC) and ComEd are both members of PJM. As requested in Reference 3, only questions 3, 4, 5, and 6 apply to QCNPS.

Offsite Power Operability

Question No. 3

Verification of RTCA Predicted Post-Trip Voltage

Your response to question 2(g) indicates that you have not verified by procedure the voltages predicted by the online grid analysis tool (software program) with actual real plant trip voltage values. It is important that the programs used for predicting post-trip voltage be verified to be reasonably accurate and conservative. What is the range of accuracy for your [grid operators] GO's contingency analysis program? Why are you confident that the post-trip voltages calculated by the GO's contingency analysis program (that you are using to determine operability of the offsite power system) are reasonably accurate and conservative? What is your standard of acceptance?

Response

What is the range of accuracy for your [grid operators] GO's contingency analysis program?

There is no established numerical range of accuracy for the TSO's (i.e., PJM) contingency analysis program. However, state estimation and real time contingency analysis have been used for many years by PJM to aid in evaluating and maintaining transmission system reliability and are proven tools for analyzing transmission system contingencies.

Why are you confident that the post-trip voltages calculated by the GO's contingency analysis program (that you are using to determine operability of the offsite power system) are reasonably accurate and conservative?

State estimation is a mathematical process by which the state of an electric power system is extracted from a set of measurements. Traditionally, the analog inputs to the state estimator are measurements of voltage and real and reactive power flows. Discrete measurements such as switch position, breaker status and transformer tap positions, are also provided to the state estimator. These measurements are combined with the model of the system (e.g., impedances, topology) to determine the state of the entire system.

The state estimator solution provides a best estimate of the system state based on the available measurements and on the system model. The system state (e.g., voltages, line power flows) is passed on to energy management system (EMS) application functions such as the real time contingency analysis (RTCA) program. The contingency analysis program calculates system voltages and power flows for the postulated loss of transmission system elements. Contingency calculations are performed individually for a large set of transmission elements including lines, generators and transformers.

Field telemetry data inherently has a degree of error and one of the primary reasons for using a state estimator is that its solution minimizes these errors across the entire system. The state estimator acts as a filter between the raw measurements received from the remote terminal units and the application functions (e.g., RTCA) that require the most reliable database for the current state of the system.

Typically more measurements are taken than the number of state variables to be determined. This redundancy permits the state estimator to determine the best estimate for the state variables given identified errors in the telemetry data. The state estimator includes measurement error-processing algorithms that provide for detection of both gross and bias errors.

PJM provided the following information to EGC regarding the periodic update of the state estimator and the real time coordination between PJM and the PJM member transmission owners (i.e., Reference 9):

"Description of State Estimation and Relation to Real Time Contingency Analysis (RTCA)

State estimation is an advanced application that is used to ensure that power system analysis that relies on complete power system models can be performed even when incomplete or conflicting data is received from the sensing devices in the field. Basically, the state estimator (SE) compares actual field data to an expected value based on the power system model resident in the application. If the actual data is unavailable or out of its expected range, the SE will calculate a value and substitute it into the power system model, creating a SE solution, so that other applications can provide reasonable results.

The relevance of the SE to the post-contingency voltage calculation discussion is that the SE results are used as the input to the real time contingency analysis (RTCA). The RTCA takes the SE solution and calculates post-contingency flows, voltages and voltage drops for each contingency in the contingency list (in PJM's case, the RTCA analyzes about 4, 000 contingencies, approximately every 2 minutes). However, without a valid SE solution, the RTCA is not possible.

On rare occasions, the SE is not able to provide a valid solution due to the magnitude of missing, conflicting, or inaccurate data. Normally, such events are caused by communications or equipment failure in the field. In these cases, PJM is required to notify the transmission owners (TOs) that PJM's capability to calculate the necessary nuclear plant post-contingency voltages is temporarily unavailable and that PJM will be deferring to the TO's RTCA results. (Refer to PJM Manual M-01 Control Center, Section 2, pg 14.) If both PJM and the TO lose the capability to perform RTCA, the impacted nuclear power plants are notified.

Advanced applications, like the SE and the RTCA, are critical to executing PJM's tasks as a Reliability Coordinator. All Reliability Coordinators are required to have such tools to be in compliance with NERC Standard IRO-002, Reliability Coordination--Facilities. Requirements addressing the accuracy and capability of field sensors and communications systems that feed the SE are covered in PJM Manual M-01, Control Center Requirements, and are necessary to be compliant with NERC Standard TOP-006, Monitoring System Conditions.

Issues related to SE accuracy

Input Data Accuracy
Continuous and accurate input data is critical to the proper functioning of the SE. An accurate representation of the configuration of the grid components that actually exist in the field is essential. The data coming in from the sensors in the field must be accurately mapped to the correct elements in the SE model.

Model Scope and Level of Detail
The other key factor to ensuring accurate SE solutions is the scope and level of detail of the model. The model must contain sufficient monitoring capability of its surrounding Reliability Coordinator areas to ensure that potential, actual operating limits are not violated.

Steps taken by PJM to assure SE "accuracy"

Given the issues stated above, PJM and its members take steps to ensure that the SE runs as accurately as possible, including the following:

Overlapping coverage of PJM and member company state estimators
In addition to PJM, the TOs have their own SEs running in parallel with the PJM SE. The respective models are different from a scope and level of detail standpoint, but the results obtained generally are close. If discrepancies between the two SEs are identified, PJM and the TO work together to correct the problem. During the interim period, the more conservative limit becomes the operational limit.

PJM works closely with the TOs and the generation owners to ensure the accuracy of the PJM data model. PJM builds the updated model and verifies its accuracy in a test environment before installing the updated model in the production system. Model updates are performed on a quarterly basis.

Review of post-contingency parameters prior to switching
Prior to switching transmission equipment out of service, the PJM operator is required to calculate the post-switching system parameters in the vicinity of the switching using RTCA. This step is taken to ensure that the switching will not result in a reliability problem. Once the switching has been done, the operator monitors the post-switching parameters, providing a near real time comparison to what RTCA predicted. Seldom does that comparison yield an unexpected result, attesting to the accuracy of the SE and RTCA solution. Any case that does yield an unexpected result is investigated and understood. Corrective actions are taken as appropriate."

Based on the state estimator and contingency analysis attributes described above and the proven use of the state estimator and contingency analysis programs for transmission system reliability evaluations, EGC is confident that the post trip voltages calculated are reasonably accurate and that the state estimator and contingency analysis programs are currently the best approach to predict unit post trip contingency voltages.

What is your standard of acceptance?

EGC relies on the TSO (i.e., PJM) to operate a state estimator and a RTCA program to evaluate the nuclear power plant contingency voltages. The state estimator and contingency analysis program are utilized by the TSO (i.e., PJM) as tools for evaluating and maintaining the reliability of the transmission system. PJM utilizes these tools as a means to satisfy their responsibilities as a North American Electric Reliability Council (NERC) Reliability Coordinator as delineated in NERC Standards IRO-002 (i.e., Reference 10) and TOP-006 (i.e., Reference 11). These NERC Standards provide the standard of acceptance with which the TSO (i.e., PJM) must comply.

Question No. 4

Identification of Applicable Single Contingencies

In response to question 3(a) you did not identify the loss of other critical transmission elements that may cause the offsite power system (OSP) to degrade, other than the loss of the nuclear unit. If it is possible for specific critical transmission elements (such as other generators, critical transmission line, transformers, capacitor banks, voltage regulators, etc.) to degrade the OSP such that inadequate post-trip voltage could result, have these elements been included in your N-1 contingency analysis? When these elements are included in your GO's contingency analysis model and failure of one of these transmission elements could result in actuation of your degraded voltage grid relay, is the offsite power declared inoperable? If not, what is your basis for not declaring the offsite power inoperable?

Response

Critical transmission elements are included in both the transmission studies and the real time contingency analysis used for predicting switchyard voltage. The N-1 contingency analysis is performed by the TSO (i.e., PJM).

As stated in Reference 2, predicted contingency voltages following the loss of a transmission facility other than the nuclear unit (e.g., the loss of the most critical transmission line or the largest supply to the grid) are not used as the basis for offsite source operability determinations.

Nuclear units (i.e., QCNPS Units 1 and 2) are reviewed for anticipated operational occurrences and postulated accidents. Various anticipated plant process disturbances, equipment malfunctions, potential operator actions or errors and component failures are examined to evaluate the nuclear unit's capability to control or accommodate these failures and malfunctions. The QCNPS UFSAR, Section 15 describes the plant's response to these anticipated operational occurrences and postulated accidents. Since several of these operational transients and postulated accidents could result in a unit trip following the event, the effects of post trip contingency voltages resulting from the tripping of the unit need to be addressed in the operability determinations of the offsite power sources. None of the operational transients or postulated accidents can be shown to cause the loss of other specific critical transmission elements. Since there is no identified causality associated with the design basis anticipated operational occurrences and postulated accidents and the loss of other transmission elements, there is no operational basis to consider the offsite sources inoperable based solely upon a transmission element post trip contingency voltage value.

Up until the time that a transmission system contingency (e.g., loss of a non nuclear unit) were to occur, the offsite power systems would be in compliance with the requirements of General Design Criterion (GDC) 17, "Electrical power systems," of 10 CFR Part 50 Appendix A, "General Design Criteria for Nuclear Power Plants." The offsite power system would provide sufficient capacity and capability to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary were not exceeded as a result of anticipated operational occurrences, and the core was cooled and containment integrity and other vital functions were maintained in the event of postulated accidents.

Maintenance Rule

Question No. 5

Seasonal Variation in Grid Stress (Reliability and Loss-of-offsite Power (LOOP) Probability)

Certain regions during certain times of the year (seasonal variations) experience higher grid stress as indicated in Electrical Power Research Institute (EPRI) Report 1011759, Table 4-7, Grid LOOP Adjustment Factor, and NRC NUREG/CR-6890. Do you adjust the base LOOP frequency in your probabilistic risk assessment (PRA) and Maintenance Rule evaluations for various seasons? If you do not consider seasonal variations in base LOOP frequency in your PRA and Maintenance Rule evaluations, explain why it is acceptable not to do so.

Response

The QCNPS base probabilistic risk assessment (PRA) represents an annual estimate of core damage frequency (CDF). As such, there is no seasonal variation included in the base PRA. The annual average Loss of Offsite Power (LOOP) frequency is the appropriate parameter to use for the base PRA calculation of an annual average CDF.

As stated in the response to Question 5(c) submitted in Reference 2, PJM provided the following information to EGC regarding stress on the grid in a letter from PJM to all PJM nuclear owners (i.e., Reference 4):

> "Stress on the grid is manifested in a number of ways. Stress can represent the loading levels on individual facilities, overall demand levels, the degree of facilities out of service for maintenance, occurrence of severe weather, etc. Each aspect creates a level of stress on the grid and challenges for the system operators."

QCNPS has an on-line risk management program consistent with 10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants," (i.e., the Maintenance Rule) and focused on the risk impact of the plant configuration, the grid integrity, and environmental conditions at the time of the on-line work window. Assessment of risk on the basis of current, rather than average, or adjusted average, plant configuration, weather, and grid conditions is judged to be the most appropriate input to safe, risk-informed work control and is therefore the most appropriate technical approach for managing risk.

The EGC method of on-line maintenance risk management uses a blended approach of quantitative and qualitative analyses. Due to substantial uncertainties in the factors that

contribute to grid stress and their impacts at any given time, a seasonal quantitative adjustment in the LOOP frequency is not used. Rather, to account for the configuration specific effects of degraded grid conditions or adverse environmental conditions, a qualitative "high risk evolution" override process is included that both provides awareness of the condition and triggers compensatory measures or procedural limitations on the on-line work as appropriate. One of the noted strengths of the EGC approach to configuration risk management is that it does not require a set "number" to trigger actions. It is a risk-informed approach that considers risk calculations, defense-in-depth, and other qualitative inputs such as grid conditions.

The seasonal LOOP frequency adjustment approach, as suggested in EPRI technical report TR1011759, "Frequency Determination Method for Cascading Grid Events," (i.e., Reference 5) has been reviewed by EGC; however, the particular implementation and conclusions in Reference 5 are not considered appropriate because of the following:

- The approach may actually underestimate the specific conditions that exist during the work-week for non-peak seasons (e.g., low grid margin or severe weather).
- The approach is not risk-informed in that it may result in the unnecessary deferral of some work that could have been performed during the "higher LOOP frequency season" but for the arbitrary global assignment of higher risk of LOOP.

The concept that the grid is "seasonal" in susceptibility to stress is in essence a different form of averaging over a shorter time interval. Even during the summer months, when there are periods of time when the grid is highly stressed there are also long periods where it is less stressed. Given this, the actual likelihood of high grid stress could vary substantially, even within a season. Attempting to reflect this concept through a quantitative "seasonal-average" approach could actually over-estimate risk during lower stress periods, or under-estimate it during high stress periods.

To address factors that could affect the likelihood of a LOOP, at any time during the year, the EGC work management procedure, WC-AA-101, "On-Line Work Control Process," (i.e., Reference 6) incorporates such measures as:

- Evaluation of maintenance activities based upon conditions, such as current power grid stability information from the system operator, the weather forecast (including information obtained from day ahead forecasts), and the current plant system and component (SSC) status. If severe weather (e.g., high wind, severe thunderstorm warning, tornado watch/warning) or conditions that are potential high risk evolutions (HREs) for loss of offsite power are expected, then planned unavailability of electrical power sources is deferred.

- Declaring an HRE, and appropriately managing the plant configuration, when such conditions as the following exist or are predicted to occur:

    - Unexpected repeated station power line trips due to area environmental conditions such as icing, wind, or storms.
    - Sustained winds above the site sustained high winds procedure entry level.
    - Declaration by the TSO of a maximum emergency generation action.

- Actual switchyard voltage alarms or notifications indicating voltage below that required for offsite source Technical Specification operability limits.
- Predicted unit trip contingency switchyard voltage below minimum required switchyard voltage.
- Notification that at the current time a condition exists such that if a transmission line or other transmission facility were to trip, then the site would be below voltage operability limits.

- Restoring availability, as soon as possible, of systems required to mitigate the loss of offsite power if an offsite power source becomes unavailable or degraded, or if the risk of losing offsite power significantly increases due to severe weather.

The EGC on-line risk management program focuses on identifying compensatory measures to cope with potential grid stress conditions, regardless of season, to support effective risk management given the current conditions within a work week window. In addition, EGC augments the on-line risk management process with guidelines that specify the planning of switchyard on-line maintenance to avoid scheduling such activities during the summer period, when peak generation periods normally occur.

The above risk-informed process ensures that potential impacts of variations in factors affecting grid reliability are evaluated on a continuing basis throughout the year and that appropriate risk management actions are taken when necessary.

Question No. 6

Interface With Transmission System Operator During Extended Plant Maintenance

How do you interface with your GO when on-going maintenance at the nuclear power plant, that has been previously coordinated with your GO for a definite time frame, gets extended past that planned time frame?

Response

As stated in the response to Question 6(e) in Reference 2, planned transmission outages are coordinated in accordance with a process detailed in PJM Manual 03, "Transmission Operations," Section 4 (i.e., Reference 7). This process requires advanced notice and subsequent PJM approval for all outages to ensure grid reliability. Once the equipment is switched out of service, grid status is continually monitored and evaluated by both the TO and the TSO.

The nuclear power plant (NPP) (i.e., QCNPS) coordinates maintenance activities that can have an impact on the transmission system with the TSO/TO. EGC formal interface procedure, WC-AA-8000, "Interface Procedure between Exelon Energy Delivery (ComEd/PECO) and Exelon Generation (Nuclear/Power) for Construction and Maintenance Activities," (i.e., Reference 8) specifies that scheduled plant equipment outages that may restrict transmission system configuration changes or outages (e.g., scheduled diesel generator outages) should be communicated and coordinated between the EGC Nuclear Duty Officer (NDO) and the TSO/TO.

In addition, EGC will clarify and enhance procedure(s) (e.g., WC-AA-8000) to specify that any extension to equipment outages or maintenance activities that could have mutual impact are appropriately communicated to the TSO/TO. These actions have been entered into the EGC Corrective Action Program.

References

1. Letter from Christopher Grimes (U.S. NRC) to Addressees, "NRC Generic Letter 2006-02: Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated February 1, 2006

2. Letter from K. R. Jury (Exelon Generation Company, LLC/AmerGen Energy Company, LLC) to U.S. NRC, "EGC/AmerGen 60-Day Response to NRC Generic Letter 2006-02: Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated April 3, 2006

3. Letter from C. Haney (U.S. NRC) to Addressees, "Request for Additional Information Regarding Resolution of Generic Letter 2006-02, Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated December 5, 2006

4. Letter from F. J. Koza (PJM Interconnection, LLC) to PJM nuclear owners, "PJM Information to Support Utilities Response to Generic Letter 2006-02, 'Grid Reliability and the Impact on Plant Risk and Operability of Offsite Power, dated February 1, 2006,'" dated February 23, 2006

5. EPRI Report 1011759, "Frequency Determination Method for Cascading Grid Events," dated December, 2005

6. EGC procedure WC-AA-101, "On-Line Work Control Process," Revision 13

7. PJM Manual 03, "Transmission Operations," Revision 22, effective October 25, 2006

8. EGC procedure WC-AA-8000, "Interface Procedure between Exelon Energy Delivery (ComEd/PECO) and Exelon Generation (Nuclear/Power) for Construction and Maintenance Activities," Revision 1

9. F.J. Koza, Executive Director, System Operations (PJM Interconnection, LLC), "RAI Question #3 Final Version," email to all PJM nuclear owners regarding accuracy of post-contingency voltage calculations, (January 12, 2007)

10. NERC Standard IRO-002, "Reliability Coordination – Facilities,"

11. NERC Standard TOP-006, "Monitoring System Conditions"

ATTACHMENT 10

Response to Request for Additional Information
Related to GL 2006-02

THREE MILE ISLAND NUCLEAR STATION, Unit 1

Facility Operating License No. DPR-50

ATTACHMENT 10
Response to Request for Additional Information
Related to GL 2006-02
THREE MILE ISLAND NUCLEAR STATION, Unit 1

As stated in Reference 2, Three Mile Island Nuclear Station, Unit 1 (TMI 1) is located in the service territory of PJM Interconnection, LLC (PJM). PJM is the Transmission System Operator (TSO) for TMI 1. The Transmission Owner (TO) providing interconnection services for TMI Unit 1 is FirstEnergy Corporation (FirstEnergy). AmerGen Energy Company, LLC (AmerGen) and FirstEnergy are both members of PJM. As requested in Reference 3, only questions 5 and 6 apply to TMI 1.

Maintenance Rule

Question No. 5

Seasonal Variation in Grid Stress (Reliability and Loss-of-offsite Power (LOOP) Probability)

Certain regions during certain times of the year (seasonal variations) experience higher grid stress as indicated in Electrical Power Research Institute (EPRI) Report 1011759, Table 4-7, Grid LOOP Adjustment Factor, and NRC NUREG/CR-6890. Do you adjust the base LOOP frequency in your probabilistic risk assessment (PRA) and Maintenance Rule evaluations for various seasons? If you do not consider seasonal variations in base LOOP frequency in your PRA and Maintenance Rule evaluations, explain why it is acceptable not to do so.

Response

The TMI 1 base probabilistic risk assessment (PRA) represents an annual estimate of core damage frequency (CDF). As such, there is no seasonal variation included in the base PRA. The annual average Loss of Offsite Power (LOOP) frequency is the appropriate parameter to use for the base PRA calculation of an annual average CDF.

As stated in the response to Question 5(c) submitted in Reference 2, PJM provided the following information to AmerGen regarding stress on the grid in a letter from PJM to all PJM nuclear owners (i.e., Reference 4):

> "Stress on the grid is manifested in a number of ways. Stress can represent the loading levels on individual facilities, overall demand levels, the degree of facilities out of service for maintenance, occurrence of severe weather, etc. Each aspect creates a level of stress on the grid and challenges for the system operators."

TMI 1 has an on-line risk management program consistent with 10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants," (i.e., the Maintenance Rule) and focused on the risk impact of the plant configuration, the grid integrity, and environmental conditions at the time of the on-line work window. Assessment of risk on the basis of current, rather than average, or adjusted average, plant configuration, weather, and grid conditions is judged to be the most appropriate input to safe, risk-informed work control and is therefore the most appropriate technical approach for managing risk.

The AmerGen method of on-line maintenance risk management uses a blended approach of quantitative and qualitative analyses. Due to substantial uncertainties in the factors that contribute to grid stress and their impacts at any given time, a seasonal quantitative adjustment in the LOOP frequency is not used. Rather, to account for the configuration specific effects of degraded grid conditions or adverse environmental conditions, a qualitative "high risk evolution" override process is included that both provides awareness of the condition and triggers compensatory measures or procedural limitations on the on-line work as appropriate. One of the noted strengths of the AmerGen approach to configuration risk management is that it does not require a set "number" to trigger actions. It is a risk-informed approach that considers risk calculations, defense-in-depth, and other qualitative inputs such as grid conditions.

The seasonal LOOP frequency adjustment approach, as suggested in EPRI technical report TR1011759, "Frequency Determination Method for Cascading Grid Events," (i.e., Reference 5) has been reviewed by AmerGen; however, the particular implementation and conclusions in Reference 5 are not considered appropriate because of the following:

- The approach may actually underestimate the specific conditions that exist during the work-week for non-peak seasons (e.g., low grid margin or severe weather).
- The approach is not risk-informed in that it may result in the unnecessary deferral of some work that could have been performed during the "higher LOOP frequency season" but for the arbitrary global assignment of higher risk of LOOP.

The concept that the grid is "seasonal" in susceptibility to stress is in essence a different form of averaging over a shorter time interval. Even during the summer months, when there are periods of time when the grid is highly stressed there are also long periods where it is less stressed. Given this, the actual likelihood of high grid stress could vary substantially, even within a season. Attempting to reflect this concept through a quantitative "seasonal-average" approach could actually over-estimate risk during lower stress periods, or under-estimate it during high stress periods.

To address factors that could affect the likelihood of a LOOP, at any time during the year, the Exelon Generation Company, LLC (EGC) work management procedure, WC-AA-101, "On-Line Work Control Process," (i.e., Reference 6) is applicable to TMI 1 and incorporates such measures as:

- Evaluation of maintenance activities based upon conditions, such as current power grid stability information from the system operator, the weather forecast (including information obtained from day ahead forecasts), and the current plant system and component (SSC) status. If severe weather (e.g., high wind, severe thunderstorm warning, tornado watch/warning) or conditions that are potential high risk evolutions (HREs) for loss of offsite power are expected, then planned unavailability of electrical power sources is deferred.

- Declaring an HRE, and appropriately managing the plant configuration, when such conditions as the following exist or are predicted to occur:

    - Unexpected repeated station power line trips due to area environmental conditions such as icing, wind, or storms.
    - Sustained winds above the site sustained high winds procedure entry level.
    - Declaration by the TSO of a maximum emergency generation action.

- Actual switchyard voltage alarms or notifications indicating voltage below that required for offsite source Technical Specification operability limits.
- Predicted unit trip contingency switchyard voltage below minimum required switchyard voltage.
- Notification that at the current time a condition exists such that if a transmission line or other transmission facility were to trip, then the site would be below voltage operability limits.

- Restoring availability, as soon as possible, of systems required to mitigate the loss of offsite power if an offsite power source becomes unavailable or degraded, or if the risk of losing offsite power significantly increases due to severe weather.

The AmerGen on-line risk management program focuses on identifying compensatory measures to cope with potential grid stress conditions, regardless of season, to support effective risk management given the current conditions within a work week window. In addition, AmerGen augments the on-line risk management process with guidelines that specify the planning of switchyard on-line maintenance to avoid scheduling such activities during the summer period, when peak generation periods normally occur.

The above risk-informed process ensures that potential impacts of variations in factors affecting grid reliability are evaluated on a continuing basis throughout the year and that appropriate risk management actions are taken when necessary.

Question No. 6

Interface With Transmission System Operator During Extended Plant Maintenance

How do you interface with your GO when on-going maintenance at the nuclear power plant, that has been previously coordinated with your GO for a definite time frame, gets extended past that planned time frame?

Response

As stated in the response to Question 6(e) in Reference 2, planned transmission outages are coordinated in accordance with a process detailed in PJM Manual 03, "Transmission Operations," Section 4 (i.e., Reference 7). This process requires advanced notice and subsequent PJM approval for all outages to ensure grid reliability. Once the equipment is switched out of service, grid status is continually monitored and evaluated by both the TO and the TSO.

The nuclear power plant (NPP) (i.e., TMI 1) coordinates maintenance activities that can have an impact on the transmission system with the TSO/TO. As further stated in the response to Question 6(e) in Reference 2, interface with the TO (i.e., FirstEnergy) is identified in accordance with a TMI site specific procedure, OP-TM-108-107-1002, "TMI Switchyard Operations," (i.e., Reference 8).

In addition, AmerGen will clarify and enhance procedure(s) (e.g., OP-TM-108-107-1002) to specify that any extension to equipment outages or maintenance activities that could have mutual impact are appropriately communicated to the TSO/TO. These actions have been entered into the EGC Corrective Action Program and are applicable to TMI Unit 1.

References

1. Letter from Christopher Grimes (U.S. NRC) to Addressees, "NRC Generic Letter 2006-02: Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated February 1, 2006

2. Letter from K. R. Jury (Exelon Generation Company, LLC/AmerGen Energy Company, LLC) to U.S. NRC, "EGC/AmerGen 60-Day Response to NRC Generic Letter 2006-02: Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated April 3, 2006

3. Letter from C. Haney (U.S. NRC) to Addressees, "Request for Additional Information Regarding Resolution of Generic Letter 2006-02, Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated December 5, 2006

4. Letter from F. J. Koza (PJM Interconnection, LLC) to PJM nuclear owners, "PJM Information to Support Utilities Response to Generic Letter 2006-02, 'Grid Reliability and the Impact on Plant Risk and Operability of Offsite Power, dated February 1, 2006,'" dated February 23, 2006

5. EPRI Report 1011759, "Frequency Determination Method for Cascading Grid Events," dated December, 2005

6. EGC procedure WC-AA-101, "On-Line Work Control Process," Revision 13

7. PJM Manual 03, "Transmission Operations," Revision 22, effective October 25, 2006

8. TMI procedure OP-TM-108-107-1002, "TMI Switchyard Operations OP-TM-108-107-1002 "