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U. S. Nuclear Regulatory Commission
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Braidwood Station, Units 1 and 2
Facility Operating License Nos. NPF-72 and NPF-77
NRC Docket Nos. STN 50-456 and STN 50-457

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

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

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

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

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

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

Peach Bottom Atomic Power Station, Units 2 and 3
Renewed Facility Operating License Nos. DPR-44 and DPR-56
NRC Docket Nos. 50-277, 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, 50-265

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

Subject: 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"

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

On February 1, 2006, the NRC issued NRC Generic Letter (GL) 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," (Reference). 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.

Attachments 1 through 10 provide 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.

Some of the questions in GL 2006-02 seek information about analyses, procedures, and activities concerning grid reliability. This information was provided by a third party and is beyond the control of EGC and AmerGen. The accuracy and completeness of this information has not been 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 3rd day of April 2006.

Respectfully,

Keith R. Jury

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

Attachment 1: 60-day Response to NRC Generic Letter 2006-02, Braidwood Station

Attachment 2: 60-day Response to NRC Generic Letter 2006-02, Byron Station

Attachment 3: 60-day Response to NRC Generic Letter 2006-02, Clinton Power Station

Attachment 4: 60-day Response to NRC Generic Letter 2006-02, Dresden Nuclear Power Station

Attachment 5: 60-day Response to NRC Generic Letter 2006-02, LaSalle County Power Station

Attachment 6: 60-day Response to NRC Generic Letter 2006-02, Limerick Generating Station

Attachment 7: 60-day Response to NRC Generic Letter 2006-02, Oyster Creek Generating Station

Attachment 8: 60-day Response to NRC Generic Letter 2006-02, Peach Bottom Atomic Power Station

Attachment 9: 60-day Response to NRC Generic Letter 2006-02, Three Mile Island Nuclear Station Unit 1

Attachment 10: 60-day Response to NRC Generic Letter 2006-02,
Quad Cities Nuclear Power Station

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 - TMI Unit 1
NRC Project Manager, NRR - Quad Cities Nuclear Power Station
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 - TMI 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

60-day Response to NRC Generic Letter 2006-02

BRAIDWOOD STATION, Units 1 and 2

FOL Nos. NPF-72 and NPF-77

On February 1, 2006, the NRC issued Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power." 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 Generic Letter requested that licensees answer the following questions and provide the information to the NRC with respect to each of their Nuclear Power Plants (NPPs).

Use of protocols between the NPP licensee and the TSO, ISO, or RC/RA and the use of analysis tools by TSOs to assist NPP licensee in monitoring grid conditions to determine the operability of offsite power system under plant TS.

GDC 17, 10 CFR Part 50, Appendix A, requires that licensees minimize the probability of the loss of power from the transmission network given a loss of the power generated by the nuclear power unit(s).

1. *Use of protocols between the NPP licensee and the TSO, ISO, or RC/RA to assist the NPP licensee in monitoring grid conditions to determine the operability of offsite power system under plant TS.*

   (a) Do you have a formal agreement or protocol with your TSO?

   Response

   Yes

   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.

   All members of PJM execute the "Operating Agreement of PJM Interconnection, LLC," (Reference 1) that details the obligations and responsibilities of both PJM and the PJM members. In the Operating Agreement, each member agrees to abide by the requirements contained in the PJM Manuals. The PJM Manuals contain the specific operational requirements that PJM and each member is required to follow.

   ComEd (i.e., the TO) is also a signatory on the "PJM Consolidated Transmission Owners Agreement (PJM TOA)," (Reference 2). Section 4.5 of the PJM TOA requires the TOs to operate and maintain their transmission facilities in accordance with the PJM Manuals.

   The PJM Operating Agreement requires PJM to, "Incorporate the grid reliability requirements applicable to nuclear generating units in the PJM Region planning and operating principles and practices." PJM Manual M01, "Control Center Requirements," Attachment B, "Nuclear Plant Communication Protocol," (Reference 3), provides the roles and responsibilities of nuclear stations, TOs, and PJM with regard to communications both in normal and emergency circumstances. The nuclear power plant (NPP) notification requirements are contained in PJM Manual M3, "Transmission Operations," Section 3 (Reference 4).

In addition to the agreements delineated in the PJM Operating Agreement and the PJM Manuals, EGC has jointly approved interface procedures with the TO that address the monitoring of the offsite source voltages and the notification protocols. EGC procedure OP-AA-108-107-1002, "Interface Agreement between Exelon Energy Delivery and Exelon Generation for Switchyard Operations," (Reference 10) outlines the responsibilities and required work interfacing activities.

(b) Describe any grid conditions that would trigger a notification from the TSO to the NPP licensee and if there is a time period required for the notification.

Response

PJM Manual M3 (Reference 4) requires PJM to initiate notification to Braidwood Station through the TO's control center if PJM identifies a switchyard voltage violation. PJM Manual M3 states: "This notification should occur within 15 minutes for voltage contingency violations and immediately for actual voltage violations. To the extent practical, PJM shall direct operations such that the violation is remedied within 30 minutes."

In addition, PJM Manual M13, "Emergency Operations," (Reference 5) identifies a series of alerts, warnings, and actions that PJM issues to PJM members depending on the identified grid condition. The PJM message is communicated to Braidwood Station by their generation dispatcher through the EGC Nuclear Duty Officer (NDO) for a variety of system conditions including the following:

Capacity Emergencies

- Maximum Emergency Generation Loading
- Load Management Curtailment
- Manual Load Dump Warning

Light Load Emergencies

- Minimum Generation Emergency
- Local Minimum Generation Emergency

Weather/Environmental Emergencies

- Hot/Cold Weather Alerts
- Thunderstorms and Tornadoes
- Solar Magnetic Disturbances

Sabotage/Terrorism Emergencies

(c) Describe any grid conditions that would cause the NPP licensee to contact the TSO. Describe the procedures associated with such a communication. If you do not have procedures, describe how you assess grid conditions that may cause the NPP licensee to contact the TSO.

Response

As required by PJM Manuals, communications between Braidwood Station and PJM (TSO) are generally through the Transmission Owner (TO) providing the interconnection service.

Braidwood Station will contact the TSO/TO for grid conditions that have parameters that are observable at the NPP. These conditions include the following:

- Loss of Offsite Power (LOOP)
- Abnormal switchyard voltage
- Automatic (protective) switchyard circuit breaker operation
- Switchyard alarms
- Grid disturbances (observable frequency or voltage fluctuations)

In addition to any alarm response procedures for the above applicable conditions, TSO/TO notifications are controlled by operating procedures, (e.g., OP-AA-108-107-1001, "Station Response to Grid Capacity Conditions"), Abnormal Operating Procedures, (e.g., BWOA ELEC-4, "Loss of Offsite Power," BWOA ELEC-3, "Loss of 4KV ESF Bus"), Emergency Operating Procedures, (e.g., BWEP-0, "Reactor Trip or Safety Injection," BWEP ES-0.1, "Reactor Trip Response"), and Emergency Contingency Action Procedures, (e.g., BWCA-0.0, "Loss of All AC").

Braidwood Station will contact the TSO/TO during a grid restoration process to obtain grid status in preparation for returning the plant buses to the offsite source.

Braidwood Station also notifies the TSO/TO of switchyard equipment deficiencies identified by NPP personnel. Jointly approved interface agreements/procedures between EGC and the TO identify the communication protocols for station identified switchyard deficiencies. EGC procedures OP-AA-108-107-1002 (Reference 10) and WC-AA-8000 (Reference 7) outline the responsibilities and required work interfacing activities.

In addition, Braidwood Station will notify the TSO/TO of NPP configurations that potentially impact grid conditions. A jointly approved interface agreement/procedure, OP-AA-108-107-1002 (Reference 10), between EGC and the TO identifies the requirements for communication of the conditions listed below:

- NPP MVAR limitations
- NPP Main generator voltage regulator not in "Automatic" mode
- NPP inability to provide the MVARs requested by the TSO/TO

Note that any Braidwood Station MW limitations or limitations on the rate at which the NPP power may be raised or lowered are communicated to the generation dispatcher.

(d) Describe how NPP operators are trained and tested on the use of the procedures or assessing grid conditions in question 1(c).

Response

Braidwood Station licensed operators are trained and tested in accordance with the Systematic Approach to Training (SAT). Procedures and policies are routinely reviewed for training through this process for improvement of operator performance. The items considered for training include Operating Procedures, Annunciator Response Procedures, Abnormal Operating Procedures, and Emergency Operating Procedures that require interface with the TSO in accordance with the established protocol. These procedures may be utilized based on various grid, switchyard, or plant symptoms to assess, respond to or mitigate off-normal plant and grid conditions. Additionally, SOER 99-01, "Loss of Grid," (Reference 25) and SOER 99-01, "Loss of Grid – Addendum," (Reference 26) specifically are captured in the Licensed Operator Requalification Training Program (LORT) Long Range Training Program. These topics, in varying detail based upon the SAT process or as part of implementing EGC procedure WC-AA-107, "Seasonal Readiness," (Reference 24) are reviewed periodically with Braidwood Station operators. Testing is commensurate with the material presented and any performance issues are identified for inclusion in future training.

(e) If you do not have a formal agreement or protocol with your TSO, describe why you believe you continue to comply with the provisions of GDC 17 as stated above, or describe what actions you intend to take to assure compliance with GDC 17.

Response

Not applicable. Formal agreements exist for Braidwood Station.

(f) If you have an existing formal interconnection agreement or protocol that ensures adequate communication and coordination between the NPP license and the TSO, describe whether this agreement or protocol requires that you be promptly notified when the conditions of the surrounding grid could result in degraded voltage (i.e., below TS nominal trip setpoint value requirements; including NPP licensees using allowable value in its TSs) or LOOP after a trip of the reactor units(s).

Response

PJM Manual M3 (Reference 4) requires PJM to initiate a notification to Braidwood Station through its respective transmission owner's control center if PJM identifies a NPP switchyard voltage violation. PJM Manual M3 states: "This notification should occur within 15 minutes for voltage contingency violations and immediately for actual voltage violations. To the extent practical, PJM shall direct operations such that the violation is remedied within 30 minutes." The trip of a NPP (i.e., trip of a Braidwood Station unit) is one of the contingencies analyzed by PJM. PJM analyzes the Braidwood Station switchyard contingency voltages to the voltage limits provided by Braidwood Station. The voltage limits provided for Braidwood Station are based on the existing design basis analysis.

(g) Describe the low switchyard voltage conditions that would initiate operation of plant degraded voltage protection.

Response

Switchyard voltage below a value maintaining emergency bus voltage above the setpoint of the degraded voltage relay (3987 volts) will cause a trip of the preferred power source after a time delay of approximately 10 seconds with a Loss of Coolant Accident (LOCA) signal present. The relation between the switchyard voltage and the emergency bus voltage is dependent on the system auxiliary transformer impedance and the winding load. Under design basis accident (i.e., Large Break LOCA) conditions, the maximum loading is known and contained in the Braidwood Station calculations of record. The design basis maximum loading and the degraded voltage relay reset voltage were used to determine the switchyard voltage needed for the system to remain connected to the offsite power source. For Braidwood Station, this corresponds to a switchyard voltage of approximately 349 kV.

In other conditions, the loading is less than the expected LOCA loading and will vary considerably depending on which loads are needed to support unit conditions. Under these conditions the required Braidwood Station switchyard voltage will be less than that required to support LOCA loading.

2. *Use of criteria and methodologies to assess whether the offsite power system will become inoperable as a result of a trip of your NPP.*

(a) Does your NPP's TSO use any analysis tools, an online analytical transmission system studies program, or other equivalent predictive methods to determine the grid conditions that would make the NPP offsite power system inoperable during various contingencies? If available to you, please provide a brief description of the analysis tool that is used by the TSO.

Response

Yes

The PJM Energy Management System (EMS) includes a Security Analysis application which runs approximately every 1 minute and analyzes ~4,000 contingencies on the PJM system (Reference 6). The analysis provides results with respect to thermal, voltage, and voltage drop limit violations. One of the contingencies analyzed by the PJM EMS is the trip of a NPP (i.e., trip of a Braidwood Station unit).

In addition, ComEd (i.e., the TO) possesses a similar system that also calculates post-contingency voltage limit violations. One of the contingencies analyzed by ComEd is the trip of a Braidwood unit.

(b) Does your NPP's TSO use an analysis tool as the basis for notifying the NPP licensee when such a condition is identified? If not, how does the TSO determine if conditions on the grid warrant NPP licensee notification?

Response

Yes

The results of the PJM Security Analysis application contain the specific contingency of the NPP tripping as the contingent element. Violation of the unit trip contingency voltage limit would result in notification of the NPP (i.e., Braidwood Station) in accordance with PJM Manual M3, Section 3 (Reference 4).

ComEd (i.e., the TO) also possesses similar capability to monitor the same condition.

(c) If your TSO uses an analysis tool, would the analysis tool identify a condition in which a trip of the NPP would result in switchyard voltages (immediate and/or long-term) falling below TS nominal trip setpoint value requirements (including NPP licensees using allowable value in its TSs) and consequent actuation of plant degraded voltage protection? If not, discuss how such a condition would be identified on the grid.

Response

Yes

The trip of the NPP (i.e., trip of a Braidwood Station unit) is one of the contingencies analyzed by the PJM Security Analysis application. PJM analyzes the NPP switchyard contingency voltages to the voltage limits provided by Braidwood Station. The voltage limits provided by Braidwood Station are based on the plant's design basis analysis as discussed in the response to 1(g).

ComEd (i.e., the TO) also possesses similar capability to monitor the same condition.

(d) If your TSO uses an analysis tool, how frequently does the analysis tool program update?

Response

The PJM EMS includes a Security Analysis application that currently updates approximately every 1 minute. In addition, ComEd (i.e., the TO) possesses a Security Analysis application that updates approximately every 6 minutes (Reference 27).

(e) Provide details of analysis tool-identified contingency conditions that would trigger an NPP licensee notification from the TSO.

Response

PJM notifies Braidwood Station through the TO (i.e., ComEd) control center whenever actual or post-contingency voltages are determined to be below the Braidwood Station switchyard voltage limits. This requirement applies to all contingencies involving the tripping of the NPP or any transmission facility as the contingent element. In accordance with PJM Manual M3 (Reference 4) the notification is required even if the voltage limits are the same as the standard PJM voltage limits.

(f) If an interface agreement exists between the TSO and the NPP licensee, does it require that the NPP licensee be notified of periods when the TSO is unable to determine if offsite power voltage and capacity could be inadequate? If so, how does

the NPP licensee determine that the offsite power would remain operable when such a notification is received?

Response

Yes

Braidwood Station unit trip contingency voltage calculations are performed by the PJM EMS and the TO (i.e., ComEd) Security Analysis application. The PJM EMS consists of a primary and backup system. If the PJM EMS fails, the ComEd Security Analysis application continues to analyze the Braidwood Station unit trip contingency voltage. Braidwood Station will be notified if the real time contingency analysis capability of PJM and the TO (i.e., ComEd) are lost simultaneously in accordance with PJM Manual M01, Section 2 (Reference 3).

If Braidwood Station is notified that PJM and ComEd (i.e., the TO) have both lost their real time contingency analysis capability, Braidwood Station would request PJM and ComEd to provide an assessment of the current condition of the grid based on the tools that PJM and ComEd have available. The determination of the operability of the offsite sources would consider the assessment provided by PJM and ComEd and whether the current condition of the grid is bounded by the grid studies previously performed for Braidwood Station.

(g) After an unscheduled inadvertent trip of the NPP, are the resultant switchyard voltages verified by procedure to be bounded by the voltages predicted by the analysis tool?

Response

No

There is presently no formal process for comparing the actual post-trip voltages to the post-trip contingency voltage results calculated by the PJM and the TO (i.e., ComEd) Security Analysis applications.

PJM provided the following information to EGC regarding this response in a letter from PJM to all PJM nuclear owners (Reference 6).

"Because the PJM transmission owning member companies have similar Security Analysis programs to PJM, there are many opportunities to compare the results of the respective Security Analysis programs. In this manner, there is a high confidence that the Security Analysis results are accurate within the precision of the calculations.

PJM retains the EMS results for a period of approximately 3 weeks after real time. It is possible to use those saved EMS results to repeat the Security Analysis calculations and compare them to the actual voltages from a unit trip. However, the NPP trips occur so infrequently that it would take a number of data points to verify the accuracy with any statistical significance. This process could take years if the process is limited to a comparison of only NPP trips."

(h) If an analysis tool is not available to the NPP licensee's TSO, do you know if there are any plans for the TSO to obtain one? If so, when?

Response

Not applicable. Braidwood Station TSO (i.e., PJM) has an analysis tool.

(i) If an analysis tool is not available, does your TSO perform period studies to verify that adequate offsite power capability, including adequate NPP post-trip switchyard voltages (immediate and/or long-term), will be available to the NPP licensee over the projected timeframe of the study?

Response

Not applicable. Braidwood Station TSO (i.e., PJM) has an analysis tool.

(a) Are the key assumptions and parameters of these periodic studies translated into TSO guidance to ensure that the transmission system is operated within the bounds of the analyses?

Response

Not applicable. Braidwood Station TSO (i.e., PJM) has an analysis tool.

(b) If the bounds of the analyses are exceeded, does this condition trigger the notification provisions discussed in question 1 above?

Response

Not applicable. Braidwood Station TSO (i.e., PJM) has an analysis tool.

(j) If your TSO does not use, or you do not have access to the results of an analysis tool, or your TSO does not perform and make available to you periodic studies that determine the adequacy of offsite power capability, please describe why you believe you comply with the provisions of GDC 17 as stated above, or describe what compensatory actions you intend to take to ensure that the offsite power system will be sufficiently reliable and remain operable with high probability following a trip of your NPP.

Response

Not applicable. Braidwood Station TSO (i.e., PJM) has an analysis tool. In addition the applicable contingency voltage results are made available to Braidwood Station as needed.

3. *Use of criteria and methodologies to assess whether the NPP's offsite power system and safety-related components will remain operable when switchyard voltages are inadequate.*

(a) If the TSO notifies the NPP operator that a trip of the NPP, or the loss of the most critical transmission line or the largest supply to the grid would result in switchyard

voltages (immediate and/or long-term) below TS nominal trip setpoint value requirements (including NPP licensees using allowable value in its TSs) and would actuate plant degraded voltage protection, is the NPP offsite power system declared inoperable under the plant TSs? If not, why not?

Response

If the TSO (i.e., PJM) notifies Braidwood Station that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., trip of a Braidwood Station unit) is below the pre-determined notification value, Braidwood Station will review the applicability to the plant operating configuration and will declare the offsite power source inoperable in accordance with Technical Specifications (TSs) if appropriate. The notification value provided to PJM by Braidwood Station is based on the Braidwood Station degraded voltage design basis analysis.

Predicted contingency voltages following the loss of a transmission facility (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 for Braidwood Station at this time. If the TSO (i.e., PJM) notifies Braidwood Station of a predicted contingency voltage violation resulting from the postulated trip of a transmission facility, Braidwood Station will perform a risk analysis of in-progress and scheduled plant work and will take action as appropriate.

The NPP unit trip contingency can be caused by plant-centered events. The use of the NPP unit trip contingency as the contingency element upon which offsite power operability is based is consistent with the final paragraph of General Design Criterion (GDC) 17, “Electric power systems,” of 10 CFR Part 50 Appendix A, “General Design Criteria for Nuclear Power Plants,” which requires provisions be included to minimize the probability of the loss of power from the transmission network given a loss of the power generated by the NPP (i.e., a Braidwood Station unit).

Postulated contingencies on the transmission system are currently not used as the basis for offsite source operability determinations since loss of power from the transmission network would not occur as a result of loss of power generated by a NPP unit (i.e., a Braidwood Station unit). Such events (e.g., loss of a transmission line) are only postulated and have not actually occurred, and the offsite power sources remain capable of supporting a safe shutdown and mitigating the effects of an accident. Loss of power from the transmission network would not occur as a result of loss of power generated by a NPP unit and therefore the GDC 17 provision discussed in GL 2006-02 is met.

(b) If onsite safety-related equipment (e.g., emergency diesel generators or safety-related motors) is lost when subjected to a double sequencing (LOCA with delayed LOOP event) as a result of the anticipated system performance and is incapable of performing its safety functions as a result of responding to an emergency actuation signal during this condition, is the equipment considered inoperable? If not, why not?

Response

Although some features have been incorporated into the plant design, requirements for analysis and design considerations for double sequencing are not included within the

Braidwood Station current licensing and design basis as documented in the Braidwood Updated Final Safety Analysis Report (UFSAR). Braidwood Station has not been explicitly analyzed for all issues associated with double sequencing. Onsite safety-related equipment at Braidwood Station (e.g., emergency diesel generators or safety-related motors) is not declared inoperable as a result of a TSO (i.e., PJM) unit trip contingency voltage notification.

Based on Enclosure 2 of SECY-05-0219, "Issuance of Nuclear Regulatory Commission Generic Letter 2005-XX, 'Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power,'" (Reference 17) which provided NRC guidance on responding to this issue, a review was performed for Braidwood Station of the loading logic for the diesel generators as well as the safety-related breakers' anti-pumping logic. This review concluded that onsite safety-related equipment (i.e., emergency diesel generators or safety-related motors) is not lost as a result of diesel generator block loading and breaker lockout from anti-pump circuitry when subjected to a double sequencing event resulting from inadequate post unit trip voltages. The scope of the review performed for Braidwood Station is discussed in the response to question 3(c) below.

(c) Describe your evaluation of onsite-related equipment to determine whether it will operate as designed during the condition described in question 3(b).

Response

Although some features have been incorporated into the plant design, requirements for analysis and design considerations for double sequencing are not included within the Braidwood Station current licensing and design basis as documented in the Braidwood UFSAR. Braidwood Station has not been explicitly analyzed for all issues associated with double sequencing. However, using the NRC clarification provided in Enclosure 2 of SECY-05-0219 as guidance, a review was performed for the purpose of addressing question 3(b).

This review examined the effects of a double sequencing event on diesel generator block loading and the potential for breaker lockout from the anti-pump circuitry. The review assumed that following a LOCA initiation, the grid separation occurred as a result of degraded voltage relay operation triggered by the loss of a Braidwood Station unit. The review examined the diesel generator loading logic and determined that the logic is reset by the LOOP event. The second sequence is consistent with that described in the Braidwood Station UFSAR for a LOOP/LOCA event. Loads are shed as a result of the LOOP signal and the loads are not block loaded onto the diesel generator.

The review also examined the potential for breaker lockout due to the anti-pumping circuitry. This review determined that there was sufficient time between the two sequences such that the breaker charging springs would re-charge and the second closure would be successful. To ensure that a breaker lockout would not occur, the breaker closing logics were also examined to assure that the trip signals were cleared before the second close signal was initiated.

(d) If the NPP licensee is notified by the TSO of other grid conditions that may impair the capability or availability of offsite power, are any plant TS action statements entered? If so, please identify them.

Response

As discussed in the response to 3(a), if the TSO (i.e., PJM) notifies Braidwood Station that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., trip of a Braidwood Station unit) is below the pre-determined notification value, Braidwood Station will review the applicability to the plant operating configuration and will declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by Braidwood Station is based on the Braidwood Station degraded voltage design basis analysis.

In addition, if PJM notifies Braidwood Station that the actual offsite power source voltage is less than the pre-determined notification value, Braidwood Station will review the applicability to the plant operating configuration and would declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by Braidwood Station is based on the Braidwood Station degraded voltage design basis analysis.

(e) If you believe your plant TSs do not require you to declare your offsite power system or safety-related equipment inoperable in any of these circumstances, explain why you believe you comply with the provisions of GDC 17 and your plant TSs, or describe what compensatory actions you intend to take to ensure that the offsite power system and safety-related components will remain operable when switchyard voltages are inadequate.

Response

The following notifications from the TSO (i.e., PJM) will result in Braidwood Station declaring the offsite power source inoperable in accordance with TSs.

- If the TSO (i.e., PJM) notifies Braidwood Station that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., trip of a Braidwood Station unit) is below the pre-determined notification value, Braidwood Station will review the applicability to the plant operating configuration and will declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by Braidwood Station is based on the Braidwood Station degraded voltage design basis analysis.

- If the TSO (i.e., PJM) notifies Braidwood Station that the actual offsite power source voltage is less than the pre-determined notification value, Braidwood Station will review the applicability to the plant operating configuration and would declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by Braidwood Station is based on the Braidwood Station degraded voltage design basis analysis.

Predicted contingency voltages following the loss of a transmission facility (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. If the TSO notifies the NPP of a predicted contingency voltage violation resulting from the postulated trip of a transmission facility, the NPP performs a risk analysis of in-progress and scheduled plant work and takes action as appropriate.

The NPP unit trip contingency can be caused by plant-centered events. The use of the NPP unit trip contingency as the contingency element upon which offsite power operability is based is consistent with the final paragraph of GDC 17 which requires provisions to minimize the probability of the loss of power from the transmission network given a loss of the power generated by the NPP.

Postulated contingencies on the transmission system are not used as the basis for offsite source operability determinations since loss of power from the transmission network would not occur as a result of loss of power generated by the NPP unit. Such events (e.g., loss of a transmission line) are only postulated and have not actually occurred, and the offsite power sources remain capable of affecting a safe shutdown and mitigating the effects of an accident. The GDC 17 provision discussed in the Generic Letter is still met; loss of power from the transmission network would not occur as a result of loss of power generated by the NPP unit.

Onsite safety-related equipment at Braidwood Station (e.g., emergency diesel generators or safety-related motors) is not declared inoperable as a result of a TSO (i.e., PJM) unit trip contingency voltage notification. Although some features have been incorporated into the plant design, requirements for analysis and design considerations for double sequencing are not included within the Braidwood Station current licensing and design basis as documented in the Braidwood Station UFSAR. Braidwood Station has not been explicitly analyzed for all issues associated with double sequencing.

(f) Describe if and how NPP operators are trained and tested on the compensatory actions mentioned in your answers to questions 3(a) through (e).

Response

Braidwood Station licensed operators are trained and tested in accordance with the Systematic Approach to Training (SAT). Equipment operability, as defined by TS, including normal and emergency power, offsite circuits, and safety-related components, is under continuous review. Procedures are in place to provide operator guidance and required actions necessary during predicted or actual degraded grid voltage conditions based on information provided by the TSO/TO in accordance with established protocol or as observed by the NPP operator. As part of initial training, requalification training, and annual operating tests, licensed operators are subjected to written examinations, dynamic learning activities, static and/or dynamic simulator examinations, Job Performance Measures (JPMs), and evaluated simulator scenarios incorporating topics including the actual or predicted switchyard voltage issues and its effect on AC Source operability. Testing is commensurate with the material presented and any performance issues are identified for inclusion in future training.

4. *Use of criteria and methodologies to assess whether the offsite power system will remain operable following a trip of your NPP.*

(a) Do the NPP operators have any guidance or procedures in plant TS bases sections, the final safety analysis report, or plant procedures regarding situations in which the condition of plant-controlled or monitored equipment (e.g., voltage regulator, auto tap changing transformers, capacitors, static VAR compensators, main generator voltage regulators) can adversely affect the operability of the NPP offsite power system? If so, describe how the operators are trained and tested on the guidance and procedures.

Response

Yes

Braidwood Station plant controlled or monitored equipment that can adversely affect the operability of the offsite power system is limited to the main generator voltage regulators. EGC and plant specific procedures provide guidance for notification of the TSO/TO (i.e., PJM/ComEd) when the voltage regulator is not in automatic.

Braidwood Station procedures direct operator actions to control excitation in manual or other mitigating actions to control excitation. Operator actions on a loss of automatic control of the voltage regulator include the requirement to notify the TO (i.e., ComEd) of the failure.

Braidwood Station licensed operators are trained and tested in accordance with the Systematic Approach to Training (SAT). Procedures and policies are routinely reviewed for training through this process for improvement of operator performance. The items considered for training include Annunciator Response Procedures, Abnormal Operating Procedures, and Emergency Operating Procedures that require interface with the TSO/TO in accordance with the established protocol. In addition as part of initial training, requalification training, and annual operating tests, licensed operators are subjected to written examinations, static and/or dynamic simulator examinations, Job Performance Measures (JPMs), and evaluated simulator scenarios. These evaluations may incorporate topics including the loss of the main generator voltage regulator and actions to mitigate the effect of the failure. Testing is commensurate with the material presented and any performance issues are identified for inclusion in future training.

(b) If your TS bases sections, the final safety analysis report, and plant procedures do not provide guidance regarding situations in which the condition of plant-controlled or monitored equipment can adversely affect the operability of the NPP offsite power system, explain why you believe you comply with the provisions of GDC 17 and the plant TSs, or describe what actions you intend to take to provide such guidance or procedures.

Response

Not applicable

Use of NPP licensee/TSO protocols and analysis tool by TSOs to assist NPP licensees in monitoring grid conditions for consideration in maintenance risk assessments.

The Maintenance Rule (10 CFR 50.65(a)(4)) requires that licensees assess and manage the increase in risk that may result from proposed maintenance activities before performing them.

5. *Performance of grid reliability evaluations as part of the maintenance risk assessments required by 10 CFR 50.65(a)(4).*

(a) Is a quantitative or qualitative grid reliability evaluation performed at your NPP as part of the maintenance risk assessment required by 10 CFR 50.65(a)(4) before performing grid-risk-sensitive maintenance activities? This includes surveillances, post-maintenance testing, and preventive and corrective maintenance that could increase the probability of a plant trip or LOOP or impact LOOP or SBO coping capability, for example, before taking a risk-significant piece of equipment (such as an EDG, a battery, a steam-driven pump, an alternate AC power source) out-of-service?

Response

Yes

Risk is assessed using a process that combines quantitative results from a probabilistic risk assessment (PRA) with a qualitative defense-in-depth model. During the planning and scheduling of work and prior to the execution of work, many factors are assessed for risk including the effect of weather, time of year and grid instability. The combination of unavailable Systems, Structures and Components (SSCs) and planned activities is then assessed in the risk assessment tool. Currently, a procedure update is being implemented to provide additional detail for how to factor grid reliability into the risk assessment tool before taking equipment out of service for planned maintenance. These procedure changes are currently scheduled to be in place at Braidwood Station by May 15, 2006.

(b) Is grid status monitored by some means for the duration of the grid-risk-sensitive maintenance to confirm the continued validity of the risk assessment and is risk reassessed when warranted? If not, how is the risk assessed during grid-risk-sensitive maintenance?

Response

Yes

Grid status is continually evaluated by PJM using the Security Analysis application. PJM notifies Braidwood Station through its Transmission Operator, (i.e., ComEd), of emergent grid conditions as discussed in the response to 1(b) above. In addition, ComEd (i.e., the TO) is also performing similar monitoring and evaluation. Existing EGC procedures require evaluation of the risk of scheduled online maintenance activities based on conditions such as power grid stability, weather forecast, and current plant system conditions.

(c) Is there a significant variation in the stress on the grid in the vicinity of your NPP site caused by seasonal loads or maintenance activities associated with critical transmission elements? Is there a seasonal variation (or the potential for a seasonal variation) in the

LOOP frequency in the local transmission region? If the answer to either question is yes, discuss the time of year when the variations occur and their magnitude.

Response

The base PRA model reflects the yearly average LOOP frequency because seasonal variations that would cause changes to the frequency of a LOOP cannot be accurately predicted. While time related variations are not factored into the base PRA model for Braidwood Station, symptoms of grid stress such as maximum generation conditions, low grid voltage, or severe weather conditions require identification of such dynamic conditions should they occur, and risk management actions are then taken to mitigate the risk or reschedule the work as appropriate.

PJM provided the following information to EGC regarding this response in a letter from PJM to all PJM nuclear owners (Reference 6).

"Stress on the grid is manifested in a number of ways. Stress can mean 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.

Regarding the seasonal variability of the stress causers, each has a seasonal component. For example, peak load levels occur at the peak seasons of the summer and winter seasons. While the specific days cannot be predicted, it is known roughly when they will occur. Consequently, maintenance during these times of the year is avoided.

From a transmission system operations perspective, it is the simultaneous combination of stress causers that results in the most difficult operational challenges. For example, experiencing very hot (or cold) weather when we (i.e., PJM) are in the maintenance seasons with a lot of equipment out of service can cause the most severe challenges.

We (i.e., PJM) are aware of the existence of the North American Electric Reliability Council (NERC) and NRC data regarding LOOP frequency. However, it is difficult to assign differential risks to any seasonal variation because of the complexity of the various competing factors, as explained above."

(d) Are known time-related variations in the probability of a LOOP at your plant site considered in the grid-risk-sensitive maintenance evaluation? If not, what is your basis for not considering them?

Response

No

While time related variations are not factored into the base PRA model for Braidwood Station, symptoms of grid stress such as maximum generation conditions, low grid voltage, or severe weather conditions require identification of such dynamic conditions should they occur, and risk management actions are then taken to mitigate the risk or reschedule the work as appropriate.

(e) Do you have contacts with the TSO to determine current and anticipated grid conditions as part of the grid reliability evaluation performed before conducting grid-risk-sensitive maintenance activities?

Response

Yes

The protocol for NPP notification of actual or anticipated grid conditions is outlined in the response to 1(b). Any work performed on the grid risk sensitive equipment is evaluated for risk using these current or anticipated conditions as part of the evaluation prior to performance. Work is coordinated based on anticipated conditions and planned maintenance during bi-monthly interface meetings between the transmission operator (i.e., ComEd) and the EGC NPPs (i.e., Braidwood Station).

As stated in the response to 1(b), communication is shared between the TSO (i.e., PJM) and Braidwood Station if grid conditions deteriorate from an acceptable level. If contingencies are anticipated (e.g., the predicted post NPP trip offsite source voltage less than required) the TSO will provide Braidwood Station with a one day look ahead notice.

(f) Describe any formal agreement or protocol that you have with your TSO to assure that you are promptly alerted to a worsening grid condition that may emerge during a maintenance activity.

Response

As stated in the response to 1(a), Braidwood Station is located in the service territory of PJM. PJM is the TSO for Braidwood Station. The TO providing interconnection services for Braidwood Station is ComEd. EGC and ComEd are both members of PJM.

All members of PJM execute the PJM Operating Agreement (Reference 1) that details the obligations and responsibilities of both PJM and the PJM members. In the Operating Agreement, each member agrees to abide by the requirements contained in the PJM Manuals. The PJM Manuals contain the specific operational requirements that PJM and each member is required to follow.

As stated in the response to 1(b), PJM Manual M13 (Reference 5) identifies a series of alerts, warnings, and actions that PJM issues to PJM members depending on the identified grid condition. The PJM message is communicated to Braidwood Station by their generation dispatcher through the EGC NDO for a variety of system conditions including capacity emergencies, light load emergencies, weather/environmental emergencies or sabotage/terrorism emergencies.

PJM Manual M3 (Reference 4) requires PJM to initiate notification to Braidwood Station through the TO's control center if PJM identifies a switchyard voltage violation. PJM Manual M3 states: "This notification should occur within 15 minutes for voltage contingency violations and immediately for actual voltage violations. To the extent practical, PJM shall direct operations such that the violation is remedied within 30 minutes."

(g) Do you contact your TSO periodically for the duration of the grid-risk sensitive maintenance activities?

Response

No

Communications take place between the TSO (i.e., PJM) through the TO (i.e., ComEd), the NDO and Braidwood Station as detailed in the response to 1(b) above if grid conditions deteriorate from an acceptable level. If contingencies (e.g., the post trip voltages for Braidwood Station are predicted to be below the required limit) are anticipated, the TSO/TO will provide Braidwood Station with a one day look ahead notice. At this time there is no periodic mandated contact between the TSO/TO and Braidwood Station during the duration of grid-risk-sensitive maintenance activities.

(h) If you have a formal agreement or protocol with your TSO, describe how NPP operators and maintenance personnel are trained and tested on this formal agreement or protocol.

Response

Braidwood Station maintenance, operations, and work management personnel associated with schedule development or communicating with the TO (i.e., ComEd) are briefed on TSO/TO interface requirements and expectations but are not formally tested on knowledge retention in this area.

(i) If your grid reliability evaluation, performed as part of the maintenance risk assessment required by 10 CFR 50.65(a)(4), does not consider or rely on some arrangement for communication with the TSO, explain why you believe you comply with 10 CFR 50.65(a)(4).

Response

Not applicable

The methods used to integrate grid risk into the quantitative risk evaluation prior to taking equipment out of service for planned maintenance at Braidwood Station rely on communication with the TSO/TO.

(j) If risk is not assessed (when warranted) based on continuing communication with the TSO throughout the duration of grid-risk-sensitive maintenance activities, explain why you believe you have effectively implemented the relevant provisions of the endorsed industry guidance associated with the maintenance rule.

Response

Not applicable

As detailed in the response to 2(a), grid status is continually evaluated by PJM using the Security Analysis application. PJM notifies Braidwood Station through the TO (i.e., ComEd) of emergent grid conditions. In addition, ComEd (i.e., the TO) possesses a similar system and is also monitoring and evaluating grid conditions. Existing EGC procedures require evaluation of the risk of scheduled on line maintenance activities based on conditions such as power grid stability, weather forecast, and current plant system conditions.

(k) With respect to questions 5(i) and 5(j), you may, as an alternative, describe what actions you intend to take to ensure that the increase in risk that may result from proposed grid-risk-sensitive activities is assessed before and during grid-risk-sensitive maintenance activities, respectively.

Response

Not applicable

6. *Use of risk assessment results, including the results of grid reliability evaluations, in managing maintenance risk, as required by 10 CFR 50.65(a)(4).*

(a) Does the TSO coordinate transmission system maintenance activities that can have an impact on the NPP operation with the NPP operator?

Response

Yes

The TSO/TO coordinates transmission system maintenance activities that can have an impact on the NPP (i.e., Braidwood Station) with Braidwood Station.

(b) Do you coordinate NPP maintenance activities that can have an impact on the transmission system with the TSO?

Response

Yes

The NPP (i.e., Braidwood Station) coordinates maintenance activities that can have an impact on the transmission system with the TSO/TO.

(c) Do you consider and implement, if warranted, the rescheduling of grid-risk-sensitive maintenance activities (activities that could (1) increase the likelihood of a plant trip, (ii) increase LOOP probability, or (iii) reduce LOOP or SBO coping capability) under existing, imminent, or worsening degraded grid reliability conditions?

Response

Yes

Existing procedures require deferring work that would render AC power sources unavailable if severe weather is expected. Risk of scheduled on line work is evaluated based on grid conditions, the weather forecast, and current plant systems status. If the risk analysis determines that risk exceeds a predetermined level, then that configuration is not voluntarily entered and schedule changes are made to reduce the risk to an acceptable level.

(d) If there is an overriding need to perform grid-risk-sensitive maintenance activities under existing or imminent conditions of degraded grid reliability, or continue grid-risk-sensitive maintenance when grid conditions worsen, do you implement appropriate risk management actions? If so, describe the actions that you would take. (These actions could include alternate equipment protection and compensatory measures to limit or minimize risk.)

Response

Yes

When any risk significant SSC is made unavailable, actions are taken to protect redundant or diverse SSCs commensurate with the risk significance of the work being performed in accordance with approved procedures.

(e) Describe the actions associated with questions 6(a) through 6(d) above that would be taken, state whether each action is governed by documented procedures and identify the procedures, and explain why these actions are effective and will be consistently accomplished.

Response

The outage coordination process is documented in the PJM Manuals and agreed to by PJM (i.e., the TSO) and the members. EGC and ComEd (i.e., the TO) are both members of PJM. In addition, PJM has computerized tools to track the process throughout its evolution, so that PJM, ComEd and EGC are clear what the status is and what the expectations are.

Planned transmission outages are coordinated in accordance with a process detailed in PJM Manual M3, "Transmission Operations," Section 4 (Reference 4). This process requires advanced notice and subsequent PJM approval for all outages to ensure grid reliability. On the outage start day, the system is analyzed one last time by PJM before permitting the equipment to be switched out of service.

Once the equipment is switched out of service, grid status is continually evaluated by the PJM Security Analysis application as detailed in the response to 2(a). In addition, the TO (i.e., ComEd) is performing similar monitoring and evaluation. PJM notifies the NPP (i.e., Braidwood Station) through the TO's control center, as discussed in the response to 1(b).

An 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," (Reference 7) directs that schedule coordination meetings are held bi-monthly between the TSO/TO and the NPPs (i.e., Braidwood Station) to coordinate maintenance activities that can have mutual impact.

Actions specified in questions 6(c) and 6(d) are specified in the EGC Work Management procedure, WC-AA-101, "On-Line Work Control Process," (Reference 8) and is applicable to Braidwood Station.

(f) Describe how NPP operators and maintenance personnel are trained and tested to assure they can accomplish the actions described in your answers to question 6(e).

Response

Braidwood Station Maintenance, Operations, and Work Management personnel associated with schedule development and/or risk assessment are briefed on procedure expectations but are not formally tested on knowledge retention in this area.

(g) If there is no effective coordination between the NPP operator and the TSO regarding transmission system maintenance or NPP maintenance activities, please explain why you believe you comply with the provisions of 10 CFR 50.65(a)(4).

Response

Not applicable

Effective coordination is directed by PJM (i.e., the TSO) procedures and jointly approved interface procedures between ComEd (i.e., the TO) and EGC.

(h) If you do not consider and effectively implement appropriate risk management actions during the conditions described above, explain why you believe you effectively addressed the relevant provisions of the associated NRC-endorsed industry guidance.

Response

Not applicable

Effective and appropriate risk management actions are described in plant procedures and implemented during the conditions described above.

(i) You may, as alternative to questions 6(g) and 6 (h) describe what actions you intend to take to ensure that the increase in risk that may result from grid-risk-sensitive maintenance activities is managed in accordance with 10 CFR 50.65(a)(4).

Response

Not applicable

Offsite power restoration procedures in accordance with 10 CFR 50.63 as developed in Section 2 of RG 1.155.

Pursuant to 10 CFR 50.63, the NRC requires that each NPP licensed to operate to be able to withstand an SBO for a specified duration and recover from the SBO. NRC RG 1.155 gives licensees guidance on developing their approaches for complying with 10 CFR 50.63.

7. Procedures for identifying local power sources[1] that could be made available to resupply your plant following a LOOP event.

Note: Section 2, "Offsite Power," of RG 1.155 (ADAMS Accession No. ML003740034) states:

> *Procedures should include the actions necessary to restore offsite power and use nearby power sources when offsite power is unavailable. As a minimum, the following potential causes for loss of offsite power should be considered:*
>
> - *Grid undervoltage and collapse*
> - *Weather-induced power loss*
> - *Preferred power distribution system faults that could result in the loss of normal power to essential switchgear buses*

(a) Briefly describe any agreement made with the TSO to identify local power sources that could be made available to resupply power to your plant following a LOOP event.

Response

Braidwood Station is located in the service territory of PJM. PJM is the Transmission System Operator (TSO) for Braidwood Station. The Transmission Owner (TO) providing interconnection services for Braidwood Station is ComEd. EGC and ComEd are both members of PJM.

All members of PJM execute the "Operating Agreement of PJM Interconnection, LLC," (Reference 1) that details the obligations and responsibilities of both PJM and the PJM members. In the Operating Agreement, each member agrees to abide by the requirements contained in the PJM Manuals. The PJM Manuals contain the specific operational requirements that PJM and each member is required to follow.

ComEd (i.e., the TO) is also a signatory on the "PJM Consolidated Transmission Owners Agreement (PJM TOA)," (Reference 2). Section 4.5 of the PJM TOA requires the TOs to operate and maintain their transmission facilities in accordance with the PJM Manuals.

PJM (i.e., the TSO) is responsible for coordinating restoration of all or parts of the bulk power system in the PJM service territory. ComEd (i.e., the TO) is responsible for cooperating and coordinating with PJM and other PJM members during the restoration of all or parts of the bulk power system in the PJM service territory.

PJM Manual M36, "System Restoration," (Reference 11) gives priority to the restoration of offsite power to NPPs (i.e., Braidwood Station) in the PJM service territory. The TSO (i.e., PJM) and the TO (i.e., ComEd) will utilize the best power sources and transmission paths available based on the specific event to restore offsite power since there is no way to accurately predict the extent and characteristics of a specific blackout. The TSO and

[1] *This includes items such as nearby or onsite gas turbine generators, portable generators, hydro generators, and black-start fossil power plants.*

TO have multiple options available to restore offsite power and these would not be limited to local power sources.

The Interconnection Agreement between the NPP (i.e., Braidwood Station) and ComEd (i.e., the TO) reinforces the importance and priority of restoring the NPP offsite power source (Reference 14). In addition, Braidwood Station has an Affiliate Level Arrangement Agreement (ALA) with ComEd (Reference 15) to apply "best efforts" to restore to service the facilities that they own or control in order to restore the Braidwood Station offsite power circuit back to an operable status.

PJM provided the following information to EGC regarding this response in a letter from PJM to all PJM nuclear owners (Reference 6).

"The PJM Restoration Manual (M36) details the process to be followed during a system restoration. The process reiterates the specific offsite power requirements for NPPs:

> 'Offsite power should be restored as soon as possible to nuclear units, both units that had been operating and those that were already offline prior to the system disturbance, without regard to using these units for restoring customer load.'

However, due to the myriad of possible restoration scenarios, no specific power sources to resupply NPPs are identified. The PJM restoration process allows for the fact that the blacked out area may or may not be separated from the remainder of the system. Regardless of the scenario, there is a clear recognition of the importance of restoring an NPP offsite power source.

PJM Manual M36 further states: 'Transmission Owners and Nuclear Power Plants must effectively communicate to keep the Nuclear Power Plant apprised of the anticipated restoration time for offsite power.' The manual also states that for PJM Restoration Drills the objectives should include 'Ensure that all nuclear units have been provided with one offsite source within 4 hours,' and that the PJM Nuclear Generation Owner/Operator Users Group should be debriefed on the drill results.

In support of the restoration objectives outlined in the PJM Restoration Manual (M36), there are generating units designated as critical black-start units electrically close to each of the NPPs. These black start units are required to provide black start capability whenever necessary. The adequacy of black-start resources to support system restoration is managed through a process contained in PJM Manual M10, "PreScheduling Operations," (Reference 12), Section 2. The process ensures the continuous availability of black start units to support the restoration needs of the NPPs even when a designated black start unit is on a planned outage."

(b) Are your NPP operators trained and tested on identifying and using local power sources to resupply your plant following a LOOP event? If so, describe how.

<u>Response</u>

No

Braidwood Station operators are not specifically trained and tested on identifying and using local power sources to resupply the NPP (i.e., Braidwood Station) following a LOOP event. The identification and use of local power sources for Braidwood Station are under the control of PJM (i.e., the TSO) and ComEd (i.e., the TO) in accordance with the procedures and interface agreements described in the response to 7(a). The response to this question does not address the operation of the Braidwood Station alternate AC source established under 10 CFR 50.63, "Loss of all alternating current power," (i.e., Station Blackout (SBO) Rule), for which Braidwood Station operators are trained and tested to identify and use under SBO conditions.

(c) If you have not established an agreement with your plant's TSO to identify local power sources that could be made available to resupply power to your plant following a LOOP event, explain why you believe you comply with the provisions of 10 CFR 50.63, or describe what actions you intend to take to establish compliance.

Response

The identification and use of local power sources for restoration of offsite power to Braidwood Station following a LOOP event are under the control of PJM (i.e., the TSO) and ComEd (i.e., the TO) in accordance with the procedures and interface agreements described in the response to 7(a). Due to the myriad of possible restoration scenarios, no specific power sources to resupply Braidwood Station are identified. The procedures identified by RG 1.155, "Station Blackout," (Reference 13) that include the actions necessary to restore offsite power and the use of nearby power sources are also under the control of PJM and ComEd.

Note that, as detailed in the response to 7(a), both ComEd (i.e., the TO) and PJM (i.e., the TSO) have stated that restoring offsite power to a NPP (i.e., Braidwood Station) is a priority.

The identification and use of local power sources that could be made available to resupply power to the NPP following a LOOP event are not part of the current Braidwood Station operating procedures and training since they are outside of Braidwood Station's direct control.

Losses of offsite power caused by grid failures at a frequency of equal to or greater than once in 20 site-years in accordance with Table 4 of Regulatory Guide 1.155 for complying with 10 CFR 50.63.

Pursuant to 10 CFR 50.63, the NRC requires that each NPP licensed to operate be able to withstand an SBO for a specified duration and recover from the SBO. NRC RG 1.155 gives licensees guidance on developing their approaches to complying with 10 CFR 50.63.

8. Maintaining SBO coping capabilities in accordance with 10 CFR 50.63.

(a) Has your NPP experienced a total LOOP caused by grid failure since the plant's coping duration was initially determined under 10 CFR 50.63?

Response

Braidwood Station has not experienced a total LOOP caused by grid failure since the coping duration was initially determined under 10 CFR 50.63, "Loss of all alternating current power," (i.e., Station Blackout (SBO) Rule). A review of Braidwood Station records including the Licensee Event Report (LER) database from July 1988, when the SBO Rule was added, was performed to make this determination.

This determination is consistent with the data presented in NUREG/CR-6890, Volume 1, "Reevaluation of Station Blackout Risk at Nuclear Power Plants – Analysis of Offsite Power Events: 1986-2004," (Reference 9), Appendix A, "LOOP Event Database," Section A-2, "Data Tables," Table A -1, "Loop Events for 1986-2004, sorted by plant."

In addition, the review of LERs since Reference 9 was issued to present has concluded that there were no additional grid failure based LOOP events during this period.

(b) If so, have you reevaluated the NPP using the guidance in Table 4 of RG 1.155 to determine if your NPP should be assigned to the P3 offsite power design characteristic group?

Response

Not applicable

(c) If so, what were the results of this reevaluation, and did the initially determined coping duration for the NPP need to be adjusted?

Response

Not applicable

(d) If your NPP has experienced a total LOOP caused by grid failure since the plant's coping duration was initially determined under 10 CFR 50.63 and has not been reevaluated using the guidance in Table 4 of RG 1.155, explain why you believe you comply with the provisions of 10 CFR 50.63 as stated above, or described what actions you intend to take to ensure that the NPP maintains its SBO coping capabilities in accordance with 10 CFR 50.63.

Response

Not applicable

Actions to ensure compliance

9. *If you determine that any action is warranted to bring your NPP into compliance with NRC regulatory requirements, including TSs, GDC 17, 10 CFR 50.65(a)(4), 10 CFR 50.63, 10 CFR 55.59 or 10 CFR 50.120, describe the schedule for implementing it.*

Response

Not applicable

References

1. "Operating Agreement of PJM Interconnection, LLC," revised through February 6. 2006

2. "Consolidated Transmission Owners Agreement," effective March 19, 2006

3. PJM Manual 01, "Control Center Requirements," Revision 10, effective February 7, 2006

4. PJM Manual 3, "Transmission Operations," Revision 20, effective February 10, 2006

5. PJM Manual 13, "Emergency Operations," Revision 24, effective February 22, 2006

6. 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

7. EGC procedure WC-AA-8000, "Interface Procedure between Exelon Energy Delivery (ComEd/PECO) and Exelon Generation (Nuclear/Power) for Construction and Maintenance Activities," Revision 0

8. EGC procedure WC-AA-101, "On-Line Work Control Process," Revision 11

9. NUREG/CR-6890, Volume 1, "Reevaluation of Station Blackout Risk at Nuclear Power Plants – Analysis of Offsite Power Events: 1986-2004," Revision 0

10. EGC procedure OP-AA-108-107-1002, "Interface Agreement between Exelon Energy Delivery and Exelon Generation for Switchyard Operations," Revision 2

11. PJM Manual 36, "System Restoration," Revision 2, effective November 1, 2005

12. PJM Manual 10, "Pre-Scheduling Operations," Revision 18, effective August 10, 2005

13. Regulatory Guide 1.155, "Station Blackout," Revision 0

14. "Facilities, Interconnection and Easement Agreement among ComEd Generation Company LLC, Exelon Generation Company, LLC and Commonweatlh Edison Company," Braidwood Station Final Form, dated January 12, 2001

15. "Affiliate Level Arrangement ('ALA') by and among Exelon Energy Delivery Groups of ComEd and Exelon Generation Company, LLC," effective January 1, 2006

16. NRC Information Notice IN 93-17, "Safety Systems Response to Loss of Coolant and Loss of Offsite Power," Revision 1, dated March 25, 1994

17. SECY-05-0219, "Issuance of Nuclear Regulatory Commission Generic Letter 2005-XX, 'Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power,'" dated December 2, 2005

18. EGC procedure OP-AA-108-107-1001, "Station Response to Grid Capacity Conditions," Revision 1

19. Braidwood Station Abnormal Operating Procedure BWOA ELEC-4, "Loss of Offsite Power"

20. Braidwood Station Abnormal Operating Procedure BWOA ELEC-3, "Loss of 4KV ESF Bus"

21. Braidwood Station Emergency Operating Procedure BWEP-0, "Reactor Trip or Safety Injection,"

22. Braidwood Station Emergency Operating Procedure ES-0.1, "Reactor Trip Response"

23. Braidwood Station Emergency Contingency Action Procedure BWCA-0.0, "Loss of All AC"

24. EGC procedure WC-AA-107, "Seasonal Readiness," Revision 2

25. SOER 99-1, "Loss of Grid," December 27, 1999

26. SOER 99-1, "Loss of Grid – Addendum," December 9, 2004

27. Jennifer Sterling, Exelon Transmission Planning, "NRC Generic Letter – Draft responses to questions 1 and 2," February 14, 2006, personal email to John Gyrath, Exelon Nuclear, (February 14, 2006)

ATTACHMENT 2

60-day Response to NRC Generic Letter 2006-02

BYRON STATION, Units 1 and 2

FOL Nos. NPF-37 and NPF-66

ATTACHMENT 2
60-day Response to NRC Generic Letter 2006-02
BYRON STATION, Units 1 and 2

On February 1, 2006, the NRC issued Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power." 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 Generic Letter requested that licensees answer the following questions and provide the information to the NRC with respect to each of their Nuclear Power Plants (NPPs).

Use of protocols between the NPP licensee and the TSO, ISO, or RC/RA and the use of analysis tools by TSOs to assist NPP licensee in monitoring grid conditions to determine the operability of offsite power system under plant TS.

GDC 17, 10 CFR Part 50, Appendix A, requires that licensees minimize the probability of the loss of power from the transmission network given a loss of the power generated by the nuclear power unit(s).

1. *Use of protocols between the NPP licensee and the TSO, ISO, or RC/RA to assist the NPP licensee in monitoring grid conditions to determine the operability of offsite power system under plant TS.*

    (a) Do you have a formal agreement or protocol with your TSO?

    Response

    Yes

    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.

    All members of PJM execute the "Operating Agreement of PJM Interconnection, LLC," (Reference 1) that details the obligations and responsibilities of both PJM and the PJM members. In the Operating Agreement, each member agrees to abide by the requirements contained in the PJM Manuals. The PJM Manuals contain the specific operational requirements that PJM and each member is required to follow.

    ComEd (i.e., the TO) is also a signatory on the "PJM Consolidated Transmission Owners Agreement (PJM TOA)," (Reference 2). Section 4.5 of the PJM TOA requires the TOs to operate and maintain their transmission facilities in accordance with the PJM Manuals.

    The PJM Operating Agreement requires PJM to, "Incorporate the grid reliability requirements applicable to nuclear generating units in the PJM Region planning and operating principles and practices." PJM Manual M01, "Control Center Requirements," Attachment B, "Nuclear Plant Communication Protocol," (Reference 3), provides the roles and responsibilities of nuclear stations, TOs, and PJM with regard to communications both in normal and emergency circumstances. The nuclear power plant (NPP) notification requirements are contained in PJM Manual M3, "Transmission Operations," Section 3 (Reference 4).

In addition to the agreements delineated in the PJM Operating Agreement and the PJM Manuals, EGC has jointly approved interface procedures with the TO that address the monitoring of the offsite source voltages and the notification protocols. EGC procedure OP-AA-108-107-1002, "Interface Agreement between Exelon Energy Delivery and Exelon Generation for Switchyard Operations," (Reference 10) outlines the responsibilities and required work interfacing activities.

(b) Describe any grid conditions that would trigger a notification from the TSO to the NPP licensee and if there is a time period required for the notification.

Response

PJM Manual M3 (Reference 4) requires PJM to initiate notification to Byron Station through the TO's control center if PJM identifies a switchyard voltage violation. PJM Manual M3 states: "This notification should occur within 15 minutes for voltage contingency violations and immediately for actual voltage violations. To the extent practical, PJM shall direct operations such that the violation is remedied within 30 minutes."

In addition, PJM Manual M13, "Emergency Operations," (Reference 5) identifies a series of alerts, warnings, and actions that PJM issues to PJM members depending on the identified grid condition. The PJM message is communicated to Byron Station by their generation dispatcher through the EGC Nuclear Duty Officer (NDO) for a variety of system conditions including the following:

Capacity Emergencies
- Maximum Emergency Generation Loading
- Load Management Curtailment
- Manual Load Dump Warning

Light Load Emergencies
- Minimum Generation Emergency
- Local Minimum Generation Emergency

Weather/Environmental Emergencies
- Hot/Cold Weather Alerts
- Thunderstorms and Tornadoes
- Solar Magnetic Disturbances

Sabotage/Terrorism Emergencies

(c) Describe any grid conditions that would cause the NPP licensee to contact the TSO. Describe the procedures associated with such a communication. If you do not have procedures, describe how you assess grid conditions that may cause the NPP licensee to contact the TSO.

Response

As required by PJM Manuals, communications between Byron Station and PJM (TSO) are generally through the Transmission Owner (TO) providing the interconnection service.

Byron Station will contact the TSO/TO for grid conditions that have parameters that are observable at the NPP. These conditions include the following:

- Loss of Offsite Power (LOOP)
- Abnormal switchyard voltage
- Automatic (protective) switchyard circuit breaker operation
- Switchyard alarms
- Grid disturbances (observable frequency or voltage fluctuations)

In addition to any alarm response procedures for the above applicable conditions, TSO/TO notifications are controlled by operating procedures, (e.g., OP-AA-108-107-1001, "Station Response to Grid Capacity Conditions"), Abnormal Operating Procedures, (e.g., BOA ELEC-4, "Loss of Offsite Power," BOA ELEC-3, "Loss of 4KV ESF Bus"), Emergency Operating Procedures, (e.g., BEP-0, "Reactor Trip or Safety Injection," BEP ES-0.1, "Reactor Trip Response"), and Emergency Contingency Action Procedures, (e.g., BCA-0.0, "Loss of All AC").

Byron Station will contact the TSO/TO during a grid restoration process to obtain grid status in preparation for returning the plant buses to the offsite source.

Byron Station also notifies the TSO/TO of switchyard equipment deficiencies identified by NPP personnel. Jointly approved interface agreements/procedures between EGC and the TO identify the communication protocols for station identified switchyard deficiencies. EGC procedures OP-AA-108-107-1002 (Reference 10) and WC-AA-8000 (Reference 7) outline the responsibilities and required work interfacing activities.

In addition, Byron Station will notify the TSO/TO of NPP configurations that potentially impact grid conditions. A jointly approved interface agreement/procedure, OP-AA-108-107-1002 (Reference 10), between EGC and the TO identifies the requirements for communication of the conditions listed below:

- NPP MVAR limitations
- NPP Main generator voltage regulator not in "Automatic" mode
- NPP inability to provide the MVARs requested by the TSO/TO

Note that any Byron Station MW limitations or limitations on the rate at which the NPP power may be raised or lowered are communicated to the generation dispatcher.

(d) Describe how NPP operators are trained and tested on the use of the procedures or assessing grid conditions in question 1(c).

Response

Byron Station licensed operators are trained and tested in accordance with the Systematic Approach to Training (SAT). Procedures and policies are routinely reviewed for training through this process for improvement of operator performance. The items considered for training include Operating Procedures, Annunciator Response Procedures, Abnormal Operating Procedures, and Emergency Operating Procedures that require interface with the TSO in accordance with the established protocol. These procedures may be utilized based on various grid, switchyard, or plant symptoms to assess, respond to or mitigate off-normal plant and grid conditions. Additionally, SOER 99-01, "Loss of Grid," (Reference 25) and SOER 99-01, "Loss of Grid – Addendum," (Reference 26) specifically are captured in the Licensed Operator Requalification Training Program (LORT) Long Range Training Program. These topics, in varying detail based upon the SAT process or as part of implementing EGC procedure WC-AA-107, "Seasonal Readiness," (Reference 24) are reviewed periodically with Byron Station operators. Testing is commensurate with the material presented and any performance issues are identified for inclusion in future training.

(e) If you do not have a formal agreement or protocol with your TSO, describe why you believe you continue to comply with the provisions of GDC 17 as stated above, or describe what actions you intend to take to assure compliance with GDC 17.

Response

Not applicable. Formal agreements exist for Byron Station.

(f) If you have an existing formal interconnection agreement or protocol that ensures adequate communication and coordination between the NPP license and the TSO, describe whether this agreement or protocol requires that you be promptly notified when the conditions of the surrounding grid could result in degraded voltage (i.e., below TS nominal trip setpoint value requirements; including NPP licensees using allowable value in its TSs) or LOOP after a trip of the reactor units(s).

Response

PJM Manual M3 (Reference 4) requires PJM to initiate a notification to Byron Station through its respective transmission owner's control center if PJM identifies a NPP switchyard voltage violation. PJM Manual M3 states: "This notification should occur within 15 minutes for voltage contingency violations and immediately for actual voltage violations. To the extent practical, PJM shall direct operations such that the violation is remedied within 30 minutes." The trip of a NPP (i.e., trip of a Byron Station unit) is one of the contingencies analyzed by PJM. PJM analyzes the Byron Station switchyard contingency voltages to the voltage limits provided by Byron Station. The voltage limits provided for Byron Station are based on the existing design basis analysis.

(g) Describe the low switchyard voltage conditions that would initiate operation of plant degraded voltage protection.

Response

Switchyard voltage below a value maintaining emergency bus voltage above the setpoint of the degraded voltage relay (3847 volts) will cause a trip of the preferred power source after a time delay of approximately 10 seconds with a Loss of Coolant Accident (LOCA) signal present. The relation between the switchyard voltage and the emergency bus voltage is dependent on the system auxiliary transformer impedance and the winding load. Under design basis accident (i.e., Large Break LOCA) conditions, the maximum loading is known and contained in the Byron Station calculations of record. The design basis maximum loading and the degraded voltage relay reset voltage were used to determine the switchyard voltage needed for the system to remain connected to the offsite power source. For Byron Station, this corresponds to a switchyard voltage of approximately 339 kV.

In other conditions, the loading is less than the expected LOCA loading and will vary considerably depending on which loads are needed to support unit conditions. Under these conditions the required Byron Station switchyard voltage will be less than that required to support LOCA loading.

2. *Use of criteria and methodologies to assess whether the offsite power system will become inoperable as a result of a trip of your NPP.*

(a) Does your NPP's TSO use any analysis tools, an online analytical transmission system studies program, or other equivalent predictive methods to determine the grid conditions that would make the NPP offsite power system inoperable during various contingencies? If available to you, please provide a brief description of the analysis tool that is used by the TSO.

Response

Yes

The PJM Energy Management System (EMS) includes a Security Analysis application which runs approximately every 1 minute and analyzes ~4,000 contingencies on the PJM system (Reference 6). The analysis provides results with respect to thermal, voltage, and voltage drop limit violations. One of the contingencies analyzed by the PJM EMS is the trip of a NPP (i.e., trip of a Byron Station unit).

In addition, ComEd (i.e., the TO) possesses a similar system that also calculates post-contingency voltage limit violations. One of the contingencies analyzed by ComEd is the trip of a Byron unit.

(b) Does your NPP's TSO use an analysis tool as the basis for notifying the NPP licensee when such a condition is identified? If not, how does the TSO determine if conditions on the grid warrant NPP licensee notification?

Response

Yes

The results of the PJM Security Analysis application contain the specific contingency of the NPP tripping as the contingent element. Violation of the unit trip contingency voltage limit would result in notification of the NPP (i.e., Byron Station) in accordance with PJM Manual M3, Section 3 (Reference 4).

ComEd (i.e., the TO) also possesses similar capability to monitor the same condition.

(c) If your TSO uses an analysis tool, would the analysis tool identify a condition in which a trip of the NPP would result in switchyard voltages (immediate and/or long-term) falling below TS nominal trip setpoint value requirements (including NPP licensees using allowable value in its TSs) and consequent actuation of plant degraded voltage protection? If not, discuss how such a condition would be identified on the grid.

Response

Yes

The trip of the NPP (i.e., trip of a Byron Station unit) is one of the contingencies analyzed by the PJM Security Analysis application. PJM analyzes the NPP switchyard contingency voltages to the voltage limits provided by Byron Station. The voltage limits provided by Byron Station are based on the plant's design basis analysis as discussed in the response to 1(g).

ComEd (i.e., the TO) also possesses similar capability to monitor the same condition.

(d) If your TSO uses an analysis tool, how frequently does the analysis tool program update?

Response

The PJM EMS includes a Security Analysis application that currently updates approximately every 1-minute. In addition, ComEd (i.e., the TO) possesses a Security Analysis application that updates approximately every 6 minutes (Reference 27).

(e) Provide details of analysis tool-identified contingency conditions that would trigger an NPP licensee notification from the TSO.

Response

PJM notifies Byron Station through the TO (i.e., ComEd) control center whenever actual or post-contingency voltages are determined to be below the Byron Station switchyard voltage limits. This requirement applies to all contingencies involving the tripping of the NPP or any transmission facility as the contingent element. In accordance with PJM Manual M3 (Reference 4) the notification is required even if the voltage limits are the same as the standard PJM voltage limits.

(f) If an interface agreement exists between the TSO and the NPP licensee, does it require that the NPP licensee be notified of periods when the TSO is unable to determine if offsite power voltage and capacity could be inadequate? If so, how does

the NPP licensee determine that the offsite power would remain operable when such a notification is received?

Response

Yes

Byron Station unit trip contingency voltage calculations are performed by the PJM EMS and the TO (i.e., ComEd) Security Analysis application. The PJM EMS consists of a primary and backup system. If the PJM EMS fails, the ComEd Security Analysis application continues to analyze the Byron Station unit trip contingency voltage. Byron Station will be notified if the real time contingency analysis capability of PJM and the TO (i.e., ComEd) are lost simultaneously in accordance with PJM Manual M01, Section 2 (Reference 3).

If Byron Station is notified that PJM and ComEd (i.e., the TO) have both lost their real time contingency analysis capability, Byron Station would request PJM and ComEd to provide an assessment of the current condition of the grid based on the tools that PJM and ComEd have available. The determination of the operability of the offsite sources would consider the assessment provided by PJM and ComEd and whether the current condition of the grid is bounded by the grid studies previously performed for Byron Station.

(g) After an unscheduled inadvertent trip of the NPP, are the resultant switchyard voltages verified by procedure to be bounded by the voltages predicted by the analysis tool?

Response

No

There is presently no formal process for comparing the actual post-trip voltages to the post-trip contingency voltage results calculated by the PJM and the TO (i.e., ComEd) Security Analysis applications.

PJM provided the following information to EGC regarding this response in a letter from PJM to all PJM nuclear owners (Reference 6).

"Because the PJM transmission owning member companies have similar Security Analysis programs to PJM, there are many opportunities to compare the results of the respective Security Analysis programs. In this manner, there is a high confidence that the Security Analysis results are accurate within the precision of the calculations.

PJM retains the EMS results for a period of approximately 3 weeks after real time. It is possible to use those saved EMS results to repeat the Security Analysis calculations and compare them to the actual voltages from a unit trip. However, the NPP trips occur so infrequently that it would take a number of data points to verify the accuracy with any statistical significance. This process could take years if the process is limited to a comparison of only NPP trips."

(h) If an analysis tool is not available to the NPP licensee's TSO, do you know if there are any plans for the TSO to obtain one? If so, when?

Response

Not applicable. Byron Station TSO (i.e., PJM) has an analysis tool.

(i) If an analysis tool is not available, does your TSO perform period studies to verify that adequate offsite power capability, including adequate NPP post-trip switchyard voltages (immediate and/or long-term), will be available to the NPP licensee over the projected timeframe of the study?

Response

Not applicable. Byron Station TSO (i.e., PJM) has an analysis tool.

(a) Are the key assumptions and parameters of these periodic studies translated into TSO guidance to ensure that the transmission system is operated within the bounds of the analyses?

Response

Not applicable. Byron Station TSO (i.e., PJM) has an analysis tool.

(b) If the bounds of the analyses are exceeded, does this condition trigger the notification provisions discussed in question 1 above?

Response

Not applicable. Byron Station TSO (i.e., PJM) has an analysis tool.

(j) If your TSO does not use, or you do not have access to the results of an analysis tool, or your TSO does not perform and make available to you periodic studies that determine the adequacy of offsite power capability, please describe why you believe you comply with the provisions of GDC 17 as stated above, or describe what compensatory actions you intend to take to ensure that the offsite power system will be sufficiently reliable and remain operable with high probability following a trip of your NPP.

Response

Not applicable. Byron Station TSO (i.e., PJM) has an analysis tool. In addition the applicable contingency voltage results are made available to Byron Station as needed.

3. *Use of criteria and methodologies to assess whether the NPP's offsite power system and safety-related components will remain operable when switchyard voltages are inadequate.*

(a) If the TSO notifies the NPP operator that a trip of the NPP, or the loss of the most critical transmission line or the largest supply to the grid would result in switchyard voltages (immediate and/or long-term) below TS nominal trip setpoint value

requirements (including NPP licensees using allowable value in its TSs) and would actuate plant degraded voltage protection, is the NPP offsite power system declared inoperable under the plant TSs? If not, why not?

Response

If the TSO (i.e., PJM) notifies Byron Station that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., trip of a Byron Station unit) is below the pre-determined notification value, Byron Station will review the applicability to the plant operating configuration and will declare the offsite power source inoperable in accordance with Technical Specifications (TSs) if appropriate. The notification value provided to PJM by Byron Station is based on the Byron Station degraded voltage design basis analysis.

Predicted contingency voltages following the loss of a transmission facility (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 for Byron Station at this time. If the TSO (i.e., PJM) notifies Byron Station of a predicted contingency voltage violation resulting from the postulated trip of a transmission facility, Byron Station will perform a risk analysis of in-progress and scheduled plant work and will take action as appropriate.

The NPP unit trip contingency can be caused by plant-centered events. The use of the NPP unit trip contingency as the contingency element upon which offsite power operability is based is consistent with the final paragraph of General Design Criterion (GDC) 17, "Electric power systems," of 10 CFR Part 50 Appendix A, "General Design Criteria for Nuclear Power Plants," which requires provisions be included to minimize the probability of the loss of power from the transmission network given a loss of the power generated by the NPP (i.e., a Byron Station unit).

Postulated contingencies on the transmission system are currently not used as the basis for offsite source operability determinations since loss of power from the transmission network would not occur as a result of loss of power generated by a NPP unit (i.e., a Byron Station unit). Such events (e.g., loss of a transmission line) are only postulated and have not actually occurred, and the offsite power sources remain capable of supporting a safe shutdown and mitigating the effects of an accident. Loss of power from the transmission network would not occur as a result of loss of power generated by a NPP unit and therefore the GDC 17 provision discussed in GL 2006-02 is met.

(b) If onsite safety-related equipment (e.g., emergency diesel generators or safety-related motors) is lost when subjected to a double sequencing (LOCA with delayed LOOP event) as a result of the anticipated system performance and is incapable of performing its safety functions as a result of responding to an emergency actuation signal during this condition, is the equipment considered inoperable? If not, why not?

Response

Although some features have been incorporated into the plant design, requirements for analysis and design considerations for double sequencing are not included within the Byron Station current licensing and design basis as documented in the Byron Station Updated Final Safety Analysis Report (UFSAR). Byron Station has not been explicitly analyzed for all issues associated with double sequencing. Onsite safety-related equipment at Byron Station (e.g., emergency diesel generators or safety-related motors) is not declared inoperable as a result of a TSO (i.e., PJM) unit trip contingency voltage notification.

Based on Enclosure 2 of SECY-05-0219, "Issuance of Nuclear Regulatory Commission Generic Letter 2005-XX, 'Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power,'" (Reference 17) which provided NRC guidance on responding to this issue, a review was performed for Byron Station of the loading logic for the diesel generators as well as the safety-related breakers' anti-pumping logic. This review concluded that onsite safety-related equipment (i.e., emergency diesel generators or safety-related motors) is not lost as a result of diesel generator block loading and breaker lockout from anti-pump circuitry when subjected to a double sequencing event resulting from inadequate post unit trip voltages. The scope of the review performed for Byron Station is discussed in the response to question 3(c) below.

(c) Describe your evaluation of onsite-related equipment to determine whether it will operate as designed during the condition described in question 3(b).

Response

Although some features have been incorporated into the plant design, requirements for analysis and design considerations for double sequencing are not included within the Byron Station current licensing and design basis as documented in the Byron Station UFSAR. Byron Station has not been explicitly analyzed for all issues associated with double sequencing. However, using the NRC clarification provided in Enclosure 2 of SECY-05-0219 as guidance, a review was performed for the purpose of addressing question 3(b).

This review examined the effects of a double sequencing event on diesel generator block loading and the potential for breaker lockout from the anti-pump circuitry. The review assumed that following a LOCA initiation, the grid separation occurred as a result of degraded voltage relay operation triggered by the loss of a Byron Station unit. The review examined the diesel generator loading logic and determined that the logic is reset by the LOOP event. The second sequence is consistent with that described in the Byron Station UFSAR for a LOOP/LOCA event. Loads are shed as a result of the LOOP signal and the loads are not block loaded onto the diesel generator.

The review also examined the potential for breaker lockout due to the anti-pumping circuitry. This review determined that there was sufficient time between the two sequences such that the breaker charging springs would re-charge and the second closure would be successful. To ensure that a breaker lockout would not occur, the breaker closing logics were also examined to assure that the trip signals were cleared before the second close signal was initiated.

(d) If the NPP licensee is notified by the TSO of other grid conditions that may impair the capability or availability of offsite power, are any plant TS action statements entered? If so, please identify them.

Response

As discussed in the response to 3(a), if the TSO (i.e., PJM) notifies Byron Station that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., trip of a Byron Station unit) is below the pre-determined notification value, Byron Station will review the applicability to the plant operating configuration and will declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by Byron Station is based on the Byron Station degraded voltage design basis analysis.

In addition, if PJM notifies Byron Station that the actual offsite power source voltage is less than the pre-determined notification value, Byron Station will review the applicability to the plant operating configuration and would declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by Byron Station is based on the Byron Station degraded voltage design basis analysis.

(e) If you believe your plant TSs do not require you to declare your offsite power system or safety-related equipment inoperable in any of these circumstances, explain why you believe you comply with the provisions of GDC 17 and your plant TSs, or describe what compensatory actions you intend to take to ensure that the offsite power system and safety-related components will remain operable when switchyard voltages are inadequate.

Response

The following notifications from the TSO (i.e., PJM) will result in Byron Station declaring the offsite power source inoperable in accordance with TSs.

- If the TSO (i.e., PJM) notifies Byron Station that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., trip of a Byron Station unit) is below the pre-determined notification value, Byron Station will review the applicability to the plant operating configuration and will declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by Byron Station is based on the Byron Station degraded voltage design basis analysis.

- If the TSO (i.e., PJM) notifies Byron Station that the actual offsite power source voltage is less than the pre-determined notification value, Byron Station will review the applicability to the plant operating configuration and would declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by Byron Station is based on the Byron Station degraded voltage design basis analysis.

Predicted contingency voltages following the loss of a transmission facility (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. If the TSO notifies the NPP of a predicted contingency voltage violation resulting from the postulated trip of a transmission facility, the NPP performs a risk analysis of in-progress and scheduled plant work and takes action as appropriate.

The NPP unit trip contingency can be caused by plant-centered events. The use of the NPP unit trip contingency as the contingency element upon which offsite power operability is based is consistent with the final paragraph of GDC 17 which requires provisions to minimize the probability of the loss of power from the transmission network given a loss of the power generated by the NPP.

Postulated contingencies on the transmission system are not used as the basis for offsite source operability determinations since loss of power from the transmission network would not occur as a result of loss of power generated by the NPP unit. Such events (e.g., loss of a transmission line) are only postulated and have not actually occurred, and the offsite power sources remain capable of affecting a safe shutdown and mitigating the effects of an accident. The GDC 17 provision discussed in the Generic Letter is still met; loss of power from the transmission network would not occur as a result of loss of power generated by the NPP unit.

Onsite safety-related equipment at Byron Station (e.g., emergency diesel generators or safety-related motors) is not declared inoperable as a result of a TSO (i.e., PJM) unit trip contingency voltage notification. Although some features have been incorporated into the plant design, requirements for analysis and design considerations for double sequencing are not included within the Byron Station current licensing and design basis as documented in the Byron Station UFSAR. Byron Station has not been explicitly analyzed for all issues associated with double sequencing.

(f) Describe if and how NPP operators are trained and tested on the compensatory actions mentioned in your answers to questions 3(a) through (e).

Response

Byron Station licensed operators are trained and tested in accordance with the Systematic Approach to Training (SAT). Equipment operability, as defined by TS, including normal and emergency power, offsite circuits, and safety-related components, is under continuous review. Procedures are in place to provide operator guidance and required actions necessary during predicted or actual degraded grid voltage conditions based on information provided by the TSO/TO in accordance with established protocol or as observed by the NPP operator. As part of initial training, requalification training, and annual operating tests, licensed operators are subjected to written examinations, dynamic learning activities, static and/or simulator examinations, Job Performance Measures (JPMs), and evaluated simulator scenarios incorporating topics including the actual or predicted switchyard voltage issues and its effect on AC Source operability. Testing is commensurate with the material presented and any performance issues are identified for inclusion in future training.

4. Use of criteria and methodologies to assess whether the offsite power system will remain operable following a trip of your NPP.

(a) Do the NPP operators have any guidance or procedures in plant TS bases sections, the final safety analysis report, or plant procedures regarding situations in which the condition of plant-controlled or monitored equipment (e.g., voltage regulator, auto tap changing transformers, capacitors, static VAR compensators, main generator voltage

regulators) can adversely affect the operability of the NPP offsite power system? If so, describe how the operators are trained and tested on the guidance and procedures.

Response

Yes

Byron Station plant controlled or monitored equipment that can adversely affect the operability of the offsite power system is limited to the main generator voltage regulator, power system stabilizers on each unit, and stability protection schemes. EGC and plant specific procedures provide guidance for notification of the TSO/TO (i.e., PJM/ComEd) when the voltage regulator is not in automatic.

Byron Station procedures direct operator actions to control excitation in manual or other mitigating actions to control excitation. Operator actions on a loss of automatic control of the voltage regulator include the requirement to notify the TO (i.e., ComEd) of the failure.

The power system stabilizers for Byron Station are normally on. If a power system stabilizer trips, Byron Station operators are directed to notify the TO (i.e., ComEd). An operating guideline is then used to determine main generator output limitations with a power system stabilizer not in service. The output limitations are established to ensure main generator stability.

The status of the stability protection schemes is monitored in the main control room by alarms. If an alarm occurs, Byron Station operators are directed to immediately notify the TO (i.e., ComEd). An operating guideline is then used to determine main generator output limitations with the affected stability trip status.

Byron Station licensed operators are trained and tested in accordance with the Systematic Approach to Training (SAT). Procedures and policies are routinely reviewed for training through this process for improvement of operator performance. The items considered for training include Annunciator Response Procedures, Abnormal Operating Procedures, and Emergency Operating Procedures that require interface with the TSO/TO in accordance with the established protocol. In addition as part of initial training, requalification training, and annual operating tests, licensed operators are subjected to written examinations, static and/or simulator examinations, Job Performance Measures (JPMs), and evaluated simulator scenarios. These evaluations may incorporate topics including the loss of the main generator voltage regulator and actions to mitigate the effect of the failure. Testing is commensurate with the material presented and any performance issues are identified for inclusion in future training.

(b) If your TS bases sections, the final safety analysis report, and plant procedures do not provide guidance regarding situations in which the condition of plant-controlled or monitored equipment can adversely affect the operability of the NPP offsite power system, explain why you believe you comply with the provisions of GDC 17 and the plant TSs, or describe what actions you intend to take to provide such guidance or procedures.

Response

Not applicable

Use of NPP licensee/TSO protocols and analysis tool by TSOs to assist NPP licensees in monitoring grid conditions for consideration in maintenance risk assessments.

The Maintenance Rule (10 CFR 50.65(a)(4)) requires that licensees assess and manage the increase in risk that may result from proposed maintenance activities before performing them.

5. *Performance of grid reliability evaluations as part of the maintenance risk assessments required by 10 CFR 50.65(a)(4).*

   (a) Is a quantitative or qualitative grid reliability evaluation performed at your NPP as part of the maintenance risk assessment required by 10 CFR 50.65(a)(4) before performing grid-risk-sensitive maintenance activities? This includes surveillances, post-maintenance testing, and preventive and corrective maintenance that could increase the probability of a plant trip or LOOP or impact LOOP or SBO coping capability, for example, before taking a risk-significant piece of equipment (such as an EDG, a battery, a steam-driven pump, an alternate AC power source) out-of-service?

Response

Yes

Risk is assessed using a process that combines quantitative results from a probabilistic risk assessment (PRA) with a qualitative defense-in-depth model. During the planning and scheduling of work and prior to the execution of work, many factors are assessed for risk including the effect of weather/time of year and grid instability. The combination of unavailable Systems, Structures and Components (SSCs) and planned activities is then assessed in the risk assessment tool. Currently, a procedure update is being implemented to provide additional detail for how to factor grid reliability into the risk assessment tool before taking equipment out of service for planned maintenance. These procedure changes are currently scheduled to be in place at Byron Station by May 15, 2006.

(b) Is grid status monitored by some means for the duration of the grid-risk-sensitive maintenance to confirm the continued validity of the risk assessment and is risk reassessed when warranted? If not, how is the risk assessed during grid-risk-sensitive maintenance?

Response

Yes

Grid status is continually evaluated by PJM using the Security Analysis application. PJM notifies Byron Station through its Transmission Operator, (i.e., ComEd), of emergent grid conditions as discussed in the response to 1(b) above. In addition, ComEd (i.e., the TO) is also performing similar monitoring and evaluation. Existing EGC procedures require evaluation of the risk of scheduled online maintenance activities based on conditions such as power grid stability, weather forecast, and current plant system conditions.

(c) Is there a significant variation in the stress on the grid in the vicinity of your NPP site caused by seasonal loads or maintenance activities associated with critical transmission elements? Is there a seasonal variation (or the potential for a seasonal variation) in the LOOP frequency in the local transmission region? If the answer to either question is yes, discuss the time of year when the variations occur and their magnitude.

Response

The base PRA model reflects the yearly average LOOP frequency because seasonal variations that would cause changes to the frequency of a LOOP cannot be accurately predicted. While time related variations are not factored into the base PRA model for Byron Station, symptoms of grid stress such as maximum generation conditions, low grid voltage, or severe weather conditions require identification of such dynamic conditions should they occur, and risk management actions are then taken to mitigate the risk or reschedule the work as appropriate.

PJM provided the following information to EGC regarding this response in a letter from PJM to all PJM nuclear owners (Reference 6).

"Stress on the grid is manifested in a number of ways. Stress can mean 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.

Regarding the seasonal variability of the stress causers, each has a seasonal component. For example, peak load levels occur at the peak seasons of the summer and winter seasons. While the specific days cannot be predicted, it is known roughly when they will occur. Consequently, maintenance during these times of the year is avoided.

From a transmission system operations perspective, it is the simultaneous combination of stress causers that results in the most difficult operational challenges. For example, experiencing very hot (or cold) weather when we (i.e., PJM) are in the maintenance seasons with a lot of equipment out of service can cause the most severe challenges.

We (i.e., PJM) are aware of the existence of the North American Electric Reliability Council (NERC) and NRC data regarding LOOP frequency. However, it is difficult to assign differential risks to any seasonal variation because of the complexity of the various competing factors, as explained above."

(d) Are known time-related variations in the probability of a LOOP at your plant site considered in the grid-risk-sensitive maintenance evaluation? If not, what is your basis for not considering them?

Response

No

While time related variations are not factored into the base PRA model for Byron Station, symptoms of grid stress such as maximum generation conditions, low grid voltage, or severe weather conditions require identification of such dynamic conditions should they occur, and risk management actions are then taken to mitigate the risk or reschedule the work as appropriate.

(e) Do you have contacts with the TSO to determine current and anticipated grid conditions as part of the grid reliability evaluation performed before conducting grid-risk-sensitive maintenance activities?

Response

Yes

The protocol for NPP notification of actual or anticipated grid conditions is outlined in the response to 1(b). Any work performed on the grid risk sensitive equipment is evaluated for risk using these current or anticipated conditions as part of the evaluation prior to performance. Work is coordinated based on anticipated conditions and planned maintenance during bi-monthly interface meetings between the transmission operator (i.e., ComEd) and the EGC NPPs (i.e., Byron Station).

As stated in the response to 1(b), communication is shared between the TSO (i.e., PJM) and Byron Station if grid conditions deteriorate from an acceptable level. If contingencies are anticipated (e.g., the predicted post NPP trip offsite source voltage less than required) the TSO will provide Byron Station with a one day look ahead notice.

(f) Describe any formal agreement or protocol that you have with your TSO to assure that you are promptly alerted to a worsening grid condition that may emerge during a maintenance activity.

Response

As stated in the response to 1(a), Byron Station is located in the service territory of PJM. PJM is the TSO for Byron Station. The TO providing interconnection services for Byron Station is ComEd. EGC and ComEd are both members of PJM.

All members of PJM execute the PJM Operating Agreement (Reference 1) that details the obligations and responsibilities of both PJM and the PJM members. In the Operating Agreement, each member agrees to abide by the requirements contained in the PJM Manuals. The PJM Manuals contain the specific operational requirements that PJM and each member is required to follow.

As stated in the response to 1(b), PJM Manual M13 (Reference 5) identifies a series of alerts, warnings, and actions that PJM issues to PJM members depending on the identified grid condition. The PJM message is communicated to Byron Station by their generation dispatcher through the EGC NDO for a variety of system conditions including capacity emergencies, light load emergencies, weather/environmental emergencies or sabotage/terrorism emergencies.

PJM Manual M3 (Reference 4) requires PJM to initiate notification to Byron Station through the TO's control center if PJM identifies a switchyard voltage violation. PJM Manual M3 states: "This notification should occur within 15 minutes for voltage contingency violations and immediately for actual voltage violations. To the extent practical, PJM shall direct operations such that the violation is remedied within 30 minutes."

(g) Do you contact your TSO periodically for the duration of the grid-risk sensitive maintenance activities?

Response

No

Communications take place between the TSO (i.e., PJM) through the TO (i.e., ComEd), the NDO and Byron Station as detailed in the response to 1(b) above if grid conditions deteriorate from an acceptable level. If contingencies (e.g., the post trip voltages for Byron Station are predicted to be below the required limit) are anticipated, the TSO/TO will provide Byron Station with a one day look ahead notice. At this time there is no periodic mandated contact between the TSO/TO and Byron Station during the duration of grid-risk-sensitive maintenance activities.

(h) If you have a formal agreement or protocol with your TSO, describe how NPP operators and maintenance personnel are trained and tested on this formal agreement or protocol.

Response

Byron Station maintenance, operations, and work management personnel associated with schedule development or communicating with the TO (i.e., ComEd) are briefed on TSO/TO interface requirements and expectations but are not formally tested on knowledge retention in this area.

(i) If your grid reliability evaluation, performed as part of the maintenance risk assessment required by 10 CFR 50.65(a)(4), does not consider or rely on some arrangement for communication with the TSO, explain why you believe you comply with 10 CFR 50.65(a)(4).

Response

Not applicable

The methods used to integrate grid risk into the quantitative risk evaluation prior to taking equipment out of service for planned maintenance at Byron Station rely on communication with the TSO/TO.

(j) If risk is not assessed (when warranted) based on continuing communication with the TSO throughout the duration of grid-risk-sensitive maintenance activities, explain why you believe you have effectively implemented the relevant provisions of the endorsed industry guidance associated with the maintenance rule.

Response

Not applicable

As detailed in the response to 2(a), grid status is continually evaluated by PJM using the Security Analysis application. PJM notifies Byron Station through the TO (i.e., ComEd) of emergent grid conditions. In addition, ComEd (i.e., the TO) possesses a similar system and is also monitoring and evaluating grid conditions. Existing EGC procedures require evaluation of the risk of scheduled on line maintenance activities based on conditions such as power grid stability, weather forecast, and current plant system conditions.

(k) With respect to questions 5(i) and 5(j), you may, as an alternative, describe what actions you intend to take to ensure that the increase in risk that may result from proposed grid-risk-sensitive activities is assessed before and during grid-risk-sensitive maintenance activities, respectively.

Response

Not applicable

6. *Use of risk assessment results, including the results of grid reliability evaluations, in managing maintenance risk, as required by 10 CFR 50.65(a)(4).*

(a) Does the TSO coordinate transmission system maintenance activities that can have an impact on the NPP operation with the NPP operator?

Response

Yes

The TSO/TO coordinates transmission system maintenance activities that can have an impact on the NPP (i.e., Byron Station) with Byron Station.

(b) Do you coordinate NPP maintenance activities that can have an impact on the transmission system with the TSO?

Response

Yes

The NPP (i.e., Byron Station) coordinates maintenance activities that can have an impact on the transmission system with the TSO/TO.

(c) Do you consider and implement, if warranted, the rescheduling of grid-risk-sensitive maintenance activities (activities that could (1) increase the likelihood of a plant trip, (ii) increase LOOP probability, or (iii) reduce LOOP or SBO coping capability) under existing, imminent, or worsening degraded grid reliability conditions?

Response

Yes

Existing procedures require deferring work that would render AC power sources unavailable if severe weather is expected. Risk of scheduled on line work is evaluated based on grid conditions, the weather forecast, and current plant systems status. If the risk analysis determines that risk exceeds a predetermined level, then that configuration is not voluntarily entered and schedule changes are made to reduce the risk to an acceptable level.

(d) If there is an overriding need to perform grid-risk-sensitive maintenance activities under existing or imminent conditions of degraded grid reliability, or continue grid-risk-sensitive maintenance when grid conditions worsen, do you implement appropriate risk management actions? If so, describe the actions that you would take. (These actions could include alternate equipment protection and compensatory measures to limit or minimize risk.)

Response

Yes

When any risk significant SSC is made unavailable, actions are taken to protect redundant or diverse SSCs commensurate with the risk significance of the work being performed in accordance with approved procedures.

(e) Describe the actions associated with questions 6(a) through 6(d) above that would be taken, state whether each action is governed by documented procedures and identify the procedures, and explain why these actions are effective and will be consistently accomplished.

Response

The outage coordination process is documented in the PJM Manuals and agreed to by PJM (i.e., the TSO) and the members. EGC and ComEd (i.e., the TO) are both members of PJM. In addition, PJM has computerized tools to track the process throughout its evolution, so that PJM, ComEd and EGC are clear what the status is and what the expectations are.

Planned transmission outages are coordinated in accordance with a process detailed in PJM Manual M3, "Transmission Operations," Section 4 (Reference 4). This process requires advanced notice and subsequent PJM approval for all outages to ensure grid reliability. On the outage start day, the system is analyzed one last time by PJM before permitting the equipment to be switched out of service.

Once the equipment is switched out of service, grid status is continually evaluated by the PJM Security Analysis application as detailed in the response to 2(a). In addition, the TO (i.e., ComEd) is performing similar monitoring and evaluation. PJM notifies the NPP (i.e., Byron Station) through the TO's control center, as discussed in the response to 1(b).

An 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," (Reference 7) directs that schedule coordination meetings are held bi-monthly between the TSO/TO and the NPPs (i.e., Byron Station) to coordinate maintenance activities that can have mutual impact.

Actions specified in questions 6(c) and 6(d) are specified in the EGC Work Management procedure, WC-AA-101, "On-Line Work Control Process," (Reference 8) and is applicable to Byron Station.

(f) Describe how NPP operators and maintenance personnel are trained and tested to assure they can accomplish the actions described in your answers to question 6(e).

Response

Byron Station Maintenance, Operations, and Work Management personnel associated with schedule development and/or risk assessment are briefed on procedure expectations but are not formally tested on knowledge retention in this area.

(g) If there is no effective coordination between the NPP operator and the TSO regarding transmission system maintenance or NPP maintenance activities, please explain why you believe you comply with the provisions of 10 CFR 50.65(a)(4).

Response

Not applicable

Effective coordination is directed by PJM (i.e., the TSO) procedures and jointly approved interface procedures between ComEd (i.e., the TO) and EGC.

(h) If you do not consider and effectively implement appropriate risk management actions during the conditions described above, explain why you believe you effectively addressed the relevant provisions of the associated NRC-endorsed industry guidance.

Response

Not applicable

Effective and appropriate risk management actions are described in plant procedures and implemented during the conditions described above.

(i) You may, as alternative to questions 6(g) and 6 (h) describe what actions you intend to take to ensure that the increase in risk that may result from grid-risk-sensitive maintenance activities is managed in accordance with 10 CFR 50.65(a)(4).

Response

Not applicable

Offsite power restoration procedures in accordance with 10 CFR 50.63 as developed in Section 2 of RG 1.155.

Pursuant to 10 CFR 50.63, the NRC requires that each NPP licensed to operate to be able to withstand an SBO for a specified duration and recover from the SBO. NRC RG 1.155 gives licensees guidance on developing their approaches for complying with 10 CFR 50.63.

7. *Procedures for identifying local power sources[1] that could be made available to resupply your plant following a LOOP event.*

Note: Section 2, "Offsite Power," of RG 1.155 (ADAMS Accession No. ML003740034) states:

> *Procedures should include the actions necessary to restore offsite power and use nearby power sources when offsite power is unavailable. As a minimum, the following potential causes for loss of offsite power should be considered:*
>
> - *Grid undervoltage and collapse*
> - *Weather-induced power loss*
> - *Preferred power distribution system faults that could result in the loss of normal power to essential switchgear buses*

(a) Briefly describe any agreement made with the TSO to identify local power sources that could be made available to resupply power to your plant following a LOOP event.

Response

Byron Station is located in the service territory of PJM. PJM is the Transmission System Operator (TSO) for Byron Station. The Transmission Owner (TO) providing interconnection services for Byron Station is ComEd. EGC and ComEd are both members of PJM.

All members of PJM execute the "Operating Agreement of PJM Interconnection, LLC," (Reference 1) that details the obligations and responsibilities of both PJM and the PJM members. In the Operating Agreement, each member agrees to abide by the requirements contained in the PJM Manuals. The PJM Manuals contain the specific operational requirements that PJM and each member is required to follow.

ComEd (i.e., the TO) is also a signatory on the "PJM Consolidated Transmission Owners Agreement (PJM TOA)," (Reference 2). Section 4.5 of the PJM TOA requires the TOs to operate and maintain their transmission facilities in accordance with the PJM Manuals.

PJM (i.e., the TSO) is responsible for coordinating restoration of all or parts of the bulk power system in the PJM service territory. ComEd (i.e., the TO) is responsible for cooperating and coordinating with PJM and other PJM members during the restoration of all or parts of the bulk power system in the PJM service territory.

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[1] *This includes items such as nearby or onsite gas turbine generators, portable generators, hydro generators, and black-start fossil power plants.*

PJM Manual M36, "System Restoration," (Reference 11) gives priority to the restoration of offsite power to NPPs (i.e., Byron Station) in the PJM service territory. The TSO (i.e., PJM) and the TO (i.e., ComEd) will utilize the best power sources and transmission paths available based on the specific event to restore offsite power since there is no way to accurately predict the extent and characteristics of a specific blackout. The TSO and TO have multiple options available to restore offsite power and these would not be limited to local power sources.

The Interconnection Agreement between the NPP (i.e., Byron Station) and ComEd (i.e., the TO) reinforces the importance and priority of restoring the NPP offsite power source (Reference 14). In addition, Byron Station has an Affiliate Level Arrangement Agreement (ALA) with ComEd (Reference 15) to apply "best efforts" to restore to service the facilities that they own or control in order to restore the Byron Station offsite power circuit back to an operable status.

PJM provided the following information to EGC regarding this response in a letter from PJM to all PJM nuclear owners (Reference 6).

"The PJM Restoration Manual (M36) details the process to be followed during a system restoration. The process reiterates the specific offsite power requirements for NPPs:

> 'Offsite power should be restored as soon as possible to nuclear units, both units that had been operating and those that were already offline prior to the system disturbance, without regard to using these units for restoring customer load.'

However, due to the myriad of possible restoration scenarios, no specific power sources to resupply NPPs are identified. The PJM restoration process allows for the fact that the blacked out area may or may not be separated from the remainder of the system. Regardless of the scenario, there is a clear recognition of the importance of restoring an NPP offsite power source.

PJM Manual M36 further states: 'Transmission Owners and Nuclear Power Plants must effectively communicate to keep the Nuclear Power Plant apprised of the anticipated restoration time for offsite power.' The manual also states that for PJM Restoration Drills the objectives should include 'Ensure that all nuclear units have been provided with one offsite source within 4 hours,' and that the PJM Nuclear Generation Owner/Operator Users Group should be debriefed on the drill results.

In support of the restoration objectives outlined in the PJM Restoration Manual (M36), there are generating units designated as critical black-start units electrically close to each of the NPPs. These black start units are required to provide black start capability whenever necessary. The adequacy of black-start resources to support system restoration is managed through a process contained in PJM Manual M10, "PreScheduling Operations," (Reference 12), Section 2. The process ensures the continuous availability of black start units to support the restoration needs of the NPPs even when a designated black start unit is on a planned outage."

(b) Are your NPP operators trained and tested on identifying and using local power sources to resupply your plant following a LOOP event? If so, describe how.

Response

No

Byron Station operators are not specifically trained and tested on identifying and using local power sources to resupply the NPP (i.e., Byron Station) following a LOOP event. The identification and use of local power sources for Byron Station are under the control of PJM (i.e., the TSO) and ComEd (i.e., the TO) in accordance with the procedures and interface agreements described in the response to 7(a). The response to this question does not address the operation of the Byron Station alternate AC source established under 10 CFR 50.63, "Loss of all alternating current power," (i.e., Station Blackout (SBO) Rule), for which Byron Station operators are trained and tested to identify and use under SBO conditions.

(c) If you have not established an agreement with your plant's TSO to identify local power sources that could be made available to resupply power to your plant following a LOOP event, explain why you believe you comply with the provisions of 10 CFR 50.63, or describe what actions you intend to take to establish compliance.

Response

The identification and use of local power sources for restoration of offsite power to Byron Station following a LOOP event are under the control of PJM (i.e., the TSO) and ComEd (i.e., the TO) in accordance with the procedures and interface agreements described in the response to 7(a). Due to the myriad of possible restoration scenarios, no specific power sources to resupply Byron Station are identified. The procedures identified by RG 1.155, "Station Blackout," (Reference 13) that include the actions necessary to restore offsite power and the use of nearby power sources are also under the control of PJM and ComEd.

Note that, as detailed in the response to 7(a), both ComEd (i.e., the TO) and PJM (i.e., the TSO) have stated that restoring offsite power to a NPP (i.e., Byron Station) is a priority.

The identification and use of local power sources that could be made available to resupply power to the NPP following a LOOP event are not part of the current Byron Station operating procedures and training since they are outside of Byron Station's direct control.

Losses of offsite power caused by grid failures at a frequency of equal to or greater than once in 20 site-years in accordance with Table 4 of Regulatory Guide 1.155 for complying with 10 CFR 50.63.

Pursuant to 10 CFR 50.63, the NRC requires that each NPP licensed to operate be able to withstand an SBO for a specified duration and recover from the SBO. NRC RG 1.155 gives licensees guidance on developing their approaches to complying with 10 CFR 50.63.

8. Maintaining SBO coping capabilities in accordance with 10 CFR 50.63.

(a) Has your NPP experienced a total LOOP caused by grid failure since the plant's coping duration was initially determined under 10 CFR 50.63?

Response

Byron Station has not experienced a total LOOP caused by grid failure since the coping duration was initially determined under 10 CFR 50.63, "Loss of all alternating current power," (i.e., Station Blackout (SBO) Rule). A review of Byron Station records including the Licensee Event Report (LER) database from July 1988, when the SBO Rule was added, was performed to make this determination.

This determination is consistent with the data presented in NUREG/CR-6890, Volume 1, "Reevaluation of Station Blackout Risk at Nuclear Power Plants – Analysis of Offsite Power Events: 1986-2004," (Reference 9), Appendix A, "LOOP Event Database," Section A-2, "Data Tables," Table A -1, "Loop Events for 1986-2004, sorted by plant."

In addition, the review of LERs since Reference 9 was issued to present has concluded that there were no additional grid failure based LOOP events during this period.

(b) If so, have you reevaluated the NPP using the guidance in Table 4 of RG 1.155 to determine if your NPP should be assigned to the P3 offsite power design characteristic group?

Response

Not applicable

(c) If so, what were the results of this reevaluation, and did the initially determined coping duration for the NPP need to be adjusted?

Response

Not applicable

(d) If your NPP has experienced a total LOOP caused by grid failure since the plant's coping duration was initially determined under 10 CFR 50.63 and has not been reevaluated using the guidance in Table 4 of RG 1.155, explain why you believe you comply with the provisions of 10 CFR 50.63 as stated above, or described what actions you intend to take to ensure that the NPP maintains its SBO coping capabilities in accordance with 10 CFR 50.63.

Response

Not applicable

Actions to ensure compliance

9. *If you determine that any action is warranted to bring your NPP into compliance with NRC regulatory requirements, including TSs, GDC 17, 10 CFR 50.65(a)(4), 10 CFR 50.63, 10 CFR 55.59 or 10 CFR 50.120, describe the schedule for implementing it.*

Response

Not applicable

References

1. "Operating Agreement of PJM Interconnection, LLC," revised through February 6. 2006

2. "Consolidated Transmission Owners Agreement," effective March 19, 2006

3. PJM Manual 01, "Control Center Requirements," Revision 10, effective February 7, 2006

4. PJM Manual 3, "Transmission Operations," Revision 20, effective February 10, 2006

5. PJM Manual 13, "Emergency Operations," Revision 24, effective February 22, 2006

6. 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

7. EGC procedure WC-AA-8000, "Interface Procedure between Exelon Energy Delivery (ComEd/PECO) and Exelon Generation (Nuclear/Power) for Construction and Maintenance Activities," Revision 0

8. EGC procedure WC-AA-101, "On-Line Work Control Process," Revision 11

9. NUREG/CR-6890, Volume 1, "Reevaluation of Station Blackout Risk at Nuclear Power Plants – Analysis of Offsite Power Events: 1986-2004," Revision 0

10. EGC procedure OP-AA-108-107-1002, "Interface Agreement between Exelon Energy Delivery and Exelon Generation for Switchyard Operations," Revision 2

11. PJM Manual 36, "System Restoration," Revision 2, effective November 1, 2005

12. PJM Manual 10, "Pre-Scheduling Operations," Revision 18, effective August 10, 2005

13. Regulatory Guide 1.155, "Station Blackout," Revision 0

14. "Facilities, Interconnection and Easement Agreement among ComEd Generation Company LLC, Exelon Generation Company, LLC and Commonweatlh Edison Company," Byron Station Final Form, dated January 12, 2001

15. "Affiliate Level Arrangement ('ALA') by and among Exelon Energy Delivery Groups of ComEd and Exelon Generation Company, LLC," effective January 1, 2006

16. NRC Information Notice IN 93-17, "Safety Systems Response to Loss of Coolant and Loss of Offsite Power," Revision 1, dated March 25, 1994

17. SECY-05-0219, "Issuance of Nuclear Regulatory Commission Generic Letter 2005-XX, 'Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power,'" dated December 2, 2005

18. EGC procedure OP-AA-108-107-1001, "Station Response to Grid Capacity Conditions," Revision 1

19. Byron Station Abnormal Operating Procedure BOA ELEC-4, "Loss of Offsite Power"

20. Byron Station Abnormal Operating Procedure BOA ELEC-3, "Loss of 4KV ESF Bus"

21. Byron Station Emergency Operating Procedure BEP-0, "Reactor Trip or Safety Injection,"

22. Byron Station Emergency Operating Procedure BEP ES-0.1, "Reactor Trip Response"

23. Byron Station Emergency Contingency Action Procedure BCA-0.0, "Loss of All AC"

24. EGC procedure WC-AA-107, "Seasonal Readiness," Revision 2

25. SOER 99-1, "Loss of Grid," December 27, 1999

26. SOER 99-1, "Loss of Grid – Addendum," December 9, 2004

27. Jennifer Sterling, Exelon Transmission Planning, "NRC Generic Letter – Draft responses to questions 1 and 2," February 14, 2006, personal email to John Gyrath, Exelon Nuclear, (February 14, 2006)

ATTACHMENT 3

60-day Response to NRC Generic Letter 2006-02

CLINTON POWER STATION, Unit 1

FOL No. NPF-62

ATTACHMENT 3
60-day Response to NRC Generic Letter 2006-02
CLINTON POWER STATION

On February 1, 2006, the NRC issued Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power." 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 Generic Letter requested that licensees answer the following questions and provide the information to the NRC with respect to each of their Nuclear Power Plants (NPPs).

Use of protocols between the NPP licensee and the TSO, ISO, or RC/RA and the use of analysis tools by TSOs to assist NPP licensee in monitoring grid conditions to determine the operability of offsite power system under plant TS.

GDC 17, 10 CFR Part 50, Appendix A, requires that licensees minimize the probability of the loss of power from the transmission network given a loss of the power generated by the nuclear power unit(s).

1. *Use of protocols between the NPP licensee and the TSO, ISO, or RC/RA to assist the NPP licensee in monitoring grid conditions to determine the operability of offsite power system under plant TS.*

   (a) Do you have a formal agreement or protocol with your TSO?

   Response

   Yes

   Clinton Power Station (CPS) has entered into a Nuclear Plant Operating Agreement (NPOA) with AmerenIP and the Midwest Independent Transmission System Operator (Midwest ISO), (Reference 1). 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.

   The NPOA is intended to document the respective roles of CPS, AmerenIP, and Midwest ISO and to define scheduling protocols, emergency procedures, operating limitations and any other restrictions applicable to CPS.

   The Midwest ISO and the interconnected nuclear power plants (NPPs) and their associated Transmission Owners developed a generic communication protocol, RTO-OP-03, "Communication and Mitigation Protocols for Nuclear Plant/Electric System Interfaces," (Reference 2) to address roles and responsibilities in grid monitoring and communication. RTO-OP-03 is also incorporated as Attachment D to the CPS NPOA.

   In addition to the NPOA, CPS has an Interconnection Agreement with AmerenIP that provides for interconnection service (Reference 8). The Interconnection Agreement contains the requirement for AmerenIP to monitor the CPS offsite source voltages and notify CPS of any limit violations.

   (b) Describe any grid conditions that would trigger a notification from the TSO to the NPP licensee and if there is a time period required for the notification.

Response

The TSO (i.e., AmerenIP) is obligated by the NPOA (Reference 1) to do the following.

- Notify CPS whenever real-time operation or any contingency results in the 345 kV bus voltage migrating outside the required 327.4 kV to 362.2 kV range. In addition, the contingency that causes this voltage excursion shall be communicated.

- Notify CPS whenever real-time operation or any contingency results in the 138 kV bus voltage migrating outside the required 126.21 kV to 144.9 kV range. In addition, the contingency that causes this voltage excursion shall be communicated.

- Notify Midwest ISO should the TSO's (i.e., AmerenIP) ability to predict the post-contingent operation of the transmission system at CPS switchyard becomes disabled. The Midwest ISO State Estimator (SE) and Real Time Contingency Analysis (RTCA) shall be used for determination of post-contingent operation under this circumstance. If AmerenIP and the Midwest ISO are unable to determine the post-contingent voltages, AmerenIP is required to notify CPS of that condition.

The communication protocol established in the NPOA states that the TSO (i.e., AmerenIP) will immediately initiate communication with the NPP and the Midwest ISO if the TSO verifies an actual violation to the CPS operating criteria.

The communication protocol established in the NPOA also states that the Midwest ISO or the TSO (i.e., AmerenIP) will initiate communication with each other to verify study results that indicate a post-contingent violation of operating criteria. Upon verification, the TSO and the Midwest ISO will immediately initiate steps to mitigate the pre-contingent and post-contingent operating criteria violation. If the violation is not mitigated within 15 minutes of the verification of the study results, the TSO shall immediately notify the NPP (i.e., CPS).

The NPOA requires that Midwest ISO and AmerenIP provide priority notice to each other of abnormal transmission system conditions that could create adverse operating conditions at CPS. AmerenIP is required to notify CPS of such conditions.

The NPOA also requires that Midwest ISO provide updates to AmerenIP and CPS on transmission system status during emergency restoration activities.

(c) Describe any grid conditions that would cause the NPP licensee to contact the TSO. Describe the procedures associated with such a communication. If you do not have procedures, describe how you assess grid conditions that may cause the NPP licensee to contact the TSO.

Response

CPS is obligated by the NPOA (Reference 1) to do the following.

- Notify the TSO (i.e., AmerenIP) and the Midwest ISO of any abnormal plant conditions that could lead to a loss of the NPP, entering into a Technical Specification (TS) Limiting Condition for Operation (LCO) that could lead to a plant shutdown, or entering into any operating restrictions or limitations that may affect the reliability of the transmission system.

- Evaluate the impact of transmission system parameter changes on CPS operation and communicate any impact to the TSO (i.e., AmerenIP). AmerenIP will communicate this information to the Midwest ISO.

- Notify the TSO whenever the automatic voltage regulator is inoperative or has limited range of operation.

- Notify the TSO whenever the Static VAR Compensator is inoperative or has a limited range of operation.

Midwest ISO procedure RTO-OP-03 (Reference 2) requires CPS to notify the TSO (i.e., AmerenIP) during any of the following conditions:

- when real and reactive power output is limited due to plant limitations;

- when the voltage regulator is being operated in manual mode or taken out of service;

- when CPS enters either an unplanned shutdown Limiting Condition for Operation (LCO) or if the plant exceeds 50% of the time allotted for a planned shutdown LCO entry;

- when back-up electrical sources (i.e., diesel generators) are removed from service;

- when the nuclear unit has responded to a possible transmission system operation so the cause of the unit response can be determined; or

- when the plant system degradation has affected the inputs used for establishing the transmission system limits.

CPS annunciator procedures direct a TSO (i.e., AmerenIP) notification when certain conditions arise such as switchyard breaker trouble, line fault protection system trouble, control power trouble, and transient recorder start/trouble. CPS procedures also direct TSO notification for high or low voltage conditions on safety-related buses.

In addition, CPS will contact the TSO/TO during a grid restoration process to obtain grid status in preparation for returning the plant buses to the offsite source.

(d) Describe how NPP operators are trained and tested on the use of the procedures or assessing grid conditions in question 1(c).

Response

CPS licensed operators are trained and tested in accordance with the Systematic Approach to Training (SAT). Procedures and policies are routinely reviewed for training through this process for improvement of operator performance. The items considered for training include Operating Procedures, Annunciator Response Procedures, Abnormal Operating Procedures, and Emergency Operating Procedures that require interface with the TSO in accordance with the established protocol. These procedures may be utilized based on various grid, switchyard, or plant symptoms to assess, respond to or mitigate off-normal plant and grid conditions. Additionally, SOER 99-01, "Loss of Grid," (Reference 12) and SOER 99-01, "Loss of Grid – Addendum," (Reference 13) specifically are captured in the Licensed Operator Requalification Training Program (LORT) Long Range Training Program. These topics, in varying detail based upon the SAT process or as part of implementing Exelon Generation Company, LLC (EGC) procedure WC-AA-107, "Seasonal Readiness," (Reference 11) are reviewed periodically with CPS operators. Testing is commensurate with the material presented and any performance issues are identified for inclusion in future training.

(e) If you do not have a formal agreement or protocol with your TSO, describe why you believe you continue to comply with the provisions of GDC 17 as stated above, or describe what actions you intend to take to assure compliance with GDC 17.

Response

Not applicable. Formal agreements exist for CPS.

(f) If you have an existing formal interconnection agreement or protocol that ensures adequate communication and coordination between the NPP license and the TSO, describe whether this agreement or protocol requires that you be promptly notified when the conditions of the surrounding grid could result in degraded voltage (i.e., below TS nominal trip setpoint value requirements; including NPP licensees using allowable value in its TSs) or LOOP after a trip of the reactor units(s).

Response

The TSO (i.e., AmerenIP) is obligated by the NPOA (Reference 1) to do the following.

- Notify CPS whenever real-time operation or any contingency results in the 345 kV bus voltage migrating outside the required 327.4 kV to 362.2 kV range. In addition, the contingency that causes this voltage excursion shall be communicated.

- Notify CPS whenever real-time operation or any contingency results in the 138 kV bus voltage migrating outside the required 126.21 kV to 144.9 kV range. In addition, the contingency that causes this voltage excursion shall be communicated.

The trip of CPS is one of the contingencies analyzed by AmerenIP (i.e., the TSO) and Midwest ISO.

The minimum 138 kV and 345 kV voltages specified in the NPOA are based on the TS value of 4.16 kV bus degraded voltage reset setpoint allowable value.

(g) Describe the low switchyard voltage conditions that would initiate operation of plant degraded voltage protection.

Response

Switchyard voltage below a value maintaining emergency bus voltage above the dropout value of the degraded voltage relay (4078 volts) will cause a trip of the preferred power source after a time delay of approximately 15 seconds. The relation between the switchyard voltage and the emergency bus voltage is dependent on the system auxiliary transformer impedance and the winding load. Under design basis accident (i.e., Large Break LOCA) conditions, the maximum loading is known and contained in the CPS calculations of record. The design basis maximum loading and the degraded voltage relay reset voltage (4107 volts on the safety-related bus) were used to determine the switchyard voltage needed for the system to remain connected to the offsite power source. This corresponds to a voltage of 126.2 kV on the 138 kV source if the safety-related bus is supplied from the Emergency Reserve Auxiliary Transformer and 327.4 kV on the 345 kV source with all vital and non-vital loads on the Reserve Auxiliary Transformer.

In other conditions, the loading is less than the expected LOCA loading and will vary considerably depending on which loads are needed to support unit conditions. Under these conditions the required CPS switchyard voltage will be less than that required to support LOCA loading.

2. *Use of criteria and methodologies to assess whether the offsite power system will become inoperable as a result of a trip of your NPP.*

(a) Does your NPP's TSO use any analysis tools, an online analytical transmission system studies program, or other equivalent predictive methods to determine the grid conditions that would make the NPP offsite power system inoperable during various contingencies? If available to you, please provide a brief description of the analysis tool that is used by the TSO.

Response

Yes

The Midwest ISO and TSO (i.e., AmerenIP) use analysis tools to predict grid conditions that would make the CPS offsite power system inoperable. The tools presently used by the Midwest ISO and TSO include a fully commissioned Real-Time Contingency Analysis (RTCA) program, a grid state estimator and Supervisory Control and Data Acquisition (SCADA) system. AmerenIP is responsible for analyzing the transmission system from a local perspective for contingency impacts on CPS.

The analyses provide results with respect to thermal, voltage, and voltage drop limit violations. One of the contingencies analyzed by the AmerenIP and Midwest ISO systems is the trip of CPS.

In addition, periodic studies are performed by AmerenIP to evaluate the predicted seasonal loads and generation patterns for their impact on the CPS offsite power source.

(b) Does your NPP's TSO use an analysis tool as the basis for notifying the NPP licensee when such a condition is identified? If not, how does the TSO determine if conditions on the grid warrant NPP licensee notification?

Response

Yes

The Midwest ISO and TSO (i.e., AmerenIP) use the analysis tools identified in 2(a) above, in conjunction with procedures, as the basis for determining when conditions warrant notification. The preferred notification to the CPS control room is from TSO. Both the Midwest ISO and the TSO monitor the CPS unit trip contingency. Operation outside the voltage limits for a unit trip contingency would result in notification to CPS in accordance with Midwest ISO procedure RTO-OP-03 (Reference 2). If the Midwest ISO first recognizes the system condition, the Midwest ISO will normally notify the TSO. If necessary, the Midwest ISO may directly contact the CPS control room.

(c) If your TSO uses an analysis tool, would the analysis tool identify a condition in which a trip of the NPP would result in switchyard voltages (immediate and/or long-term) falling below TS nominal trip setpoint value requirements (including NPP licensees using allowable value in its TSs) and consequent actuation of plant degraded voltage protection? If not, discuss how such a condition would be identified on the grid.

Response

Yes

The trip of CPS is one of the contingencies analyzed by the TSO (i.e., AmerenIP) and Midwest ISO real-time analysis tools. AmerenIP and Midwest ISO analyze the CPS switchyard contingency voltages to the voltage limits provided by CPS. The voltage limits provided by CPS are based on the plant's design basis analysis.

(d) If your TSO uses an analysis tool, how frequently does the analysis tool program update?

Response

The AmerenIP (i.e., the TSO) RTCA program updates the CPS plant trip contingency, and the entire set of contingencies, every six minutes (Reference 16). The AmerenIP contingency simulation can be activated on a more frequent basis as needed for changing system conditions. The Midwest ISO RTCA program presently updates the entire set of contingencies every five minutes (Reference 7). The Midwest ISO state estimator program updates on a 90 second time interval (Reference 7). The SCADA information available to the TSO updates on a four to 10 second interval. AmerenIP transmits this data to the Midwest ISO every 10 seconds (Reference 16).

(e) Provide details of analysis tool-identified contingency conditions that would trigger an NPP licensee notification from the TSO.

Response

AmerenIP (i.e., the TSO) notifies CPS whenever actual or post-contingency voltages are determined to be outside of the operating criteria provided by CPS in the NPOA (Reference 1). Midwest ISO may make this notification to CPS under certain circumstances. This notification requirement applies to all contingencies including the tripping of CPS or the loss of a transmission facility as the contingent element.

(f) If an interface agreement exists between the TSO and the NPP licensee, does it require that the NPP licensee be notified of periods when the TSO is unable to determine if offsite power voltage and capacity could be inadequate? If so, how does the NPP licensee determine that the offsite power would remain operable when such a notification is received?

Response

Yes

AmerenIP (i.e., the TSO) monitors CPS contingency voltages. Midwest ISO is scheduled to revise their RTCA program to monitor CPS contingency voltages in June 2006 (Reference 17). The NPOA (Reference 1) requires that both Midwest ISO and AmerenIP notify each other if the ability of one party to determine the CPS post contingency voltages is lost. If both Midwest ISO and AmerenIP lose the ability to determine the CPS post-contingency voltages, the NPP is notified of that fact.

If CPS is notified that AmerenIP and Midwest ISO have lost their real time contingency analysis capability, CPS would request AmerenIP to provide an assessment of the current condition of the grid based on the tools that AmerenIP and Midwest ISO have available. The determination of the operability of the offsite sources would consider the assessment provided by AmerenIP and whether the current condition of the grid is bounded by the grid studies previously performed for CPS.

(g) After an unscheduled inadvertent trip of the NPP, are the resultant switchyard voltages verified by procedure to be bounded by the voltages predicted by the analysis tool?

Response

No

Presently, there is no formal process for comparing the actual post-trip voltages to the post-trip contingency voltage results calculated by the AmerenIP and Midwest ISO real time contingency analysis (RTCA) programs.

Midwest ISO provided the following information to AmerGen regarding this response in a letter from Midwest ISO to nuclear plants (i.e., including CPS) interconnected with the transmission system controlled by Midwest ISO (Reference 7).

"Because many of the MISO transmission owning member companies have similar RTCA programs, there are many opportunities to compare the results. This results in a high confidence that the RTCA results are accurate. However, if the resultant voltages are outside of the criteria, when they are predicted to be within, MISO would be initiating an investigation."

(h) If an analysis tool is not available to the NPP licensee's TSO, do you know if there are any plans for the TSO to obtain one? If so, when?

Response

Not applicable. CPS's TSO (i.e., AmerenIP) has an analysis tool.

(i) If an analysis tool is not available, does your TSO perform period studies to verify that adequate offsite power capability, including adequate NPP post-trip switchyard voltages (immediate and/or long-term), will be available to the NPP licensee over the projected timeframe of the study?

Response

Not applicable. CPS's TSO (i.e., AmerenIP) has an analysis tool.

(a) Are the key assumptions and parameters of these periodic studies translated into TSO guidance to ensure that the transmission system is operated within the bounds of the analyses?

Response

Not applicable. CPS's TSO (i.e., AmerenIP) has an analysis tool.

(b) If the bounds of the analyses are exceeded, does this condition trigger the notification provisions discussed in question 1 above?

Response

Not applicable. CPS's TSO (i.e., AmerenIP) has an analysis tool.

(j) If your TSO does not use, or you do not have access to the results of an analysis tool, or your TSO does not perform and make available to you periodic studies that determine the adequacy of offsite power capability, please describe why you believe you comply with the provisions of GDC 17 as stated above, or describe what compensatory actions you intend to take to ensure that the offsite power system will be sufficiently reliable and remain operable with high probability following a trip of your NPP.

Response

Not applicable. CPS's TSO (i.e., AmerenIP) has an analysis tool. In addition, the applicable contingency voltage results are made available to CPS when requested.

3. *Use of criteria and methodologies to assess whether the NPP's offsite power system and safety-related components will remain operable when switchyard voltages are inadequate.*

(a) If the TSO notifies the NPP operator that a trip of the NPP, or the loss of the most critical transmission line or the largest supply to the grid would result in switchyard voltages (immediate and/or long-term) below TS nominal trip setpoint value requirements (including NPP licensees using allowable value in its TSs) and would actuate plant degraded voltage protection, is the NPP offsite power system declared inoperable under the plant TSs? If not, why not?

Response

If the TSO (i.e., AmerenIP) notifies CPS that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., CPS) is below the pre-determined notification value, CPS will review the applicability to the plant operating configuration and will declare the offsite power source inoperable in accordance with Technical Specifications (TSs) if appropriate. The notification value provided to AmerenIP by CPS is based on the CPS degraded voltage design basis analysis.

Predicted contingency voltages following the loss of a transmission facility (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 for CPS at this time. If the TSO (i.e., AmerenIP) notifies CPS of a predicted contingency voltage violation resulting from the postulated trip of a transmission facility, CPS will perform a risk analysis of in progress and scheduled plant work and will take action as appropriate.

The NPP unit trip contingency can be caused by plant-centered events. The use of the NPP unit trip contingency as the contingency element upon which offsite power operability is based is consistent with the final paragraph of General Design Criterion (GDC) 17, "Electric power systems," of 10 CFR Part 50 Appendix A, "General Design Criteria for Nuclear Power Plants," which requires provisions be included to minimize the probability of the loss of power from the transmission network given a loss of the power generated by the NPP (i.e., CPS).

Postulated contingencies on the transmission system are currently not used as the basis for offsite source operability determinations since loss of power from the transmission network would not occur as a result of loss of power generated by a NPP unit (i.e., CPS). Such events (e.g., loss of a transmission line) are only postulated and have not actually occurred, and the offsite power sources remain capable of supporting a safe shutdown and mitigating the effects of an accident. Loss of power from the transmission network would not occur as a result of loss of power generated by a NPP unit and therefore the GDC 17 provision discussed in GL 2006-02 is met.

(b) If onsite safety-related equipment (e.g., emergency diesel generators or safety-related motors) is lost when subjected to a double sequencing (LOCA with delayed LOOP event) as a result of the anticipated system performance and is incapable of performing its safety functions as a result of responding to an emergency actuation signal during this condition, is the equipment considered inoperable? If not, why not?

Response

Although some features have been incorporated into the plant design, requirements for analysis and design considerations for double sequencing are not included within the CPS current licensing and design basis as documented in the CPS Updated Safety Analysis Report (USAR). CPS has not been explicitly analyzed for all issues associated with double sequencing. Onsite safety-related equipment at CPS (e.g., emergency diesel generators or safety-related motors) is not declared inoperable as a result of a TSO (i.e., AmerenIP) unit trip contingency voltage notification.

Based on Enclosure 2 of SECY-05-0219, "Issuance of Nuclear Regulatory Commission Generic Letter 2005-XX, 'Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power,'" (Reference 10) which provided NRC guidance on responding to this issue, a review was performed for CPS of the loading logic for the diesel generators as well as the safety-related breakers' anti-pumping logic. This review concluded that onsite safety-related equipment (i.e., emergency diesel generators or safety-related motors) is not lost as a result of diesel generator block loading and breaker lockout from anti-pump circuitry when subjected to a double sequencing event resulting from inadequate post unit tip voltages. The scope of the review performed for CPS is discussed in the response to question 3(c) below.

(c) Describe your evaluation of onsite-related equipment to determine whether it will operate as designed during the condition described in question 3(b).

Response

Although some features have been incorporated into the plant design, requirements for analysis and design considerations for double sequencing are not included within the CPS current licensing and design basis as documented in the CPS USAR. CPS has not been explicitly analyzed for all issues associated with double sequencing. However, using the NRC clarification provided in Enclosure 2 of SECY-05-0219 as guidance, a review was performed for the purpose of addressing question 3(b).

This review examined the effects of a double sequencing event on diesel generator block loading and the potential for breaker lockout from the anti-pump circuitry. The review assumed that following a LOCA initiation, the grid separation occurred as a result of degraded voltage relay operation triggered by the loss of CPS. The review examined the diesel generator loading logic and determined that the logic is reset by the LOOP event. The second sequence is consistent with that described in the CPS USAR for a LOOP/LOCA event. Loads are shed as a result of the LOOP signal and the loads are not block loaded onto the diesel generator.

The review also examined the potential for breaker lockout due to the anti-pumping circuitry. This review determined that there was sufficient time between the two sequences such that the breaker charging springs would re-charge and the second closure would be successful. To ensure that a breaker lockout would not occur, the breaker closing logics were also examined to assure that the trip signals were cleared before the second close signal was initiated.

(d) If the NPP licensee is notified by the TSO of other grid conditions that may impair the capability or availability of offsite power, are any plant TS action statements entered? If so, please identify them.

Response

As discussed in the response to 3(a), if the TSO (i.e., AmerenIP) notifies CPS that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., CPS) is below the pre-determined notification value, CPS will review the applicability to the plant operating configuration and will declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to AmerenIP by CPS is based on the CPS degraded voltage design basis analysis.

In addition, if AmerenIP notifies CPS that the actual offsite power source voltage is less than the pre-determined notification value, CPS will review the applicability to the plant operating configuration and would declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to AmerenIP by CPS is based on the CPS degraded voltage design basis analysis.

(e) If you believe your plant TSs do not require you to declare your offsite power system or safety-related equipment inoperable in any of these circumstances, explain why you believe you comply with the provisions of GDC 17 and your plant TSs, or describe what compensatory actions you intend to take to ensure that the offsite power system and safety-related components will remain operable when switchyard voltages are inadequate.

Response

The following notifications from the TSO (i.e., AmerenIP) will result in CPS declaring the offsite power source inoperable in accordance with TSs.

- If the TSO (i.e., AmerenIP) notifies CPS that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., CPS) is below the pre-determined notification value, CPS will review the applicability to the plant operating configuration and will declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to AmerenIP by CPS is based on the CPS degraded voltage design basis analysis.

- If the TSO (i.e., AmerenIP) notifies CPS that the actual offsite power source voltage is less than the pre-determined notification value, CPS will review the applicability to the plant operating configuration and would declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to AmerenIP by CPS is based on the CPS degraded voltage design basis analysis.

Predicted contingency voltages following the loss of a transmission facility (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. If the TSO notifies the NPP of a predicted contingency voltage violation resulting from the postulated trip of a transmission facility, the NPP performs a risk analysis of in-progress and scheduled plant work and takes action as appropriate.

The NPP unit trip contingency can be caused by plant-centered events. The use of the NPP unit trip contingency as the contingency element upon which offsite power operability is based is consistent with the final paragraph of GDC 17 which requires provisions to minimize the probability of the loss of power from the transmission network given a loss of the power generated by the NPP.

Postulated contingencies on the transmission system are not used as the basis for offsite source operability determinations since loss of power from the transmission network would not occur as a result of loss of power generated by the NPP unit. Such events (e.g., loss of a transmission line) are only postulated and have not actually occurred, and the offsite power sources remain capable of affecting a safe shutdown and mitigating the effects of an accident. The GDC 17 provision discussed in the Generic Letter is still met; loss of power from the transmission network would not occur as a result of loss of power generated by the NPP unit.

Onsite safety-related equipment at CPS (e.g., emergency diesel generators or safety-related motors) is not declared inoperable as a result of a TSO (i.e., AmerenIP) unit trip contingency voltage notification. Although some features have been incorporated into the plant design, requirements for analysis and design considerations for double sequencing are not included within the CPS current licensing and design basis as documented in the CPS USAR. CPS has not been explicitly analyzed for all issues associated with double sequencing.

(f) Describe if and how NPP operators are trained and tested on the compensatory actions mentioned in your answers to questions 3(a) through (e).

Response

CPS licensed operators are trained and tested in accordance with the Systematic Approach to Training (SAT). Equipment operability, as defined by TS, including normal and emergency power, offsite circuits, and safety-related components, is under continuous review. Procedures are in place to provide operator guidance and required actions necessary during predicted or actual degraded grid voltage conditions based on information provided by the TSO/TO in accordance with established protocol or as observed by the NPP operator. As part of initial training, requalification training, and annual operating tests, licensed operators are subjected to written examinations, dynamic learning activities, static and/or simulator examinations, Job Performance Measures (JPMs), and evaluated simulator scenarios incorporating topics including the actual or predicted switchyard voltage issues and its effect on AC Source operability. Testing is commensurate with the material presented and any performance issues are identified for inclusion in future training.

4. *Use of criteria and methodologies to assess whether the offsite power system will remain operable following a trip of your NPP.*

(a) Do the NPP operators have any guidance or procedures in plant TS bases sections, the final safety analysis report, or plant procedures regarding situations in which the condition of plant-controlled or monitored equipment (e.g., voltage regulator, auto tap changing transformers, capacitors, static VAR compensators, main generator voltage regulators) can adversely affect the operability of the NPP offsite power system? If so, describe how the operators are trained and tested on the guidance and procedures.

Response

Yes

CPS plant controlled or monitored equipment that can adversely affect the operability of the offsite power system is limited to the main generator voltage regulator and the Static VAR Compensator (SVC). Plant specific procedures provide guidance for notification of the TSO (i.e., AmerenIP) when the voltage regulator is not in automatic or the SVC is not in service.

CPS procedures direct operator actions to control excitation in manual or other mitigating actions to control excitation. Operator actions on a loss of automatic control of the voltage regulator include the requirement to notify the TSO (i.e., AmerenIP) of the failure.

CPS TS Bases Section 3.8.1, "AC Sources Operating," discusses operability requirements for off-site sources. The minimum voltage for operability of the 138 kV and 345 kV sources are dependent upon the operability of the SVC. If a SVC becomes inoperable, then the associated off-site source is considered inoperable until such time as the TSO (i.e., AmerenIP) is provided with a higher minimum voltage for contingency monitoring. In addition, AmerenIP is notified if the SVC is not operable.

CPS licensed operators are trained and tested in accordance with the Systematic Approach to Training (SAT). Procedures and policies are routinely reviewed for training through this process for improvement of operator performance. The items considered for training include Annunciator Response Procedures, Abnormal Operating Procedures, and Emergency Operating Procedures that require interface with the TSO in accordance with the established protocol. In addition as part of initial training, requalification training, and annual operating tests, licensed operators are subjected to written examinations, static and/or simulator examinations, Job Performance Measures (JPMs), and evaluated simulator scenarios. These evaluations may incorporate topics including the loss of the main generator voltage regulator and actions to mitigate the effect of the failure. Testing is commensurate with the material presented and any performance issues are identified for inclusion in future training.

(b) If your TS bases sections, the final safety analysis report, and plant procedures do not provide guidance regarding situations in which the condition of plant-controlled or monitored equipment can adversely affect the operability of the NPP offsite power system, explain why you believe you comply with the provisions of GDC 17 and the plant TSs, or describe what actions you intend to take to provide such guidance or procedures.

Response

Not applicable

Use of NPP licensee/TSO protocols and analysis tool by TSOs to assist NPP licensees in monitoring grid conditions for consideration in maintenance risk assessments.

The Maintenance Rule (10 CFR 50.65(a)(4)) requires that licensees assess and manage the increase in risk that may result from proposed maintenance activities before performing them.

5. *Performance of grid reliability evaluations as part of the maintenance risk assessments required by 10 CFR 50.65(a)(4).*

(a) Is a quantitative or qualitative grid reliability evaluation performed at your NPP as part of the maintenance risk assessment required by 10 CFR 50.65(a)(4) before performing grid-risk-sensitive maintenance activities? This includes surveillances, post-maintenance testing, and preventive and corrective maintenance that could increase the probability of a plant trip or LOOP or impact LOOP or SBO coping capability, for example, before taking a risk-significant piece of equipment (such as an EDG, a battery, a steam-driven pump, an alternate AC power source) out-of-service?

Response

Yes

Risk is assessed using a process that combines quantitative results from a probabilistic risk assessment (PRA) with a qualitative defense-in-depth model. During the planning and scheduling of work and prior to the execution of work, many factors are assessed for risk including the effect of weather/time of year and grid instability. The combination of unavailable Systems, Structures and Components (SSCs) and planned activities is then assessed in the risk assessment tool. Currently, a procedure update is being implemented to provide additional detail for how to factor grid reliability into the risk assessment tool before taking equipment out of service for planned maintenance. These procedure changes are currently scheduled to be in place at CPS by May 15, 2006.

(b) Is grid status monitored by some means for the duration of the grid-risk-sensitive maintenance to confirm the continued validity of the risk assessment and is risk reassessed when warranted? If not, how is the risk assessed during grid-risk-sensitive maintenance?

Response

Yes

Grid status is evaluated by the TSO (i.e., AmerenIP) using a RTCA program, a grid state estimator, and SCADA system. AmerenIP notifies CPS of emergent grid conditions as discussed in the response to 1(b). Existing procedures require evaluation of the risk of scheduled on online maintenance activities based on conditions such as power grid stability, weather forecast, and current plant system conditions.

(c) Is there a significant variation in the stress on the grid in the vicinity of your NPP site caused by seasonal loads or maintenance activities associated with critical transmission elements? Is there a seasonal variation (or the potential for a seasonal variation) in the LOOP frequency in the local transmission region? If the answer to either question is yes, discuss the time of year when the variations occur and their magnitude.

Response

The base PRA model reflects the yearly average LOOP frequency because seasonal variations that would cause changes to the frequency of a LOOP cannot be accurately predicted. While time related variations are not factored into the base PRA model for CPS, symptoms of grid stress such as maximum generation conditions, grid contingencies, or severe weather conditions require identification of such dynamic conditions should they occur, and risk management actions are then taken to mitigate the risk or reschedule the work as appropriate.

(d) Are known time-related variations in the probability of a LOOP at your plant site considered in the grid-risk-sensitive maintenance evaluation? If not, what is your basis for not considering them?

Response

No

While time related variations are not factored into the base PRA model for CPS, symptoms of grid stress such as maximum generation conditions, grid contingencies, or severe weather conditions require identification of such dynamic conditions should they occur, and risk management actions are then taken to mitigate the risk or reschedule the work as appropriate.

(e) Do you have contacts with the TSO to determine current and anticipated grid conditions as part of the grid reliability evaluation performed before conducting grid-risk-sensitive maintenance activities?

Response

Yes

Grid risk sensitive maintenance activities are coordinated based on anticipated conditions and planned maintenance at interface meetings between the TSO (i.e., AmerenIP) and CPS. Additional communication will occur between the TSO and CPS as stated in the response to 1(b) if grid conditions deteriorate from acceptable levels.

(f) Describe any formal agreement or protocol that you have with your TSO to assure that you are promptly alerted to a worsening grid condition that may emerge during a maintenance activity.

Response

The NPOA (Reference 1) states that the Midwest ISO (i.e., the TO) and AmerenIP (i.e., the TSO) will provide priority notice to each other of any abnormal transmission system conditions that could create adverse operating conditions at CPS. AmerenIP will notify CPS of such conditions.

(g) Do you contact your TSO periodically for the duration of the grid-risk sensitive maintenance activities?

Response

No

Communications take place between the TSO (i.e., AmerenIP) and CPS as detailed in the response to 1(b) if grid conditions deteriorate from an acceptable level. At this time there is no periodic mandated contact between the TSO/TO and CPS during the duration of grid-risk-sensitive maintenance activities.

(h) If you have a formal agreement or protocol with your TSO, describe how NPP operators and maintenance personnel are trained and tested on this formal agreement or protocol.

Response

CPS maintenance, operations, and work management personnel associated with schedule development or communicating with the TSO (i.e., AmerenIP) are briefed on TSO/TO interface requirements and expectations but are not formally tested on knowledge retention in this area.

(i) If your grid reliability evaluation, performed as part of the maintenance risk assessment required by 10 CFR 50.65(a)(4), does not consider or rely on some arrangement for communication with the TSO, explain why you believe you comply with 10 CFR 50.65(a)(4).

Response

Not applicable

The methods used to integrate grid risk into the quantitative risk evaluation prior to taking equipment out of service for planned maintenance at CPS rely on communication with the TSO (i.e., AmerenIP).

(j) If risk is not assessed (when warranted) based on continuing communication with the TSO throughout the duration of grid-risk-sensitive maintenance activities, explain why you believe you have effectively implemented the relevant provisions of the endorsed industry guidance associated with the maintenance rule.

Response

Not applicable

Grid status is continually evaluated by AmerenIP (i.e., the TSO) using a RTCA program, a grid state estimator and SCADA system. AmerenIP notifies CPS of emergent grid conditions as discussed in the response to 1(b). In addition, the Midwest ISO performs similar monitoring and evaluation. Existing EGC procedures require evaluation of the risk of scheduled on line maintenance activities based on conditions such as power grid stability, weather forecast, and current plant system conditions.

(k) With respect to questions 5(i) and 5(j), you may, as an alternative, describe what actions you intend to take to ensure that the increase in risk that may result from proposed grid-risk-sensitive activities is assessed before and during grid-risk-sensitive maintenance activities, respectively.

Response

Not applicable

6. *Use of risk assessment results, including the results of grid reliability evaluations, in managing maintenance risk, as required by 10 CFR 50.65(a)(4).*

(a) Does the TSO coordinate transmission system maintenance activities that can have an impact on the NPP operation with the NPP operator?

Response

Yes

The TSO (i.e., AmerenIP) coordinates transmission system maintenance activities that can have an impact on the NPP (i.e., CPS) with CPS. Coordination of maintenance activities is discussed in Article 5 of the Interconnection Agreement between CPS and AmerenIP (Reference 8).

(b) Do you coordinate NPP maintenance activities that can have an impact on the transmission system with the TSO?

Response

Yes

The NPP (i.e., CPS) coordinates maintenance activities that can have an impact on the transmission system with the TSO (i.e., AmerenIP). Coordination of maintenance activities is discussed in Article 5 of the Interconnection Agreement between CPS and AmerenIP (Reference 8).

(c) Do you consider and implement, if warranted, the rescheduling of grid-risk-sensitive maintenance activities (activities that could (1) increase the likelihood of a plant trip, (ii)

increase LOOP probability, or (iii) reduce LOOP or SBO coping capability) under existing, imminent, or worsening degraded grid reliability conditions?

Response

Yes

Existing procedures require deferring work that would render AC power sources unavailable if severe weather is expected. Risk of scheduled on line work is evaluated based on grid conditions, the weather forecast, and current plant systems status. If the risk analysis determines that risk exceeds a predetermined level, then that configuration is not voluntarily entered and schedule changes are made to reduce the risk to an acceptable level.

(d) If there is an overriding need to perform grid-risk-sensitive maintenance activities under existing or imminent conditions of degraded grid reliability, or continue grid-risk-sensitive maintenance when grid conditions worsen, do you implement appropriate risk management actions? If so, describe the actions that you would take. (These actions could include alternate equipment protection and compensatory measures to limit or minimize risk.)

Response

Yes

When any risk significant SSC is made unavailable, actions are taken to protect redundant or diverse SSCs commensurate with the risk significance of the work being performed in accordance with approved procedures.

(e) Describe the actions associated with questions 6(a) through 6(d) above that would be taken, state whether each action is governed by documented procedures and identify the procedures, and explain why these actions are effective and will be consistently accomplished.

Response

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 a final time before permitting the equipment to be switched out of service.

Once the equipment is switched out of service, the Midwest ISO continually evaluates grid status. In addition, AmerenIP (i.e., the TSO) is performing similar monitoring and evaluation. AmerenIP notifies CPS through the TO's control center, as discussed in the response to 1(b).

Actions specified in 6(c) and 6(d) are specified in the EGC Work Management procedure, WC-AA-101, "On-Line Work Control Process," (Reference 5).

(f) Describe how NPP operators and maintenance personnel are trained and tested to assure they can accomplish the actions described in your answers to question 6(e).

Response

CPS Maintenance, Operations, and Work Management personnel associated with schedule development and/or risk assessment are briefed on procedure expectations but are not formally tested on knowledge retention in this area.

(g) If there is no effective coordination between the NPP operator and the TSO regarding transmission system maintenance or NPP maintenance activities, please explain why you believe you comply with the provisions of 10 CFR 50.65(a)(4).

Response

Not applicable

Effective coordination is directed by Article 5 of the Interconnection Agreement between CPS and AmerenIP (Reference 8).

(h) If you do not consider and effectively implement appropriate risk management actions during the conditions described above, explain why you believe you effectively addressed the relevant provisions of the associated NRC-endorsed industry guidance.

Response

Not applicable

Effective and appropriate risk management actions are described in plant procedures and implemented during the conditions described above.

(i) You may, as alternative to questions 6(g) and 6 (h) describe what actions you intend to take to ensure that the increase in risk that may result from grid-risk-sensitive maintenance activities is managed in accordance with 10 CFR 50.65(a)(4).

Response

Not applicable

Offsite power restoration procedures in accordance with 10 CFR 50.63 as developed in Section 2 of RG 1.155.

Pursuant to 10 CFR 50.63, the NRC requires that each NPP licensed to operate to be able to withstand an SBO for a specified duration and recover from the SBO. NRC RG 1.155 gives licensees guidance on developing their approaches for complying with 10 CFR 50.63.

7. *Procedures for identifying local power sources[1] that could be made available to resupply your plant following a LOOP event.*

Note: Section 2, "Offsite Power," of RG 1.155 (ADAMS Accession No. ML003740034) states:

> *Procedures should include the actions necessary to restore offsite power and use nearby power sources when offsite power is unavailable. As a minimum, the following potential causes for loss of offsite power should be considered:*
>
> - *Grid undervoltage and collapse*
> - *Weather-induced power loss*
> - *Preferred power distribution system faults that could result in the loss of normal power to essential switchgear buses*

(a) Briefly describe any agreement made with the TSO to identify local power sources that could be made available to resupply power to your plant following a LOOP event.

Response

CPS has entered into a NPOA with AmerenIP and the Midwest ISO (Reference 1). 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.

The NPOA is intended to document the respective roles of CPS, AmerenIP, and Midwest ISO and to define scheduling protocols, emergency procedures, operating limitations and any other restrictions applicable to CPS.

Midwest ISO will provide updates to AmerenIP and CPS on transmission system status during emergency restoration, and will give the highest priority to restoring power to essential affected nuclear facilities, including CPS, in accordance with North American Electric Reliability Council (NERC) standard EOP-005-0,"System Restoration Plans," (Reference 15).

Midwest ISO provided the following information to AmerGen regarding this response in a letter from Midwest ISO to nuclear plants (i.e., including CPS) interconnected with the transmission system controlled by Midwest ISO (Reference 7).

"The Midwest ISO restoration process coordinates the development of individual Transmission Owner Restoration Plans, Midwest ISO conducts reviews, workshops and drills to ensure the effectiveness of the restoration plan.

The Midwest ISO restoration process will provide updates to the TO and NPP on transmission system status during emergency restoration, and will give the highest

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[1] *This includes items such as nearby or onsite gas turbine generators, portable generators, hydro generators, and black-start fossil power plants.*

priority to restoring power to essential affected nuclear facilities, per NERC standard EOP-005-0.

However, due to the myriad of possible restoration scenarios, no specific power sources to resupply NPPs are identified. The MISO restoration process allows for the fact that the blacked out area may or may not be separated from the remainder of the system. The MISO restoration process allows the use of black start unit or cranking path from non-blacked out areas. Regardless of the scenario, there is a clear recognition of the importance of expeditious restoration of an NPP offsite power source."

(b) Are your NPP operators trained and tested on identifying and using local power sources to resupply your plant following a LOOP event? If so, describe how.

Response

No

CPS operators are not specifically trained and tested on identifying and using local power sources to resupply the NPP (i.e., CPS) following a LOOP event. The identification and use of local power sources for CPS are under the control of AmerenIP (i.e., the TSO) and Midwest ISO in accordance with the procedures and interface agreements described in the response to 7(a).

(c) If you have not established an agreement with your plant's TSO to identify local power sources that could be made available to resupply power to your plant following a LOOP event, explain why you believe you comply with the provisions of 10 CFR 50.63, or describe what actions you intend to take to establish compliance.

Response

The identification and use of local power sources for restoration of offsite power to CPS following a LOOP event are under the control of AmerenIP (i.e., the TSO) and Midwest ISO in accordance with the procedures and interface agreements described in the response to 7(a). AmerenIP (i.e., the TSO) has identified black start and/or local sources that could be made available to restore the grid following a LOOP event, however, due to the myriad of possible restoration scenarios, no specific power sources to resupply CPS are identified. The procedures identified by RG 1.155, "Station Blackout," (Reference 14) that include the actions necessary to restore offsite power and the use of nearby power sources are also under the control of AmerenIP and Midwest ISO.

The identification and use of local power sources that could be made available to resupply power to the NPP following a LOOP event are not part of the current CPS operating procedures and training since they are outside of CPS's direct control.

Losses of offsite power caused by grid failures at a frequency of equal to or greater than once in 20 site-years in accordance with Table 4 of Regulatory Guide 1.155 for complying with 10 CFR 50.63.

Pursuant to 10 CFR 50.63, the NRC requires that each NPP licensed to operate be able to withstand an SBO for a specified duration and recover from the SBO. NRC RG 1.155 gives licensees guidance on developing their approaches to complying with 10 CFR 50.63.

8. *Maintaining SBO coping capabilities in accordance with 10 CFR 50.63.*

(a) Has your NPP experienced a total LOOP caused by grid failure since the plant's coping duration was initially determined under 10 CFR 50.63?

Response

CPS has not experienced a total LOOP caused by grid failure since the coping duration was initially determined under 10 CFR 50.63, "Loss of all alternating current power," (i.e., Station Blackout (SBO) Rule). A review of CPS records including the Licensee Event Report (LER) database from July 1988, when the SBO Rule was added, was performed to make this determination.

This determination is consistent with the data presented in NUREG/CR-6890, Volume 1, "Reevaluation of Station Blackout Risk at Nuclear Power Plants – Analysis of Offsite Power Events: 1986-2004," (Reference 6), Appendix A, "LOOP Event Database," Section A-2, "Data Tables," Table A -1, "Loop Events for 1986-2004, sorted by plant."

In addition, the review of LERs since Reference 6 was issued to present has concluded that there were no additional grid failure based LOOP events during this period.

(b) If so, have you reevaluated the NPP using the guidance in Table 4 of RG 1.155 to determine if your NPP should be assigned to the P3 offsite power design characteristic group?

Response

Not applicable

(c) If so, what were the results of this reevaluation, and did the initially determined coping duration for the NPP need to be adjusted?

Response

Not applicable

(d) If your NPP has experienced a total LOOP caused by grid failure since the plant's coping duration was initially determined under 10 CFR 50.63 and has not been reevaluated using the guidance in Table 4 of RG 1.155, explain why you believe you comply with the provisions of 10 CFR 50.63 as stated above, or described what actions you intend to take to ensure that the NPP maintains its SBO coping capabilities in accordance with 10 CFR 50.63.

Response

Not applicable

Actions to ensure compliance

9. *If you determine that any action is warranted to bring your NPP into compliance with NRC regulatory requirements, including TSs, GDC 17, 10 CFR 50.65(a)(4), 10 CFR 50.63, 10 CFR 55.59 or 10 CFR 50.120, describe the schedule for implementing it.*

Response

Not applicable

References

1. "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
2. Midwest ISO procedure RTO-OP-03, "Communication and Mitigation Protocols for Nuclear Plant/Electrical System Interfaces," Revision 10
3. CPS Procedure OP-CL-108-107-1001, "Degraded Grid Actions," Revision 4
4. CPS Procedure 4100.01, "Reactor Scram," Revision 18e
5. EGC procedure WC-AA-101, "On-Line Work Control Process," Revision 11
6. NUREG/CR-6890, Volume 1, "Reevaluation of Station Blackout Risk at Nuclear Power Plants – Analysis of Offsite Power Events: 1986-2004," Revision 0
7. Letter from R.C. Harszy (Midwest ISO) to Nuclear Plant or Transmission Operator, "Midwest ISO Process for Nuclear Power Plant Operations," dated March 10, 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
9. NRC Information Notice IN 93-17, "Safety Systems Response to Loss of Coolant and Loss of Offsite Power," Revision 1, dated March 25, 1994
10. SECY-05-0219, "Issuance of Nuclear Regulatory Commission Generic Letter 2005-XX, 'Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power,'" dated December 2, 2005
11. EGC procedure WC-AA-107, "Seasonal Readiness," Revision 2
12. SOER 99-1, "Loss of Grid," December 27, 1999
13. SOER 99-1, "Loss of Grid – Addendum," December 9, 2004
14. Regulatory Guide 1.155, "Station Blackout," Revision 0
15. NERC standard EOP-005-0, "System Restoration Plans," effective April 1, 2005

16. Jeffrey V Hackman, Ameren Transmission, "Clinton Contingency Voltage Monitoring," February 28, 2006, personal email to John Gyrath and Pat Ryan, Exelon Nuclear, (February 28, 2006)

17. Terry Volkman, Midwest ISO, "MISO modeling of the Clinton Station Aux," March 31, 2006, personal email to John Gyrath, Exelon Nuclear, (March 31, 2006)

ATTACHMENT 4

60-day Response to NRC Generic Letter 2006-02

DRESDEN NUCLEAR POWER STATION, Units 2 and 3

Renewed FOL Nos. DPR-19 and DPR-25

On February 1, 2006, the NRC issued Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power." 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 Generic Letter requested that licensees answer the following questions and provide the information to the NRC with respect to each of their Nuclear Power Plants (NPPs).

Use of protocols between the NPP licensee and the TSO, ISO, or RC/RA and the use of analysis tools by TSOs to assist NPP licensee in monitoring grid conditions to determine the operability of offsite power system under plant TS.

GDC 17, 10 CFR Part 50, Appendix A, requires that licensees minimize the probability of the loss of power from the transmission network given a loss of the power generated by the nuclear power unit(s).

1. *Use of protocols between the NPP licensee and the TSO, ISO, or RC/RA to assist the NPP licensee in monitoring grid conditions to determine the operability of offsite power system under plant TS.*

   (a) Do you have a formal agreement or protocol with your TSO?

   Response

   Yes

   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.

   All members of PJM execute the "Operating Agreement of PJM Interconnection, LLC," (Reference 1) that details the obligations and responsibilities of both PJM and the PJM members. In the Operating Agreement, each member agrees to abide by the requirements contained in the PJM Manuals. The PJM Manuals contain the specific operational requirements that PJM and each member is required to follow.

   ComEd (i.e., the TO) is also a signatory on the "PJM Consolidated Transmission Owners Agreement (PJM TOA)," (Reference 2). Section 4.5 of the PJM TOA requires the TOs to operate and maintain their transmission facilities in accordance with the PJM Manuals.

   The PJM Operating Agreement requires PJM to, "Incorporate the grid reliability requirements applicable to nuclear generating units in the PJM Region planning and operating principles and practices." PJM Manual M01, "Control Center Requirements," Attachment B, "Nuclear Plant Communication Protocol," (Reference 3), provides the roles and responsibilities of nuclear stations, TOs, and PJM with regard to communications both in normal and emergency circumstances. The nuclear power plant (NPP) notification requirements are contained in PJM Manual M3, "Transmission Operations," Section 3 (Reference 4).

In addition to the agreements delineated in the PJM Operating Agreement and the PJM Manuals, EGC has jointly approved interface procedures with the TO that address the monitoring of the offsite source voltages and the notification protocols. EGC procedure OP-AA-108-107-1002, "Interface Agreement between Exelon Energy Delivery and Exelon Generation for Switchyard Operations," (Reference 10) outlines the responsibilities and required work interfacing activities.

(b) Describe any grid conditions that would trigger a notification from the TSO to the NPP licensee and if there is a time period required for the notification.

Response

PJM Manual M3 (Reference 4) requires PJM to initiate notification to DNPS through the TO's control center if PJM identifies a switchyard voltage violation. PJM Manual M3 states: "This notification should occur within 15 minutes for voltage contingency violations and immediately for actual voltage violations. To the extent practical, PJM shall direct operations such that the violation is remedied within 30 minutes."

In addition, PJM Manual M13, "Emergency Operations," (Reference 5) identifies a series of alerts, warnings, and actions that PJM issues to PJM members depending on the identified grid condition. The PJM message is communicated to DNPS by their generation dispatcher through the EGC Nuclear Duty Officer (NDO) for a variety of system conditions including the following:

Capacity Emergencies
- Maximum Emergency Generation Loading
- Load Management Curtailment
- Manual Load Dump Warning

Light Load Emergencies
- Minimum Generation Emergency
- Local Minimum Generation Emergency

Weather/Environmental Emergencies
- Hot/Cold Weather Alerts
- Thunderstorms and Tornadoes
- Solar Magnetic Disturbances

Sabotage/Terrorism Emergencies

(c) Describe any grid conditions that would cause the NPP licensee to contact the TSO. Describe the procedures associated with such a communication. If you do not have procedures, describe how you assess grid conditions that may cause the NPP licensee to contact the TSO.

Response

As required by PJM Manuals, communications between DNPS and PJM (TSO) are generally through the Transmission Owner (TO) providing the interconnection service.

DNPS will contact the TSO/TO for grid conditions that have parameters that are observable at the NPP. These conditions include the following:

- Loss of Offsite Power (LOOP)
- Abnormal switchyard voltage
- Automatic (protective) switchyard circuit breaker operation
- Switchyard alarms

In addition to any alarm response procedures for the above applicable conditions, TSO/TO notifications are controlled by operating procedures, (e.g., OP-AA-108-107-1001, "Station Response to Grid Capacity Conditions"), Abnormal Operating Procedures, (e.g., DGA-12, "Loss of Offsite Power," and DOA 6500-12, "Abnormal Switchyard Voltage").

DNPS will contact the TSO/TO during a grid restoration process to obtain grid status in preparation for returning the plant buses to the offsite source.

DNPS also notifies the TSO/TO of switchyard equipment deficiencies identified by NPP personnel. Jointly approved interface agreements/procedures between EGC and the TO identify the communication protocols for station identified switchyard deficiencies. EGC procedures OP-AA-108-107-1002 (Reference 10) and WC-AA-8000 (Reference 7) outline the responsibilities and required work interfacing activities.

In addition, DNPS will notify the TSO/TO of NPP configurations that potentially impact grid conditions. A jointly approved interface agreement/procedure, OP-AA-108-107-1002 (Reference 10), between EGC and the TO identifies the requirements for communication of the conditions listed below:

- NPP MVAR limitations
- NPP Main generator voltage regulator not in "Automatic" mode
- NPP inability to provide the MVARs requested by the TSO/TO

Note that any DNPS MW limitations or limitations on the rate at which the NPP power may be raised or lowered are communicated to the generation dispatcher.

(d) Describe how NPP operators are trained and tested on the use of the procedures or assessing grid conditions in question 1(c).

<u>Response</u>

DNPS licensed operators are trained and tested in accordance with the Systematic Approach to Training (SAT). Procedures and policies are routinely reviewed for training through this process for improvement of operator performance. The items considered for training include Operating Procedures, Annunciator Response Procedures, Abnormal Operating Procedures, and Emergency Operating Procedures that require interface with the TSO in accordance with the established protocol. These procedures may be utilized based on various grid, switchyard, or plant symptoms to assess, respond to or mitigate off-normal plant and grid conditions. Additionally, SOER 99-01, "Loss of Grid," (Reference 24) and SOER 99-01, "Loss of Grid – Addendum," (Reference 25) specifically are captured in the Licensed Operator Requalification Training Program (LORT) Long Range Training Program. These topics, in varying detail based upon the SAT process or as part of implementing EGC procedure WC-AA-107, "Seasonal Readiness," (Reference 23) are reviewed periodically with DNPS operators. Testing is commensurate with the material presented and any performance issues are identified by for inclusion in future training.

(e) If you do not have a formal agreement or protocol with your TSO, describe why you believe you continue to comply with the provisions of GDC 17 as stated above, or describe what actions you intend to take to assure compliance with GDC 17.

Response

Not applicable. Formal agreements exist for DNPS.

(f) If you have an existing formal interconnection agreement or protocol that ensures adequate communication and coordination between the NPP license and the TSO, describe whether this agreement or protocol requires that you be promptly notified when the conditions of the surrounding grid could result in degraded voltage (i.e., below TS nominal trip setpoint value requirements; including NPP licensees using allowable value in its TSs) or LOOP after a trip of the reactor units(s).

Response

PJM Manual M3 (Reference 4) requires PJM to initiate a notification to DNPS through its respective transmission owner's control center if PJM identifies a NPP switchyard voltage violation. PJM Manual M3 states: "This notification should occur within 15 minutes for voltage contingency violations and immediately for actual voltage violations. To the extent practical, PJM shall direct operations such that the violation is remedied within 30 minutes." The trip of a NPP (i.e., trip of a DNPS unit) is one of the contingencies analyzed by PJM. PJM analyzes the DNPS switchyard contingency voltages to the voltage limits provided by DNPS. The voltage limits provided for DNPS are based on the existing design basis analysis.

(g) Describe the low switchyard voltage conditions that would initiate operation of plant degraded voltage protection.

Response

Switchyard voltage below a value maintaining emergency bus voltage above the maximum reset value of the degraded voltage relay (3924 volts) will cause a trip of the preferred power source after a time delay of approximately 7 seconds with a Loss of Coolant Accident (LOCA) signal present. The relation between the switchyard voltage and the emergency bus voltage is dependent on the system auxiliary transformer impedance and the winding load. Under design basis accident (i.e., Large Break LOCA) conditions, the maximum loading is known and contained in the DNPS calculations of record. For DNPS, this corresponds to a switchyard voltage of approximately 346.0kV for Unit 2 and 344.9kV for Unit 3.

In other conditions, the loading is less than the expected LOCA loading and will vary considerably depending on which loads are needed to support unit conditions. Under these conditions the required DNPS switchyard voltage will be less than that required to support LOCA loading.

Note that the second level undervoltage calculations for DNPS have recently been revised. As a result there is a revised maximum reset value for the degraded voltage relay of 3915 volts. A License Amendment Request (Reference 9) was submitted to revise the Technical Specification setpoints affected by the revised calculations and NRC approval was received on March 17, 2006 (Reference 16). Implementation will occur within 60 days.

2. Use of criteria and methodologies to assess whether the offsite power system will become inoperable as a result of a trip of your NPP.

(a) Does your NPP's TSO use any analysis tools, an online analytical transmission system studies program, or other equivalent predictive methods to determine the grid conditions that would make the NPP offsite power system inoperable during various contingencies? If available to you, please provide a brief description of the analysis tool that is used by the TSO.

Response

Yes

The PJM Energy Management System (EMS) includes a Security Analysis application which runs approximately every 1 minute and analyzes ~4,000 contingencies on the PJM system (Reference 6). The analysis provides results with respect to thermal, voltage, and voltage drop limit violations. One of the contingencies analyzed by the PJM EMS is the trip of a NPP (i.e., trip of a DNPS unit).

In addition, ComEd (i.e., the TO) possesses a similar system that also calculates post-contingency voltage limit violations. One of the contingencies analyzed by ComEd is the trip of a DNPS unit.

(b) Does your NPP's TSO use an analysis tool as the basis for notifying the NPP licensee when such a condition is identified? If not, how does the TSO determine if conditions on the grid warrant NPP licensee notification?

Response

Yes

The results of the PJM Security Analysis application contain the specific contingency of the NPP tripping as the contingent element. Violation of the unit trip contingency voltage limit would result in notification of the NPP (i.e., DNPS) in accordance with PJM Manual M3, Section 3 (Reference 4).

ComEd (i.e., the TO) also possesses similar capability to monitor the same condition.

(c) If your TSO uses an analysis tool, would the analysis tool identify a condition in which a trip of the NPP would result in switchyard voltages (immediate and/or long-term) falling below TS nominal trip setpoint value requirements (including NPP licensees using allowable value in its TSs) and consequent actuation of plant degraded voltage protection? If not, discuss how such a condition would be identified on the grid.

Response

Yes

The trip of the NPP (i.e., trip of a DNPS unit) is one of the contingencies analyzed by the PJM Security Analysis application. PJM analyzes the NPP switchyard contingency voltages to the voltage limits provided by DNPS. The voltage limits provided by DNPS are based on the plant's design basis analysis as discussed in the response to 1(g).

ComEd (i.e., the TO) also possesses similar capability to monitor the same condition.

(d) If your TSO uses an analysis tool, how frequently does the analysis tool program update?

Response

The PJM EMS includes a Security Analysis application that currently updates approximately every 1-minute. In addition, ComEd (i.e., the TO) possesses a Security Analysis application that updates approximately every 6 minutes (Reference 26).

(e) Provide details of analysis tool-identified contingency conditions that would trigger an NPP licensee notification from the TSO.

Response

PJM notifies DNPS through the TO (i.e., ComEd) control center whenever actual or post-contingency voltages are determined to be below the DNPS switchyard voltage limits. This requirement applies to all contingencies involving the tripping of the NPP or any transmission facility as the contingent element. In accordance with PJM Manual M3 (Reference 4) the notification is required even if the voltage limits are the same as the standard PJM voltage limits.

(f) If an interface agreement exists between the TSO and the NPP licensee, does it require that the NPP licensee be notified of periods when the TSO is unable to determine if offsite power voltage and capacity could be inadequate? If so, how does the NPP licensee determine that the offsite power would remain operable when such a notification is received?

Response

Yes

DNPS unit trip contingency voltage calculations are performed by the PJM EMS and the TO (i.e., ComEd) Security Analysis application. The PJM EMS consists of a primary and backup system. If the PJM EMS fails, the ComEd Security Analysis application continues to analyze the DNPS unit trip contingency voltage. DNPS will be notified if the real time contingency analysis capability of PJM and the TO (i.e., ComEd) are lost simultaneously in accordance with PJM Manual M01, Section 2 (Reference 3).

If DNPS is notified that PJM and ComEd (i.e., the TO) have both lost their real time contingency analysis capability, DNPS would request PJM and ComEd to provide an assessment of the current condition of the grid based on the tools that PJM and ComEd have available. The determination of the operability of the offsite sources would consider the assessment provided by PJM and ComEd and whether the current condition of the grid is bounded by the grid studies previously performed for DNPS.

(g) After an unscheduled inadvertent trip of the NPP, are the resultant switchyard voltages verified by procedure to be bounded by the voltages predicted by the analysis tool?

Response

No

There is presently no formal process for comparing the actual post-trip voltages to the post-trip contingency voltage results calculated by the PJM and the TO (i.e., ComEd) Security Analysis applications.

PJM provided the following information to EGC regarding this response in a letter from PJM to all PJM nuclear owners (Reference 6).

"Because the PJM transmission owning member companies have similar Security Analysis programs to PJM, there are many opportunities to compare the results of the respective Security Analysis programs. In this manner, there is a high confidence that the Security Analysis results are accurate within the precision of the calculations.

PJM retains the EMS results for a period of approximately 3 weeks after real time. It is possible to use those saved EMS results to repeat the Security Analysis calculations and compare them to the actual voltages from a unit trip. However, the NPP trips occur so infrequently that it would take a number of data points to verify the accuracy with any statistical significance. This process could take years if the process is limited to a comparison of only NPP trips."

(h) If an analysis tool is not available to the NPP licensee's TSO, do you know if there are any plans for the TSO to obtain one? If so, when?

Response

Not applicable. DNPS TSO (i.e., PJM) has an analysis tool.

(i) If an analysis tool is not available, does your TSO perform period studies to verify that adequate offsite power capability, including adequate NPP post-trip switchyard voltages (immediate and/or long-term), will be available to the NPP licensee over the projected timeframe of the study?

Response

Not applicable. DNPS TSO (i.e., PJM) has an analysis tool.

(a) Are the key assumptions and parameters of these periodic studies translated into TSO guidance to ensure that the transmission system is operated within the bounds of the analyses?

Response

Not applicable. DNPS TSO (i.e., PJM) has an analysis tool.

(b) If the bounds of the analyses are exceeded, does this condition trigger the notification provisions discussed in question 1 above?

Response

Not applicable. DNPS TSO (i.e., PJM) has an analysis tool.

(j) If your TSO does not use, or you do not have access to the results of an analysis tool, or your TSO does not perform and make available to you periodic studies that determine the adequacy of offsite power capability, please describe why you believe you comply with the provisions of GDC 17 as stated above, or describe what compensatory actions you intend to take to ensure that the offsite power system will be sufficiently reliable and remain operable with high probability following a trip of your NPP.

Response

Not applicable. DNPS TSO (i.e., PJM) has an analysis tool. In addition the applicable contingency voltage results are made available to DNPS as needed.

3. *Use of criteria and methodologies to assess whether the NPP's offsite power system and safety-related components will remain operable when switchyard voltages are inadequate.*

(a) If the TSO notifies the NPP operator that a trip of the NPP, or the loss of the most critical transmission line or the largest supply to the grid would result in switchyard voltages (immediate and/or long-term) below TS nominal trip setpoint value requirements (including NPP licensees using allowable value in its TSs) and would actuate plant degraded voltage protection, is the NPP offsite power system declared inoperable under the plant TSs? If not, why not?

Response

If the TSO (i.e., PJM) notifies DNPS that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., trip of a DNPS unit) is below the pre-determined notification value, DNPS will review the applicability to the plant operating configuration and will declare the offsite power source inoperable in accordance with Technical Specifications (TSs) if appropriate. The notification value provided to PJM by DNPS is based on the DNPS degraded voltage design basis analysis.

Predicted contingency voltages following the loss of a transmission facility (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 for DNPS at this time. If the TSO (i.e., PJM) notifies DNPS of a predicted contingency voltage violation resulting from the postulated trip of a transmission facility, DNPS will perform a risk analysis of in-progress and scheduled plant work and will take action as appropriate.

The NPP unit trip contingency can be caused by plant-centered events. The use of the NPP unit trip contingency as the contingency element upon which offsite power operability is based is consistent with the final paragraph of General Design Criterion (GDC) 17, "Electric power systems," of 10 CFR Part 50 Appendix A, "General Design Criteria for Nuclear Power Plants," which requires provisions be included to minimize the probability of the loss of power from the transmission network given a loss of the power generated by the NPP (i.e., a DNPS unit).

Postulated contingencies on the transmission system are currently not used as the basis for offsite source operability determinations since loss of power from the transmission network would not occur as a result of loss of power generated by a NPP unit (i.e., a DNPS unit). Such events (e.g., loss of a transmission line) are only postulated and have not actually occurred, and the offsite power sources remain capable of supporting a safe shutdown and mitigating the effects of an accident. Loss of power from the transmission network would not occur as a result of loss of power generated by a NPP unit and therefore the GDC 17 provision discussed in GL 2006-02 is met.

(b) If onsite safety-related equipment (e.g., emergency diesel generators or safety-related motors) is lost when subjected to a double sequencing (LOCA with delayed LOOP event) as a result of the anticipated system performance and is incapable of performing its safety functions as a result of responding to an emergency actuation signal during this condition, is the equipment considered inoperable? If not, why not?

Response

Although some features have been incorporated into the plant design, requirements for analysis and design considerations for double sequencing are not included within the DNPS current licensing and design basis as documented in the DNPS Updated Final Safety Analysis Report (UFSAR). DNPS has not been explicitly analyzed for all issues associated with double sequencing. Onsite safety-related equipment at DNPS (e.g., emergency diesel generators or safety-related motors) is not declared inoperable as a result of a TSO (i.e., PJM) unit trip contingency voltage notification.

Based on Enclosure 2 of SECY-05-0219, "Issuance of Nuclear Regulatory Commission Generic Letter 2005-XX, 'Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power,'" (Reference 19) which provided NRC guidance on responding to this issue, a review was performed for DNPS of the loading logic for the diesel generators as well as the safety-related breakers' anti-pumping logic. This review concluded that onsite safety-related equipment (i.e., emergency diesel generators or safety-related motors) is not lost as a result of diesel generator block loading and breaker lockout from anti-pump circuitry when subjected to a double sequencing event resulting from inadequate post unit trip voltages. The scope of the review performed for DNPS is discussed in the response to question 3(c) below.

(c) Describe your evaluation of onsite-related equipment to determine whether it will operate as designed during the condition described in question 3(b).

Response

Although some features have been incorporated into the plant design, requirements for analysis and design considerations for double sequencing are not included within the DNPS current licensing and design basis as documented in the DNPS UFSAR. DNPS has not been explicitly analyzed for all issues associated with double sequencing. However, using the NRC clarification provided in Enclosure 2 of SECY-05-0219 as guidance, a review was performed for the purpose of addressing question 3(b).

This review examined the effects of a double sequencing event on diesel generator block loading and the potential for breaker lockout from the anti-pump circuitry. The review assumed that following a LOCA initiation, separation occurred as a result of degraded voltage relay operation triggered by the loss of a DNPS unit. The review examined the diesel generator loading logic and determined that the logic is reset by the LOOP event. The second sequence is consistent with that described in the DNPS UFSAR for a LOOP/LOCA event. Loads are shed as a result of the LOOP signal and the loads are not block loaded onto the diesel generator.

The review also examined the potential for breaker lockout due to the anti-pumping circuitry. This review determined that there was sufficient time between the two sequences such that the breaker charging springs would re-charge and the second closure would be successful. To ensure that a breaker lockout would not occur, the breaker closing logics were also examined to assure that the trip signals were cleared before the second close signal was initiated.

(d) If the NPP licensee is notified by the TSO of other grid conditions that may impair the capability or availability of offsite power, are any plant TS action statements entered? If so, please identify them.

Response

As discussed in the response to 3(a), if the TSO (i.e., PJM) notifies DNPS that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., trip of a DNPS unit) is below the pre-determined notification value, DNPS will review the applicability to the plant operating configuration and will declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by DNPS is based on the DNPS degraded voltage design basis analysis.

In addition, if PJM notifies DNPS that the actual offsite power source voltage is less than the pre-determined notification value, DNPS will review the applicability to the plant operating configuration and would declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by DNPS is based on the DNPS degraded voltage design basis analysis.

(e) If you believe your plant TSs do not require you to declare your offsite power system or safety-related equipment inoperable in any of these circumstances, explain why you believe you comply with the provisions of GDC 17 and your plant TSs, or describe what

compensatory actions you intend to take to ensure that the offsite power system and safety-related components will remain operable when switchyard voltages are inadequate.

Response

The following notifications from the TSO (i.e., PJM) will result in DNPS declaring the offsite power source inoperable in accordance with TSs.

- If the TSO (i.e., PJM) notifies DNPS that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., trip of a DNPS unit) is below the pre-determined notification value, DNPS will review the applicability to the plant operating configuration and will declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by DNPS is based on the DNPS degraded voltage design basis analysis.

- If the TSO (i.e., PJM) notifies DNPS that the actual offsite power source voltage is less than the pre-determined notification value, DNPS will review the applicability to the plant operating configuration and would declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by DNPS is based on the DNPS degraded voltage design basis analysis.

Predicted contingency voltages following the loss of a transmission facility (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. If the TSO notifies the NPP of a predicted contingency voltage violation resulting from the postulated trip of a transmission facility, the NPP performs a risk analysis of in-progress and scheduled plant work and takes action as appropriate.

The NPP unit trip contingency can be caused by plant-centered events. The use of the NPP unit trip contingency as the contingency element upon which offsite power operability is based is consistent with the final paragraph of GDC 17 which requires provisions to minimize the probability of the loss of power from the transmission network given a loss of the power generated by the NPP.

Postulated contingencies on the transmission system are not used as the basis for offsite source operability determinations since loss of power from the transmission network would not occur as a result of loss of power generated by the NPP unit. Such events (e.g., loss of a transmission line) are only postulated and have not actually occurred, and the offsite power sources remain capable of affecting a safe shutdown and mitigating the effects of an accident. The GDC 17 provision discussed in the Generic Letter is still met; loss of power from the transmission network would not occur as a result of loss of power generated by the NPP unit.

Onsite safety-related equipment at DNPS (e.g., emergency diesel generators or safety-related motors) is not declared inoperable as a result of a TSO (i.e., PJM) unit trip contingency voltage notification. Although some features have been incorporated into the plant design, requirements for analysis and design considerations for double sequencing are not included within the DNPS current licensing and design basis as documented in the DNPS UFSAR. DNPS has not been explicitly analyzed for all issues associated with double sequencing.

(f) Describe if and how NPP operators are trained and tested on the compensatory actions mentioned in your answers to questions 3(a) through (e).

Response

DNPS licensed operators are trained and tested in accordance with the Systematic Approach to Training (SAT). Equipment operability, as defined by TS, including normal and emergency power, offsite circuits, and safety-related components, is under continuous review. Procedures are in place to provide operator guidance and required actions necessary during predicted or actual degraded grid voltage conditions based on information provided by the TSO/TO in accordance with established protocol or as observed by the NPP operator. As part of initial training, requalification training, and annual operating tests, licensed operators are subjected to written examinations, dynamic learning activities, static and/or simulator examinations, Job Performance Measures (JPMs), and evaluated simulator scenarios incorporating topics including the actual or predicted switchyard voltage issues and its effect on AC Source operability. Testing is commensurate with the material presented and any performance issues are identified for inclusion in future training.

4. Use of criteria and methodologies to assess whether the offsite power system will remain operable following a trip of your NPP.

(a) Do the NPP operators have any guidance or procedures in plant TS bases sections, the final safety analysis report, or plant procedures regarding situations in which the condition of plant-controlled or monitored equipment (e.g., voltage regulator, auto tap changing transformers, capacitors, static VAR compensators, main generator voltage regulators) can adversely affect the operability of the NPP offsite power system? If so, describe how the operators are trained and tested on the guidance and procedures.

Response

Yes

DNPS plant controlled or monitored equipment that can adversely affect the operability of the offsite power system is limited to the main generator voltage regulators and automatic load tap changers (LTCs). EGC and plant specific procedures provide guidance for notification of the TSO/TO (i.e., PJM/ComEd) when the voltage regulator is not in automatic.

DNPS procedures direct operator actions to control excitation in manual or other mitigating actions to control excitation. Operator actions on a loss of automatic control of the voltage regulator include the requirement to notify the TO (i.e., ComEd) of the failure. EGC has recently installed new transformers with automatic LTCs that provide offsite power to DNPS Units 2 and 3. Currently the LTCs are operated in the manual mode and were pending NRC approval (Reference 9) to allow operation in the automatic mode.

On March 17, 2006, the NRC issued TS amendments to DNPS Units 2 and 3 to implement the use of automatic load tap changers (Reference 16). The license amendments are effective on the date of issuance and are required to be implemented within 60 days of the date of issuance. During the implementation period, procedures addressing automatic actions will be implemented at DNPS and the LTCs will be placed in automatic.

DNPS licensed operators are trained and tested in accordance with the Systematic Approach to Training (SAT). Procedures and policies are routinely reviewed for training through this process for improvement of operator performance. The items considered for training include Annunciator Response Procedures, Abnormal Operating Procedures, and Emergency Operating Procedures that require interface with the TSO/TO in accordance with the established protocol. In addition as part of initial training, requalification training, and annual operating tests, licensed operators are subjected to written examinations, static and/or simulator examinations, Job Performance Measures (JPMs), and evaluated simulator scenarios. These evaluations may incorporate topics including the loss of the main generator voltage regulator and actions to mitigate the effect of the failure. Testing is commensurate with the material presented and any performance issues are identified for inclusion in future training.

(b) If your TS bases sections, the final safety analysis report, and plant procedures do not provide guidance regarding situations in which the condition of plant-controlled or monitored equipment can adversely affect the operability of the NPP offsite power system, explain why you believe you comply with the provisions of GDC 17 and the plant TSs, or describe what actions you intend to take to provide such guidance or procedures.

Response

Not applicable

Use of NPP licensee/TSO protocols and analysis tool by TSOs to assist NPP licensees in monitoring grid conditions for consideration in maintenance risk assessments.

The Maintenance Rule (10 CFR 50.65(a)(4)) requires that licensees assess and manage the increase in risk that may result from proposed maintenance activities before performing them.

5. Performance of grid reliability evaluations as part of the maintenance risk assessments required by 10 CFR 50.65(a)(4).

(a) Is a quantitative or qualitative grid reliability evaluation performed at your NPP as part of the maintenance risk assessment required by 10 CFR 50.65(a)(4) before performing grid-risk-sensitive maintenance activities? This includes surveillances, post-maintenance testing, and preventive and corrective maintenance that could increase the probability of a plant trip or LOOP or impact LOOP or SBO coping capability, for example, before taking a risk-significant piece of equipment (such as an EDG, a battery, a steam-driven pump, an alternate AC power source) out-of-service?

Response

Yes

Risk is assessed using a process that combines quantitative results from a probabilistic risk assessment (PRA) with a qualitative defense-in-depth model. During the planning and scheduling of work and prior to the execution of work, many factors are assessed for risk including the effect of weather/time of year and grid instability. The combination of unavailable Systems, Structures and Components (SSCs) and planned activities is then assessed in the risk assessment tool. Currently, a procedure update is being implemented to provide additional detail for how to factor grid reliability into the risk assessment tool before taking equipment out of service for planned maintenance. These procedure changes are currently scheduled to be in place at DNPS by May 15, 2006.

(b) Is grid status monitored by some means for the duration of the grid-risk-sensitive maintenance to confirm the continued validity of the risk assessment and is risk reassessed when warranted? If not, how is the risk assessed during grid-risk-sensitive maintenance?

Response

Yes

Grid status is continually evaluated by PJM using the Security Analysis application. PJM notifies DNPS through its Transmission Operator, (i.e., ComEd), of emergent grid conditions as discussed in the response to 1(b) above. In addition, ComEd (i.e., the TO) is also performing similar monitoring and evaluation. Existing EGC procedures require evaluation of the risk of scheduled online maintenance activities based on conditions such as power grid stability, weather forecast, and current plant system conditions.

(c) Is there a significant variation in the stress on the grid in the vicinity of your NPP site caused by seasonal loads or maintenance activities associated with critical transmission elements? Is there a seasonal variation (or the potential for a seasonal variation) in the LOOP frequency in the local transmission region? If the answer to either question is yes, discuss the time of year when the variations occur and their magnitude.

Response

The base PRA model reflects the yearly average LOOP frequency because seasonal variations that would cause changes to the frequency of a LOOP cannot be accurately predicted. While time related variations are not factored into the base PRA model for DNPS, symptoms of grid stress such as maximum generation conditions, low grid voltage, or severe weather conditions require identification of such dynamic conditions should they occur, and risk management actions are then taken to mitigate the risk or reschedule the work as appropriate.

PJM provided the following information to EGC regarding this response in a letter from PJM to all PJM nuclear owners (Reference 6).

"Stress on the grid is manifested in a number of ways. Stress can mean 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.

Regarding the seasonal variability of the stress causers, each has a seasonal component. For example, peak load levels occur at the peak seasons of the summer and winter seasons. While the specific days cannot be predicted, it is known roughly when they will occur. Consequently, maintenance during these times of the year is avoided.

From a transmission system operations perspective, it is the simultaneous combination of stress causers that results in the most difficult operational challenges. For example, experiencing very hot (or cold) weather when we (i.e., PJM) are in the maintenance seasons with a lot of equipment out of service can cause the most severe challenges.

We (i.e., PJM) are aware of the existence of the North American Electric Reliability Council (NERC) and NRC data regarding LOOP frequency. However, it is difficult to assign differential risks to any seasonal variation because of the complexity of the various competing factors, as explained above."

(d) Are known time-related variations in the probability of a LOOP at your plant site considered in the grid-risk-sensitive maintenance evaluation? If not, what is your basis for not considering them?

Response

No

While time related variations are not factored into the base PRA model for DNPS, symptoms of grid stress such as maximum generation conditions, low grid voltage, or severe weather conditions require identification of such dynamic conditions should they occur, and risk management actions are then taken to mitigate the risk or reschedule the work as appropriate.

(e) Do you have contacts with the TSO to determine current and anticipated grid conditions as part of the grid reliability evaluation performed before conducting grid-risk-sensitive maintenance activities?

Response

Yes

The protocol for NPP notification of actual or anticipated grid conditions is outlined in the response to 1(b). Any work performed on the grid risk sensitive equipment is evaluated for risk using these current or anticipated conditions as part of the evaluation prior to performance. Work is coordinated based on anticipated conditions and planned maintenance during bi-monthly interface meetings between the transmission operator (i.e., ComEd) and the EGC NPPs (i.e., DNPS).

As stated in the response to 1(b), communication is shared between the TSO (i.e., PJM) and DNPS if grid conditions deteriorate from an acceptable level. If contingencies are anticipated (e.g., the predicted post NPP trip offsite source voltage less than required) the TSO will provide DNPS with a one day look ahead notice.

(f) Describe any formal agreement or protocol that you have with your TSO to assure that you are promptly alerted to a worsening grid condition that may emerge during a maintenance activity.

Response

As stated in the response to 1(a), DNPS is located in the service territory of PJM. PJM is the TSO for DNPS. The TO providing interconnection services for DNPS is ComEd. EGC and ComEd are both members of PJM.

All members of PJM execute the PJM Operating Agreement (Reference 1) that details the obligations and responsibilities of both PJM and the PJM members. In the Operating Agreement, each member agrees to abide by the requirements contained in the PJM Manuals. The PJM Manuals contain the specific operational requirements that PJM and each member is required to follow.

As stated in the response to 1(b), PJM Manual M13 (Reference 5) identifies a series of alerts, warnings, and actions that PJM issues to PJM members depending on the identified grid condition. The PJM message is communicated to DNPS by their generation dispatcher through the EGC NDO for a variety of system conditions including capacity emergencies, light load emergencies, weather/environmental emergencies or sabotage/terrorism emergencies.

PJM Manual M3 (Reference 4) requires PJM to initiate notification to DNPS through the TO's control center if PJM identifies a switchyard voltage violation. PJM Manual M3 states: "This notification should occur within 15 minutes for voltage contingency violations and immediately for actual voltage violations. To the extent practical, PJM shall direct operations such that the violation is remedied within 30 minutes."

(g) Do you contact your TSO periodically for the duration of the grid-risk sensitive maintenance activities?

Response

No

Communications take place between the TSO (i.e., PJM) through the TO (i.e., ComEd), the NDO and DNPS as detailed in the response to 1(b) above if grid conditions deteriorate from an acceptable level. If contingencies (e.g., the post trip voltages for DNPS are predicted to be below the required limit) are anticipated, the TSO/TO will provide DNPS with a one day look ahead notice. At this time there is no periodic mandated contact between the TSO/TO and DNPS during the duration of grid-risk-sensitive maintenance activities.

(h) If you have a formal agreement or protocol with your TSO, describe how NPP operators and maintenance personnel are trained and tested on this formal agreement or protocol.

Response

DNPS maintenance, operations, and work management personnel associated with schedule development or communicating with the TO (i.e., ComEd) are briefed on TSO/TO interface requirements and expectations but are not formally tested on knowledge retention in this area.

(i) If your grid reliability evaluation, performed as part of the maintenance risk assessment required by 10 CFR 50.65(a)(4), does not consider or rely on some arrangement for communication with the TSO, explain why you believe you comply with 10 CFR 50.65(a)(4).

Response

Not applicable

The methods used to integrate grid risk into the quantitative risk evaluation prior to taking equipment out of service for planned maintenance at DNPS rely on communication with the TSO/TO.

(j) If risk is not assessed (when warranted) based on continuing communication with the TSO throughout the duration of grid-risk-sensitive maintenance activities, explain why you believe you have effectively implemented the relevant provisions of the endorsed industry guidance associated with the maintenance rule.

Response

Not applicable

As detailed in the response to 2(a), grid status is continually evaluated by PJM using the Security Analysis application. PJM notifies DNPS through the TO (i.e., ComEd) of emergent grid conditions. In addition, ComEd (i.e., the TO) possesses a similar system and is also monitoring and evaluating grid conditions. Existing EGC procedures require evaluation of the risk of scheduled on line maintenance activities based on conditions such as power grid stability, weather forecast, and current plant system conditions.

(k) With respect to questions 5(i) and 5(j), you may, as an alternative, describe what actions you intend to take to ensure that the increase in risk that may result from proposed grid-risk-sensitive activities is assessed before and during grid-risk-sensitive maintenance activities, respectively.

Response

Not applicable

6. *Use of risk assessment results, including the results of grid reliability evaluations, in managing maintenance risk, as required by 10 CFR 50.65(a)(4).*

(a) Does the TSO coordinate transmission system maintenance activities that can have an impact on the NPP operation with the NPP operator?

Response

Yes

The TSO/TO coordinates transmission system maintenance activities that can have an impact on the NPP (i.e., DNPS) with DNPS.

(b) Do you coordinate NPP maintenance activities that can have an impact on the transmission system with the TSO?

Response

Yes

The NPP (i.e., DNPS) coordinates maintenance activities that can have an impact on the transmission system with the TSO/TO.

(c) Do you consider and implement, if warranted, the rescheduling of grid-risk-sensitive maintenance activities (activities that could (1) increase the likelihood of a plant trip, (ii) increase LOOP probability, or (iii) reduce LOOP or SBO coping capability) under existing, imminent, or worsening degraded grid reliability conditions?

Response

Yes

Existing procedures require deferring work that would render AC power sources unavailable if severe weather is expected. Risk of scheduled on line work is evaluated based on grid conditions, the weather forecast, and current plant systems status. If the risk analysis determines that risk exceeds a predetermined level, then that configuration is not voluntarily entered and schedule changes are made to reduce the risk to an acceptable level.

(d) If there is an overriding need to perform grid-risk-sensitive maintenance activities under existing or imminent conditions of degraded grid reliability, or continue grid-risk-sensitive maintenance when grid conditions worsen, do you implement appropriate risk management actions? If so, describe the actions that you would take. (These actions could include alternate equipment protection and compensatory measures to limit or minimize risk.)

Response

Yes

When any risk significant SSC is made unavailable, actions are taken to protect redundant or diverse SSCs commensurate with the risk significance of the work being performed in accordance with approved procedures.

(e) Describe the actions associated with questions 6(a) through 6(d) above that would be taken, state whether each action is governed by documented procedures and identify the procedures, and explain why these actions are effective and will be consistently accomplished.

Response

The outage coordination process is documented in the PJM Manuals and agreed to by PJM (i.e., the TSO) and the members. EGC and ComEd (i.e., the TO) are both members of PJM. In addition, PJM has computerized tools to track the process throughout its evolution, so that PJM, ComEd and EGC are clear what the status is and what the expectations are.

Planned transmission outages are coordinated in accordance with a process detailed in PJM Manual M3, "Transmission Operations," Section 4 (Reference 4). This process requires advanced notice and subsequent PJM approval for all outages to ensure grid reliability. On the outage start day, the system is analyzed one last time by PJM before permitting the equipment to be switched out of service.

Once the equipment is switched out of service, grid status is continually evaluated by the PJM Security Analysis application as detailed in the response to 2(a). In addition, the TO (i.e., ComEd) is performing similar monitoring and evaluation. PJM notifies the NPP (i.e., DNPS) through the TO's control center, as discussed in the response to 1(b).

An 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," (Reference 7) directs that schedule coordination meetings are held bi-monthly between the TSO/TO and the NPPs (i.e., DNPS) to coordinate maintenance activities that can have mutual impact.

Actions specified in questions 6(c) and 6(d) are specified in the EGC Work Management procedure, WC-AA-101, "On-Line Work Control Process," (Reference 8) and is applicable to DNPS.

(f) Describe how NPP operators and maintenance personnel are trained and tested to assure they can accomplish the actions described in your answers to question 6(e).

Response

DNPS Maintenance, Operations, and Work Management personnel associated with schedule development and/or risk assessment are briefed on procedure expectations but are not formally tested on knowledge retention in this area.

(g) If there is no effective coordination between the NPP operator and the TSO regarding transmission system maintenance or NPP maintenance activities, please explain why you believe you comply with the provisions of 10 CFR 50.65(a)(4).

Response

Not applicable

Effective coordination is directed by PJM (i.e., the TSO) procedures and jointly approved interface procedures between ComEd (i.e., the TO) and EGC.

(h) If you do not consider and effectively implement appropriate risk management actions during the conditions described above, explain why you believe you effectively addressed the relevant provisions of the associated NRC-endorsed industry guidance.

Response

Not applicable

Effective and appropriate risk management actions are described in plant procedures and implemented during the conditions described above.

(i) You may, as alternative to questions 6(g) and 6 (h) describe what actions you intend to take to ensure that the increase in risk that may result from grid-risk-sensitive maintenance activities is managed in accordance with 10 CFR 50.65(a)(4).

Response

Not applicable

Offsite power restoration procedures in accordance with 10 CFR 50.63 as developed in Section 2 of RG 1.155.

Pursuant to 10 CFR 50.63, the NRC requires that each NPP licensed to operate to be able to withstand an SBO for a specified duration and recover from the SBO. NRC RG 1.155 gives licensees guidance on developing their approaches for complying with 10 CFR 50.63.

7. Procedures for identifying local power sources[1] that could be made available to resupply your plant following a LOOP event.

Note: Section 2, "Offsite Power," of RG 1.155 (ADAMS Accession No. ML003740034) states:

> *Procedures should include the actions necessary to restore offsite power and use nearby power sources when offsite power is unavailable. As a minimum, the following potential causes for loss of offsite power should be considered:*
>
> - *Grid undervoltage and collapse*
> - *Weather-induced power loss*

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1 *This includes items such as nearby or onsite gas turbine generators, portable generators, hydro generators, and black-start fossil power plants.*

- *Preferred power distribution system faults that could result in the loss of normal power to essential switchgear buses*

(a) Briefly describe any agreement made with the TSO to identify local power sources that could be made available to resupply power to your plant following a LOOP event.

Response

DNPS is located in the service territory of PJM. PJM is the Transmission System Operator (TSO) for DNPS. The Transmission Owner (TO) providing interconnection services for DNPS is ComEd. EGC and ComEd are both members of PJM.

All members of PJM execute the "Operating Agreement of PJM Interconnection, LLC," (Reference 1) that details the obligations and responsibilities of both PJM and the PJM members. In the Operating Agreement, each member agrees to abide by the requirements contained in the PJM Manuals. The PJM Manuals contain the specific operational requirements that PJM and each member is required to follow.

ComEd (i.e., the TO) is also a signatory on the "PJM Consolidated Transmission Owners Agreement (PJM TOA)," (Reference 2). Section 4.5 of the PJM TOA requires the TOs to operate and maintain their transmission facilities in accordance with the PJM Manuals.

PJM (i.e., the TSO) is responsible for coordinating restoration of all or parts of the bulk power system in the PJM service territory. ComEd (i.e., the TO) is responsible for cooperating and coordinating with PJM and other PJM members during the restoration of all or parts of the bulk power system in the PJM service territory.

PJM Manual M36, "System Restoration," (Reference 12) gives priority to the restoration of offsite power to NPPs (i.e., DNPS) in the PJM service territory. The TSO (i.e., PJM) and the TO (i.e., ComEd) will utilize the best power sources and transmission paths available based on the specific event to restore offsite power since there is no way to accurately predict the extent and characteristics of a specific blackout. The TSO and TO have multiple options available to restore offsite power and these would not be limited to local power sources.

The Interconnection Agreement between the NPP (i.e., DNPS) and ComEd (i.e., the TO) reinforces the importance and priority of restoring the NPP offsite power source (Reference 15). In addition, DNPS has an Affiliate Level Arrangement Agreement (ALA) with ComEd (Reference 17) to apply "best efforts" to restore to service the facilities that they own or control in order to restore the DNPS offsite power circuit back to an operable status.

PJM provided the following information to EGC regarding this response in a letter from PJM to all PJM nuclear owners (Reference 6).

"The PJM Restoration Manual (M36) details the process to be followed during a system restoration. The process reiterates the specific offsite power requirements for NPPs:

> 'Offsite power should be restored as soon as possible to nuclear units, both units that had been operating and those that were already offline prior to the system disturbance, without regard to using these units for restoring customer load.'

However, due to the myriad of possible restoration scenarios, no specific power sources to resupply NPPs are identified. The PJM restoration process allows for the fact that the blacked out area may or may not be separated from the remainder of the system. Regardless of the scenario, there is a clear recognition of the importance of restoring an NPP offsite power source.

PJM Manual M36 further states: 'Transmission Owners and Nuclear Power Plants must effectively communicate to keep the Nuclear Power Plant apprised of the anticipated restoration time for offsite power.' The manual also states that for PJM Restoration Drills the objectives should include 'Ensure that all nuclear units have been provided with one offsite source within 4 hours,' and that the PJM Nuclear Generation Owner/Operator Users Group should be debriefed on the drill results.

In support of the restoration objectives outlined in the PJM Restoration Manual (M36), there are generating units designated as critical black-start units electrically close to each of the NPPs. These black start units are required to provide black start capability whenever necessary. The adequacy of black-start resources to support system restoration is managed through a process contained in PJM Manual M10, "PreScheduling Operations," (Reference 13), Section 2. The process ensures the continuous availability of black start units to support the restoration needs of the NPPs even when a designated black start unit is on a planned outage."

(b) Are your NPP operators trained and tested on identifying and using local power sources to resupply your plant following a LOOP event? If so, describe how.

Response

No

DNPS operators are not specifically trained and tested on identifying and using local power sources to resupply the NPP (i.e., DNPS) following a LOOP event. The identification and use of local power sources for DNPS are under the control of PJM (i.e., the TSO) and ComEd (i.e., the TO) in accordance with the procedures and interface agreements described in the response to 7(a). The response to this question does not address the operation of the DNPS alternate AC source established under 10 CFR 50.63, "Loss of all alternating current power," (i.e., Station Blackout (SBO) Rule), for which DNPS operators are trained and tested to identify and use under SBO conditions.

(c) If you have not established an agreement with your plant's TSO to identify local power sources that could be made available to resupply power to your plant following a LOOP event, explain why you believe you comply with the provisions of 10 CFR 50.63, or describe what actions you intend to take to establish compliance.

Response

The identification and use of local power sources for restoration of offsite power to DNPS following a LOOP event are under the control of PJM (i.e., the TSO) and ComEd (i.e., the TO) in accordance with the procedures and interface agreements described in the response to 7(a). Due to the myriad of possible restoration scenarios, no specific power sources to resupply DNPS are identified. The procedures identified by RG 1.155, "Station Blackout," (Reference 14) that include the actions necessary to restore offsite power and the use of nearby power sources are also under the control of PJM and ComEd.

Note that, as detailed in the response to 7(a), both ComEd (i.e., the TO) and PJM (i.e., the TSO) have stated that restoring offsite power to a NPP (i.e., DNPS) is a priority.

The identification and use of local power sources that could be made available to resupply power to the NPP following a LOOP event are not part of the current DNPS operating procedures and training since they are outside of DNPS's direct control.

Losses of offsite power caused by grid failures at a frequency of equal to or greater than once in 20 site-years in accordance with Table 4 of Regulatory Guide 1.155 for complying with 10 CFR 50.63.

Pursuant to 10 CFR 50.63, the NRC requires that each NPP licensed to operate be able to withstand an SBO for a specified duration and recover from the SBO. NRC RG 1.155 gives licensees guidance on developing their approaches to complying with 10 CFR 50.63.

8. Maintaining SBO coping capabilities in accordance with 10 CFR 50.63.

(a) Has your NPP experienced a total LOOP caused by grid failure since the plant's coping duration was initially determined under 10 CFR 50.63?

Response

DNPS has not experienced a total LOOP caused by grid failure since the coping duration was initially determined under 10 CFR 50.63, "Loss of all alternating current power," (i.e., Station Blackout (SBO) Rule). A review of DNPS records including the Licensee Event Report (LER) database from July 1988, when the SBO Rule was added, was performed to make this determination.

This determination is consistent with the data presented in NUREG/CR-6890, Volume 1, "Reevaluation of Station Blackout Risk at Nuclear Power Plants – Analysis of Offsite Power Events: 1986-2004," (Reference 11), Appendix A, "LOOP Event Database," Section A-2, "Data Tables," Table A -1, "Loop Events for 1986-2004, sorted by plant."

In addition, the review of LERs since Reference 11 was issued to present has concluded that there were no additional grid failure based LOOP events during this period.

(b) If so, have you reevaluated the NPP using the guidance in Table 4 of RG 1.155 to determine if your NPP should be assigned to the P3 offsite power design characteristic group?

Response

Not applicable

(c) If so, what were the results of this reevaluation, and did the initially determined coping duration for the NPP need to be adjusted?

Response

Not applicable

(d) If your NPP has experienced a total LOOP caused by grid failure since the plant's coping duration was initially determined under 10 CFR 50.63 and has not been reevaluated using the guidance in Table 4 of RG 1.155, explain why you believe you comply with the provisions of 10 CFR 50.63 as stated above, or described what actions you intend to take to ensure that the NPP maintains its SBO coping capabilities in accordance with 10 CFR 50.63.

Response

Not applicable

Actions to ensure compliance

9. If you determine that any action is warranted to bring your NPP into compliance with NRC regulatory requirements, including TSs, GDC 17, 10 CFR 50.65(a)(4), 10 CFR 50.63, 10 CFR 55.59 or 10 CFR 50.120, describe the schedule for implementing it.

Response

Not applicable

References

1. "Operating Agreement of PJM Interconnection, LLC," revised through February 6. 2006
2. "Consolidated Transmission Owners Agreement," effective March 19, 2006
3. PJM Manual 01, "Control Center Requirements," Revision 10, effective February 7, 2006
4. PJM Manual 3, "Transmission Operations," Revision 20, effective February 10, 2006
5. PJM Manual 13, "Emergency Operations," Revision 24, effective February 22, 2006
6. 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

7. EGC procedure WC-AA-8000, "Interface Procedure between Exelon Energy Delivery (ComEd/PECO) and Exelon Generation (Nuclear/Power) for Construction and Maintenance Activities," Revision 0

8. EGC procedure WC-AA-101, "On-Line Work Control Process," Revision 11

9. Letter from P. R. Simpson (Exelon Generation Company, LLC) to U.S. NRC, "Request for License Amendment Regarding Offsite Power Instrumentation and Voltage Control," dated April 4, 2005

10. EGC procedure OP-AA-108-107-1002, "Interface Agreement between Exelon Energy Delivery and Exelon Generation for Switchyard Operations," Revision 2

11. NUREG/CR-6890, Volume 1, "Reevaluation of Station Blackout Risk at Nuclear Power Plants – Analysis of Offsite Power Events: 1986-2004," Revision 0

12. PJM Manual 36, "System Restoration," Revision 2, effective November 1, 2005

13. PJM Manual 10, "Pre-Scheduling Operations," Revision 18, effective August 10, 2005

14. Regulatory Guide 1.155, "Station Blackout," Revision 0

15. "Facilities, Interconnection and Easement Agreement among ComEd Generation Company LLC, Exelon Generation Company, LLC and Commonweatlh Edison Company," Dresden Nuclear Power Station Final Form, dated January 12, 2001

16. Letter from M. Banerjee, (NRC), to C. M. Crane, (Exelon Generation Company, LLC), "Dresden Nuclear Power Station, Units 2 and 3 - Issuance of Amendments Regarding Offsite Power Instrumentation and Voltage Control," dated March 17, 2006

17. "Affiliate Level Arrangement ('ALA') by and among Exelon Energy Delivery Groups of ComEd and Exelon Generation Company, LLC," effective January 1, 2006

18. NRC Information Notice IN 93-17, "Safety Systems Response to Loss of Coolant and Loss of Offsite Power," Revision 1, dated March 25, 1994

19. SECY-05-0219, "Issuance of Nuclear Regulatory Commission Generic Letter 2005-XX, 'Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power,'" dated December 2, 2005

20. EGC procedure OP-AA-108-107-1001, "Station Response to Grid Capacity Conditions," Revision 1

21. DNPS Abnormal Operating Procedure DGA-12, "Loss of Offsite Power"

22. DNPS Abnormal Operating Procedure DOA 6500-12, "Abnormal Switchyard Voltage"

23. EGC procedure WC-AA-107, "Seasonal Readiness," Revision 2

24. SOER 99-1, "Loss of Grid," December 27, 1999

25. SOER 99-1, "Loss of Grid – Addendum," December 9, 2004

26. Jennifer Sterling, Exelon Transmission Planning, "NRC Generic Letter – Draft responses to questions 1 and 2," February 14, 2006, personal email to John Gyrath, Exelon Nuclear, (February 14, 2006)

ATTACHMENT 5

60-day Response to NRC Generic Letter 2006-02

LASALLE COUNTY STATION, Units 1 and 2

FOL Nos. NPF-11 and NPF-18

ATTACHMENT 5
60-day Response to NRC Generic Letter 2006-02,
LASALLE COUNTY STATION, Units 1 and 2

On February 1, 2006, the NRC issued Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power." 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 Generic Letter requested that licensees answer the following questions and provide the information to the NRC with respect to each of their Nuclear Power Plants (NPPs).

Use of protocols between the NPP licensee and the TSO, ISO, or RC/RA and the use of analysis tools by TSOs to assist NPP licensee in monitoring grid conditions to determine the operability of offsite power system under plant TS.

GDC 17, 10 CFR Part 50, Appendix A, requires that licensees minimize the probability of the loss of power from the transmission network given a loss of the power generated by the nuclear power unit(s).

1. *Use of protocols between the NPP licensee and the TSO, ISO, or RC/RA to assist the NPP licensee in monitoring grid conditions to determine the operability of offsite power system under plant TS.*

   (a) Do you have a formal agreement or protocol with your TSO?

   Response

   Yes

   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.

   All members of PJM execute the "Operating Agreement of PJM Interconnection, LLC," (Reference 1) that details the obligations and responsibilities of both PJM and the PJM members. In the Operating Agreement, each member agrees to abide by the requirements contained in the PJM Manuals. The PJM Manuals contain the specific operational requirements that PJM and each member is required to follow.

   ComEd (i.e., the TO) is also a signatory on the "PJM Consolidated Transmission Owners Agreement (PJM TOA)," (Reference 2). Section 4.5 of the PJM TOA requires the TOs to operate and maintain their transmission facilities in accordance with the PJM Manuals.

   The PJM Operating Agreement requires PJM to, "Incorporate the grid reliability requirements applicable to nuclear generating units in the PJM Region planning and operating principles and practices." PJM Manual M01, "Control Center Requirements," Attachment B, "Nuclear Plant Communication Protocol," (Reference 3), provides the roles and responsibilities of nuclear stations, TOs, and PJM with regard to communications both in normal and emergency circumstances. The nuclear power plant (NPP) notification requirements are contained in PJM Manual M3, "Transmission Operations," Section 3 (Reference 4).

In addition to the agreements delineated in the PJM Operating Agreement and the PJM Manuals, EGC has jointly approved interface procedures with the TO that address the monitoring of the offsite source voltages and the notification protocols. EGC procedure OP-AA-108-107-1002, "Interface Agreement between Exelon Energy Delivery and Exelon Generation for Switchyard Operations," (Reference 10) outlines the responsibilities and required work interfacing activities.

(b) Describe any grid conditions that would trigger a notification from the TSO to the NPP licensee and if there is a time period required for the notification.

Response

PJM Manual M3 (Reference 4) requires PJM to initiate notification to LSCS through the TO's control center if PJM identifies a switchyard voltage violation. PJM Manual M3 states: "This notification should occur within 15 minutes for voltage contingency violations and immediately for actual voltage violations. To the extent practical, PJM shall direct operations such that the violation is remedied within 30 minutes."

In addition, PJM Manual M13, "Emergency Operations," (Reference 5) identifies a series of alerts, warnings, and actions that PJM issues to PJM members depending on the identified grid condition. The PJM message is communicated to LSCS by their generation dispatcher through the EGC Nuclear Duty Officer (NDO) for a variety of system conditions including the following:

Capacity Emergencies
- Maximum Emergency Generation Loading
- Load Management Curtailment
- Manual Load Dump Warning

Light Load Emergencies
- Minimum Generation Emergency
- Local Minimum Generation Emergency

Weather/Environmental Emergencies
- Hot/Cold Weather Alerts
- Thunderstorms and Tornadoes
- Solar Magnetic Disturbances

Sabotage/Terrorism Emergencies

(c) Describe any grid conditions that would cause the NPP licensee to contact the TSO. Describe the procedures associated with such a communication. If you do not have procedures, describe how you assess grid conditions that may cause the NPP licensee to contact the TSO.

Response

As required by PJM Manuals, communications between LSCS and PJM (TSO) are generally through the Transmission Owner (TO) providing the interconnection service.

LSCS will contact the TSO/TO for grid conditions that have parameters that are observable at the NPP. These conditions include the following:

- Loss of Offsite Power (LOOP)
- Abnormal switchyard voltage
- Automatic (protective) switchyard circuit breaker operation
- Switchyard alarms
- Grid disturbances (observable frequency or voltage fluctuations)

In addition to any alarm response procedures for the above applicable conditions, TSO/TO notifications are controlled by operating procedures, (e.g., OP-AA-108-107-1001, "Station Response to Grid Capacity Conditions"), and Abnormal Operating Procedures, (e.g., LOA-AP-1(2)01, "AC Power System Abnormal," and LOA-GRID-001, "Abnormal Switchyard Voltage").

LSCS will contact the TSO/TO during a grid restoration process to obtain grid status in preparation for returning the plant buses to the offsite source.

LSCS also notifies the TSO/TO of switchyard equipment deficiencies identified by NPP personnel. Jointly approved interface agreements/procedures between EGC and the TO identify the communication protocols for station identified switchyard deficiencies. EGC procedures OP-AA-108-107-1002 (Reference 10) and WC-AA-8000 (Reference 7) outline the responsibilities and required work interfacing activities.

In addition, LSCS will notify the TSO/TO of NPP configurations that potentially impact grid conditions. A jointly approved interface agreement/procedure, OP-AA-108-107-1002 (Reference 10), between EGC and the TO identifies the requirements for communication of the conditions listed below:

- NPP MVAR limitations
- NPP Main generator voltage regulator not in "Automatic" mode
- NPP inability to provide the MVARs requested by the TSO/TO

Note that any LSCS MW limitations or limitations on the rate at which the NPP power may be raised or lowered are communicated to the generation dispatcher.

(d) Describe how NPP operators are trained and tested on the use of the procedures or assessing grid conditions in question 1(c).

<u>Response</u>

LSCS licensed operators are trained and tested in accordance with the Systematic Approach to Training (SAT). Procedures and policies are routinely reviewed for training through this process for improvement of operator performance. The items considered for training include Operating Procedures, Annunciator Response Procedures, Abnormal Operating Procedures, and Emergency Operating Procedures that require interface with the TSO in accordance with the established protocol. These procedures may be utilized based on various grid, switchyard, or plant symptoms to assess, respond to or mitigate off-normal plant and grid conditions. Additionally, SOER 99-01, "Loss of Grid," (Reference 22) and SOER 99-01, "Loss of Grid – Addendum," (Reference 23) specifically are captured in the Licensed Operator Requalification Training Program (LORT) Long Range Training Program. These topics, in varying detail based upon the SAT process or as part of implementing EGC procedure WC-AA-107, "Seasonal Readiness," (Reference 21) are reviewed periodically with LSCS operators. Testing is commensurate with the material presented and any performance issues are identified by for inclusion in future training.

(e) If you do not have a formal agreement or protocol with your TSO, describe why you believe you continue to comply with the provisions of GDC 17 as stated above, or describe what actions you intend to take to assure compliance with GDC 17.

Response

Not applicable. Formal agreements exist for LSCS.

(f) If you have an existing formal interconnection agreement or protocol that ensures adequate communication and coordination between the NPP license and the TSO, describe whether this agreement or protocol requires that you be promptly notified when the conditions of the surrounding grid could result in degraded voltage (i.e., below TS nominal trip setpoint value requirements; including NPP licensees using allowable value in its TSs) or LOOP after a trip of the reactor units(s).

Response

PJM Manual M3 (Reference 4) requires PJM to initiate a notification to LSCS through its respective transmission owner's control center if PJM identifies a NPP switchyard voltage violation. PJM Manual M3 states: "This notification should occur within 15 minutes for voltage contingency violations and immediately for actual voltage violations. To the extent practical, PJM shall direct operations such that the violation is remedied within 30 minutes." The trip of a NPP (i.e., trip of a LSCS unit) is one of the contingencies analyzed by PJM. PJM analyzes the LSCS switchyard contingency voltages to the voltage limits provided by LSCS. The voltage limits provided for LSCS are based on the existing design basis analysis.

(g) Describe the low switchyard voltage conditions that would initiate operation of plant degraded voltage protection.

Response

Switchyard voltage below a value maintaining emergency bus voltage above the setpoint of the degraded voltage relay (≥3814 volts and ≤3900 volts) will cause a trip of the preferred power source after a time delay of approximately 10 seconds with a Loss of Coolant Accident (LOCA) signal present. The relation between the switchyard voltage and the emergency bus voltage is dependent on the system auxiliary transformer impedance and the winding load. Under design basis accident (i.e., Large Break LOCA) conditions, the maximum loading is known and contained in the LSCS calculations of record. This maximum loading requires a minimum switchyard voltage of 352 kV after block starting all of the LOCA loads. The minimum switchyard voltage of 352 kV corresponds to a Class 1E 4kV bus voltage of ≥3920V, which is the maximum reset of the degraded voltage relays, and ensures that there will be adequate voltage available at the Class 1E busses for the maximum loading condition. The design basis maximum loading and the degraded voltage relay reset voltage were used to determine the switchyard voltage needed to ensure successful operation of the ECCS loads. The alarm setpoint transmitted to the TSO/TO is 353 kV, a value that ensures the switchyard voltage will be greater than that required to support LOCA loading.

In other conditions, the loading is less than the expected LOCA loading and will vary considerably depending on which loads are needed to support unit conditions. Under these conditions the required LSCS switchyard voltage will be less than that required to support LOCA loading.

2. *Use of criteria and methodologies to assess whether the offsite power system will become inoperable as a result of a trip of your NPP.*

(a) Does your NPP's TSO use any analysis tools, an online analytical transmission system studies program, or other equivalent predictive methods to determine the grid conditions that would make the NPP offsite power system inoperable during various contingencies? If available to you, please provide a brief description of the analysis tool that is used by the TSO.

Response

Yes

The PJM Energy Management System (EMS) includes a Security Analysis application which runs approximately every 1 minute and analyzes ~4,000 contingencies on the PJM system (Reference 6). The analysis provides results with respect to thermal, voltage, and voltage drop limit violations. One of the contingencies analyzed by the PJM EMS is the trip of a NPP (i.e., trip of a LSCS unit).

In addition, ComEd (i.e., the TO) possesses a similar system that also calculates post-contingency voltage limit violations. One of the contingencies analyzed by ComEd is the trip of a LSCS unit.

(b) Does your NPP's TSO use an analysis tool as the basis for notifying the NPP licensee when such a condition is identified? If not, how does the TSO determine if conditions on the grid warrant NPP licensee notification?

Response

Yes

The results of the PJM Security Analysis application contain the specific contingency of the NPP tripping as the contingent element. Violation of the unit trip contingency voltage limit would result in notification of the NPP (i.e., LSCS) in accordance with PJM Manual M3, Section 3 (Reference 4).

ComEd (i.e., the TO) also possesses similar capability to monitor the same condition.

(c) If your TSO uses an analysis tool, would the analysis tool identify a condition in which a trip of the NPP would result in switchyard voltages (immediate and/or long-term) falling below TS nominal trip setpoint value requirements (including NPP licensees using allowable value in its TSs) and consequent actuation of plant degraded voltage protection? If not, discuss how such a condition would be identified on the grid.

Response

Yes

The trip of the NPP (i.e., trip of a LSCS unit) is one of the contingencies analyzed by the PJM Security Analysis application. PJM analyzes the NPP switchyard contingency voltages to the voltage limits provided by LSCS. The voltage limits provided by LSCS are based on the plant's design basis analysis as discussed in the response to 1(g).

ComEd (i.e., the TO) also possesses similar capability to monitor the same condition.

(d) If your TSO uses an analysis tool, how frequently does the analysis tool program update?

Response

The PJM EMS includes a Security Analysis application that currently updates approximately every 1-minute. In addition, ComEd (i.e., the TO) possesses a Security Analysis application that updates approximately every 6 minutes (Reference 24).

(e) Provide details of analysis tool-identified contingency conditions that would trigger an NPP licensee notification from the TSO.

Response

PJM notifies LSCS through the TO (i.e., ComEd) control center whenever actual or post-contingency voltages are determined to be below the LSCS switchyard voltage limits. This requirement applies to all contingencies involving the tripping of the NPP or any transmission facility as the contingent element. In accordance with PJM Manual M3 (Reference 4) the notification is required even if the voltage limits are the same as the standard PJM voltage limits.

(f) If an interface agreement exists between the TSO and the NPP licensee, does it require that the NPP licensee be notified of periods when the TSO is unable to determine if offsite power voltage and capacity could be inadequate? If so, how does the NPP licensee determine that the offsite power would remain operable when such a notification is received?

Response

Yes

LSCS unit trip contingency voltage calculations are performed by the PJM EMS and the TO (i.e., ComEd) Security Analysis application. The PJM EMS consists of a primary and backup system. If the PJM EMS fails, the ComEd Security Analysis application continues to analyze the LSCS unit trip contingency voltage. LSCS will be notified if the real time contingency analysis capability of PJM and the TO (i.e., ComEd) are lost simultaneously in accordance with PJM Manual M01, Section 2 (Reference 3).

If LSCS is notified that PJM and ComEd (i.e., the TO) have both lost their real time contingency analysis capability, LSCS would request PJM and ComEd to provide an assessment of the current condition of the grid based on the tools that PJM and ComEd have available. The determination of the operability of the offsite sources would consider the assessment provided by PJM and ComEd and whether the current condition of the grid is bounded by the grid studies previously performed for LSCS.

(g) After an unscheduled inadvertent trip of the NPP, are the resultant switchyard voltages verified by procedure to be bounded by the voltages predicted by the analysis tool?

Response

No

There is presently no formal process for comparing the actual post-trip voltages to the post-trip contingency voltage results calculated by the PJM and the TO (i.e., ComEd) Security Analysis applications.

PJM provided the following information to EGC regarding this response in a letter from PJM to all PJM nuclear owners (Reference 6).

"Because the PJM transmission owning member companies have similar Security Analysis programs to PJM, there are many opportunities to compare the results of the respective Security Analysis programs. In this manner, there is a high confidence that the Security Analysis results are accurate within the precision of the calculations.

PJM retains the EMS results for a period of approximately 3 weeks after real time. It is possible to use those saved EMS results to repeat the Security Analysis calculations and compare them to the actual voltages from a unit trip. However, the NPP trips occur so infrequently that it would take a number of data points to verify the accuracy with any statistical significance. This process could take years if the process is limited to a comparison of only NPP trips."

(h) If an analysis tool is not available to the NPP licensee's TSO, do you know if there are any plans for the TSO to obtain one? If so, when?

Response

Not applicable. LSCS TSO (i.e., PJM) has an analysis tool.

(i) If an analysis tool is not available, does your TSO perform period studies to verify that adequate offsite power capability, including adequate NPP post-trip switchyard voltages (immediate and/or long-term), will be available to the NPP licensee over the projected timeframe of the study?

(a) Are the key assumptions and parameters of these periodic studies translated into TSO guidance to ensure that the transmission system is operated within the bounds of the analyses?

Response

Not applicable. LSCS TSO (i.e., PJM) has an analysis tool.

(b) If the bounds of the analyses are exceeded, does this condition trigger the notification provisions discussed in question 1 above?

Response

Not applicable. LSCS TSO (i.e., PJM) has an analysis tool.

(j) If your TSO does not use, or you do not have access to the results of an analysis tool, or your TSO does not perform and make available to you periodic studies that determine the adequacy of offsite power capability, please describe why you believe you comply with the provisions of GDC 17 as stated above, or describe what compensatory actions you intend to take to ensure that the offsite power system will be sufficiently reliable and remain operable with high probability following a trip of your NPP.

Response

Not applicable. LSCS TSO (i.e., PJM) has an analysis tool. In addition the applicable contingency voltage results are made available to LSCS as needed.

3. *Use of criteria and methodologies to assess whether the NPP's offsite power system and safety-related components will remain operable when switchyard voltages are inadequate.*

(a) If the TSO notifies the NPP operator that a trip of the NPP, or the loss of the most critical transmission line or the largest supply to the grid would result in switchyard voltages (immediate and/or long-term) below TS nominal trip setpoint value requirements (including NPP licensees using allowable value in its TSs) and would actuate plant degraded voltage protection, is the NPP offsite power system declared inoperable under the plant TSs? If not, why not?

Response

If the TSO (i.e., PJM) notifies LSCS that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., trip of a LSCS unit) is below the pre-determined notification value, LSCS will review the applicability to the plant operating configuration and will declare the offsite power source inoperable in accordance with Technical Specifications (TSs) if appropriate. The notification value provided to PJM by LSCS is based on the LSCS degraded voltage design basis analysis.

Predicted contingency voltages following the loss of a transmission facility (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 for LSCS at this time. If the TSO (i.e., PJM) notifies LSCS of a predicted contingency voltage violation resulting from the postulated trip of a transmission facility, LSCS will perform a risk analysis of in-progress and scheduled plant work and will take action as appropriate.

The NPP unit trip contingency can be caused by plant-centered events. The use of the NPP unit trip contingency as the contingency element upon which offsite power operability is based is consistent with the final paragraph of General Design Criterion (GDC) 17, "Electric power systems," of 10 CFR Part 50 Appendix A, "General Design Criteria for Nuclear Power Plants," which requires provisions be included to minimize the probability of the loss of power from the transmission network given a loss of the power generated by the NPP (i.e., a LSCS unit).

Postulated contingencies on the transmission system are currently not used as the basis for offsite source operability determinations since loss of power from the transmission network would not occur as a result of loss of power generated by a NPP unit (i.e., a LSCS unit). Such events (e.g., loss of a transmission line) are only postulated and have not actually occurred, and the offsite power sources remain capable of supporting a safe shutdown and mitigating the effects of an accident. Loss of power from the transmission network would not occur as a result of loss of power generated by a NPP unit and therefore the GDC 17 provision discussed in GL 2006-02 is met.

(b) If onsite safety-related equipment (e.g., emergency diesel generators or safety-related motors) is lost when subjected to a double sequencing (LOCA with delayed LOOP event) as a result of the anticipated system performance and is incapable of performing its safety functions as a result of responding to an emergency actuation signal during this condition, is the equipment considered inoperable? If not, why not?

Response

Although some features have been incorporated into the plant design, requirements for analysis and design considerations for double sequencing are not included within the LSCS current licensing and design basis as documented in the LSCS Updated Final Safety Analysis Report (UFSAR). LSCS has not been explicitly analyzed for all issues associated with double sequencing. Onsite safety-related equipment at LSCS (e.g., emergency diesel generators or safety-related motors) is not declared inoperable as a result of a TSO (i.e., PJM) unit trip contingency voltage notification.

Based on Enclosure 2 of SECY-05-0219, "Issuance of Nuclear Regulatory Commission Generic Letter 2005-XX, 'Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power,'" (Reference 17) which provided NRC guidance on responding to this issue, a review was performed for LSCS of the loading logic for the diesel generators as well as the safety-related breakers' anti-pumping logic. This review concluded that onsite safety-related equipment (i.e., emergency diesel generators or safety-related motors) is not lost as a result of diesel generator block loading and breaker lockout from anti-pump circuitry when subjected to a double sequencing event resulting from inadequate post unit trip voltages. The scope of the review performed for LSCS is discussed in the response to question 3(c) below.

(c) Describe your evaluation of onsite-related equipment to determine whether it will operate as designed during the condition described in question 3(b).

Response

Although some features have been incorporated into the plant design, requirements for analysis and design considerations for double sequencing are not included within the LSCS current licensing and design basis as documented in the LSCS UFSAR. LSCS has not been explicitly analyzed for all issues associated with double sequencing. However, using the NRC clarification provided in Enclosure 2 of SECY-05-0219 as guidance, a review was performed for the purpose of addressing question 3(b).

This review examined the effects of a double sequencing event on diesel generator block loading and the potential for breaker lockout from the anti-pump circuitry. The review assumed that following a LOCA initiation, separation occurred as a result of degraded voltage relay operation triggered by the loss of a LSCS unit. The review examined the diesel generator loading logic and determined that the logic is reset by the LOOP event. The second sequence is consistent with that described in the LSCS UFSAR for a LOOP/LOCA event. Loads are shed as a result of the LOOP signal and the loads are not block loaded onto the diesel generator.

The review also examined the potential for breaker lockout due to the anti-pumping circuitry. This review determined that there was sufficient time between the two sequences such that the breaker charging springs would re-charge and the second closure would be successful. To ensure that a breaker lockout would not occur, the breaker closing logics were also examined to assure that the trip signals were cleared before the second close signal was initiated.

In addition, LSCS reviewed the calculations of record for the safety-related loads' protective devices. Using these calculations as a basis, the effects of the double sequencing scenario on the protective devices' performance was also reviewed. This review examined the existing bounding block start analysis and the associated relay travel calculations. The review considered the amount of relay travel during the block start and the amount of reset (negative travel) prior to the subsequent start. This preliminary review identified some protective devices that would require additional detailed analysis and testing to fully determine the protective devices' response to the double sequence scenario. It is expected that this further analysis and testing would conclude that the safety-related loads would not be lost during a double start scenario.

(d) If the NPP licensee is notified by the TSO of other grid conditions that may impair the capability or availability of offsite power, are any plant TS action statements entered? If so, please identify them.

Response

As discussed in the response to 3(a), if the TSO (i.e., PJM) notifies LSCS that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., trip of a LSCS unit) is below the pre-determined notification value, LSCS will review the applicability to the plant operating configuration and will declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by LSCS is based on the LSCS degraded voltage design basis analysis.

In addition, if PJM notifies LSCS that the actual offsite power source voltage is less than the pre-determined notification value, LSCS will review the applicability to the plant operating configuration and would declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by LSCS is based on the LSCS degraded voltage design basis analysis.

(e) If you believe your plant TSs do not require you to declare your offsite power system or safety-related equipment inoperable in any of these circumstances, explain why you believe you comply with the provisions of GDC 17 and your plant TSs, or describe what compensatory actions you intend to take to ensure that the offsite power system and safety-related components will remain operable when switchyard voltages are inadequate.

Response

The following notifications from the TSO (i.e., PJM) will result in LSCS declaring the offsite power source inoperable in accordance with TSs.

- If the TSO (i.e., PJM) notifies LSCS that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., trip of a LSCS unit) is below the pre-determined notification value, LSCS will review the applicability to the plant operating configuration and will declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by LSCS is based on the LSCS degraded voltage design basis analysis.

- If the TSO (i.e., PJM) notifies LSCS that the actual offsite power source voltage is less than the pre-determined notification value, LSCS will review the applicability to the plant operating configuration and would declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by LSCS is based on the LSCS degraded voltage design basis analysis.

Predicted contingency voltages following the loss of a transmission facility (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. If the TSO notifies the NPP of a predicted contingency voltage violation resulting from the postulated trip of a transmission facility, the NPP performs a risk analysis of in-progress and scheduled plant work and takes action as appropriate.

The NPP unit trip contingency can be caused by plant-centered events. The use of the NPP unit trip contingency as the contingency element upon which offsite power operability is based is consistent with the final paragraph of GDC 17 which requires provisions to minimize the probability of the loss of power from the transmission network given a loss of the power generated by the NPP.

Postulated contingencies on the transmission system are not used as the basis for offsite source operability determinations since loss of power from the transmission network would not occur as a result of loss of power generated by the NPP unit. Such events (e.g., loss of a transmission line) are only postulated and have not actually occurred, and the offsite power sources remain capable of affecting a safe shutdown and mitigating the effects of an accident. The GDC 17 provision discussed in the Generic Letter is still met; loss of power from the transmission network would not occur as a result of loss of power generated by the NPP unit.

Onsite safety-related equipment at LSCS (e.g., emergency diesel generators or safety-related motors) is not declared inoperable as a result of a TSO (i.e., PJM) unit trip contingency voltage notification. Although some features have been incorporated into the plant design, requirements for analysis and design considerations for double sequencing are not included within the LSCS current licensing and design basis as documented in the LSCS UFSAR. LSCS has not been explicitly analyzed for all issues associated with double sequencing.

(f) Describe if and how NPP operators are trained and tested on the compensatory actions mentioned in your answers to questions 3(a) through (e).

Response

LSCS licensed operators are trained and tested in accordance with the Systematic Approach to Training (SAT). Equipment operability, as defined by TS, including normal and emergency power, offsite circuits, and safety-related components, is under continuous review. Procedures are in place to provide operator guidance and required actions necessary during predicted or actual degraded grid voltage conditions based on information provided by the TSO/TO in accordance with established protocol or as observed by the NPP operator. As part of initial training, requalification training, and annual operating tests, licensed operators are subjected to written examinations, dynamic learning activities, static and/or simulator examinations, Job Performance Measures (JPMs), and evaluated simulator scenarios incorporating topics including the actual or predicted switchyard voltage issues and its effect on AC Source operability. Testing is commensurate with the material presented and any performance issues are identified for inclusion in future training.

4. Use of criteria and methodologies to assess whether the offsite power system will remain operable following a trip of your NPP.

(a) Do the NPP operators have any guidance or procedures in plant TS bases sections, the final safety analysis report, or plant procedures regarding situations in which the condition of plant-controlled or monitored equipment (e.g., voltage regulator, auto tap changing transformers, capacitors, static VAR compensators, main generator voltage regulators) can adversely affect the operability of the NPP offsite power system? If so, describe how the operators are trained and tested on the guidance and procedures.

Response

Yes

LSCS plant controlled or monitored equipment that can adversely affect the operability of the offsite power system is limited to the main generator voltage regulators. EGC procedures provide guidance for notification of the TSO/TO (i.e., PJM/ComEd) when the voltage regulator is not in automatic. LSCS procedures direct operator actions to control excitation in manual or other mitigating actions to control excitation.

LSCS licensed operators are trained and tested in accordance with the Systematic Approach to Training (SAT). Procedures and policies are routinely reviewed for training through this process for improvement of operator performance. The items considered for training include Annunciator Response Procedures, Abnormal Operating Procedures, and Emergency Operating Procedures that require interface with the TSO/TO in accordance with the established protocol. In addition as part of initial training, requalification training, and annual operating tests, licensed operators are subjected to written examinations, static and/or simulator examinations, Job Performance Measures (JPMs), and evaluated simulator scenarios. These evaluations may incorporate topics including the loss of the main generator voltage regulator and actions to mitigate the effect of the failure. Testing is commensurate with the material presented and any performance issues are identified for inclusion in future training.

(b) If your TS bases sections, the final safety analysis report, and plant procedures do not provide guidance regarding situations in which the condition of plant-controlled or monitored equipment can adversely affect the operability of the NPP offsite power system, explain why you believe you comply with the provisions of GDC 17 and the plant TSs, or describe what actions you intend to take to provide such guidance or procedures.

Response

Not applicable

Use of NPP licensee/TSO protocols and analysis tool by TSOs to assist NPP licensees in monitoring grid conditions for consideration in maintenance risk assessments.

The Maintenance Rule (10 CFR 50.65(a)(4)) requires that licensees assess and manage the increase in risk that may result from proposed maintenance activities before performing them.

5. Performance of grid reliability evaluations as part of the maintenance risk assessments required by 10 CFR 50.65(a)(4).

(a) Is a quantitative or qualitative grid reliability evaluation performed at your NPP as part of the maintenance risk assessment required by 10 CFR 50.65(a)(4) before performing grid-risk-sensitive maintenance activities? This includes surveillances, post-maintenance testing, and preventive and corrective maintenance that could increase the probability of a plant trip or LOOP or impact LOOP or SBO coping capability, for example, before taking a risk-significant piece of equipment (such as an EDG, a battery, a steam-driven pump, an alternate AC power source) out-of-service?

Response

Yes

Risk is assessed using a process that combines quantitative results from a probabilistic risk assessment (PRA) with a qualitative defense-in-depth model. During the planning and scheduling of work and prior to the execution of work, many factors are assessed for risk including the effect of weather/time of year and grid instability. The combination of unavailable Systems, Structures and Components (SSCs) and planned activities is then assessed in the risk assessment tool. Currently, a procedure update is being implemented to provide additional detail for how to factor grid reliability into the risk assessment tool before taking equipment out of service for planned maintenance. These procedure changes are currently scheduled to be in place at LSCS by May 15, 2006.

(b) Is grid status monitored by some means for the duration of the grid-risk-sensitive maintenance to confirm the continued validity of the risk assessment and is risk reassessed when warranted? If not, how is the risk assessed during grid-risk-sensitive maintenance?

Response

Yes

Grid status is continually evaluated by PJM using the Security Analysis application. PJM notifies LSCS through its Transmission Operator, (i.e., ComEd), of emergent grid conditions as discussed in the response to 1(b) above. In addition, ComEd (i.e., the TO) is also performing similar monitoring and evaluation. Existing EGC procedures require evaluation of the risk of scheduled online maintenance activities based on conditions such as power grid stability, weather forecast, and current plant system conditions.

(c) Is there a significant variation in the stress on the grid in the vicinity of your NPP site caused by seasonal loads or maintenance activities associated with critical transmission elements? Is there a seasonal variation (or the potential for a seasonal variation) in the LOOP frequency in the local transmission region? If the answer to either question is yes, discuss the time of year when the variations occur and their magnitude.

Response

The base PRA model reflects the yearly average LOOP frequency because seasonal variations that would cause changes to the frequency of a LOOP cannot be accurately predicted. While time related variations are not factored into the base PRA model for LSCS, symptoms of grid stress such as maximum generation conditions, low grid voltage, or severe weather conditions require identification of such dynamic conditions should they occur, and risk management actions are then taken to mitigate the risk or reschedule the work as appropriate.

PJM provided the following information to EGC regarding this response in a letter from PJM to all PJM nuclear owners (Reference 6).

"Stress on the grid is manifested in a number of ways. Stress can mean 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.

Regarding the seasonal variability of the stress causers, each has a seasonal component. For example, peak load levels occur at the peak seasons of the summer and winter seasons. While the specific days cannot be predicted, it is known roughly when they will occur. Consequently, maintenance during these times of the year is avoided.

From a transmission system operations perspective, it is the simultaneous combination of stress causers that results in the most difficult operational challenges. For example, experiencing very hot (or cold) weather when we (i.e., PJM) are in the maintenance seasons with a lot of equipment out of service can cause the most severe challenges.

We (i.e., PJM) are aware of the existence of the North American Electric Reliability Council (NERC) and NRC data regarding LOOP frequency. However, it is difficult to assign differential risks to any seasonal variation because of the complexity of the various competing factors, as explained above."

(d) Are known time-related variations in the probability of a LOOP at your plant site considered in the grid-risk-sensitive maintenance evaluation? If not, what is your basis for not considering them?

Response

No

While time related variations are not factored into the base PRA model for LSCS, symptoms of grid stress such as maximum generation conditions, low grid voltage, or severe weather conditions require identification of such dynamic conditions should they occur, and risk management actions are then taken to mitigate the risk or reschedule the work as appropriate.

(e) Do you have contacts with the TSO to determine current and anticipated grid conditions as part of the grid reliability evaluation performed before conducting grid-risk-sensitive maintenance activities?

Response

Yes

The protocol for NPP notification of actual or anticipated grid conditions is outlined in the response to 1(b). Any work performed on the grid risk sensitive equipment is evaluated for risk using these current or anticipated conditions as part of the evaluation prior to performance. Work is coordinated based on anticipated conditions and planned maintenance during bi-monthly interface meetings between the transmission operator (i.e., ComEd) and the EGC NPPs (i.e., LSCS).

As stated in the response to 1(b), communication is shared between the TSO (i.e., PJM) and LSCS if grid conditions deteriorate from an acceptable level. If contingencies are anticipated (e.g., the predicted post NPP trip offsite source voltage less than required) the TSO will provide LSCS with a one day look ahead notice.

(f) Describe any formal agreement or protocol that you have with your TSO to assure that you are promptly alerted to a worsening grid condition that may emerge during a maintenance activity.

Response

As stated in the response to 1(a), LSCS is located in the service territory of PJM. PJM is the TSO for LSCS. The TO providing interconnection services for LSCS is ComEd. EGC and ComEd are both members of PJM.

All members of PJM execute the PJM Operating Agreement (Reference 1) that details the obligations and responsibilities of both PJM and the PJM members. In the Operating Agreement, each member agrees to abide by the requirements contained in the PJM Manuals. The PJM Manuals contain the specific operational requirements that PJM and each member is required to follow.

As stated in the response to 1(b), PJM Manual M13 (Reference 5) identifies a series of alerts, warnings, and actions that PJM issues to PJM members depending on the identified grid condition. The PJM message is communicated to LSCS by their generation dispatcher through the EGC NDO for a variety of system conditions including capacity emergencies, light load emergencies, weather/environmental emergencies or sabotage/terrorism emergencies.

PJM Manual M3 (Reference 4) requires PJM to initiate notification to LSCS through the TO's control center if PJM identifies a switchyard voltage violation. PJM Manual M3 states: "This notification should occur within 15 minutes for voltage contingency violations and immediately for actual voltage violations. To the extent practical, PJM shall direct operations such that the violation is remedied within 30 minutes."

(g) Do you contact your TSO periodically for the duration of the grid-risk sensitive maintenance activities?

Response

No

Communications take place between the TSO (i.e., PJM) through the TO (i.e., ComEd), the NDO and LSCS as detailed in the response to 1(b) above if grid conditions deteriorate from an acceptable level. If contingencies (e.g., the post trip voltages for LSCS are predicted to be below the required limit) are anticipated, the TSO/TO will provide LSCS with a one day look ahead notice. At this time there is no periodic mandated contact between the TSO/TO and LSCS during the duration of grid-risk-sensitive maintenance activities.

(h) If you have a formal agreement or protocol with your TSO, describe how NPP operators and maintenance personnel are trained and tested on this formal agreement or protocol.

Response

LSCS maintenance, operations, and work management personnel associated with schedule development or communicating with the TO (i.e., ComEd) are briefed on TSO/TO interface requirements and expectations but are not formally tested on knowledge retention in this area.

(i) If your grid reliability evaluation, performed as part of the maintenance risk assessment required by 10 CFR 50.65(a)(4), does not consider or rely on some arrangement for communication with the TSO, explain why you believe you comply with 10 CFR 50.65(a)(4).

Response

Not applicable

The methods used to integrate grid risk into the quantitative risk evaluation prior to taking equipment out of service for planned maintenance at LSCS rely on communication with the TSO/TO.

(j) If risk is not assessed (when warranted) based on continuing communication with the TSO throughout the duration of grid-risk-sensitive maintenance activities, explain why you believe you have effectively implemented the relevant provisions of the endorsed industry guidance associated with the maintenance rule.

Response

Not applicable

As detailed in the response to 2(a), grid status is continually evaluated by PJM using the Security Analysis application. PJM notifies LSCS through the TO (i.e., ComEd) of emergent grid conditions. In addition, ComEd (i.e., the TO) possesses a similar system and is also monitoring and evaluating grid conditions. Existing EGC procedures require evaluation of the risk of scheduled on line maintenance activities based on conditions such as power grid stability, weather forecast, and current plant system conditions.

(k) With respect to questions 5(i) and 5(j), you may, as an alternative, describe what actions you intend to take to ensure that the increase in risk that may result from proposed grid-risk-sensitive activities is assessed before and during grid-risk-sensitive maintenance activities, respectively.

Response

Not applicable

6. *Use of risk assessment results, including the results of grid reliability evaluations, in managing maintenance risk, as required by 10 CFR 50.65(a)(4).*

(a) Does the TSO coordinate transmission system maintenance activities that can have an impact on the NPP operation with the NPP operator?

Response

Yes

The TSO/TO coordinates transmission system maintenance activities that can have an impact on the NPP (i.e., LSCS) with LSCS.

(b) Do you coordinate NPP maintenance activities that can have an impact on the transmission system with the TSO?

Response

Yes

The NPP (i.e., LSCS) coordinates maintenance activities that can have an impact on the transmission system with the TSO/TO.

(c) Do you consider and implement, if warranted, the rescheduling of grid-risk-sensitive maintenance activities (activities that could (1) increase the likelihood of a plant trip, (ii) increase LOOP probability, or (iii) reduce LOOP or SBO coping capability) under existing, imminent, or worsening degraded grid reliability conditions?

Response

Yes

Existing procedures require deferring work that would render AC power sources unavailable if severe weather is expected. Risk of scheduled on line work is evaluated based on grid conditions, the weather forecast, and current plant systems status. If the risk analysis determines that risk exceeds a predetermined level, then that configuration is not voluntarily entered and schedule changes are made to reduce the risk to an acceptable level.

(d) If there is an overriding need to perform grid-risk-sensitive maintenance activities under existing or imminent conditions of degraded grid reliability, or continue grid-risk-sensitive maintenance when grid conditions worsen, do you implement appropriate risk management actions? If so, describe the actions that you would take. (These actions could include alternate equipment protection and compensatory measures to limit or minimize risk.)

Response

Yes

When any risk significant SSC is made unavailable, actions are taken to protect redundant or diverse SSCs commensurate with the risk significance of the work being performed in accordance with approved procedures.

(e) Describe the actions associated with questions 6(a) through 6(d) above that would be taken, state whether each action is governed by documented procedures and identify

the procedures, and explain why these actions are effective and will be consistently accomplished.

Response

The outage coordination process is documented in the PJM Manuals and agreed to by PJM (i.e., the TSO) and the members. EGC and ComEd (i.e., the TO) are both members of PJM. In addition, PJM has computerized tools to track the process throughout its evolution, so that PJM, ComEd and EGC are clear what the status is and what the expectations are.

Planned transmission outages are coordinated in accordance with a process detailed in PJM Manual M3, "Transmission Operations," Section 4 (Reference 4). This process requires advanced notice and subsequent PJM approval for all outages to ensure grid reliability. On the outage start day, the system is analyzed one last time by PJM before permitting the equipment to be switched out of service.

Once the equipment is switched out of service, grid status is continually evaluated by the PJM Security Analysis application as detailed in the response to 2(a). In addition, the TO (i.e., ComEd) is performing similar monitoring and evaluation. PJM notifies the NPP (i.e., LSCS) through the TO's control center, as discussed in the response to 1(b).

An 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," (Reference 7) directs that schedule coordination meetings are held bi-monthly between the TSO/TO and the NPPs (i.e., LSCS) to coordinate maintenance activities that can have mutual impact.

Actions specified in questions 6(c) and 6(d) are specified in the EGC Work Management procedure, WC-AA-101, "On-Line Work Control Process," (Reference 8) and is applicable to LSCS.

(f) Describe how NPP operators and maintenance personnel are trained and tested to assure they can accomplish the actions described in your answers to question 6(e).

Response

LSCS Maintenance, Operations, and Work Management personnel associated with schedule development and/or risk assessment are briefed on procedure expectations but are not formally tested on knowledge retention in this area.

(g) If there is no effective coordination between the NPP operator and the TSO regarding transmission system maintenance or NPP maintenance activities, please explain why you believe you comply with the provisions of 10 CFR 50.65(a)(4).

Response

Not applicable

Effective coordination is directed by PJM (i.e., the TSO) procedures and jointly approved interface procedures between ComEd (i.e., the TO) and EGC.

(h) If you do not consider and effectively implement appropriate risk management actions during the conditions described above, explain why you believe you effectively addressed the relevant provisions of the associated NRC-endorsed industry guidance.

Response

Not applicable

Effective and appropriate risk management actions are described in plant procedures and implemented during the conditions described above.

(i) You may, as alternative to questions 6(g) and 6 (h) describe what actions you intend to take to ensure that the increase in risk that may result from grid-risk-sensitive maintenance activities is managed in accordance with 10 CFR 50.65(a)(4).

Response

Not applicable

Offsite power restoration procedures in accordance with 10 CFR 50.63 as developed in Section 2 of RG 1.155.

Pursuant to 10 CFR 50.63, the NRC requires that each NPP licensed to operate to be able to withstand an SBO for a specified duration and recover from the SBO. NRC RG 1.155 gives licensees guidance on developing their approaches for complying with 10 CFR 50.63.

7. *Procedures for identifying local power sources[1] that could be made available to resupply your plant following a LOOP event.*

Note: Section 2, "Offsite Power," of RG 1.155 (ADAMS Accession No. ML003740034) states:

> *Procedures should include the actions necessary to restore offsite power and use nearby power sources when offsite power is unavailable. As a minimum, the following potential causes for loss of offsite power should be considered:*
>
> - *Grid undervoltage and collapse*
> - *Weather-induced power loss*
> - *Preferred power distribution system faults that could result in the loss of normal power to essential switchgear buses*

(a) Briefly describe any agreement made with the TSO to identify local power sources that could be made available to resupply power to your plant following a LOOP event.

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[1] *This includes items such as nearby or onsite gas turbine generators, portable generators, hydro generators, and black-start fossil power plants.*

Response

LSCS is located in the service territory of PJM. PJM is the Transmission System Operator (TSO) for LSCS. The Transmission Owner (TO) providing interconnection services for LSCS is ComEd. EGC and ComEd are both members of PJM.

All members of PJM execute the "Operating Agreement of PJM Interconnection, LLC," (Reference 1) that details the obligations and responsibilities of both PJM and the PJM members. In the Operating Agreement, each member agrees to abide by the requirements contained in the PJM Manuals. The PJM Manuals contain the specific operational requirements that PJM and each member is required to follow.

ComEd (i.e., the TO) is also a signatory on the "PJM Consolidated Transmission Owners Agreement (PJM TOA)," (Reference 2). Section 4.5 of the PJM TOA requires the TOs to operate and maintain their transmission facilities in accordance with the PJM Manuals.

PJM (i.e., the TSO) is responsible for coordinating restoration of all or parts of the bulk power system in the PJM service territory. ComEd (i.e., the TO) is responsible for cooperating and coordinating with PJM and other PJM members during the restoration of all or parts of the bulk power system in the PJM service territory.

PJM Manual M36, "System Restoration," (Reference 11) gives priority to the restoration of offsite power to NPPs (i.e., LSCS) in the PJM service territory. The TSO (i.e., PJM) and the TO (i.e., ComEd) will utilize the best power sources and transmission paths available based on the specific event to restore offsite power since there is no way to accurately predict the extent and characteristics of a specific blackout. The TSO and TO have multiple options available to restore offsite power and these would not be limited to local power sources.

The Interconnection Agreement between the NPP (i.e., LSCS) and ComEd (i.e., the TO) reinforces the importance and priority of restoring the NPP offsite power source (Reference 14). In addition, LSCS has an Affiliate Level Arrangement Agreement (ALA) with ComEd (Reference 15) to apply "best efforts" to restore to service the facilities that they own or control in order to restore the LSCS offsite power circuit back to an operable status.

PJM provided the following information to EGC regarding this response in a letter from PJM to all PJM nuclear owners (Reference 6).

"The PJM Restoration Manual (M36) details the process to be followed during a system restoration. The process reiterates the specific offsite power requirements for NPPs:

> 'Offsite power should be restored as soon as possible to nuclear units, both units that had been operating and those that were already offline prior to the system disturbance, without regard to using these units for restoring customer load.'

However, due to the myriad of possible restoration scenarios, no specific power sources to resupply NPPs are identified. The PJM restoration process allows for the fact that the blacked out area may or may not be separated from the remainder of the system.

Regardless of the scenario, there is a clear recognition of the importance of restoring an NPP offsite power source.

PJM Manual M36 further states: 'Transmission Owners and Nuclear Power Plants must effectively communicate to keep the Nuclear Power Plant apprised of the anticipated restoration time for offsite power.' The manual also states that for PJM Restoration Drills the objectives should include 'Ensure that all nuclear units have been provided with one offsite source within 4 hours,' and that the PJM Nuclear Generation Owner/Operator Users Group should be debriefed on the drill results.

In support of the restoration objectives outlined in the PJM Restoration Manual (M36), there are generating units designated as critical black-start units electrically close to each of the NPPs. These black start units are required to provide black start capability whenever necessary. The adequacy of black-start resources to support system restoration is managed through a process contained in PJM Manual M10, "PreScheduling Operations," (Reference 12), Section 2. The process ensures the continuous availability of black start units to support the restoration needs of the NPPs even when a designated black start unit is on a planned outage."

(b) Are your NPP operators trained and tested on identifying and using local power sources to resupply your plant following a LOOP event? If so, describe how.

Response

No

LSCS operators are not specifically trained and tested on identifying and using local power sources to resupply the NPP (i.e., LSCS) following a LOOP event. The identification and use of local power sources for LSCS are under the control of PJM (i.e., the TSO) and ComEd (i.e., the TO) in accordance with the procedures and interface agreements described in the response to 7(a). The response to this question does not address the operation of the LSCS alternate AC source established under 10 CFR 50.63, "Loss of all alternating current power," (i.e., Station Blackout (SBO) Rule), for which LSCS operators are trained and tested to identify and use under SBO conditions.

(c) If you have not established an agreement with your plant's TSO to identify local power sources that could be made available to resupply power to your plant following a LOOP event, explain why you believe you comply with the provisions of 10 CFR 50.63, or describe what actions you intend to take to establish compliance.

Response

The identification and use of local power sources for restoration of offsite power to LSCS following a LOOP event are under the control of PJM (i.e., the TSO) and ComEd (i.e., the TO) in accordance with the procedures and interface agreements described in the response to 7(a). Due to the myriad of possible restoration scenarios, no specific power sources to resupply LSCS are identified. The procedures identified by RG 1.155, "Station Blackout," (Reference 13) that include the actions necessary to restore offsite power and the use of nearby power sources are also under the control of PJM and ComEd.

Note that, as detailed in the response to 7(a), both ComEd (i.e., the TO) and PJM (i.e., the TSO) have stated that restoring offsite power to a NPP (i.e., LSCS) is a priority.

The identification and use of local power sources that could be made available to resupply power to the NPP following a LOOP event are not part of the current LSCS operating procedures and training since they are outside of LSCS's direct control.

Losses of offsite power caused by grid failures at a frequency of equal to or greater than once in 20 site-years in accordance with Table 4 of Regulatory Guide 1.155 for complying with 10 CFR 50.63.

Pursuant to 10 CFR 50.63, the NRC requires that each NPP licensed to operate be able to withstand an SBO for a specified duration and recover from the SBO. NRC RG 1.155 gives licensees guidance on developing their approaches to complying with 10 CFR 50.63.

8. Maintaining SBO coping capabilities in accordance with 10 CFR 50.63.

(a) Has your NPP experienced a total LOOP caused by grid failure since the plant's coping duration was initially determined under 10 CFR 50.63?

Response

LSCS has not experienced a total LOOP caused by grid failure since the coping duration was initially determined under 10 CFR 50.63, "Loss of all alternating current power," (i.e., Station Blackout (SBO) Rule). A review of LSCS records including the Licensee Event Report (LER) database from July 1988, when the SBO Rule was added, was performed to make this determination.

This determination is consistent with the data presented in NUREG/CR-6890, Volume 1, "Reevaluation of Station Blackout Risk at Nuclear Power Plants – Analysis of Offsite Power Events: 1986-2004," (Reference 9), Appendix A, "LOOP Event Database," Section A-2, "Data Tables," Table A -1, "Loop Events for 1986-2004, sorted by plant."

In addition, the review of LERs since Reference 9 was issued to present has concluded that there were no additional grid failure based LOOP events during this period.

(b) If so, have you reevaluated the NPP using the guidance in Table 4 of RG 1.155 to determine if your NPP should be assigned to the P3 offsite power design characteristic group?

Response

Not applicable

(c) If so, what were the results of this reevaluation, and did the initially determined coping duration for the NPP need to be adjusted?

Response

Not applicable

(d) If your NPP has experienced a total LOOP caused by grid failure since the plant's coping duration was initially determined under 10 CFR 50.63 and has not been reevaluated using the guidance in Table 4 of RG 1.155, explain why you believe you comply with the provisions of 10 CFR 50.63 as stated above, or described what actions you intend to take to ensure that the NPP maintains its SBO coping capabilities in accordance with 10 CFR 50.63.

Response

Not applicable

Actions to ensure compliance

9. *If you determine that any action is warranted to bring your NPP into compliance with NRC regulatory requirements, including TSs, GDC 17, 10 CFR 50.65(a)(4), 10 CFR 50.63, 10 CFR 55.59 or 10 CFR 50.120, describe the schedule for implementing it.*

Response

Not applicable

References

1. "Operating Agreement of PJM Interconnection, LLC," revised through February 6. 2006

2. "Consolidated Transmission Owners Agreement," effective March 19, 2006

3. PJM Manual 01, "Control Center Requirements," Revision 10, effective February 7, 2006

4. PJM Manual 3, "Transmission Operations," Revision 20, effective February 10, 2006

5. PJM Manual 13, "Emergency Operations," Revision 24, effective February 22, 2006

6. 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

7. EGC procedure WC-AA-8000, "Interface Procedure between Exelon Energy Delivery (ComEd/PECO) and Exelon Generation (Nuclear/Power) for Construction and Maintenance Activities," Revision 0

8. EGC procedure WC-AA-101, "On-Line Work Control Process," Revision 11

9. NUREG/CR-6890, Volume 1, "Reevaluation of Station Blackout Risk at Nuclear Power Plants – Analysis of Offsite Power Events: 1986-2004," Revision 0

10. EGC procedure OP-AA-108-107-1002, "Interface Agreement between Exelon Energy Delivery and Exelon Generation for Switchyard Operations," Revision 2

11. PJM Manual 36, "System Restoration," Revision 2, effective November 1, 2005

12. PJM Manual 10, "Pre-Scheduling Operations," Revision 18, effective August 10, 2005

13. Regulatory Guide 1.155, "Station Blackout," Revision 0

14. "Facilities, Interconnection and Easement Agreement among ComEd Generation Company LLC, Exelon Generation Company, LLC and Commonweatlh Edison Company," LaSalle County Station Final Form, dated January 12, 2001

15. "Affiliate Level Arrangement ('ALA') by and among Exelon Energy Delivery Groups of ComEd and Exelon Generation Company, LLC," effective January 1, 2006

16. NRC Information Notice IN 93-17, "Safety Systems Response to Loss of Coolant and Loss of Offsite Power," Revision 1, dated March 25, 1994

17. SECY-05-0219, "Issuance of Nuclear Regulatory Commission Generic Letter 2005-XX, 'Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power,'" dated December 2, 2005

18. EGC procedure OP-AA-108-107-1001, "Station Response to Grid Capacity Conditions," Revision 1

19. LSCS Abnormal Operating Procedure LOA-AP-1(2)01, "AC Power System Abnormal"

20. LSCS Abnormal Operating Procedure LOA-GRID-001, "Abnormal Switchyard Voltage"

21. EGC procedure WC-AA-107, "Seasonal Readiness," Revision 2

22. SOER 99-1, "Loss of Grid," December 27, 1999

23. SOER 99-1, "Loss of Grid – Addendum," December 9, 2004

24. Jennifer Sterling, Exelon Transmission Planning, "NRC Generic Letter – Draft responses to questions 1 and 2," February 14, 2006, personal email to John Gyrath, Exelon Nuclear, (February 14, 2006)

ATTACHMENT 6

60-day Response to NRC Generic Letter 2006-02

LIMERICK GENERATING STATION, Units 1 and 2

FOL Nos. NPF-39 and NPF-85

ATTACHMENT 6
60-day Response to NRC Generic Letter 2006-02, LIMERICK GENERATING STATION, Units 1 and 2

On February 1, 2006, the NRC issued Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power." 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 Generic Letter requested that licensees answer the following questions and provide the information to the NRC with respect to each of their Nuclear Power Plants (NPPs).

Use of protocols between the NPP licensee and the TSO, ISO, or RC/RA and the use of analysis tools by TSOs to assist NPP licensee in monitoring grid conditions to determine the operability of offsite power system under plant TS.

GDC 17, 10 CFR Part 50, Appendix A, requires that licensees minimize the probability of the loss of power from the transmission network given a loss of the power generated by the nuclear power unit(s).

1. *Use of protocols between the NPP licensee and the TSO, ISO, or RC/RA to assist the NPP licensee in monitoring grid conditions to determine the operability of offsite power system under plant TS.*

   (a) Do you have a formal agreement or protocol with your TSO?

   Response

   Yes

   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.

   All members of PJM execute the "Operating Agreement of PJM Interconnection, LLC," (Reference 1) that details the obligations and responsibilities of both PJM and the PJM members. In the Operating Agreement, each member agrees to abide by the requirements contained in the PJM Manuals. The PJM Manuals contain the specific operational requirements that PJM and each member is required to follow.

   PECO (i.e., the TO) is also a signatory on the "PJM Consolidated Transmission Owners Agreement (PJM TOA)," (Reference 2). Section 4.5 of the PJM TOA requires the TOs to operate and maintain their transmission facilities in accordance with the PJM Manuals.

   The PJM Operating Agreement requires PJM to, "Incorporate the grid reliability requirements applicable to nuclear generating units in the PJM Region planning and operating principles and practices." PJM Manual M01, "Control Center Requirements," Attachment B, "Nuclear Plant Communication Protocol," (Reference 3), provides the roles and responsibilities of nuclear stations, TOs, and PJM with regard to communications both in normal and emergency circumstances. The nuclear power plant (NPP) notification requirements are contained in PJM Manual M3, "Transmission Operations," Section 3 (Reference 4).

In addition to the agreements delineated in the PJM Operating Agreement and the PJM Manuals, EGC has jointly approved interface procedures with the TO that address the monitoring of the offsite source voltages and the notification protocols. EGC procedure OP-AA-108-107-1002, "Interface Agreement between Exelon Energy Delivery and Exelon Generation for Switchyard Operations," (Reference 10) outlines the responsibilities and required work interfacing activities.

(b) Describe any grid conditions that would trigger a notification from the TSO to the NPP licensee and if there is a time period required for the notification.

Response

PJM Manual M3 (Reference 4) requires PJM to initiate notification to LGS through the TO's control center if PJM identifies a switchyard voltage violation. PJM Manual M3 states: "This notification should occur within 15 minutes for voltage contingency violations and immediately for actual voltage violations. To the extent practical, PJM shall direct operations such that the violation is remedied within 30 minutes."

In addition, PJM Manual M13, "Emergency Operations," (Reference 5) identifies a series of alerts, warnings, and actions that PJM issues to PJM members depending on the identified grid condition. The PJM message is communicated to LGS by their generation dispatcher for a variety of system conditions including the following:

Capacity Emergencies
- Maximum Emergency Generation Loading
- Load Management Curtailment
- Manual Load Dump Warning

Light Load Emergencies
- Minimum Generation Emergency
- Local Minimum Generation Emergency

Weather/Environmental Emergencies
- Hot/Cold Weather Alerts
- Thunderstorms and Tornadoes
- Solar Magnetic Disturbances

Sabotage/Terrorism Emergencies

(c) Describe any grid conditions that would cause the NPP licensee to contact the TSO. Describe the procedures associated with such a communication. If you do not have procedures, describe how you assess grid conditions that may cause the NPP licensee to contact the TSO.

Response

As required by PJM Manuals, communications between LGS and PJM (TSO) are generally through the Transmission Owner (TO) providing the interconnection service.

LGS will contact the TSO/TO for grid conditions that have parameters that are observable at the NPP. These conditions include the following:

- Loss of Offsite Power (LOOP)
- Abnormal switchyard voltage
- Automatic (protective) switchyard circuit breaker operation
- Switchyard alarms
- Grid disturbances (observable frequency or voltage fluctuations)

In addition to any alarm response procedures for the above applicable conditions, TSO/TO notifications are controlled by operating procedures, (e.g., S92.1.0, "Local and Remote Manual Startup of a Diesel Generator, GP-5"), Abnormal Operating Procedures, (e.g., ON-126, "Uncontrolled Main Generator Hydrogen Depressurization"), Emergency Operating Procedures, (e.g., E-5, "Grid Emergency," E-10/20, "Loss of Offsite Power," E-1, "Loss of all AC Power," S91.0.B, "Alternate Offsite Source Implementation," and S32.3, "Main Generator Inspection During Heavy Grid Load").

LGS will contact the TSO/TO during a grid restoration process to obtain grid status in preparation for returning the plant buses to the offsite source.

LGS also notifies the TSO/TO of switchyard equipment deficiencies identified by NPP personnel. Jointly approved interface agreements/procedures between EGC and the TO identify the communication protocols for station identified switchyard deficiencies. EGC procedures OP-AA-108-107-1002 (Reference 10) and WC-AA-8000 (Reference 7) outline the responsibilities and required work interfacing activities.

In addition, LGS will notify the TSO/TO of NPP configurations that potentially impact grid conditions. A jointly approved interface agreement/procedure, OP-AA-108-107-1002 (Reference 10), between EGC and the TO identifies the requirements for communication of the conditions listed below:

- NPP MVAR limitations
- NPP Main generator voltage regulator not in "Automatic" mode
- NPP inability to provide the MVARs requested by the TSO/TO

Note that any LGS MW limitations or limitations on the rate at which the NPP power may be raised or lowered are communicated to the generation dispatcher.

(d) Describe how NPP operators are trained and tested on the use of the procedures or assessing grid conditions in question 1(c).

<u>Response</u>

LGS licensed operators are trained and tested in accordance with the Systematic Approach to Training (SAT). Procedures and policies are routinely reviewed for training through this process for improvement of operator performance. The items considered for training include Operating Procedures, Annunciator Response Procedures, Abnormal Operating Procedures, and Emergency Operating Procedures that require interface with the TSO in accordance with the established protocol. These procedures may be utilized based on various grid, switchyard, or plant symptoms to assess, respond to or mitigate off-normal plant and grid conditions. Additionally, SOER 99-01, "Loss of Grid," (Reference 26) and SOER 99-01, "Loss of Grid – Addendum," (Reference 27) specifically are captured in the Licensed Operator Requalification Training Program (LORT) Long Range Training Program. These topics, in varying detail based upon the SAT process or as part of implementing EGC procedure WC-AA-107, "Seasonal Readiness," (Reference 25) are reviewed periodically with LGS operators. Testing is commensurate with the material presented and any performance issues are identified for inclusion in future training.

(e) If you do not have a formal agreement or protocol with your TSO, describe why you believe you continue to comply with the provisions of GDC 17 as stated above, or describe what actions you intend to take to assure compliance with GDC 17.

Response

Not applicable. Formal agreements exist for LGS.

(f) If you have an existing formal interconnection agreement or protocol that ensures adequate communication and coordination between the NPP license and the TSO, describe whether this agreement or protocol requires that you be promptly notified when the conditions of the surrounding grid could result in degraded voltage (i.e., below TS nominal trip setpoint value requirements; including NPP licensees using allowable value in its TSs) or LOOP after a trip of the reactor units(s).

Response

PJM Manual M3 (Reference 4) requires PJM to initiate a notification to LGS through its respective transmission owner's control center if PJM identifies a NPP switchyard voltage violation. PJM Manual M3 states: "This notification should occur within 15 minutes for voltage contingency violations and immediately for actual voltage violations. To the extent practical, PJM shall direct operations such that the violation is remedied within 30 minutes." The trip of a NPP (trip of a LGS unit) is one of the contingencies analyzed by PJM. PJM analyzes the LGS switchyard contingency voltages to the voltage limits provided by LGS. The voltage limits provided for LGS are based on the existing design basis analysis.

(g) Describe the low switchyard voltage conditions that would initiate operation of plant degraded voltage protection.

Response

Switchyard voltage below a value maintaining emergency bus voltage above the setpoint of the degraded voltage relay (3910 volts) will cause a trip of the preferred power source after a time delay of approximately 9 seconds with a Loss of Coolant Accident (LOCA) signal present. The relation between the switchyard voltage and the emergency bus voltage is dependent on the system auxiliary transformer impedance, the winding load, and transformer auto voltage regulators. Under design basis accident (i.e., Large Break LOCA) conditions, the maximum loading is known and contained in the LGS calculations of record. The design basis maximum loading and the degraded voltage relay reset voltage were used to determine the switchyard voltage needed for the system to remain connected to the offsite power source. For LGS, this corresponds to a switchyard voltage of approximately 218.5 kV for the 230 kV switchyard and 498 kV for the 525 kV switchyard.

In other conditions, the loading is less than the expected LOCA loading and will vary considerably depending on which loads are needed to support unit conditions. Under these conditions the required LGS switchyard voltage will be less than that required to support LOCA loading.

2. *Use of criteria and methodologies to assess whether the offsite power system will become inoperable as a result of a trip of your NPP.*

(a) Does your NPP's TSO use any analysis tools, an online analytical transmission system studies program, or other equivalent predictive methods to determine the grid conditions that would make the NPP offsite power system inoperable during various contingencies? If available to you, please provide a brief description of the analysis tool that is used by the TSO.

Response

Yes

The PJM Energy Management System (EMS) includes a Security Analysis application which runs approximately every 1 minute and analyzes ~4,000 contingencies on the PJM system (Reference 6). The analysis provides results with respect to thermal, voltage, and voltage drop limit violations. One of the contingencies analyzed by the PJM EMS is the trip of a NPP (i.e., trip of a LGS unit).

In addition, PECO (i.e., the TO) possesses a similar system that also calculates post-contingency voltage limit violations. One of the contingencies analyzed by PECO is the trip of a LGS unit.

(b) Does your NPP's TSO use an analysis tool as the basis for notifying the NPP licensee when such a condition is identified? If not, how does the TSO determine if conditions on the grid warrant NPP licensee notification?

Response

Yes

The results of the PJM Security Analysis application contain the specific contingency of the NPP tripping as the contingent element. Violation of the unit trip contingency voltage limit would result in notification of the NPP (i.e., LGS) in accordance with PJM Manual M3, Section 3 (Reference 4).

PECO (i.e., the TO) also possesses similar capability to monitor the same condition.

(c) If your TSO uses an analysis tool, would the analysis tool identify a condition in which a trip of the NPP would result in switchyard voltages (immediate and/or long-term)

falling below TS nominal trip setpoint value requirements (including NPP licensees using allowable value in its TSs) and consequent actuation of plant degraded voltage protection? If not, discuss how such a condition would be identified on the grid.

Response

Yes

The trip of the NPP (i.e., trip of a LGS unit) is one of the contingencies analyzed by the PJM Security Analysis application. PJM analyzes the NPP switchyard contingency voltages to the voltage limits provided by LGS. The voltage limits provided by LGS are based on the plant's design basis analysis as discussed in the response to 1(g).

PECO (i.e., the TO) also possesses similar capability to monitor the same condition.

(d) If your TSO uses an analysis tool, how frequently does the analysis tool program update?

Response

The PJM EMS includes a Security Analysis application that currently updates approximately every 1-minute. In addition, PECO (i.e., the TO) possesses a Security Analysis application that updates approximately every 10 minutes (Reference 28).

(e) Provide details of analysis tool-identified contingency conditions that would trigger an NPP licensee notification from the TSO.

Response

PJM notifies LGS through the TO (i.e., PECO) control center whenever actual or post-contingency voltages are determined to be below the LGS switchyard voltage limits. This requirement applies to all contingencies involving the tripping of the NPP or any transmission facility as the contingent element. In accordance with PJM Manual M3 (Reference 4) the notification is required even if the voltage limits are the same as the standard PJM voltage limits.

(f) If an interface agreement exists between the TSO and the NPP licensee, does it require that the NPP licensee be notified of periods when the TSO is unable to determine if offsite power voltage and capacity could be inadequate? If so, how does the NPP licensee determine that the offsite power would remain operable when such a notification is received?

Response

Yes

LGS unit trip contingency voltage calculations are performed by the PJM EMS and the TO (i.e., PECO) Security Analysis application. The PJM EMS consists of a primary and backup system. If the PJM EMS fails, the PECO Security Analysis application continues to analyze the LGS unit trip contingency voltage. LGS will be notified if the real time contingency analysis capability of PJM and the TO (i.e., PECO) are lost simultaneously in accordance with PJM Manual M01, Section 2 (Reference 3).

If LGS is notified that PJM and PECO (i.e., the TO) have both lost their real time contingency analysis capability, LGS would request PJM and PECO to provide an assessment of the current condition of the grid based on the tools that PJM and PECO have available. The determination of the operability of the offsite sources would consider the assessment provided by PJM and PECO and whether the current condition of the grid is bounded by the grid studies previously performed for LGS.

(g) After an unscheduled inadvertent trip of the NPP, are the resultant switchyard voltages verified by procedure to be bounded by the voltages predicted by the analysis tool?

Response

No

There is presently no formal process for comparing the actual post-trip voltages to the post-trip contingency voltage results calculated by the PJM and the TO (i.e., PECO) Security Analysis applications.

PJM provided the following information to EGC regarding this response in a letter from PJM to all PJM nuclear owners (Reference 6).

"Because the PJM transmission owning member companies have similar Security Analysis programs to PJM, there are many opportunities to compare the results of the respective Security Analysis programs. In this manner, there is a high confidence that the Security Analysis results are accurate within the precision of the calculations.

PJM retains the EMS results for a period of approximately 3 weeks after real time. It is possible to use those saved EMS results to repeat the Security Analysis calculations and compare them to the actual voltages from a unit trip. However, the NPP trips occur so infrequently that it would take a number of data points to verify the accuracy with any statistical significance. This process could take years if the process is limited to a comparison of only NPP trips."

(h) If an analysis tool is not available to the NPP licensee's TSO, do you know if there are any plans for the TSO to obtain one? If so, when?

Response

Not applicable. LGS TSO (i.e., PJM) has an analysis tool.

(i) If an analysis tool is not available, does your TSO perform period studies to verify that adequate offsite power capability, including adequate NPP post-trip switchyard voltages (immediate and/or long-term), will be available to the NPP licensee over the projected timeframe of the study?

Response

Not applicable. LGS TSO (i.e., PJM) has an analysis tool.

(a) Are the key assumptions and parameters of these periodic studies translated into TSO guidance to ensure that the transmission system is operated within the bounds of the analyses?

Response

Not applicable. LGS TSO (i.e., PJM) has an analysis tool.

(b) If the bounds of the analyses are exceeded, does this condition trigger the notification provisions discussed in question 1 above?

Response

Not applicable. LGS TSO (i.e., PJM) has an analysis tool.

(j) If your TSO does not use, or you do not have access to the results of an analysis tool, or your TSO does not perform and make available to you periodic studies that determine the adequacy of offsite power capability, please describe why you believe you comply with the provisions of GDC 17 as stated above, or describe what compensatory actions you intend to take to ensure that the offsite power system will be sufficiently reliable and remain operable with high probability following a trip of your NPP.

Response

Not applicable. LGS TSO (i.e., PJM) has an analysis tool. In addition the applicable contingency voltage results are made available to LGS as needed.

3. *Use of criteria and methodologies to assess whether the NPP's offsite power system and safety-related components will remain operable when switchyard voltages are inadequate.*

(a) If the TSO notifies the NPP operator that a trip of the NPP, or the loss of the most critical transmission line or the largest supply to the grid would result in switchyard voltages (immediate and/or long-term) below TS nominal trip setpoint value requirements (including NPP licensees using allowable value in its TSs) and would actuate plant degraded voltage protection, is the NPP offsite power system declared inoperable under the plant TSs? If not, why not?

Response

If the TSO (i.e., PJM) notifies LGS that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., trip of a LGS unit) is below the pre-determined notification value, LGS will review the applicability to the plant operating configuration and will declare the offsite power source inoperable in accordance with Technical

Specifications (TSs) if appropriate. The notification value provided to PJM by LGS is based on the LGS degraded voltage design basis analysis.

Predicted contingency voltages following the loss of a transmission facility (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 for LGS at this time. If the TSO (i.e., PJM) notifies LGS of a predicted contingency voltage violation resulting from the postulated trip of a transmission facility, LGS will perform a risk analysis of in-progress and scheduled plant work and will take action as appropriate.

The NPP unit trip contingency can be caused by plant-centered events. The use of the NPP unit trip contingency as the contingency element upon which offsite power operability is based is consistent with the final paragraph of General Design Criterion (GDC) 17, "Electric power systems," of 10 CFR Part 50 Appendix A, "General Design Criteria for Nuclear Power Plants," which requires provisions be included to minimize the probability of the loss of power from the transmission network given a loss of the power generated by the NPP (i.e., a LGS unit).

Postulated contingencies on the transmission system are currently not used as the basis for offsite source operability determinations since loss of power from the transmission network would not occur as a result of loss of power generated by a NPP unit (i.e., a LGS unit). Such events (e.g., loss of a transmission line) are only postulated and have not actually occurred, and the offsite power sources remain capable of supporting a safe shutdown and mitigating the effects of an accident. Loss of power from the transmission network would not occur as a result of loss of power generated by a NPP unit and therefore the GDC 17 provision discussed in GL 2006-02 is met.

(b) If onsite safety-related equipment (e.g., emergency diesel generators or safety-related motors) is lost when subjected to a double sequencing (LOCA with delayed LOOP event) as a result of the anticipated system performance and is incapable of performing its safety functions as a result of responding to an emergency actuation signal during this condition, is the equipment considered inoperable? If not, why not?

Response

Although some features have been incorporated into the plant design, requirements for analysis and design considerations for double sequencing are not included within the LGS current licensing and design basis as documented in the LGS Updated Final Safety Analysis Report (UFSAR). LGS has not been explicitly analyzed for all issues associated with double sequencing. Onsite safety-related equipment at LGS (e.g., emergency diesel generators or safety-related motors) is not declared inoperable as a result of a TSO (i.e., PJM) unit trip contingency voltage notification.

Based on Enclosure 2 of SECY-05-0219, "Issuance of Nuclear Regulatory Commission Generic Letter 2005-XX, 'Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power,'" (Reference 17) which provided NRC guidance on responding to this issue, a review was performed for LGS of the loading logic for the diesel generators as well as the safety-related breakers' anti-pumping logic. This review concluded that onsite safety-related equipment (i.e., emergency diesel generators or safety-related motors) is not lost as a result of diesel generator block loading and breaker lockout from anti-pump circuitry when subjected to a double sequencing event resulting from inadequate post unit trip voltages. The scope of the review performed for LGS is discussed in the response to question 3(c) below.

(c) Describe your evaluation of onsite-related equipment to determine whether it will operate as designed during the condition described in question 3(b).

Response

Although some features have been incorporated into the plant design, requirements for analysis and design considerations for double sequencing are not included within the LGS current licensing and design basis as documented in the LGS UFSAR. LGS has not been explicitly analyzed for all issues associated with double sequencing. However, using the NRC clarification provided in Enclosure 2 of SECY-05-0219 as guidance, a review was performed for the purpose of addressing question 3(b).

This review examined the effects of a double sequencing event on diesel generator block loading and the potential for breaker lockout from the anti-pump circuitry. The review assumed that following a LOCA initiation, separation occurred as a result of degraded voltage relay operation triggered by the loss of a LGS unit. The review examined the diesel generator loading logic and determined that the logic is reset by the LOOP event. The second sequence is consistent with that described in the LGS UFSAR for a LOOP/LOCA event with the exception of the load center transformer. The load center transformer is not load shed on a LOOP signal and remains on the emergency bus during the LOOP/LOCA loading sequence. The review concluded that the diesel generator was capable of supporting the LOOP/LOCA loading sequence with the load center transformer remaining connected to the emergency bus.

The review also examined the potential for breaker lockout due to the anti-pumping circuitry. This review determined that there was sufficient time between the two sequences such that the breaker charging springs would re-charge and the second closure would be successful. To ensure that a breaker lockout would not occur, the breaker closing logics were also examined to assure that the trip signals were cleared before the second close signal was initiated.

(d) If the NPP licensee is notified by the TSO of other grid conditions that may impair the capability or availability of offsite power, are any plant TS action statements entered? If so, please identify them.

Response

As discussed in the response to 3(a), if the TSO (i.e., PJM) notifies LGS that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., trip of a LGS unit) is below the pre-determined notification value, LGS will review the applicability to the plant operating configuration and will declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by LGS is based on the LGS degraded voltage design basis analysis.

In addition, if PJM notifies LGS that the actual offsite power source voltage is less than the pre-determined notification value, LGS will review the applicability to the plant operating configuration and would declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by LGS is based on the LGS degraded voltage design basis analysis.

(e) If you believe your plant TSs do not require you to declare your offsite power system or safety-related equipment inoperable in any of these circumstances, explain why you believe you comply with the provisions of GDC 17 and your plant TSs, or describe what compensatory actions you intend to take to ensure that the offsite power system and safety-related components will remain operable when switchyard voltages are inadequate.

Response

The following notifications from the TSO (i.e., PJM) will result in LGS declaring the offsite power source inoperable in accordance with TSs.

- If the TSO (i.e., PJM) notifies LGS that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., trip of a LGS unit) is below the pre-determined notification value, LGS will review the applicability to the plant operating configuration and will declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by LGS is based on the LGS degraded voltage design basis analysis.

- If the TSO (i.e., PJM) notifies LGS that the actual offsite power source voltage is less than the pre-determined notification value, LGS will review the applicability to the plant operating configuration and would declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by LGS is based on the LGS degraded voltage design basis analysis.

Predicted contingency voltages following the loss of a transmission facility (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. If the TSO notifies the NPP of a predicted contingency voltage violation resulting from the postulated trip of a transmission facility, the NPP performs a risk analysis of in-progress and scheduled plant work and takes action as appropriate.

The NPP unit trip contingency can be caused by plant-centered events. The use of the NPP unit trip contingency as the contingency element upon which offsite power operability is based is consistent with the final paragraph of GDC 17 which requires provisions to minimize the probability of the loss of power from the transmission network given a loss of the power generated by the NPP.

Postulated contingencies on the transmission system are not used as the basis for offsite source operability determinations since loss of power from the transmission network would not occur as a result of loss of power generated by the NPP unit. Such events (e.g., loss of a transmission line) are only postulated and have not actually occurred, and the offsite power sources remain capable of affecting a safe shutdown and mitigating the effects of an accident. The GDC 17 provision discussed in the Generic Letter is still met; loss of power from the transmission network would not occur as a result of loss of power generated by the NPP unit.

Onsite safety-related equipment at LGS (e.g., emergency diesel generators or safety-related motors) is not declared inoperable as a result of a TSO (i.e., PJM) unit trip contingency voltage notification. Although some features have been incorporated into the plant design, requirements for analysis and design considerations for double sequencing are not included within the LGS current licensing and design basis as documented in the LGS UFSAR. LGS has not been explicitly analyzed for all issues associated with double sequencing.

(f) Describe if and how NPP operators are trained and tested on the compensatory actions mentioned in your answers to questions 3(a) through (e).

Response

LGS licensed operators are trained and tested in accordance with the Systematic Approach to Training (SAT). Equipment operability, as defined by TS, including normal and emergency power, offsite circuits, and safety-related components, is under continuous review. Procedures are in place to provide operator guidance and required actions necessary during predicted or actual degraded grid voltage conditions based on information provided by the TSO/TO in accordance with established protocol or as observed by the NPP operator. As part of initial training, requalification training, and annual operating tests, licensed operators are subjected to written examinations, dynamic learning activities, static and/or simulator examinations, Job Performance Measures (JPMs), and evaluated simulator scenarios incorporating topics including the actual or predicted switchyard voltage issues and its effect on AC Source operability. Testing is commensurate with the material presented and any performance issues are identified for inclusion in future training.

4. *Use of criteria and methodologies to assess whether the offsite power system will remain operable following a trip of your NPP.*

(a) Do the NPP operators have any guidance or procedures in plant TS bases sections, the final safety analysis report, or plant procedures regarding situations in which the condition of plant-controlled or monitored equipment (e.g., voltage regulator, auto tap changing transformers, capacitors, static VAR compensators, main generator voltage regulators) can adversely affect the operability of the NPP offsite power system? If so, describe how the operators are trained and tested on the guidance and procedures.

Response

Yes

LGS plant controlled or monitored equipment that can adversely affect the operability of the offsite power system is limited to the main generator voltage regulators and the safeguard transformer automatic load tap changers (LTCs). EGC and plant specific procedures provide guidance for notification of the TSO/TO (i.e., PJM/PECO) when the voltage regulator is not in automatic.

LGS procedures direct operator actions to control excitation in manual or other mitigating actions to control excitation. Operator actions on a loss of automatic control of the voltage regulator include the requirement to notify the TO (i.e., PECO) of the failure.

The operation of the main generator voltage regulators does not have any direct impact on the operability of the offsite sources. The LGS offsite sources are not directly connected to the main generator output or unit auxiliary transformers, but only connected together via the switchyard buses. The TSO is notified whenever the voltage regulators are taken from automatic to manual operation.

LGS TS Bases Section 3.8.1, "A.C. Sources" discusses operability requirements for the off-site sources. The LTCs and their associated transformers affect the operability of the offsite sources. The LGS offsite sources credit the 10 Transformer and 20 Regulating Transformer LTCs in automatic operation to support operability in accordance with TS and the TS Bases. The associated offsite source is declared inoperable if the LTC is not in automatic and functional. This guidance is written in LGS Emergency Procedures. The ability to support offsite source operability is confirmed by observing and reviewing the voltages on the low side of the 10 Transformer and 20 Regulating Transformer, observing the tap changer position switches in automatic, and by observing the tap changer counters in accordance with LGS procedures.

LGS licensed operators are trained and tested in accordance with the Systematic Approach to Training (SAT). Procedures and policies are routinely reviewed for training through this process for improvement of operator performance. The items considered for training include Annunciator Response Procedures, Abnormal Operating Procedures, and Emergency Operating Procedures that require interface with the TSO/TO in accordance with the established protocol. In addition as part of initial training, requalification training, and annual operating tests, licensed operators are subjected to written examinations, static and/or simulator examinations, Job Performance Measures (JPMs), and evaluated simulator scenarios. These evaluations may incorporate topics including the loss of the main generator voltage regulator and actions to mitigate the effect of the failure. Testing is commensurate with the material presented and any performance issues are identified for inclusion in future training.

(b) If your TS bases sections, the final safety analysis report, and plant procedures do not provide guidance regarding situations in which the condition of plant-controlled or monitored equipment can adversely affect the operability of the NPP offsite power system, explain why you believe you comply with the provisions of GDC 17 and the plant TSs, or describe what actions you intend to take to provide such guidance or procedures.

Response

Not applicable

Use of NPP licensee/TSO protocols and analysis tool by TSOs to assist NPP licensees in monitoring grid conditions for consideration in maintenance risk assessments.

The Maintenance Rule (10 CFR 50.65(a)(4)) requires that licensees assess and manage the increase in risk that may result from proposed maintenance activities before performing them.

5. *Performance of grid reliability evaluations as part of the maintenance risk assessments required by 10 CFR 50.65(a)(4).*

(a) Is a quantitative or qualitative grid reliability evaluation performed at your NPP as part of the maintenance risk assessment required by 10 CFR 50.65(a)(4) before performing grid-risk-sensitive maintenance activities? This includes surveillances, post-maintenance testing, and preventive and corrective maintenance that could increase the probability of a plant trip or LOOP or impact LOOP or SBO coping capability, for example, before taking a risk-significant piece of equipment (such as an EDG, a battery, a steam-driven pump, an alternate AC power source) out-of-service?

Response

Yes

Risk is assessed using a process that combines quantitative results from a probabilistic risk assessment (PRA) with a qualitative defense-in-depth model. During the planning and scheduling of work and prior to the execution of work, many factors are assessed for risk including the effect of weather/time of year and grid instability. The combination of unavailable Systems, Structures and Components (SSCs) and planned activities is then assessed in the risk assessment tool. Currently, a procedure update is being implemented to provide additional detail for how to factor grid reliability into the risk assessment tool before taking equipment out of service for planned maintenance. These procedure changes are currently scheduled to be in place at LGS by May 15, 2006.

(b) Is grid status monitored by some means for the duration of the grid-risk-sensitive maintenance to confirm the continued validity of the risk assessment and is risk reassessed when warranted? If not, how is the risk assessed during grid-risk-sensitive maintenance?

Response

Yes

Grid status is continually evaluated by PJM using the Security Analysis application. PJM notifies LGS through its Transmission Operator, (i.e., PECO), of emergent grid conditions as discussed in the response to 1(b) above. In addition, PECO (i.e., the TO) is also performing similar monitoring and evaluation. Existing EGC procedures require evaluation of the risk of scheduled online maintenance activities based on conditions such as power grid stability, weather forecast, and current plant system conditions.

(c) Is there a significant variation in the stress on the grid in the vicinity of your NPP site caused by seasonal loads or maintenance activities associated with critical transmission elements? Is there a seasonal variation (or the potential for a seasonal variation) in the LOOP frequency in the local transmission region? If the answer to either question is yes, discuss the time of year when the variations occur and their magnitude.

Response

The base PRA model reflects the yearly average LOOP frequency because seasonal variations that would cause changes to the frequency of a LOOP cannot be accurately predicted. While time related variations are not factored into the base PRA model for LGS, symptoms of grid stress such as maximum generation conditions, low grid voltage, or severe weather conditions require identification of such dynamic conditions should they occur, and risk management actions are then taken to mitigate the risk or reschedule the work as appropriate.

PJM provided the following information to EGC regarding this response in a letter from PJM to all PJM nuclear owners (Reference 6).

"Stress on the grid is manifested in a number of ways. Stress can mean 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.

Regarding the seasonal variability of the stress causers, each has a seasonal component. For example, peak load levels occur at the peak seasons of the summer and winter seasons. While the specific days cannot be predicted, it is known roughly when they will occur. Consequently, maintenance during these times of the year is avoided.

From a transmission system operations perspective, it is the simultaneous combination of stress causers that results in the most difficult operational challenges. For example, experiencing very hot (or cold) weather when we (i.e., PJM) are in the maintenance seasons with a lot of equipment out of service can cause the most severe challenges.

We (i.e., PJM) are aware of the existence of the North American Electric Reliability Council (NERC) and NRC data regarding LOOP frequency. However, it is difficult to assign differential risks to any seasonal variation because of the complexity of the various competing factors, as explained above."

(d) Are known time-related variations in the probability of a LOOP at your plant site considered in the grid-risk-sensitive maintenance evaluation? If not, what is your basis for not considering them?

Response

No

While time related variations are not factored into the base PRA model for LGS, symptoms of grid stress such as maximum generation conditions, low grid voltage, or severe weather conditions require identification of such dynamic conditions should they occur, and risk management actions are then taken to mitigate the risk or reschedule the work as appropriate.

(e) Do you have contacts with the TSO to determine current and anticipated grid conditions as part of the grid reliability evaluation performed before conducting grid-risk-sensitive maintenance activities?

Response

Yes

The protocol for NPP notification of actual or anticipated grid conditions is outlined in the response to 1(b). Any work performed on the grid risk sensitive equipment is evaluated for risk using these current or anticipated conditions as part of the evaluation prior to performance. Work is coordinated based on anticipated conditions and planned maintenance during bi-monthly interface meetings between the transmission operator (i.e., PECO) and the EGC NPPs (i.e., LGS).

As stated in the response to 1(b), communication is shared between the TSO (i.e., PJM) and LGS if grid conditions deteriorate from an acceptable level.

(f) Describe any formal agreement or protocol that you have with your TSO to assure that you are promptly alerted to a worsening grid condition that may emerge during a maintenance activity.

Response

As stated in the response to 1(a), LGS is located in the service territory of PJM. PJM is the TSO for LGS. The TO providing interconnection services for LGS is PECO. EGC and PECO are both members of PJM.

All members of PJM execute the PJM Operating Agreement (Reference 1) that details the obligations and responsibilities of both PJM and the PJM members. In the Operating Agreement, each member agrees to abide by the requirements contained in the PJM Manuals. The PJM Manuals contain the specific operational requirements that PJM and each member is required to follow.

As stated in the response to 1(b), PJM Manual M13 (Reference 5) identifies a series of alerts, warnings, and actions that PJM issues to PJM members depending on the identified grid condition. The PJM message is communicated to LGS by their generation dispatcher for a variety of system conditions including capacity emergencies, light load emergencies, weather/environmental emergencies or sabotage/terrorism emergencies.

PJM Manual M3 (Reference 4) requires PJM to initiate notification to LGS through the TO's control center if PJM identifies a switchyard voltage violation. PJM Manual M3 states: "This notification should occur within 15 minutes for voltage contingency violations and immediately for actual voltage violations. To the extent practical, PJM shall direct operations such that the violation is remedied within 30 minutes."

(g) Do you contact your TSO periodically for the duration of the grid-risk sensitive maintenance activities?

Response

No

Communications take place between the TSO (i.e., PJM) through the TO (i.e., PECO) and LGS as detailed in the response to 1(b) above if grid conditions deteriorate from an acceptable level. At this time there is no periodic mandated contact between the TSO/TO and LGS during the duration of grid-risk-sensitive maintenance activities.

(h) If you have a formal agreement or protocol with your TSO, describe how NPP operators and maintenance personnel are trained and tested on this formal agreement or protocol.

Response

LGS maintenance, operations, and work management personnel associated with schedule development or communicating with the TO (i.e., PECO) are briefed on TSO/TO interface requirements and expectations but are not formally tested on knowledge retention in this area.

(i) If your grid reliability evaluation, performed as part of the maintenance risk assessment required by 10 CFR 50.65(a)(4), does not consider or rely on some arrangement for communication with the TSO, explain why you believe you comply with 10 CFR 50.65(a)(4).

Response

Not applicable

The methods used to integrate grid risk into the quantitative risk evaluation prior to taking equipment out of service for planned maintenance at LGS rely on communication with the TSO/TO.

(j) If risk is not assessed (when warranted) based on continuing communication with the TSO throughout the duration of grid-risk-sensitive maintenance activities, explain why you believe you have effectively implemented the relevant provisions of the endorsed industry guidance associated with the maintenance rule.

Response

Not applicable

As detailed in the response to 2(a), grid status is continually evaluated by PJM using the Security Analysis application. PJM notifies LGS through the TO (i.e., PECO) of emergent grid conditions. In addition, PECO (i.e., the TO) possesses a similar system and is also monitoring and evaluating grid conditions. Existing EGC procedures require evaluation of the risk of scheduled on line maintenance activities based on conditions such as power grid stability, weather forecast, and current plant system conditions.

(k) With respect to questions 5(i) and 5(j), you may, as an alternative, describe what actions you intend to take to ensure that the increase in risk that may result from proposed grid-risk-sensitive activities is assessed before and during grid-risk-sensitive maintenance activities, respectively.

Response

Not applicable

6. *Use of risk assessment results, including the results of grid reliability evaluations, in managing maintenance risk, as required by 10 CFR 50.65(a)(4).*

(a) Does the TSO coordinate transmission system maintenance activities that can have an impact on the NPP operation with the NPP operator?

Response

Yes

The TSO/TO coordinates transmission system maintenance activities that can have an impact on the NPP (i.e., LGS) with LGS.

(b) Do you coordinate NPP maintenance activities that can have an impact on the transmission system with the TSO?

Response

Yes

The NPP (i.e., LGS) coordinates maintenance activities that can have an impact on the transmission system with the TSO/TO.

(c) Do you consider and implement, if warranted, the rescheduling of grid-risk-sensitive maintenance activities (activities that could (1) increase the likelihood of a plant trip, (ii) increase LOOP probability, or (iii) reduce LOOP or SBO coping capability) under existing, imminent, or worsening degraded grid reliability conditions?

Response

Yes

Existing procedures require deferring work that would render AC power sources unavailable if severe weather is expected. Risk of scheduled on line work is evaluated based on grid conditions, the weather forecast, and current plant systems status. If the risk analysis determines that risk exceeds a predetermined level, then that configuration is not voluntarily entered and schedule changes are made to reduce the risk to an acceptable level.

(d) If there is an overriding need to perform grid-risk-sensitive maintenance activities under existing or imminent conditions of degraded grid reliability, or continue grid-risk-

sensitive maintenance when grid conditions worsen, do you implement appropriate risk management actions? If so, describe the actions that you would take. (These actions could include alternate equipment protection and compensatory measures to limit or minimize risk.)

<u>Response</u>

Yes

When any risk significant SSC is made unavailable, actions are taken to protect redundant or diverse SSCs commensurate with the risk significance of the work being performed in accordance with approved procedures.

(e) Describe the actions associated with questions 6(a) through 6(d) above that would be taken, state whether each action is governed by documented procedures and identify the procedures, and explain why these actions are effective and will be consistently accomplished.

<u>Response</u>

The outage coordination process is documented in the PJM Manuals and agreed to by PJM (i.e., the TSO) and the members. EGC and PECO (i.e., the TO) are both members of PJM. In addition, PJM has computerized tools to track the process throughout its evolution, so that PJM, PECO and EGC are clear what the status is and what the expectations are.

Planned transmission outages are coordinated in accordance with a process detailed in PJM Manual M3, "Transmission Operations," Section 4 (Reference 4). This process requires advanced notice and subsequent PJM approval for all outages to ensure grid reliability. On the outage start day, the system is analyzed one last time by PJM before permitting the equipment to be switched out of service.

Once the equipment is switched out of service, grid status is continually evaluated by the PJM Security Analysis application as detailed in the response to 2(a). In addition, the TO (i.e., PECO) is performing similar monitoring and evaluation. PJM notifies the NPP (i.e., LGS) through the TO's control center, as discussed in the response to 1(b).

An 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," (Reference 7) directs that schedule coordination meetings are held bi-monthly between the TSO/TO and the NPPs (i.e., LGS) to coordinate maintenance activities that can have mutual impact.

Actions specified in questions 6(c) and 6(d) are specified in the EGC Work Management procedure, WC-AA-101, "On-Line Work Control Process," (Reference 8) and is applicable to LGS.

(f) Describe how NPP operators and maintenance personnel are trained and tested to assure they can accomplish the actions described in your answers to question 6(e).

Response

LGS Maintenance, Operations, and Work Management personnel associated with schedule development and/or risk assessment are briefed on procedure expectations but are not formally tested on knowledge retention in this area.

(g) If there is no effective coordination between the NPP operator and the TSO regarding transmission system maintenance or NPP maintenance activities, please explain why you believe you comply with the provisions of 10 CFR 50.65(a)(4).

Response

Not applicable

Effective coordination is directed by PJM (i.e., the TSO) procedures and jointly approved interface procedures between PECO (i.e., the TO) and EGC.

(h) If you do not consider and effectively implement appropriate risk management actions during the conditions described above, explain why you believe you effectively addressed the relevant provisions of the associated NRC-endorsed industry guidance.

Response

Not applicable

Effective and appropriate risk management actions are described in plant procedures and implemented during the conditions described above.

(i) You may, as alternative to questions 6(g) and 6 (h) describe what actions you intend to take to ensure that the increase in risk that may result from grid-risk-sensitive maintenance activities is managed in accordance with 10 CFR 50.65(a)(4).

Response

Not applicable

Offsite power restoration procedures in accordance with 10 CFR 50.63 as developed in Section 2 of RG 1.155.

Pursuant to 10 CFR 50.63, the NRC requires that each NPP licensed to operate to be able to withstand an SBO for a specified duration and recover from the SBO. NRC RG 1.155 gives licensees guidance on developing their approaches for complying with 10 CFR 50.63.

7. Procedures for identifying local power sources[1] that could be made available to resupply your plant following a LOOP event.

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[1] *This includes items such as nearby or onsite gas turbine generators, portable generators, hydro generators, and black-start fossil power plants.*

Note: Section 2, "Offsite Power," of RG 1.155 (ADAMS Accession No. ML003740034) states:

> *Procedures should include the actions necessary to restore offsite power and use nearby power sources when offsite power is unavailable. As a minimum, the following potential causes for loss of offsite power should be considered:*
>
> - *Grid undervoltage and collapse*
> - *Weather-induced power loss*
> - *Preferred power distribution system faults that could result in the loss of normal power to essential switchgear buses*

(a) Briefly describe any agreement made with the TSO to identify local power sources that could be made available to resupply power to your plant following a LOOP event.

Response

LGS is located in the service territory of PJM. PJM is the Transmission System Operator (TSO) for LGS. The Transmission Owner (TO) providing interconnection services for LGS is PECO. EGC and PECO are both members of PJM.

All members of PJM execute the "Operating Agreement of PJM Interconnection, LLC," (Reference 1) that details the obligations and responsibilities of both PJM and the PJM members. In the Operating Agreement, each member agrees to abide by the requirements contained in the PJM Manuals. The PJM Manuals contain the specific operational requirements that PJM and each member is required to follow.

PECO (i.e., the TO) is also a signatory on the "PJM Consolidated Transmission Owners Agreement (PJM TOA)," (Reference 2). Section 4.5 of the PJM TOA requires the TOs to operate and maintain their transmission facilities in accordance with the PJM Manuals.

PJM (i.e., the TSO) is responsible for coordinating restoration of all or parts of the bulk power system in the PJM service territory. PECO (i.e., the TO) is responsible for cooperating and coordinating with PJM and other PJM members during the restoration of all or parts of the bulk power system in the PJM service territory.

PJM Manual M36, "System Restoration," (Reference 11) gives priority to the restoration of offsite power to NPPs (i.e., LGS) in the PJM service territory. The TSO (i.e., PJM) and the TO (i.e., PECO) will utilize the best power sources and transmission paths available based on the specific event to restore offsite power since there is no way to accurately predict the extent and characteristics of a specific blackout. The TSO and TO have multiple options available to restore offsite power and these would not be limited to local power sources.

The Interconnection Agreement between the NPP (i.e., LGS) and PECO (i.e., the TO) reinforces the importance and priority of restoring the NPP offsite power source (Reference 15). In addition, LGS has an Affiliate Level Arrangement Agreement (ALA) with PECO (Reference 14) to apply "best efforts" to restore to service the facilities that they own or control in order to restore the LGS offsite power circuit back to an operable status.

PJM provided the following information to EGC regarding this response in a letter from PJM to all PJM nuclear owners (Reference 6).

"The PJM Restoration Manual (M36) details the process to be followed during a system restoration. The process reiterates the specific offsite power requirements for NPPs:

> 'Offsite power should be restored as soon as possible to nuclear units, both units that had been operating and those that were already offline prior to the system disturbance, without regard to using these units for restoring customer load.'

However, due to the myriad of possible restoration scenarios, no specific power sources to resupply NPPs are identified. The PJM restoration process allows for the fact that the blacked out area may or may not be separated from the remainder of the system. Regardless of the scenario, there is a clear recognition of the importance of restoring an NPP offsite power source.

PJM Manual M36 further states: 'Transmission Owners and Nuclear Power Plants must effectively communicate to keep the Nuclear Power Plant apprised of the anticipated restoration time for offsite power.' The manual also states that for PJM Restoration Drills the objectives should include 'Ensure that all nuclear units have been provided with one offsite source within 4 hours,' and that the PJM Nuclear Generation Owner/Operator Users Group should be debriefed on the drill results.

In support of the restoration objectives outlined in the PJM Restoration Manual (M36), there are generating units designated as critical black-start units electrically close to each of the NPPs. These black start units are required to provide black start capability whenever necessary. The adequacy of black-start resources to support system restoration is managed through a process contained in PJM Manual M10, "PreScheduling Operations," (Reference 12), Section 2. The process ensures the continuous availability of black start units to support the restoration needs of the NPPs even when a designated black start unit is on a planned outage."

(b) Are your NPP operators trained and tested on identifying and using local power sources to resupply your plant following a LOOP event? If so, describe how.

Response

No

LGS operators are not specifically trained and tested on identifying and using local power sources to resupply the NPP (i.e., LGS) following a LOOP event. The identification and use of local power sources for LGS are under the control of PJM (i.e., the TSO) and PECO (i.e., the TO) in accordance with the procedures and interface agreements described in the response to 7(a). The response to this question does not address the operation of the LGS alternate AC source established under 10 CFR 50.63, "Loss of all alternating current power," (i.e., Station Blackout (SBO) Rule), for which LGS operators are trained and tested to identify and use under SBO conditions.

(c) If you have not established an agreement with your plant's TSO to identify local power sources that could be made available to resupply power to your plant following a LOOP event, explain why you believe you comply with the provisions of 10 CFR 50.63, or describe what actions you intend to take to establish compliance.

Response

The identification and use of local power sources for restoration of offsite power to LGS following a LOOP event are under the control of PJM (i.e., the TSO) and PECO (i.e., the TO) in accordance with the procedures and interface agreements described in the response to 7(a). Due to the myriad of possible restoration scenarios, no specific power sources to resupply LGS are identified. The procedures identified by RG 1.155, "Station Blackout," (Reference 13) that include the actions necessary to restore offsite power and the use of nearby power sources are also under the control of PJM and PECO.

Note that, as detailed in the response to 7(a), both PECO (i.e., the TO) and PJM (i.e., the TSO) have stated that restoring offsite power to a NPP (i.e., LGS) is a priority.

The identification and use of local power sources that could be made available to resupply power to the NPP following a LOOP event are not part of the current LGS operating procedures and training since they are outside of LGS's direct control.

Losses of offsite power caused by grid failures at a frequency of equal to or greater than once in 20 site-years in accordance with Table 4 of Regulatory Guide 1.155 for complying with 10 CFR 50.63.

Pursuant to 10 CFR 50.63, the NRC requires that each NPP licensed to operate be able to withstand an SBO for a specified duration and recover from the SBO. NRC RG 1.155 gives licensees guidance on developing their approaches to complying with 10 CFR 50.63.

8. Maintaining SBO coping capabilities in accordance with 10 CFR 50.63.

(a) Has your NPP experienced a total LOOP caused by grid failure since the plant's coping duration was initially determined under 10 CFR 50.63?

Response

LGS has not experienced a total LOOP caused by grid failure since the coping duration was initially determined under 10 CFR 50.63, "Loss of all alternating current power," (i.e., Station Blackout (SBO) Rule). A review of LGS records including the Licensee Event Report (LER) database from July 1988, when the SBO Rule was added, was performed to make this determination.

This determination is consistent with the data presented in NUREG/CR-6890, Volume 1, "Reevaluation of Station Blackout Risk at Nuclear Power Plants – Analysis of Offsite Power Events: 1986-2004," (Reference 9), Appendix A, "LOOP Event Database," Section A-2, "Data Tables," Table A -1, "Loop Events for 1986-2004, sorted by plant."

In addition, the review of LERs since Reference 9 was issued to present has concluded that there were no additional grid failure based LOOP events during this period.

(b) If so, have you reevaluated the NPP using the guidance in Table 4 of RG 1.155 to determine if your NPP should be assigned to the P3 offsite power design characteristic group?

Response

Not applicable

(c) If so, what were the results of this reevaluation, and did the initially determined coping duration for the NPP need to be adjusted?

Response

Not applicable

(d) If your NPP has experienced a total LOOP caused by grid failure since the plant's coping duration was initially determined under 10 CFR 50.63 and has not been reevaluated using the guidance in Table 4 of RG 1.155, explain why you believe you comply with the provisions of 10 CFR 50.63 as stated above, or described what actions you intend to take to ensure that the NPP maintains its SBO coping capabilities in accordance with 10 CFR 50.63.

Response

Not applicable

Actions to ensure compliance

9. *If you determine that any action is warranted to bring your NPP into compliance with NRC regulatory requirements, including TSs, GDC 17, 10 CFR 50.65(a)(4), 10 CFR 50.63, 10 CFR 55.59 or 10 CFR 50.120, describe the schedule for implementing it.*

Response

Not applicable

References

1. "Operating Agreement of PJM Interconnection, LLC," revised through February 6. 2006

2. "Consolidated Transmission Owners Agreement," effective March 19, 2006

3. PJM Manual 01, "Control Center Requirements," Revision 10, effective February 7, 2006

4. PJM Manual 3, "Transmission Operations," Revision 20, effective February 10, 2006

5. PJM Manual 13, "Emergency Operations," Revision 24, effective February 22, 2006

6. 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

7. EGC procedure WC-AA-8000, "Interface Procedure between Exelon Energy Delivery (ComEd/PECO) and Exelon Generation (Nuclear/Power) for Construction and Maintenance Activities," Revision 0

8. EGC procedure WC-AA-101, "On-Line Work Control Process," Revision 11

9. NUREG/CR-6890, Volume 1, "Reevaluation of Station Blackout Risk at Nuclear Power Plants – Analysis of Offsite Power Events: 1986-2004," Revision 0

10. OP-AA-108-107-1002, "Interface Agreement between Exelon Energy Delivery and Exelon Generation for Switchyard Operations," Revision 2

11. PJM Manual 36, "System Restoration," Revision 2, effective November 1, 2005

12. PJM Manual 10, "Pre-Scheduling Operations," Revision 18, effective August 10, 2005

13. Regulatory Guide 1.155, "Station Blackout," Revision 0

14. "Affiliate Level Arrangement ('ALA') by and among Exelon Energy Delivery Groups of PECO and Exelon Generation Company, LLC," effective January 1, 2006

15. "Interconnection Agreement by and between PECO Energy Company, LLC and Exelon Energy Company, LLC for the Limerick Generating Station," dated January 12, 2001

16. NRC Information Notice IN 93-17, "Safety Systems Response to Loss of Coolant and Loss of Offsite Power," Revision 1, dated March 25, 1994

17. SECY-05-0219, "Issuance of Nuclear Regulatory Commission Generic Letter 2005-XX, 'Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power,'" dated December 2, 2005

18. LGS operating procedure S92.1.0, "Local and Remote Manual Startup of a Diesel Generator, GP-5"

19. LGS Abnormal Operating Procedure ON-126, "Uncontrolled Main Generator Hydrogen Depressurization"

20. LGS Emergency Operating Procedure E-5, "Grid Emergency"

21. LGS Emergency Operating Procedure E-10/20, "Loss of Offsite Power"

22. LGS Emergency Operating Procedure E-1, "Loss of all AC Power"

23. LGS Emergency Operating Procedure S91.0.B, "Alternate Offsite Source Implementation"

24. LGS Emergency Operating Procedure S32.3, "Main Generator Inspection During Heavy Grid Load"

25. EGC procedure WC-AA-107, "Seasonal Readiness," Revision 2

26. SOER 99-1, "Loss of Grid," December 27, 1999

27. SOER 99-1, "Loss of Grid – Addendum," December 9, 2004

28. Jennifer Sterling, Exelon Transmission Planning, "NRC Generic Letter – Draft responses to questions 1 and 2," February 14, 2006, personal email to John Gyrath, Exelon Nuclear, (February 14, 2006)

ATTACHMENT 7

60-day Response to NRC Generic Letter 2006-02

OYSTER CREEK GENERATING STATION

FOL No. DPR 16

ATTACHMENT 7
60-day Response to NRC Generic Letter 2006-02,
OYSTER CREEK GENERATING STATION

On February 1, 2006, the NRC issued Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power." 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 Generic Letter requested that licensees answer the following questions and provide the information to the NRC with respect to each of their Nuclear Power Plants (NPPs).

Use of protocols between the NPP licensee and the TSO, ISO, or RC/RA and the use of analysis tools by TSOs to assist NPP licensee in monitoring grid conditions to determine the operability of offsite power system under plant TS.

GDC 17, 10 CFR Part 50, Appendix A, requires that licensees minimize the probability of the loss of power from the transmission network given a loss of the power generated by the nuclear power unit(s).

1. *Use of protocols between the NPP licensee and the TSO, ISO, or RC/RA to assist the NPP licensee in monitoring grid conditions to determine the operability of offsite power system under plant TS.*

   (a) Do you have a formal agreement or protocol with your TSO?

   Response

   Yes

   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.

   All members of PJM execute the "Operating Agreement of PJM Interconnection, LLC," (Reference 1) that details the obligations and responsibilities of both PJM and the PJM members. In the Operating Agreement, each member agrees to abide by the requirements contained in the PJM Manuals. The PJM Manuals contain the specific operational requirements that PJM and each member is required to follow.

   FirstEnergy (i.e., the TO) is also a signatory on the "PJM Consolidated Transmission Owners Agreement (PJM TOA)," (Reference 2). Section 4.5 of the PJM TOA requires the TOs to operate and maintain their transmission facilities in accordance with the PJM Manuals.

   The PJM Operating Agreement requires PJM to, "Incorporate the grid reliability requirements applicable to nuclear generating units in the PJM Region planning and operating principles and practices." PJM Manual M01, "Control Center Requirements," Attachment B, "Nuclear Plant Communication Protocol," (Reference 3), provides the roles and responsibilities of nuclear stations, TOs, and PJM with regard to communications both in normal and emergency circumstances. The nuclear power plant (NPP) notification requirements are contained in PJM Manual M3, "Transmission Operations," Section 3 (Reference 4).

In addition to the agreements delineated in the PJM Operating Agreement and the PJM Manuals, OCGS has an Interconnection Agreement with the TO (i.e., FirstEnergy) that provides for interconnection service (Reference 12). The Interconnection Agreement contains the requirement for the TO to monitor the NPP offsite source voltages and notify OCGS of any limit violations.

Note that FirstEnergy is synonymous with Jersey Central Power and Light Company as documented in Reference 12.

(b) Describe any grid conditions that would trigger a notification from the TSO to the NPP licensee and if there is a time period required for the notification.

Response

PJM Manual M3 (Reference 4) requires PJM to initiate notification to OCGS through the TO's control center if PJM identifies a switchyard voltage violation. PJM Manual M3 states: "This notification should occur within 15 minutes for voltage contingency violations and immediately for actual voltage violations. To the extent practical, PJM shall direct operations such that the violation is remedied within 30 minutes."

In addition, PJM Manual M13, "Emergency Operations," (Reference 5) identifies a series of alerts, warnings, and actions that PJM issues to PJM members depending on the identified grid condition. The PJM message is communicated to OCGS by their generation dispatcher for a variety of system conditions including the following:

Capacity Emergencies
- Maximum Emergency Generation Loading
- Load Management Curtailment
- Manual Load Dump Warning

Light Load Emergencies
- Minimum Generation Emergency
- Local Minimum Generation Emergency

Weather/Environmental Emergencies
- Hot/Cold Weather Alerts
- Thunderstorms and Tornadoes
- Solar Magnetic Disturbances

Sabotage/Terrorism Emergencies

(c) Describe any grid conditions that would cause the NPP licensee to contact the TSO. Describe the procedures associated with such a communication. If you do not have procedures, describe how you assess grid conditions that may cause the NPP licensee to contact the TSO.

Response

As required by PJM Manuals, communications between OCGS and PJM (TSO) are generally through the Transmission Owner (TO) providing the interconnection service.

OCGS will contact the TSO/TO for grid conditions that have parameters that are observable at the NPP. These conditions include the following:

- Loss of Offsite Power (LOOP)
- Abnormal switchyard voltage
- Automatic (protective) switchyard circuit breaker operation
- Switchyard alarms
- Grid disturbances (observable frequency or voltage fluctuations)

In addition to any alarm response procedures for the above applicable conditions, TSO/TO notifications are controlled by Abnormal Operating Procedures, (e.g., ABN-36, "Loss of Offsite Power," ABN-60, "Grid Emergency," and ABN-12, "Generator Excitation Equipment Malfunction").

OCGS will contact the TSO/TO during a grid restoration process to obtain grid status in preparation for returning the plant buses to the offsite source.

OCGS also notifies the TSO/TO of switchyard equipment deficiencies identified by NPP personnel. Procedure OP-OC-108-107-1002, "Interface Between FirstEnergy, JCP&L and Exelon Generation for OC Switchyard Operations," (Reference 13) identifies the communication protocols between OCGS and the TO for station identified switchyard deficiencies.

In addition, OCGS will notify the TSO/TO of NPP configurations that potentially impact grid conditions. Procedure OP-OC-108-107-1001,"Off Site Power Availability and Switchyard Control" (Reference 14) identifies the requirements for communication between OCGS and the TO of the conditions listed below:

- NPP MVAR limitations
- NPP Main generator voltage regulator not in "Automatic" mode
- NPP inability to provide the MVARs requested by the TSO/TO

Note that any OCGS MW limitations or limitations on the rate at which the NPP power may be raised or lowered are communicated to the generation dispatcher.

(d) Describe how NPP operators are trained and tested on the use of the procedures or assessing grid conditions in question 1(c).

Response

OCGS licensed operators are trained and tested in accordance with the Systematic Approach to Training (SAT). Procedures and policies are routinely reviewed for training through this process for improvement of operator performance. The items considered for training include Operating Procedures, Annunciator Response Procedures, Abnormal

Operating Procedures, and Emergency Operating Procedures that require interface with the TSO in accordance with the established protocol. These procedures may be utilized based on various grid, switchyard, or plant symptoms to assess, respond to or mitigate off-normal plant and grid conditions. Additionally, SOER 99-01, "Loss of Grid," (Reference 21) and SOER 99-01, "Loss of Grid – Addendum," (Reference 22) specifically are captured in the Licensed Operator Requalification Training Program (LORT) Long Range Training Program. These topics, in varying detail based upon the SAT process or as part of implementing EGC procedure WC-AA-107, "Seasonal Readiness," (Reference 20) are reviewed periodically with OCGS operators. Testing is commensurate with the material presented and any performance issues are identified for inclusion in future training.

(e) If you do not have a formal agreement or protocol with your TSO, describe why you believe you continue to comply with the provisions of GDC 17 as stated above, or describe what actions you intend to take to assure compliance with GDC 17.

Response

Not applicable. Formal agreements exist for OCGS.

(f) If you have an existing formal interconnection agreement or protocol that ensures adequate communication and coordination between the NPP license and the TSO, describe whether this agreement or protocol requires that you be promptly notified when the conditions of the surrounding grid could result in degraded voltage (i.e., below TS nominal trip setpoint value requirements; including NPP licensees using allowable value in its TSs) or LOOP after a trip of the reactor units(s).

Response

PJM Manual M3 (Reference 4) requires PJM to initiate a notification to OCGS through its respective transmission owner's control center if PJM identifies a NPP switchyard voltage violation. PJM Manual M3 states: "This notification should occur within 15 minutes for voltage contingency violations and immediately for actual voltage violations. To the extent practical, PJM shall direct operations such that the violation is remedied within 30 minutes." The trip of a NPP is one of the contingencies analyzed by PJM. PJM analyzes the OCGS switchyard contingency voltages to the voltage limits provided by OCGS. The voltage limits provided for OCGS are based on the existing design basis analysis.

(g) Describe the low switchyard voltage conditions that would initiate operation of plant degraded voltage protection.

Response

Switchyard voltage below a value maintaining emergency bus voltage above the maximum reset value of the degraded voltage relay (3882 volts) will cause a trip of the preferred power source after a time delay of approximately 10 seconds. The relation between the switchyard voltage and the emergency bus voltage is dependent on the system auxiliary transformer impedance and the winding load. Under design basis accident (i.e., Large Break LOCA) conditions, the maximum loading is known and contained in the OCGS calculations of record. As the offsite sources are powered through induction voltage regulators (that provide a 10% voltage boost), pre-unit trip switchyard voltage of 227 kV will ensure that safety-related loads are not lost during load sequencing.

In other conditions, the loading is less than the expected LOCA loading and will vary considerably depending on which loads are needed to support unit conditions. Under these conditions the required OCGS switchyard voltage will be less than that required to support LOCA loading.

2. *Use of criteria and methodologies to assess whether the offsite power system will become inoperable as a result of a trip of your NPP.*

(a) Does your NPP's TSO use any analysis tools, an online analytical transmission system studies program, or other equivalent predictive methods to determine the grid conditions that would make the NPP offsite power system inoperable during various contingencies? If available to you, please provide a brief description of the analysis tool that is used by the TSO.

Response

Yes

The PJM Energy Management System (EMS) includes a Security Analysis application which runs approximately every 1 minute and analyzes ~4,000 contingencies on the PJM system (Reference 6). The analysis provides results with respect to thermal, voltage, and voltage drop limit violations. One of the contingencies analyzed by the PJM EMS is the trip of a NPP (i.e., OCGS).

In addition, FirstEnergy (i.e., the TO) possesses a similar system that also calculates post-contingency voltage limit violations. One of the contingencies analyzed by FirstEnergy is the trip of OCGS.

(b) Does your NPP's TSO use an analysis tool as the basis for notifying the NPP licensee when such a condition is identified? If not, how does the TSO determine if conditions on the grid warrant NPP licensee notification?

Response

Yes

The results of the PJM Security Analysis application contain the specific contingency of the NPP tripping as the contingent element. Violation of the unit trip contingency voltage limit would result in notification of the NPP (i.e., OCGS) in accordance with PJM Manual M3, Section 3 (Reference 4).

FirstEnergy (i.e., the TO) also possesses similar capability to monitor the same condition.

(c) If your TSO uses an analysis tool, would the analysis tool identify a condition in which a trip of the NPP would result in switchyard voltages (immediate and/or long-term) falling below TS nominal trip setpoint value requirements (including NPP licensees using allowable value in its TSs) and consequent actuation of plant degraded voltage protection? If not, discuss how such a condition would be identified on the grid.

Response

Yes

The trip of the NPP (i.e., OCGS) is one of the contingencies analyzed by the PJM Security Analysis application. PJM analyzes the NPP switchyard contingency voltages to the voltage limits provided by OCGS. The voltage limits provided by OCGS are based on the plant's design basis analysis as discussed in the response to 1(g).

FirstEnergy (i.e., the TO) also possesses similar capability to monitor the same condition.

(d) If your TSO uses an analysis tool, how frequently does the analysis tool program update?

Response

The PJM EMS includes a Security Analysis application that currently updates approximately every 1 minute. In addition, FirstEnergy (i.e., the TO) possesses a Security Analysis application that updates approximately every 2 minutes (Reference 23).

(e) Provide details of analysis tool-identified contingency conditions that would trigger an NPP licensee notification from the TSO.

Response

PJM notifies OCGS through the TO (i.e., FirstEnergy) control center whenever actual or post-contingency voltages are determined to be below the OCGS switchyard voltage limits. This requirement applies to all contingencies involving the tripping of the NPP or any transmission facility as the contingent element. In accordance with PJM Manual M3 (Reference 4) the notification is required even if the voltage limits are the same as the standard PJM voltage limits.

(f) If an interface agreement exists between the TSO and the NPP licensee, does it require that the NPP licensee be notified of periods when the TSO is unable to determine if offsite power voltage and capacity could be inadequate? If so, how does the NPP licensee determine that the offsite power would remain operable when such a notification is received?

Response

Yes

OCGS unit trip contingency voltage calculations are performed by the PJM EMS and the TO (i.e., FirstEnergy) Security Analysis application. The PJM EMS consists of a primary and backup system. If the PJM EMS fails, the FirstEnergy Security Analysis application continues to analyze the OCGS unit trip contingency voltage. OCGS will be notified if the real time contingency analysis capability of PJM and the TO (i.e., FirstEnergy) are lost simultaneously in accordance with PJM Manual M01, Section 2 (Reference 3).

If OCGS is notified that PJM and FirstEnergy (i.e., the TO) have both lost their real time contingency analysis capability, OCGS would request PJM and FirstEnergy to provide an assessment of the current condition of the grid based on the tools that PJM and FirstEnergy have available. The determination of the operability of the offsite sources would consider the assessment provided by PJM and FirstEnergy and whether the current condition of the grid is bounded by the grid studies previously performed for OCGS.

(g) After an unscheduled inadvertent trip of the NPP, are the resultant switchyard voltages verified by procedure to be bounded by the voltages predicted by the analysis tool?

Response

No

There is presently no formal process for comparing the actual post-trip voltages to the post-trip contingency voltage results calculated by the PJM and the TO (i.e., FirstEnergy) Security Analysis applications.

PJM provided the following information to EGC regarding this response in a letter from PJM to all PJM nuclear owners (Reference 6).

"Because the PJM transmission owning member companies have similar Security Analysis programs to PJM, there are many opportunities to compare the results of the respective Security Analysis programs. In this manner, there is a high confidence that the Security Analysis results are accurate within the precision of the calculations.

PJM retains the EMS results for a period of approximately 3 weeks after real time. It is possible to use those saved EMS results to repeat the Security Analysis calculations and compare them to the actual voltages from a unit trip. However, the NPP trips occur so infrequently that it would take a number of data points to verify the accuracy with any statistical significance. This process could take years if the process is limited to a comparison of only NPP trips."

(h) If an analysis tool is not available to the NPP licensee's TSO, do you know if there are any plans for the TSO to obtain one? If so, when?

Response

Not applicable. OCGS TSO (i.e., PJM) has an analysis tool.

(i) If an analysis tool is not available, does your TSO perform period studies to verify that adequate offsite power capability, including adequate NPP post-trip switchyard voltages (immediate and/or long-term), will be available to the NPP licensee over the projected timeframe of the study?

Response

Not applicable. OCGS TSO (i.e., PJM) has an analysis tool.

(a) Are the key assumptions and parameters of these periodic studies translated into TSO guidance to ensure that the transmission system is operated within the bounds of the analyses?

Response

Not applicable. OCGS TSO (i.e., PJM) has an analysis tool.

(b) If the bounds of the analyses are exceeded, does this condition trigger the notification provisions discussed in question 1 above?

Response

Not applicable. OCGS TSO (i.e., PJM) has an analysis tool.

(j) If your TSO does not use, or you do not have access to the results of an analysis tool, or your TSO does not perform and make available to you periodic studies that determine the adequacy of offsite power capability, please describe why you believe you comply with the provisions of GDC 17 as stated above, or describe what compensatory actions you intend to take to ensure that the offsite power system will be sufficiently reliable and remain operable with high probability following a trip of your NPP.

Response

Not applicable. OCGS TSO (i.e., PJM) has an analysis tool. In addition the applicable contingency voltage results are made available to OCGS as needed.

3. *Use of criteria and methodologies to assess whether the NPP's offsite power system and safety-related components will remain operable when switchyard voltages are inadequate.*

(a) If the TSO notifies the NPP operator that a trip of the NPP, or the loss of the most critical transmission line or the largest supply to the grid would result in switchyard voltages (immediate and/or long-term) below TS nominal trip setpoint value requirements (including NPP licensees using allowable value in its TSs) and would actuate plant degraded voltage protection, is the NPP offsite power system declared inoperable under the plant TSs? If not, why not?

Response

If the TSO (i.e., PJM) notifies OCGS that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., OCGS) is below the pre-determined notification value, OCGS will review the applicability to the plant operating configuration and will declare the offsite power source inoperable in accordance with Technical Specifications (TSs) if appropriate. The notification value provided to PJM by OCGS is based on the OCGS degraded voltage design basis analysis.

Predicted contingency voltages following the loss of a transmission facility (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 for OCGS at this time. If the TSO (i.e., PJM) notifies OCGS of a predicted contingency voltage violation resulting from the postulated trip of a transmission facility, OCGS will perform a risk analysis of in progress and scheduled plant work and will take action as appropriate.

The NPP unit trip contingency can be caused by plant-centered events. The use of the NPP unit trip contingency as the contingency element upon which offsite power operability is based is consistent with the final paragraph of General Design Criterion (GDC) 17, "Electric power systems," of 10 CFR Part 50 Appendix A, "General Design Criteria for Nuclear Power Plants," which requires provisions be included to minimize the probability of the loss of power from the transmission network given a loss of the power generated by the NPP (i.e., OCGS).

Postulated contingencies on the transmission system are currently not used as the basis for offsite source operability determinations since loss of power from the transmission network would not occur as a result of loss of power generated by a NPP unit (i.e., OCGS). Such events (e.g., loss of a transmission line) are only postulated and have not actually occurred, and the offsite power sources remain capable of supporting a safe shutdown and mitigating the effects of an accident. Loss of power from the transmission network would not occur as a result of loss of power generated by a NPP unit and therefore the GDC 17 provision discussed in GL 2006-02 is met.

(b) If onsite safety-related equipment (e.g., emergency diesel generators or safety-related motors) is lost when subjected to a double sequencing (LOCA with delayed LOOP event) as a result of the anticipated system performance and is incapable of performing its safety functions as a result of responding to an emergency actuation signal during this condition, is the equipment considered inoperable? If not, why not?

Response

Although some features have been incorporated into the plant design, requirements for analysis and design considerations for double sequencing are not included within the OCGS current licensing and design basis as documented in the OCGS Updated Final Safety Analysis Report (UFSAR). OCGS has not been explicitly analyzed for all issues associated with double sequencing. Onsite safety-related equipment at OCGS (e.g., emergency diesel generators or safety-related motors) is not declared inoperable as a result of a TSO (i.e., PJM) unit trip contingency voltage notification.

Based on Enclosure 2 of SECY-05-0219, "Issuance of Nuclear Regulatory Commission Generic Letter 2005-XX, 'Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power,'" (Reference 16) which provided NRC guidance on responding to this issue, a review was performed for OCGS of the loading logic for the diesel generators as well as the safety-related breakers' anti-pumping logic. This review concluded that onsite safety-related equipment (i.e., emergency diesel generators or safety-related motors) is not lost as a result of diesel generator block loading and breaker lockout from anti-pump circuitry when subjected to a double sequencing event resulting from inadequate post unit trip voltages. The scope of the review performed for OCGS is discussed in the response to question 3(c) below.

(c) Describe your evaluation of onsite-related equipment to determine whether it will operate as designed during the condition described in question 3(b).

Response

Although some features have been incorporated into the plant design, requirements for analysis and design considerations for double sequencing are not included within the OCGS current licensing and design basis as documented in the OCGS UFSAR. OCGS has not been explicitly analyzed for all issues associated with double sequencing. However, using the NRC clarification provided in Enclosure 2 of SECY-05-0219 as guidance, a review was performed for the purpose of addressing question 3(b).

This review examined the effects of a double sequencing event on diesel generator block loading and the potential for breaker lockout from the anti-pump circuitry. The review assumed that following a LOCA initiation, separation occurred as a result of degraded voltage relay operation triggered by the loss of OCGS. The review examined the diesel generator loading logic and determined that the logic is reset by the LOOP event. The second sequence is consistent with that described in the OCGS UFSAR for a LOOP/LOCA event. Loads are shed as a result of the LOOP signal and the loads are not block loaded onto the diesel generator.

The review also examined the potential for breaker lockout due to the anti-pumping circuitry. This review determined that there was sufficient time between the two sequences such that the breaker charging springs would re-charge and the second closure would be successful. To ensure that a breaker lockout would not occur, the breaker closing logics were also examined to assure that the trip signals were cleared before the second close signal was initiated.

(d) If the NPP licensee is notified by the TSO of other grid conditions that may impair the capability or availability of offsite power, are any plant TS action statements entered? If so, please identify them.

Response

As discussed in the response to 3(a), if the TSO (i.e., PJM) notifies OCGS that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., OCGS) is below the pre-determined notification value, OCGS will review the applicability to the plant operating configuration and will declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by OCGS is based on the OCGS degraded voltage design basis analysis.

- If PJM notifies OCGS that the actual offsite power source voltage is less than the pre-determined notification value, OCGS will review the applicability to the plant operating configuration and would declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by OCGS is based on the OCGS degraded voltage design basis analysis.

If PJM or FirstEnergy notifies OCGS that less than two transmission/distribution lines are fully operational, TS require that the reactor be placed in Cold Shutdown. In accordance with OCGS TS, at least one out of three 230 kV lines and either an additional 230 kV line or a 34.5 kV distribution line be fully operational.

(e) If you believe your plant TSs do not require you to declare your offsite power system or safety-related equipment inoperable in any of these circumstances, explain why you believe you comply with the provisions of GDC 17 and your plant TSs, or describe what compensatory actions you intend to take to ensure that the offsite power system and safety-related components will remain operable when switchyard voltages are inadequate.

Response

The following notifications from the TSO (i.e., PJM) will result in OCGS declaring the offsite power source inoperable in accordance with TSs.

- If the TSO (i.e., PJM) notifies OCGS that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., OCGS) is below the pre-determined notification value, OCGS will review the applicability to the plant operating configuration and will declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by OCGS is based on the OCGS degraded voltage design basis analysis.

- If the TSO (i.e., PJM) notifies OCGS that the actual offsite power source voltage is less than the pre-determined notification value, OCGS will review the applicability to the plant operating configuration and would declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by OCGS is based on the OCGS degraded voltage design basis analysis.

Predicted contingency voltages following the loss of a transmission facility (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. If the TSO notifies the NPP of a predicted contingency voltage violation resulting from the postulated trip of a transmission facility, the NPP performs a risk analysis of in-progress and scheduled plant work and takes action as appropriate.

The NPP unit trip contingency can be caused by plant-centered events. The use of the NPP unit trip contingency as the contingency element upon which offsite power operability is based is consistent with the final paragraph of GDC 17 which requires provisions to minimize the probability of the loss of power from the transmission network given a loss of the power generated by the NPP.

Postulated contingencies on the transmission system are not used as the basis for offsite source operability determinations since loss of power from the transmission network would not occur as a result of loss of power generated by the NPP unit. Such events (e.g., loss of a transmission line) are only postulated and have not actually occurred, and the offsite power sources remain capable of affecting a safe shutdown and mitigating the effects of an accident. The GDC 17 provision discussed in the Generic Letter is still met; loss of power from the transmission network would not occur as a result of loss of power generated by the NPP unit.

Onsite safety-related equipment at OCGS (e.g., emergency diesel generators or safety-related motors) is not declared inoperable as a result of a TSO (i.e., PJM) unit trip contingency voltage notification. Although some features have been incorporated into the plant design, requirements for analysis and design considerations for double sequencing are not included within the OCGS current licensing and design basis as documented in the OCGS UFSAR. OCGS has not been explicitly analyzed for all issues associated with double sequencing.

(f) Describe if and how NPP operators are trained and tested on the compensatory actions mentioned in your answers to questions 3(a) through (e).

<u>Response</u>

OCGS licensed operators are trained and tested in accordance with the Systematic Approach to Training (SAT). Equipment operability, as defined by TS, including normal and emergency power, offsite circuits, and safety-related components, is under continuous review. Procedures are in place to provide operator guidance and required actions necessary during predicted or actual degraded grid voltage conditions based on information provided by the TSO/TO in accordance with established protocol or as observed by the NPP operator. As part of initial training, requalification training, and annual operating tests, licensed operators are subjected to written examinations, dynamic learning activities, static and/or simulator examinations, Job Performance Measures (JPMs), and evaluated simulator scenarios incorporating topics including the actual or predicted switchyard voltage issues and its effect on AC Source operability. Testing is commensurate with the material presented and any performance issues are identified for inclusion in future training.

4. *Use of criteria and methodologies to assess whether the offsite power system will remain operable following a trip of your NPP.*

(a) Do the NPP operators have any guidance or procedures in plant TS bases sections, the final safety analysis report, or plant procedures regarding situations in which the condition of plant-controlled or monitored equipment (e.g., voltage regulator, auto tap changing transformers, capacitors, static VAR compensators, main generator voltage

regulators) can adversely affect the operability of the NPP offsite power system? If so, describe how the operators are trained and tested on the guidance and procedures.

Response

Yes

OCGS plant controlled or monitored equipment that can adversely affect the operability of the offsite power system is limited to the main generator voltage regulators and startup transformers induction voltage regulators. EGC and plant specific procedures provide guidance for notification of the TSO/TO (i.e., PJM/FirstEnergy) when the voltage regulator is not in automatic.

OCGS procedures direct operator actions to control excitation in manual or other mitigating actions to control excitation. Operator actions on a loss of automatic control of the voltage regulator include the requirement to notify the TO (i.e., FirstEnergy) of the failure.

When the plant is operating and auxiliary power is being provided by the auxiliary transformer voltage control is provided by the main generator excitation system. If auxiliary power is being provided by the startup transformers, induction voltage regulators connected to the 34.5 kV side automatically accommodate voltage fluctuations in the sub-transmission network, providing 20% regulation to maintain proper voltage under normal and contingency system conditions. Three single phase regulators, each rated 667 kVA, 19.92 kV, with regulation in 32 steps of 5/8 % are connected to each startup transformer.

OCGS TS Bases Section 3.7, "Auxiliary Electrical Power", discusses availability requirements for the off-site sources. AC power for shutdown and operation of engineered safety feature equipment can be provided by any of three active (one or two 230 KV lines: N-line or O-line, the 230 KV S-line, and one of two 34.5 KV lines is active) and either of two standby (two diesel generators) sources of power. In applying the minimum requirement of one active and one standby source of AC power, since two 230 KV lines are on the same set of towers, either one or both of the 230 KV lines (N-line or O-Line) are considered as a single active source. However, to provide for maintenance and repair of equipment and still have redundancy of power sources the requirement of one active and one standby source of power was established. OCGS' main generator is not given credit as a source since it is not available during shutdown.

In addition, voltage support is provided first by use of either or both capacitor banks in the Oyster Creek 34.5 kV substation, which is under direct control of the TO (i.e., FirstEnergy), followed by operation of the load tap changers (LTCs) on the 230 kV/34.5 kV transformer banks feeding the 34.5 kV substation which is also under the direct control of the TO (i.e., FirstEnergy). When the additional support is no longer needed the LTCs are first returned to normal and then the capacitors are deenergized.

OCGS licensed operators are trained and tested in accordance with the Systematic Approach to Training (SAT). Procedures and policies are routinely reviewed for training through this process for improvement of operator performance. The items considered for training include Annunciator Response Procedures, Abnormal Operating Procedures, and Emergency Operating Procedures that require interface with the TSO/TO in accordance with the established protocol. In addition as part of initial training, requalification training, and annual operating tests, licensed operators are subjected to written examinations, static and/or simulator examinations, Job Performance Measures (JPMs), and evaluated simulator scenarios. These evaluations may incorporate topics including the loss of the main generator voltage regulator and actions to mitigate the effect of the failure. Testing is commensurate with the material presented and any performance issues are identified for inclusion in future training.

(b) If your TS bases sections, the final safety analysis report, and plant procedures do not provide guidance regarding situations in which the condition of plant-controlled or monitored equipment can adversely affect the operability of the NPP offsite power system, explain why you believe you comply with the provisions of GDC 17 and the plant TSs, or describe what actions you intend to take to provide such guidance or procedures.

Response

Not applicable

Use of NPP licensee/TSO protocols and analysis tool by TSOs to assist NPP licensees in monitoring grid conditions for consideration in maintenance risk assessments.

The Maintenance Rule (10 CFR 50.65(a)(4)) requires that licensees assess and manage the increase in risk that may result from proposed maintenance activities before performing them.

5. *Performance of grid reliability evaluations as part of the maintenance risk assessments required by 10 CFR 50.65(a)(4).*

(a) Is a quantitative or qualitative grid reliability evaluation performed at your NPP as part of the maintenance risk assessment required by 10 CFR 50.65(a)(4) before performing grid-risk-sensitive maintenance activities? This includes surveillances, post-maintenance testing, and preventive and corrective maintenance that could increase the probability of a plant trip or LOOP or impact LOOP or SBO coping capability, for example, before taking a risk-significant piece of equipment (such as an EDG, a battery, a steam-driven pump, an alternate AC power source) out-of-service?

Response

Yes

Risk is assessed using a process that combines quantitative results from a probabilistic risk assessment (PRA) with a qualitative defense-in-depth model. During the planning and scheduling of work and prior to the execution of work, many factors are assessed for risk including the effect of weather/time of year and grid instability. The combination of unavailable Systems, Structures and Components (SSCs) and planned activities is then assessed in the risk assessment tool. Currently, a procedure update is being implemented to provide additional detail for how to factor grid reliability into the risk assessment tool before taking equipment out of service for planned maintenance.

These procedure changes are currently scheduled to be in place at OCGS by May 15, 2006.

(b) Is grid status monitored by some means for the duration of the grid-risk-sensitive maintenance to confirm the continued validity of the risk assessment and is risk reassessed when warranted? If not, how is the risk assessed during grid-risk-sensitive maintenance?

Response

Yes

Grid status is continually evaluated by PJM using the Security Analysis application. PJM notifies OCGS through its Transmission Operator, (i.e., FirstEnergy), of emergent grid conditions as discussed in the response to 1(b) above. In addition, FirstEnergy (i.e., the TO) is also performing similar monitoring and evaluation. Existing EGC procedures require evaluation of the risk of scheduled online maintenance activities based on conditions such as power grid stability, weather forecast, and current plant system conditions.

(c) Is there a significant variation in the stress on the grid in the vicinity of your NPP site caused by seasonal loads or maintenance activities associated with critical transmission elements? Is there a seasonal variation (or the potential for a seasonal variation) in the LOOP frequency in the local transmission region? If the answer to either question is yes, discuss the time of year when the variations occur and their magnitude.

Response

The base PRA model reflects the yearly average LOOP frequency because seasonal variations that would cause changes to the frequency of a LOOP cannot be accurately predicted. While time related variations are not factored into the base PRA model for OCGS, symptoms of grid stress such as maximum generation conditions, low grid voltage, or severe weather conditions require identification of such dynamic conditions should they occur, and risk management actions are then taken to mitigate the risk or reschedule the work as appropriate.

PJM provided the following information to AmerGen regarding this response in a letter from PJM to all PJM nuclear owners (Reference 6).

"Stress on the grid is manifested in a number of ways. Stress can mean 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.

Regarding the seasonal variability of the stress causers, each has a seasonal component. For example, peak load levels occur at the peak seasons of the summer and winter seasons. While the specific days cannot be predicted, it is known roughly when they will occur. Consequently, maintenance during these times of the year is avoided.

From a transmission system operations perspective, it is the simultaneous combination of stress causers that results in the most difficult operational challenges. For example, experiencing very hot (or cold) weather when we (i.e., PJM) are in the maintenance seasons with a lot of equipment out of service can cause the most severe challenges.

We (i.e., PJM) are aware of the existence of the North American Electric Reliability Council (NERC) and NRC data regarding LOOP frequency. However, it is difficult to assign differential risks to any seasonal variation because of the complexity of the various competing factors, as explained above."

(d) Are known time-related variations in the probability of a LOOP at your plant site considered in the grid-risk-sensitive maintenance evaluation? If not, what is your basis for not considering them?

Response

No

While time related variations are not factored into the base PRA model for OCGS, symptoms of grid stress such as maximum generation conditions, low grid voltage, or severe weather conditions require identification of such dynamic conditions should they occur, and risk management actions are then taken to mitigate the risk or reschedule the work as appropriate.

(e) Do you have contacts with the TSO to determine current and anticipated grid conditions as part of the grid reliability evaluation performed before conducting grid-risk-sensitive maintenance activities?

Response

Yes

The protocol for NPP notification of actual or anticipated grid conditions is outlined in the response to 1(b). Any work performed on the grid risk sensitive equipment is evaluated for risk using these current or anticipated conditions as part of the evaluation prior to performance. Specific contacts for the TSO/TO (i.e., PJM/FirstEnergy) are identified within site specific risk management and assessment procedures. Repeated contact is made at prescribed intervals during scheduling process for grid sensitive activities.

As stated in the response to 1(b), communication is shared between the TSO (i.e., PJM) and OCGS if grid conditions deteriorate from an acceptable level.

(f) Describe any formal agreement or protocol that you have with your TSO to assure that you are promptly alerted to a worsening grid condition that may emerge during a maintenance activity.

Response

As stated in the response to 1(a), OCGS is located in the service territory of PJM. PJM is the TSO for OCGS. The TO providing interconnection services for OCGS is FirstEnergy. AmerGen and FirstEnergy are both members of PJM.

All members of PJM execute the PJM Operating Agreement (Reference 1) that details the obligations and responsibilities of both PJM and the PJM members. In the Operating Agreement, each member agrees to abide by the requirements contained in the PJM Manuals. The PJM Manuals contain the specific operational requirements that PJM and each member is required to follow.

As stated in the response to 1(b), PJM Manual M13 (Reference 5) identifies a series of alerts, warnings, and actions that PJM issues to PJM members depending on the identified grid condition. The PJM message is communicated to OCGS by their generation dispatcher for a variety of system conditions including capacity emergencies, light load emergencies, weather/environmental emergencies or sabotage/terrorism emergencies.

PJM Manual M3 (Reference 4) requires PJM to initiate notification to OCGS through the TO's control center if PJM identifies a switchyard voltage violation. PJM Manual M3 states: "This notification should occur within 15 minutes for voltage contingency violations and immediately for actual voltage violations. To the extent practical, PJM shall direct operations such that the violation is remedied within 30 minutes."

(g) Do you contact your TSO periodically for the duration of the grid-risk sensitive maintenance activities?

Response

No

Communications take place between the TSO (i.e., PJM) through the TO (i.e., FirstEnergy) and OCGS as detailed in the response to 1(b) above if grid conditions deteriorate from an acceptable level. At this time there is no periodic mandated contact between the TSO/TO and OCGS during the duration of grid-risk-sensitive maintenance activities.

(h) If you have a formal agreement or protocol with your TSO, describe how NPP operators and maintenance personnel are trained and tested on this formal agreement or protocol.

Response

OCGS maintenance, operations, and work management personnel associated with schedule development or communicating with the TO (i.e., FirstEnergy) are briefed on TSO/TO interface requirements and expectations but are not formally tested on knowledge retention in this area.

OP-OC-108-107-1002 (Reference 13) outlines the requirements and restrictions associated with work in the switchyard at the station. Operations personnel have been trained on this procedure but are not specifically tested on its content.

(i) If your grid reliability evaluation, performed as part of the maintenance risk assessment required by 10 CFR 50.65(a)(4), does not consider or rely on some arrangement for communication with the TSO, explain why you believe you comply with 10 CFR 50.65(a)(4).

Response

Not applicable

The methods used to integrate grid risk into the quantitative risk evaluation prior to taking equipment out of service for planned maintenance at OCGS rely on communication with the TSO/TO.

(j) If risk is not assessed (when warranted) based on continuing communication with the TSO throughout the duration of grid-risk-sensitive maintenance activities, explain why you believe you have effectively implemented the relevant provisions of the endorsed industry guidance associated with the maintenance rule.

Response

Not applicable

As detailed in the response to 2(a), grid status is continually evaluated by PJM using the Security Analysis application. PJM notifies OCGS through the TO (i.e., FirstEnergy) of emergent grid conditions. In addition, FirstEnergy (i.e., the TO) possesses a similar system and is also monitoring and evaluating grid conditions. Existing EGC procedures require evaluation of the risk of scheduled on line maintenance activities based on conditions such as power grid stability, weather forecast, and current plant system conditions.

(k) With respect to questions 5(i) and 5(j), you may, as an alternative, describe what actions you intend to take to ensure that the increase in risk that may result from proposed grid-risk-sensitive activities is assessed before and during grid-risk-sensitive maintenance activities, respectively.

Response

Not applicable

6. *Use of risk assessment results, including the results of grid reliability evaluations, in managing maintenance risk, as required by 10 CFR 50.65(a)(4).*

(a) Does the TSO coordinate transmission system maintenance activities that can have an impact on the NPP operation with the NPP operator?

Response

Yes

The TSO/TO coordinates transmission system maintenance activities that can have an impact on the NPP (i.e., OCGS) with OCGS.

(b) Do you coordinate NPP maintenance activities that can have an impact on the transmission system with the TSO?

Response

Yes

The NPP (i.e., OCGS) coordinates maintenance activities that can have an impact on the transmission system with the TSO/TO.

(c) Do you consider and implement, if warranted, the rescheduling of grid-risk-sensitive maintenance activities (activities that could (1) increase the likelihood of a plant trip, (ii) increase LOOP probability, or (iii) reduce LOOP or SBO coping capability) under existing, imminent, or worsening degraded grid reliability conditions?

Response

Yes

Existing procedures require deferring work that would render AC power sources unavailable if severe weather is expected. Risk of scheduled on line work is evaluated based on grid conditions, the weather forecast, and current plant systems status. If the risk analysis determines that risk exceeds a predetermined level, then that configuration is not voluntarily entered and schedule changes are made to reduce the risk to an acceptable level.

(d) If there is an overriding need to perform grid-risk-sensitive maintenance activities under existing or imminent conditions of degraded grid reliability, or continue grid-risk-sensitive maintenance when grid conditions worsen, do you implement appropriate risk management actions? If so, describe the actions that you would take. (These actions could include alternate equipment protection and compensatory measures to limit or minimize risk.)

Response

Yes

When any risk significant SSC is made unavailable, actions are taken to protect redundant or diverse SSCs commensurate with the risk significance of the work being performed in accordance with approved procedures.

(e) Describe the actions associated with questions 6(a) through 6(d) above that would be taken, state whether each action is governed by documented procedures and identify

the procedures, and explain why these actions are effective and will be consistently accomplished.

Response

The outage coordination process is documented in the PJM Manuals and agreed to by PJM (i.e., the TSO) and the members. AmerGen and FirstEnergy (i.e., the TO) are both members of PJM. In addition, PJM has computerized tools to track the process throughout its evolution, so that PJM, FirstEnergy and AmerGen are clear what the status is and what the expectations are.

Planned transmission outages are coordinated in accordance with a process detailed in PJM Manual M3, "Transmission Operations," Section 4 (Reference 4). This process requires advanced notice and subsequent PJM approval for all outages to ensure grid reliability. On the outage start day, the system is analyzed one last time by PJM before permitting the equipment to be switched out of service.

Once the equipment is switched out of service, grid status is continually evaluated by the PJM Security Analysis application as detailed in the response to 2(a). In addition, the TO (i.e., FirstEnergy) is performing similar monitoring and evaluation. PJM notifies the NPP (i.e., OCGS) through the TO's control center, as discussed in the response to 1(b).

Interface with the TO (i.e., FirstEnergy) is identified in accordance with OCGS site specific procedure OP-OC-108-107-1002 (Reference 13).

Actions specified in questions 6(c) and 6(d) are specified in the EGC Work Management procedure, WC-AA-101, "On-Line Work Control Process," (Reference 7) and is applicable to OCGS.

(f) Describe how NPP operators and maintenance personnel are trained and tested to assure they can accomplish the actions described in your answers to question 6(e).

Response

OCGS Maintenance, Operations, and Work Management personnel associated with schedule development and/or risk assessment are briefed on procedure expectations but are not formally tested on knowledge retention in this area.

(g) If there is no effective coordination between the NPP operator and the TSO regarding transmission system maintenance or NPP maintenance activities, please explain why you believe you comply with the provisions of 10 CFR 50.65(a)(4).

Response

Not applicable

Effective coordination is directed by PJM (i.e., the TSO) procedures and interface between FirstEnergy (i.e., the TO) and OCGS is identified in accordance with OP-OC-108-107-1002 (Reference 13).

(h) If you do not consider and effectively implement appropriate risk management actions during the conditions described above, explain why you believe you effectively addressed the relevant provisions of the associated NRC-endorsed industry guidance.

<u>Response</u>

Not applicable

Effective and appropriate risk management actions are described in plant procedures and implemented during the conditions described above.

(i) You may, as alternative to questions 6(g) and 6 (h) describe what actions you intend to take to ensure that the increase in risk that may result from grid-risk-sensitive maintenance activities is managed in accordance with 10 CFR 50.65(a)(4).

<u>Response</u>

Not applicable

Offsite power restoration procedures in accordance with 10 CFR 50.63 as developed in Section 2 of RG 1.155.

Pursuant to 10 CFR 50.63, the NRC requires that each NPP licensed to operate to be able to withstand an SBO for a specified duration and recover from the SBO. NRC RG 1.155 gives licensees guidance on developing their approaches for complying with 10 CFR 50.63.

7. Procedures for identifying local power sources[1] that could be made available to resupply your plant following a LOOP event.

Note: Section 2, "Offsite Power," of RG 1.155 (ADAMS Accession No. ML003740034) states:

> *Procedures should include the actions necessary to restore offsite power and use nearby power sources when offsite power is unavailable. As a minimum, the following potential causes for loss of offsite power should be considered:*
>
> - *Grid undervoltage and collapse*
> - *Weather-induced power loss*
> - *Preferred power distribution system faults that could result in the loss of normal power to essential switchgear buses*

(a) Briefly describe any agreement made with the TSO to identify local power sources that could be made available to resupply power to your plant following a LOOP event.

---

[1] *This includes items such as nearby or onsite gas turbine generators, portable generators, hydro generators, and black-start fossil power plants.*

Response

OCGS is located in the service territory of PJM. PJM is the Transmission System Operator (TSO) for OCGS. The Transmission Owner (TO) providing interconnection services for OCGS is FirstEnergy. AmerGen and FirstEnergy are both members of PJM. All members of PJM execute the "Operating Agreement of PJM Interconnection, LLC," (Reference 1) that details the obligations and responsibilities of both PJM and the PJM members. In the Operating Agreement, each member agrees to abide by the requirements contained in the PJM Manuals. The PJM Manuals contain the specific operational requirements that PJM and each member is required to follow.

FirstEnergy (i.e., the TO) is also a signatory on the "PJM Consolidated Transmission Owners Agreement (PJM TOA)," (Reference 2). Section 4.5 of the PJM TOA requires the TOs to operate and maintain their transmission facilities in accordance with the PJM Manuals.

PJM (i.e., the TSO) is responsible for coordinating restoration of all or parts of the bulk power system in the PJM service territory. FirstEnergy (i.e., the TO) is responsible for cooperating and coordinating with PJM and other PJM members during the restoration of all or parts of the bulk power system in the PJM service territory.

PJM Manual M36, "System Restoration," (Reference 9) gives priority to the restoration of offsite power to NPPs (i.e., OCGS) in the PJM service territory. The TSO (i.e., PJM) and the TO (i.e., FirstEnergy) will utilize the best power sources and transmission paths available based on the specific event to restore offsite power since there is no way to accurately predict the extent and characteristics of a specific blackout. The TSO and TO have multiple options available to restore offsite power and these would not be limited to local power sources.

OCGS has an Interconnection Agreement with FirstEnergy (i.e., the TO) that requires use of "best efforts" to restore to service the facilities that they own or control in order to restore the OCGS offsite power circuit back to an operable status (Reference 12).

PJM provided the following information to AmerGen regarding this response in a letter from PJM to all PJM nuclear owners (Reference 6).

"The PJM Restoration Manual (M36) details the process to be followed during a system restoration. The process reiterates the specific offsite power requirements for NPPs:

> 'Offsite power should be restored as soon as possible to nuclear units, both units that had been operating and those that were already offline prior to the system disturbance, without regard to using these units for restoring customer load.'

However, due to the myriad of possible restoration scenarios, no specific power sources to resupply NPPs are identified. The PJM restoration process allows for the fact that the blacked out area may or may not be separated from the remainder of the system. Regardless of the scenario, there is a clear recognition of the importance of restoring an NPP offsite power source.

PJM Manual M36 further states: 'Transmission Owners and Nuclear Power Plants must effectively communicate to keep the Nuclear Power Plant apprised of the anticipated restoration time for offsite power.' The manual also states that for PJM Restoration Drills the objectives should include 'Ensure that all nuclear units have been provided with one offsite source within 4 hours,' and that the PJM Nuclear Generation Owner/Operator Users Group should be debriefed on the drill results.
In support of the restoration objectives outlined in the PJM Restoration Manual (M36), there are generating units designated as critical black-start units electrically close to each of the NPPs. These black start units are required to provide black start capability whenever necessary. The adequacy of black-start resources to support system restoration is managed through a process contained in PJM Manual M10, "PreScheduling Operations," (Reference 10), Section 2. The process ensures the continuous availability of black start units to support the restoration needs of the NPPs even when a designated black start unit is on a planned outage."

(b) Are your NPP operators trained and tested on identifying and using local power sources to resupply your plant following a LOOP event? If so, describe how.

Response

No

OCGS operators are not specifically trained and tested on identifying and using local power sources to resupply the NPP (i.e., OCGS) following a LOOP event. The identification and use of local power sources for OCGS are under the control of PJM (i.e., the TSO) and FirstEnergy (i.e., the TO) in accordance with the procedures and interface agreements described in the response to 7(a). The response to this question does not address the operation of the OCGS alternate AC source established under 10 CFR 50.63, "Loss of all alternating current power," (i.e., Station Blackout (SBO) Rule), for which OCGS operators are trained and tested to identify and use under SBO conditions.

(c) If you have not established an agreement with your plant's TSO to identify local power sources that could be made available to resupply power to your plant following a LOOP event, explain why you believe you comply with the provisions of 10 CFR 50.63, or describe what actions you intend to take to establish compliance.

Response

The identification and use of local power sources for restoration of offsite power to OCGS following a LOOP event are under the control of PJM (i.e., the TSO) and FirstEnergy (i.e., the TO) in accordance with the procedures and interface agreements described in the response to 7(a). Due to the myriad of possible restoration scenarios, no specific power sources to resupply OCGS are identified. The procedures identified by RG 1.155, "Station Blackout," (Reference 11) that include the actions necessary to restore offsite power and the use of nearby power sources are also under the control of PJM and FirstEnergy.

Note that, as detailed in the response to 7(a), both FirstEnergy (i.e., the TO) and PJM (i.e., the TSO) have stated that restoring offsite power to a NPP (i.e., OCGS) is a priority.

The identification and use of local power sources that could be made available to resupply power to the NPP following a LOOP event are not part of the current OCGS operating procedures and training since they are outside of OCGS's direct control.

Losses of offsite power caused by grid failures at a frequency of equal to or greater than once in 20 site-years in accordance with Table 4 of Regulatory Guide 1.155 for complying with 10 CFR 50.63.

Pursuant to 10 CFR 50.63, the NRC requires that each NPP licensed to operate be able to withstand an SBO for a specified duration and recover from the SBO. NRC RG 1.155 gives licensees guidance on developing their approaches to complying with 10 CFR 50.63.

8. Maintaining SBO coping capabilities in accordance with 10 CFR 50.63.

(a) Has your NPP experienced a total LOOP caused by grid failure since the plant's coping duration was initially determined under 10 CFR 50.63?

Response

OCGS has not experienced a total LOOP caused by grid failure since the coping duration was initially determined under 10 CFR 50.63, "Loss of all alternating current power," (i.e., Station Blackout (SBO) Rule). A review of OCGS records including the Licensee Event Report (LER) database from July 1988, when the SBO Rule was added, was performed to make this determination.

This determination is consistent with the data presented in NUREG/CR-6890, Volume 1, "Reevaluation of Station Blackout Risk at Nuclear Power Plants – Analysis of Offsite Power Events: 1986-2004," (Reference 8), Appendix A, "LOOP Event Database," Section A-2, "Data Tables," Table A -1, "Loop Events for 1986-2004, sorted by plant."

In addition, the review of LERs since Reference 8 was issued to present has concluded that there were no additional grid failure based LOOP events during this period.

(b) If so, have you reevaluated the NPP using the guidance in Table 4 of RG 1.155 to determine if your NPP should be assigned to the P3 offsite power design characteristic group?

Response

Not applicable

(c) If so, what were the results of this reevaluation, and did the initially determined coping duration for the NPP need to be adjusted?

Response

Not applicable

(d) If your NPP has experienced a total LOOP caused by grid failure since the plant's coping duration was initially determined under 10 CFR 50.63 and has not been

reevaluated using the guidance in Table 4 of RG 1.155, explain why you believe you comply with the provisions of 10 CFR 50.63 as stated above, or described what actions you intend to take to ensure that the NPP maintains its SBO coping capabilities in accordance with 10 CFR 50.63.

Response

Not applicable

Actions to ensure compliance

9. If you determine that any action is warranted to bring your NPP into compliance with NRC regulatory requirements, including TSs, GDC 17, 10 CFR 50.65(a)(4), 10 CFR 50.63, 10 CFR 55.59 or 10 CFR 50.120, describe the schedule for implementing it.

Response

Not applicable

References

1. "Operating Agreement of PJM Interconnection, LLC," revised through February 6. 2006

2. "Consolidated Transmission Owners Agreement," effective March 19, 2006

3. PJM Manual 01, "Control Center Requirements," Revision 10, effective February 7, 2006

4. PJM Manual 3, "Transmission Operations," Revision 20, effective February 10, 2006

5. PJM Manual 13, "Emergency Operations," Revision 24, effective February 22, 2006

6. 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

7. EGC procedure WC-AA-101, "On-Line Work Control Process," Revision 11

8. NUREG/CR-6890, Volume 1, "Reevaluation of Station Blackout Risk at Nuclear Power Plants – Analysis of Offsite Power Events: 1986-2004," Revision 0

9. PJM Manual 36, "System Restoration," Revision 2, effective November 1, 2005

10. PJM Manual 10, "Pre-Scheduling Operations," Revision 18, effective August 10, 2005

11. Regulatory Guide 1.155, "Station Blackout," Revision 0

12. "Interconnection Agreement for the Oyster Creek Nuclear Generating Station between AmerGen Energy Company, LLC and Jersey Central Power and Light Company d/b/a GPU Energy," dated October 15, 1999

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

14. OCGS procedure OP-OC-108-107-1001,"Off Site Power Availability and Switchyard Control"

15. NRC Information Notice IN 93-17, "Safety Systems Response to Loss of Coolant and Loss of Offsite Power," Revision 1, dated March 25, 1994

16. SECY-05-0219, "Issuance of Nuclear Regulatory Commission Generic Letter 2005-XX, 'Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power,'" dated December 2, 2005

17. OCGS Abnormal Operating Procedure ABN-36, "Loss of Offsite Power"

18. OCGS Abnormal Operating Procedure ABN-60, "Grid Emergency"

19. OCGS Abnormal Operating Procedure ABN-12, "Generator Excitation Equipment Malfunction"

20. EGC procedure WC-AA-107, "Seasonal Readiness," Revision 2

21. SOER 99-1, "Loss of Grid," December 27, 1999

22. SOER 99-1, "Loss of Grid – Addendum," December 9, 2004

23. Jeffrey J. Mackauer, Manager – Transmission Operation Services, FirstEnergy Corporation, "Exelon Nuclear – NRC Generic Letter Response," March 9, 2006, personal email to John Gyrath, Exelon Nuclear, (March 9, 2006)

ATTACHMENT 8

60-day Response to NRC Generic Letter 2006-02

PEACH BOTTOM ATOMIC POWER STATION, Units 2 and 3

Renewed FOL Nos. DPR-44 and DPR-56

ATTACHMENT 8
60-day Response to NRC Generic Letter 2006-02,
PEACH BOTTOM ATOMIC POWER STATION, Units 2 and 3

On February 1, 2006, the NRC issued Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power." 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 Generic Letter requested that licensees answer the following questions and provide the information to the NRC with respect to each of their Nuclear Power Plants (NPPs).

Use of protocols between the NPP licensee and the TSO, ISO, or RC/RA and the use of analysis tools by TSOs to assist NPP licensee in monitoring grid conditions to determine the operability of offsite power system under plant TS.

GDC 17, 10 CFR Part 50, Appendix A, requires that licensees minimize the probability of the loss of power from the transmission network given a loss of the power generated by the nuclear power unit(s).

1. *Use of protocols between the NPP licensee and the TSO, ISO, or RC/RA to assist the NPP licensee in monitoring grid conditions to determine the operability of offsite power system under plant TS.*

   (a) Do you have a formal agreement or protocol with your TSO?

   <u>Response</u>

   Yes

   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.

   All members of PJM execute the "Operating Agreement of PJM Interconnection, LLC," (Reference 1) that details the obligations and responsibilities of both PJM and the PJM members. In the Operating Agreement, each member agrees to abide by the requirements contained in the PJM Manuals. The PJM Manuals contain the specific operational requirements that PJM and each member is required to follow.

   PECO (i.e., the TO) is also a signatory on the "PJM Consolidated Transmission Owners Agreement (PJM TOA)," (Reference 2). Section 4.5 of the PJM TOA requires the TOs to operate and maintain their transmission facilities in accordance with the PJM Manuals.

   The PJM Operating Agreement requires PJM to, "Incorporate the grid reliability requirements applicable to nuclear generating units in the PJM Region planning and operating principles and practices." PJM Manual M01, "Control Center Requirements," Attachment B, "Nuclear Plant Communication Protocol," (Reference 3), provides the roles and responsibilities of nuclear stations, TOs, and PJM with regard to communications both in normal and emergency circumstances. The nuclear power plant (NPP) notification requirements are contained in PJM Manual M3, "Transmission Operations," Section 3 (Reference 4).

In addition to the agreements delineated in the PJM Operating Agreement and the PJM Manuals, EGC has jointly approved interface procedures with the TO that address the monitoring of the offsite source voltages and the notification protocols. EGC procedure OP-AA-108-107-1002, "Interface Agreement between Exelon Energy Delivery and Exelon Generation for Switchyard Operations," (Reference 13) outlines the responsibilities and required work interfacing activities.

(b) Describe any grid conditions that would trigger a notification from the TSO to the NPP licensee and if there is a time period required for the notification.

Response

PJM Manual M3 (Reference 4) requires PJM to initiate notification to PBAPS through the TO's control center if PJM identifies a switchyard voltage violation. PJM Manual M3 states: "This notification should occur within 15 minutes for voltage contingency violations and immediately for actual voltage violations. To the extent practical, PJM shall direct operations such that the violation is remedied within 30 minutes."

In addition, PJM Manual M13, "Emergency Operations," (Reference 5) identifies a series of alerts, warnings, and actions that PJM issues to PJM members depending on the identified grid condition. The PJM message is communicated to PBAPS by their generation dispatcher for a variety of system conditions including the following:

Capacity Emergencies
- Maximum Emergency Generation Loading
- Load Management Curtailment
- Manual Load Dump Warning

Light Load Emergencies
- Minimum Generation Emergency
- Local Minimum Generation Emergency

Weather/Environmental Emergencies
- Hot/Cold Weather Alerts
- Thunderstorms and Tornadoes
- Solar Magnetic Disturbances

Sabotage/Terrorism Emergencies

(c) Describe any grid conditions that would cause the NPP licensee to contact the TSO. Describe the procedures associated with such a communication. If you do not have procedures, describe how you assess grid conditions that may cause the NPP licensee to contact the TSO.

Response

As required by PJM Manuals, communications between PBAPS and PJM (TSO) are generally through the Transmission Owner (TO) providing the interconnection service.

PBAPS will contact the TSO/TO for grid conditions that have parameters that are observable at the NPP. These conditions include the following:

- Loss of Offsite Power (LOOP)
- Abnormal switchyard voltage
- Automatic (protective) switchyard circuit breaker operation
- Switchyard alarms
- Grid disturbances (observable frequency or voltage fluctuations)

In addition to any alarm response procedures for the above applicable conditions, TSO/TO notifications are controlled by operating procedures, (e.g., OP-AA-108-107-1001, "Station Response to Grid Capacity Conditions"), and Special Event Procedures, (e.g., SE-11, "Loss of Offsite Power" and SE-16, "Grid Emergency").

PBAPS will contact the TSO/TO during a grid restoration process to obtain grid status in preparation for returning the plant buses to the offsite source.

PBAPS also notifies the TSO/TO of switchyard equipment deficiencies identified by NPP personnel. Jointly approved interface agreements/procedures between EGC and the TO identify the communication protocols for station identified switchyard deficiencies. EGC procedures OP-AA-108-107-1002 (Reference 13) and WC-AA-8000 (Reference 7) outline the responsibilities and required work interfacing activities.

In addition, PBAPS will notify the TSO/TO of NPP configurations that potentially impact grid conditions. A jointly approved interface agreement/procedure, OP-AA-108-107-1002 (Reference 13), between EGC and the TO identifies the requirements for communication of the conditions listed below:

- NPP MVAR limitations
- NPP Main generator voltage regulator not in "Automatic" mode
- NPP inability to provide the MVARs requested by the TSO/TO

Note that any PBAPS MW limitations or limitations on the rate at which the NPP power may be raised or lowered are communicated to the generation dispatcher.

(d) Describe how NPP operators are trained and tested on the use of the procedures or assessing grid conditions in question 1(c).

<u>Response</u>

PBAPS licensed operators are trained and tested in accordance with the Systematic Approach to Training (SAT). Procedures and policies are routinely reviewed for training through this process for improvement of operator performance. The items considered for training include Administrative Procedures, Alarm Response Cards, Abnormal Operating Procedures, and Special Event Procedures that require interface with the TSO in accordance with the established protocol. These procedures may be utilized based on various grid, switchyard, or plant symptoms to assess, respond to or mitigate off-normal plant and grid conditions. Additionally, SOER 99-01, "Loss of Grid," (Reference 25) and SOER 99-01, "Loss of Grid – Addendum," (Reference 26) specifically are captured in the Licensed Operator Requalification Training Program (LORT) Long Range Training Program. These topics, in varying detail based upon the SAT process or as part of implementing EGC procedure WC-AA-107, "Seasonal Readiness," (Reference 24) are reviewed periodically with PBAPS operators. Testing is commensurate with the material presented and any performance issues are identified for inclusion in future training.

(e) If you do not have a formal agreement or protocol with your TSO, describe why you believe you continue to comply with the provisions of GDC 17 as stated above, or describe what actions you intend to take to assure compliance with GDC 17.

Response

Not applicable. Formal agreements exist for PBAPS.

(f) If you have an existing formal interconnection agreement or protocol that ensures adequate communication and coordination between the NPP license and the TSO, describe whether this agreement or protocol requires that you be promptly notified when the conditions of the surrounding grid could result in degraded voltage (i.e., below TS nominal trip setpoint value requirements; including NPP licensees using allowable value in its TSs) or LOOP after a trip of the reactor units(s).

Response

PJM Manual M3 (Reference 4) requires PJM to initiate a notification to PBAPS through its respective transmission owner's control center if PJM identifies a NPP switchyard voltage violation. PJM Manual M3 states: "This notification should occur within 15 minutes for voltage contingency violations and immediately for actual voltage violations. To the extent practical, PJM shall direct operations such that the violation is remedied within 30 minutes." The trip of a NPP (i.e., trip of a PBAPS unit) is one of the contingencies analyzed by PJM. PJM analyzes the PBAPS switchyard contingency voltages to the voltage limits provided by PBAPS. The voltage limits provided for PBAPS are based on the existing design basis analysis.

(g) Describe the low switchyard voltage conditions that would initiate operation of plant degraded voltage protection.

Response

Switchyard voltage below a value maintaining emergency bus voltage above the setpoint of the degraded voltage relay (≥ 3766 volts and ≤ 3836 volts) will cause a trip of the preferred power source after a time delay of approximately 10 seconds with a Loss of Coolant Accident (LOCA) signal present. The relation between the switchyard voltage and the emergency bus voltage is dependent on the system transformer impedance, the winding load, and transformer auto voltage regulators. Under design basis accident (i.e., Large Break LOCA) conditions, the maximum loading is known and contained in the PBAPS calculations of record. The design basis maximum loading and the degraded voltage relay reset voltage were used to determine the switchyard voltage needed for the system to remain connected to the offsite power source. For PBAPS, this corresponds to a switchyard voltage of approximately 218.5 kV for the 230 kV switchyard and 498 kV for the 525 kV switchyard.

In other conditions, the loading is less than the expected LOCA loading and will vary considerably depending on which loads are needed to support unit conditions. Under these conditions the required PBAPS switchyard voltage will be less than that required to support LOCA loading.

2. *Use of criteria and methodologies to assess whether the offsite power system will become inoperable as a result of a trip of your NPP.*

(a) Does your NPP's TSO use any analysis tools, an online analytical transmission system studies program, or other equivalent predictive methods to determine the grid conditions that would make the NPP offsite power system inoperable during various contingencies? If available to you, please provide a brief description of the analysis tool that is used by the TSO.

Response

Yes

The PJM Energy Management System (EMS) includes a Security Analysis application which runs approximately every 1 minute and analyzes ~4,000 contingencies on the PJM system (Reference 6). The analysis provides results with respect to thermal, voltage, and voltage drop limit violations. One of the contingencies analyzed by the PJM EMS is the trip of a NPP (i.e., trip of a PBAPS unit).

In addition, PECO (i.e., the TO) possesses a similar system that also calculates post-contingency voltage limit violations. One of the contingencies analyzed by PECO is the trip of a PBAPS unit.

(b) Does your NPP's TSO use an analysis tool as the basis for notifying the NPP licensee when such a condition is identified? If not, how does the TSO determine if conditions on the grid warrant NPP licensee notification?

Response

Yes

The results of the PJM Security Analysis application contain the specific contingency of the NPP tripping as the contingent element. Violation of the unit trip contingency voltage limit would result in notification of the NPP (i.e., PBAPS) in accordance with PJM Manual M3, Section 3 (Reference 4).

PECO (i.e., the TO) also possesses similar capability to monitor the same condition.

(c) If your TSO uses an analysis tool, would the analysis tool identify a condition in which a trip of the NPP would result in switchyard voltages (immediate and/or long-term) falling below TS nominal trip setpoint value requirements (including NPP licensees using

allowable value in its TSs) and consequent actuation of plant degraded voltage protection? If not, discuss how such a condition would be identified on the grid.

Response

Yes

The trip of the NPP (i.e., trip of a PBAPS unit) is one of the contingencies analyzed by the PJM Security Analysis application. PJM analyzes the NPP switchyard contingency voltages to the voltage limits provided by PBAPS. The voltage limits provided by PBAPS are based on the plant's design basis analysis as discussed in the response to 1(g).

PECO (i.e., the TO) also possesses similar capability to monitor the same condition.

(d) If your TSO uses an analysis tool, how frequently does the analysis tool program update?

Response

The PJM EMS includes a Security Analysis application that currently updates approximately every 1-minute. In addition, PECO (i.e., the TO) possesses a Security Analysis application that updates approximately every 10 minutes (Reference 27).

(e) Provide details of analysis tool-identified contingency conditions that would trigger an NPP licensee notification from the TSO.

Response

PJM notifies PBAPS through the TO (i.e., PECO) control center whenever actual or post-contingency voltages are determined to be below the PBAPS switchyard voltage limits. This requirement applies to all contingencies involving the tripping of the NPP or any transmission facility as the contingent element. In accordance with PJM Manual M3 (Reference 4) the notification is required even if the voltage limits are the same as the standard PJM voltage limits.

(f) If an interface agreement exists between the TSO and the NPP licensee, does it require that the NPP licensee be notified of periods when the TSO is unable to determine if offsite power voltage and capacity could be inadequate? If so, how does the NPP licensee determine that the offsite power would remain operable when such a notification is received?

Response

Yes

PBAPS unit trip contingency voltage calculations are performed by the PJM EMS and the TO (i.e., PECO) Security Analysis application. The PJM EMS consists of a primary and backup system. If the PJM EMS fails, the PECO Security Analysis application continues to analyze the PBAPS unit trip contingency voltage. PBAPS will be notified if the real time contingency analysis capability of PJM and the TO (i.e., PECO) are lost simultaneously in accordance with PJM Manual M01, Section 2 (Reference 3).

If PBAPS is notified that PJM and PECO (i.e., the TO) have both lost their real time contingency analysis capability, PBAPS would request PJM and PECO to provide an assessment of the current condition of the grid based on the tools that PJM and PECO have available. The determination of the operability of the offsite sources would consider the assessment provided by PJM and PECO and whether the current condition of the grid is bounded by the grid studies previously performed for PBAPS.

(g) After an unscheduled inadvertent trip of the NPP, are the resultant switchyard voltages verified by procedure to be bounded by the voltages predicted by the analysis tool?

Response

No

There is presently no formal process for comparing the actual post-trip voltages to the post-trip contingency voltage results calculated by the PJM and the TO (i.e., PECO) Security Analysis applications.

PJM provided the following information to EGC regarding this response in a letter from PJM to all PJM nuclear owners (Reference 6).

"Because the PJM transmission owning member companies have similar Security Analysis programs to PJM, there are many opportunities to compare the results of the respective Security Analysis programs. In this manner, there is a high confidence that the Security Analysis results are accurate within the precision of the calculations.

PJM retains the EMS results for a period of approximately 3 weeks after real time. It is possible to use those saved EMS results to repeat the Security Analysis calculations and compare them to the actual voltages from a unit trip. However, the NPP trips occur so infrequently that it would take a number of data points to verify the accuracy with any statistical significance. This process could take years if the process is limited to a comparison of only NPP trips."

(h) If an analysis tool is not available to the NPP licensee's TSO, do you know if there are any plans for the TSO to obtain one? If so, when?

Response

Not applicable. PBAPS TSO (i.e., PJM) has an analysis tool.

(i) If an analysis tool is not available, does your TSO perform period studies to verify that adequate offsite power capability, including adequate NPP post-trip switchyard voltages (immediate and/or long-term), will be available to the NPP licensee over the projected timeframe of the study?

Response

Not applicable. PBAPS TSO (i.e., PJM) has an analysis tool.

(a) Are the key assumptions and parameters of these periodic studies translated into TSO guidance to ensure that the transmission system is operated within the bounds of the analyses?

Response

Not applicable. PBAPS TSO (i.e., PJM) has an analysis tool.

(b) If the bounds of the analyses are exceeded, does this condition trigger the notification provisions discussed in question 1 above?

Response

Not applicable. PBAPS TSO (i.e., PJM) has an analysis tool.

(j) If your TSO does not use, or you do not have access to the results of an analysis tool, or your TSO does not perform and make available to you periodic studies that determine the adequacy of offsite power capability, please describe why you believe you comply with the provisions of GDC 17 as stated above, or describe what compensatory actions you intend to take to ensure that the offsite power system will be sufficiently reliable and remain operable with high probability following a trip of your NPP.

Response

Not applicable. PBAPS TSO (i.e., PJM) has an analysis tool. In addition the applicable contingency voltage results are made available to PBAPS as needed.

3. *Use of criteria and methodologies to assess whether the NPP's offsite power system and safety-related components will remain operable when switchyard voltages are inadequate.*

(a) If the TSO notifies the NPP operator that a trip of the NPP, or the loss of the most critical transmission line or the largest supply to the grid would result in switchyard voltages (immediate and/or long-term) below TS nominal trip setpoint value requirements (including NPP licensees using allowable value in its TSs) and would actuate plant degraded voltage protection, is the NPP offsite power system declared inoperable under the plant TSs? If not, why not?

Response

If the TSO (i.e., PJM) notifies PBAPS that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., trip of a PBAPS unit) is below the pre-determined notification value, PBAPS will review the applicability to the plant operating configuration and will declare the offsite power source inoperable in accordance with Technical Specifications (TSs) if appropriate. The notification value provided to PJM by PBAPS is based on the PBAPS degraded voltage design basis analysis.

Predicted contingency voltages following the loss of a transmission facility (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 for PBAPS at this time. If the TSO (i.e., PJM) notifies PBAPS of a predicted contingency voltage violation resulting from the postulated trip of a transmission facility, PBAPS will perform a risk analysis of in progress and scheduled plant work and will take action as appropriate.

The NPP unit trip contingency can be caused by plant-centered events. The use of the NPP unit trip contingency as the contingency element upon which offsite power operability is based is consistent with the final paragraph of General Design Criterion (GDC) 17, "Electric power systems," of 10 CFR Part 50 Appendix A, "General Design Criteria for Nuclear Power Plants," which requires provisions be included to minimize the probability of the loss of power from the transmission network given a loss of the power generated by the NPP (i.e., a PBAPS unit).

Postulated contingencies on the transmission system are currently not used as the basis for offsite source operability determinations since loss of power from the transmission network would not occur as a result of loss of power generated by a NPP unit (i.e., a PBAPS unit). Such events (e.g., loss of a transmission line) are only postulated and have not actually occurred, and the offsite power sources remain capable of supporting a safe shutdown and mitigating the effects of an accident. Loss of power from the transmission network would not occur as a result of loss of power generated by a NPP unit and therefore the GDC 17 provision discussed in GL 2006-02 is met.

(b) If onsite safety-related equipment (e.g., emergency diesel generators or safety-related motors) is lost when subjected to a double sequencing (LOCA with delayed LOOP event) as a result of the anticipated system performance and is incapable of performing its safety functions as a result of responding to an emergency actuation signal during this condition, is the equipment considered inoperable? If not, why not?

Response

Although some features have been incorporated into the plant design, requirements for analysis and design considerations for double sequencing are not included within the PBAPS current licensing and design basis as documented in the PBAPS Updated Final Safety Analysis Report (UFSAR). PBAPS has not been explicitly analyzed for all issues associated with double sequencing. Onsite safety-related equipment at PBAPS (e.g., emergency diesel generators or safety-related motors) is not declared inoperable as a result of a TSO (i.e., PJM) unit trip contingency voltage notification.

Based on Enclosure 2 of SECY-05-0219, "Issuance of Nuclear Regulatory Commission Generic Letter 2005-XX, 'Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power,'" (Reference 20) which provided NRC guidance on responding to this issue, a review was performed for PBAPS of the loading logic for the diesel generators as well as the safety-related breakers' anti-pumping logic. This review concluded that onsite safety-related equipment (i.e., emergency diesel generators or safety-related motors) is not lost as a result of diesel generator block loading and breaker lockout from anti-pump circuitry when subjected to a double sequencing event resulting from inadequate post unit trip voltages. The scope of the review performed for PBAPS is discussed in the response to question 3(c) below.

(c) Describe your evaluation of onsite-related equipment to determine whether it will operate as designed during the condition described in question 3(b).

Response

Although some features have been incorporated into the plant design, requirements for analysis and design considerations for double sequencing are not included within the PBAPS current licensing and design basis as documented in the PBAPS UFSAR. PBAPS has not been explicitly analyzed for all issues associated with double sequencing. However, using the NRC clarification provided in Enclosure 2 of SECY-05-0219 as guidance, a review was performed for the purpose of addressing question 3(b).

This review examined the effects of a double sequencing event on diesel generator block loading and the potential for breaker lockout from the anti-pump circuitry. The review assumed that following a LOCA initiation, separation occurred as a result of degraded voltage relay operation triggered by the loss of a PBAPS unit. The review examined the diesel generator loading logic and determined that the logic is reset by the LOOP event. The second sequence is consistent with that described in the PBAPS UFSAR for a LOOP/LOCA event. Loads are shed as a result of the LOOP signal and the loads are not block loaded onto the diesel generator.

The review also examined the potential for breaker lockout due to the anti-pumping circuitry. This review determined that there was sufficient time between the two sequences such that the breaker charging springs would re-charge and the second closure would be successful. To ensure that a breaker lockout would not occur, the breaker closing logics were also examined to assure that the trip signals were cleared before the second close signal was initiated.

(d) If the NPP licensee is notified by the TSO of other grid conditions that may impair the capability or availability of offsite power, are any plant TS action statements entered? If so, please identify them.

Response

As discussed in the response to 3(a), if the TSO (i.e., PJM) notifies PBAPS that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., trip of a PBAPS unit) is below the pre-determined notification value, PBAPS will review the applicability to the plant operating configuration and will declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by PBAPS is based on the PBAPS degraded voltage design basis analysis.

In addition, if PJM notifies PBAPS that the actual offsite power source voltage is less than the pre-determined notification value, PBAPS will review the applicability to the plant operating configuration and would declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by PBAPS is based on the PBAPS degraded voltage design basis analysis.

(e) If you believe your plant TSs do not require you to declare your offsite power system or safety-related equipment inoperable in any of these circumstances, explain why you believe you comply with the provisions of GDC 17 and your plant TSs, or describe what

compensatory actions you intend to take to ensure that the offsite power system and safety-related components will remain operable when switchyard voltages are inadequate.

Response

The following notifications from the TSO (i.e., PJM) will result in PBAPS declaring the offsite power source inoperable in accordance with TSs.

- If the TSO (i.e., PJM) notifies PBAPS that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., trip of a PBAPS unit) is below the pre-determined notification value, PBAPS will review the applicability to the plant operating configuration and will declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by PBAPS is based on the PBAPS degraded voltage design basis analysis.

- If the TSO (i.e., PJM) notifies PBAPS that the actual offsite power source voltage is less than the pre-determined notification value, PBAPS will review the applicability to the plant operating configuration and would declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by PBAPS is based on the PBAPS degraded voltage design basis analysis.

Predicted contingency voltages following the loss of a transmission facility (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. If the TSO notifies the NPP of a predicted contingency voltage violation resulting from the postulated trip of a transmission facility, the NPP performs a risk analysis of in-progress and scheduled plant work and takes action as appropriate.

The NPP unit trip contingency can be caused by plant-centered events. The use of the NPP unit trip contingency as the contingency element upon which offsite power operability is based is consistent with the final paragraph of GDC 17 which requires provisions to minimize the probability of the loss of power from the transmission network given a loss of the power generated by the NPP.

Postulated contingencies on the transmission system are not used as the basis for offsite source operability determinations since loss of power from the transmission network would not occur as a result of loss of power generated by the NPP unit. Such events (e.g., loss of a transmission line) are only postulated and have not actually occurred, and the offsite power sources remain capable of affecting a safe shutdown and mitigating the effects of an accident. The GDC 17 provision discussed in the Generic Letter is still met; loss of power from the transmission network would not occur as a result of loss of power generated by the NPP unit.

Onsite safety-related equipment at PBAPS (e.g., emergency diesel generators or safety-related motors) is not declared inoperable as a result of a TSO (i.e., PJM) unit trip contingency voltage notification. Although some features have been incorporated into the plant design, requirements for analysis and design considerations for double sequencing are not included within the PBAPS current licensing and design basis as documented in the PBAPS UFSAR. PBAPS has not been explicitly analyzed for all issues associated with double sequencing.

(f) Describe if and how NPP operators are trained and tested on the compensatory actions mentioned in your answers to questions 3(a) through (e).

Response

PBAPS licensed operators are trained and tested in accordance with the Systematic Approach to Training (SAT). Equipment operability, as defined by TS, including normal and emergency power, offsite circuits, and safety-related components, is under continuous review. Procedures are in place to provide operator guidance and required actions necessary during predicted or actual degraded grid voltage conditions based on information provided by the TSO/TO in accordance with established protocol or as observed by the NPP operator. As part of initial training, requalification training, and annual operating tests, licensed operators are subjected to written examinations, dynamic learning activities, static and/or simulator examinations, Job Performance Measures (JPMs), and evaluated simulator scenarios incorporating topics including the actual or predicted switchyard voltage issues and its effect on AC Source operability. Testing is commensurate with the material presented and any performance issues are identified for inclusion in future training.

4. *Use of criteria and methodologies to assess whether the offsite power system will remain operable following a trip of your NPP.*

(a) Do the NPP operators have any guidance or procedures in plant TS bases sections, the final safety analysis report, or plant procedures regarding situations in which the condition of plant-controlled or monitored equipment (e.g., voltage regulator, auto tap changing transformers, capacitors, static VAR compensators, main generator voltage regulators) can adversely affect the operability of the NPP offsite power system? If so, describe how the operators are trained and tested on the guidance and procedures.

Response

Yes

PBAPS plant controlled or monitored equipment that can adversely affect the operability of the offsite power system is limited to the main generator voltage regulators and the 2SU, 3SU and 343SU start-up transformer automatic load tap changers (LTCs). EGC and plant specific procedures provide guidance for notification of the TSO/TO (i.e., PJM/PECO) when the voltage regulator is not in automatic.

PBAPS procedures direct operator actions to control excitation in manual or other mitigating actions to control excitation. Operator actions on a loss of automatic control of the voltage regulator include the requirement to notify the TO (i.e., PECO) of the failure.

The operation of the main generator voltage regulators does not have any direct impact on the operability of the offsite sources. The PBAPS offsite sources are not directly connected to the main generator output or unit auxiliary transformers, but only connected together via the switchyard buses. The TSO is notified whenever the voltage regulators are taken from automatic to manual operation.

PBAPS TS Bases Section 3.8.1, "AC Sources-Operating," discusses operability requirements for the off-site sources. The LTCs and their associated transformers are credited for the operability of the offsite sources. The transformers load tap changers are required to operate automatically to support operability in accordance with TS and TS Bases. The associated offsite source is declared inoperable if the load tap changer is not in automatic and functional. This guidance is addressed in PBAPS procedures. The ability to support offsite source operability is confirmed by observing and reviewing voltages of the transformers, observing the tap changer position in automatic, and by observing the tap changer counters in accordance with station procedures.

PBAPS licensed operators are trained and tested in accordance with the Systematic Approach to Training (SAT). Procedures and policies are routinely reviewed for training through this process for improvement of operator performance. The items considered for training include Annunciator Response Procedures, Abnormal Operating Procedures, and Special Event Procedures that require interface with the TSO/TO in accordance with the established protocol. In addition as part of initial training, requalification training, and annual operating tests, licensed operators are subjected to written examinations, static and/or simulator examinations, Job Performance Measures (JPMs), and evaluated simulator scenarios. These evaluations may incorporate topics including the loss of the main generator voltage regulator and actions to mitigate the effect of the failure. Testing is commensurate with the material presented and any performance issues are identified for inclusion in future training.

(b) If your TS bases sections, the final safety analysis report, and plant procedures do not provide guidance regarding situations in which the condition of plant-controlled or monitored equipment can adversely affect the operability of the NPP offsite power system, explain why you believe you comply with the provisions of GDC 17 and the plant TSs, or describe what actions you intend to take to provide such guidance or procedures.

<u>Response</u>

Not applicable

Use of NPP licensee/TSO protocols and analysis tool by TSOs to assist NPP licensees in monitoring grid conditions for consideration in maintenance risk assessments.

The Maintenance Rule (10 CFR 50.65(a)(4)) requires that licensees assess and manage the increase in risk that may result from proposed maintenance activities before performing them.

5. *Performance of grid reliability evaluations as part of the maintenance risk assessments required by 10 CFR 50.65(a)(4).*

(a) Is a quantitative or qualitative grid reliability evaluation performed at your NPP as part of the maintenance risk assessment required by 10 CFR 50.65(a)(4) before performing grid-risk-sensitive maintenance activities? This includes surveillances, post-

maintenance testing, and preventive and corrective maintenance that could increase the probability of a plant trip or LOOP or impact LOOP or SBO coping capability, for example, before taking a risk-significant piece of equipment (such as an EDG, a battery, a steam-driven pump, an alternate AC power source) out-of-service?

Response

Yes

Risk is assessed using a process that combines quantitative results from a probabilistic risk assessment (PRA) with a qualitative defense-in-depth model. During the planning and scheduling of work and prior to the execution of work, many factors are assessed for risk including the effect of weather/time of year and grid instability. The combination of unavailable Systems, Structures and Components (SSCs) and planned activities is then assessed in the risk assessment tool. Currently, a procedure update is being implemented to provide additional detail for how to factor grid reliability into the risk assessment tool before taking equipment out of service for planned maintenance. These procedure changes are currently scheduled to be in place at PBAPS by May 15, 2006.

(b) Is grid status monitored by some means for the duration of the grid-risk-sensitive maintenance to confirm the continued validity of the risk assessment and is risk reassessed when warranted? If not, how is the risk assessed during grid-risk-sensitive maintenance?

Response

Yes

Grid status is continually evaluated by PJM using the Security Analysis application. PJM notifies PBAPS through its Transmission Operator, (i.e., PECO), of emergent grid conditions as discussed in the response to 1(b) above. In addition, PECO (i.e., the TO) is also performing similar monitoring and evaluation. Existing EGC procedures require evaluation of the risk of scheduled online maintenance activities based on conditions such as power grid stability, weather forecast, and current plant system conditions.

(c) Is there a significant variation in the stress on the grid in the vicinity of your NPP site caused by seasonal loads or maintenance activities associated with critical transmission elements? Is there a seasonal variation (or the potential for a seasonal variation) in the LOOP frequency in the local transmission region? If the answer to either question is yes, discuss the time of year when the variations occur and their magnitude.

Response

The base PRA model reflects the yearly average LOOP frequency because seasonal variations that would cause changes to the frequency of a LOOP cannot be accurately predicted. While time related variations are not factored into the base PRA model for PBAPS, symptoms of grid stress such as maximum generation conditions, low grid voltage, or severe weather conditions require identification of such dynamic conditions should they occur, and risk management actions are then taken to mitigate the risk or reschedule the work as appropriate.

PJM provided the following information to EGC regarding this response in a letter from PJM to all PJM nuclear owners (Reference 6).

"Stress on the grid is manifested in a number of ways. Stress can mean 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.

Regarding the seasonal variability of the stress causers, each has a seasonal component. For example, peak load levels occur at the peak seasons of the summer and winter seasons. While the specific days cannot be predicted, it is known roughly when they will occur. Consequently, maintenance during these times of the year is avoided.

From a transmission system operations perspective, it is the simultaneous combination of stress causers that results in the most difficult operational challenges. For example, experiencing very hot (or cold) weather when we (i.e., PJM) are in the maintenance seasons with a lot of equipment out of service can cause the most severe challenges.

We (i.e., PJM) are aware of the existence of the North American Electric Reliability Council (NERC) and NRC data regarding LOOP frequency. However, it is difficult to assign differential risks to any seasonal variation because of the complexity of the various competing factors, as explained above."

(d) Are known time-related variations in the probability of a LOOP at your plant site considered in the grid-risk-sensitive maintenance evaluation? If not, what is your basis for not considering them?

Response

No

While time related variations are not factored into the base PRA model for PBAPS, symptoms of grid stress such as maximum generation conditions, low grid voltage, or severe weather conditions require identification of such dynamic conditions should they occur, and risk management actions are then taken to mitigate the risk or reschedule the work as appropriate.

(e) Do you have contacts with the TSO to determine current and anticipated grid conditions as part of the grid reliability evaluation performed before conducting grid-risk-sensitive maintenance activities?

Response

Yes

The protocol for NPP notification of actual or anticipated grid conditions is outlined in the response to 1(b). Any work performed on the grid risk sensitive equipment is evaluated for risk using these current or anticipated conditions as part of the evaluation prior to performance. Work is coordinated based on anticipated conditions and planned maintenance during bi-monthly interface meetings between the transmission operator (i.e., PECO) and the EGC NPPs (i.e., PBAPS).

As stated in the response to 1(b), communication is shared between the TSO (i.e., PJM) and PBAPS if grid conditions deteriorate from an acceptable level.

(f) Describe any formal agreement or protocol that you have with your TSO to assure that you are promptly alerted to a worsening grid condition that may emerge during a maintenance activity.

Response

As stated in the response to 1(a), PBAPS is located in the service territory of PJM. PJM is the TSO for PBAPS. The TO providing interconnection services for PBAPS is PECO. EGC and PECO are both members of PJM.

All members of PJM execute the PJM Operating Agreement (Reference 1) that details the obligations and responsibilities of both PJM and the PJM members. In the Operating Agreement, each member agrees to abide by the requirements contained in the PJM Manuals. The PJM Manuals contain the specific operational requirements that PJM and each member is required to follow.

As stated in the response to 1(b), PJM Manual M13 (Reference 5) identifies a series of alerts, warnings, and actions that PJM issues to PJM members depending on the identified grid condition. The PJM message is communicated to PBAPS by their generation dispatcher for a variety of system conditions including capacity emergencies, light load emergencies, weather/environmental emergencies or sabotage/terrorism emergencies.

PJM Manual M3 (Reference 4) requires PJM to initiate notification to PBAPS through the TO's control center if PJM identifies a switchyard voltage violation. PJM Manual M3 states: "This notification should occur within 15 minutes for voltage contingency violations and immediately for actual voltage violations. To the extent practical, PJM shall direct operations such that the violation is remedied within 30 minutes."

(g) Do you contact your TSO periodically for the duration of the grid-risk sensitive maintenance activities?

Response

No

Communications take place between the TSO (i.e., PJM) through the TO (i.e., PECO) and PBAPS as detailed in the response to 1(b) above if grid conditions deteriorate from an acceptable level. At this time there is no periodic mandated contact between the TSO/TO and PBAPS during the duration of grid-risk-sensitive maintenance activities.

(h) If you have a formal agreement or protocol with your TSO, describe how NPP operators and maintenance personnel are trained and tested on this formal agreement or protocol.

Response

PBAPS maintenance, operations, and work management personnel associated with schedule development or communicating with the TO (i.e., PECO) are briefed on TSO/TO interface requirements and expectations but are not formally tested on knowledge retention in this area.

(i) If your grid reliability evaluation, performed as part of the maintenance risk assessment required by 10 CFR 50.65(a)(4), does not consider or rely on some arrangement for communication with the TSO, explain why you believe you comply with 10 CFR 50.65(a)(4).

Response

Not applicable

The methods used to integrate grid risk into the quantitative risk evaluation prior to taking equipment out of service for planned maintenance at PBAPS rely on communication with the TSO/TO.

(j) If risk is not assessed (when warranted) based on continuing communication with the TSO throughout the duration of grid-risk-sensitive maintenance activities, explain why you believe you have effectively implemented the relevant provisions of the endorsed industry guidance associated with the maintenance rule.

Response

Not applicable

As detailed in the response to 2(a), grid status is continually evaluated by PJM using the Security Analysis application. PJM notifies PBAPS through the TO (i.e., PECO) of emergent grid conditions. In addition, PECO (i.e., the TO) possesses a similar system and is also monitoring and evaluating grid conditions. Existing EGC procedures require evaluation of the risk of scheduled on line maintenance activities based on conditions such as power grid stability, weather forecast, and current plant system conditions.

(k) With respect to questions 5(i) and 5(j), you may, as an alternative, describe what actions you intend to take to ensure that the increase in risk that may result from proposed grid-risk-sensitive activities is assessed before and during grid-risk-sensitive maintenance activities, respectively.

Response

Not applicable

6. *Use of risk assessment results, including the results of grid reliability evaluations, in managing maintenance risk, as required by 10 CFR 50.65(a)(4).*

   (a) Does the TSO coordinate transmission system maintenance activities that can have an impact on the NPP operation with the NPP operator?

   Response

   Yes

   The TSO/TO coordinates transmission system maintenance activities that can have an impact on the NPP (i.e., PBAPS) with PBAPS.

   (b) Do you coordinate NPP maintenance activities that can have an impact on the transmission system with the TSO?

   Response

   Yes

   The NPP (i.e., PBAPS) coordinates maintenance activities that can have an impact on the transmission system with the TSO/TO.

   (c) Do you consider and implement, if warranted, the rescheduling of grid-risk-sensitive maintenance activities (activities that could (1) increase the likelihood of a plant trip, (ii) increase LOOP probability, or (iii) reduce LOOP or SBO coping capability) under existing, imminent, or worsening degraded grid reliability conditions?

   Response

   Yes

   Existing procedures require deferring work that would render AC power sources unavailable if severe weather is expected. Risk of scheduled on line work is evaluated based on grid conditions, the weather forecast, and current plant systems status. If the risk analysis determines that risk exceeds a predetermined level, then that configuration is not voluntarily entered and schedule changes are made to reduce the risk to an acceptable level.

   (d) If there is an overriding need to perform grid-risk-sensitive maintenance activities under existing or imminent conditions of degraded grid reliability, or continue grid-risk-sensitive maintenance when grid conditions worsen, do you implement appropriate risk management actions? If so, describe the actions that you would take. (These actions could include alternate equipment protection and compensatory measures to limit or minimize risk.)

   Response

   Yes

When any risk significant SSC is made unavailable, actions are taken to protect redundant or diverse SSCs commensurate with the risk significance of the work being performed in accordance with approved procedures.

(e) Describe the actions associated with questions 6(a) through 6(d) above that would be taken, state whether each action is governed by documented procedures and identify the procedures, and explain why these actions are effective and will be consistently accomplished.

Response

The outage coordination process is documented in the PJM Manuals and agreed to by PJM (i.e., the TSO) and the members. EGC and PECO (i.e., the TO) are both members of PJM. In addition, PJM has computerized tools to track the process throughout its evolution, so that PJM, PECO and EGC are clear what the status is and what the expectations are.

Planned transmission outages are coordinated in accordance with a process detailed in PJM Manual M3, "Transmission Operations," Section 4 (Reference 4). This process requires advanced notice and subsequent PJM approval for all outages to ensure grid reliability. On the outage start day, the system is analyzed one last time by PJM before permitting the equipment to be switched out of service.

Once the equipment is switched out of service, grid status is continually evaluated by the PJM Security Analysis application as detailed in the response to 2(a). In addition, the TO (i.e., PECO) is performing similar monitoring and evaluation. PJM notifies the NPP (i.e., PBAPS) through the TO's control center, as discussed in the response to 1(b).

An 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," (Reference 7) directs that schedule coordination meetings are held bi-monthly between the TSO/TO and the NPPs (i.e., PBAPS) to coordinate maintenance activities that can have mutual impact.

Actions specified in questions 6(c) and 6(d) are specified in the EGC Work Management procedure, WC-AA-101, "On-Line Work Control Process," (Reference 8) and is applicable to PBAPS.

(f) Describe how NPP operators and maintenance personnel are trained and tested to assure they can accomplish the actions described in your answers to question 6(e).

Response

PBAPS Maintenance, Operations, and Work Management personnel associated with schedule development and/or risk assessment are briefed on procedure expectations but are not formally tested on knowledge retention in this area.

(g) If there is no effective coordination between the NPP operator and the TSO regarding transmission system maintenance or NPP maintenance activities, please explain why you believe you comply with the provisions of 10 CFR 50.65(a)(4).

Response

Not applicable

Effective coördination is directed by PJM (i.e., the TSO) procedures and jointly approved interface procedures between PECO (i.e., the TO) and EGC.

(h) If you do not consider and effectively implement appropriate risk management actions during the conditions described above, explain why you believe you effectively addressed the relevant provisions of the associated NRC-endorsed industry guidance.

Response

Not applicable

Effective and appropriate risk management actions are described in plant procedures and implemented during the conditions described above.

(i) You may, as alternative to questions 6(g) and 6 (h) describe what actions you intend to take to ensure that the increase in risk that may result from grid-risk-sensitive maintenance activities is managed in accordance with 10 CFR 50.65(a)(4).

Response

Not applicable

Offsite power restoration procedures in accordance with 10 CFR 50.63 as developed in Section 2 of RG 1.155.

Pursuant to 10 CFR 50.63, the NRC requires that each NPP licensed to operate to be able to withstand an SBO for a specified duration and recover from the SBO. NRC RG 1.155 gives licensees guidance on developing their approaches for complying with 10 CFR 50.63.

7. *Procedures for identifying local power sources[1] that could be made available to resupply your plant following a LOOP event.*

Note: Section 2, "Offsite Power," of RG 1.155 (ADAMS Accession No. ML003740034) states:

> *Procedures should include the actions necessary to restore offsite power and use nearby power sources when offsite power is unavailable. As a minimum, the following potential causes for loss of offsite power should be considered:*
>
> - *Grid undervoltage and collapse*
> - *Weather-induced power loss*

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[1] *This includes items such as nearby or onsite gas turbine generators, portable generators, hydro generators, and black-start fossil power plants.*

- *Preferred power distribution system faults that could result in the loss of normal power to essential switchgear buses*

(a) Briefly describe any agreement made with the TSO to identify local power sources that could be made available to resupply power to your plant following a LOOP event.

Response

PBAPS is located in the service territory of PJM. PJM is the Transmission System Operator (TSO) for PBAPS. The Transmission Owner (TO) providing interconnection services for PBAPS is PECO. EGC and PECO are both members of PJM.

All members of PJM execute the "Operating Agreement of PJM Interconnection, LLC," (Reference 1) that details the obligations and responsibilities of both PJM and the PJM members. In the Operating Agreement, each member agrees to abide by the requirements contained in the PJM Manuals. The PJM Manuals contain the specific operational requirements that PJM and each member is required to follow.

PECO (i.e., the TO) is also a signatory on the "PJM Consolidated Transmission Owners Agreement (PJM TOA)," (Reference 2). Section 4.5 of the PJM TOA requires the TOs to operate and maintain their transmission facilities in accordance with the PJM Manuals.

PJM (i.e., the TSO) is responsible for coordinating restoration of all or parts of the bulk power system in the PJM service territory. PECO (i.e., the TO) is responsible for cooperating and coordinating with PJM and other PJM members during the restoration of all or parts of the bulk power system in the PJM service territory.

PJM Manual M36, "System Restoration," (Reference 15) gives priority to the restoration of offsite power to NPPs (i.e., PBAPS) in the PJM service territory. The TSO (i.e., PJM) and the TO (i.e., PECO) will utilize the best power sources and transmission paths available based on the specific event to restore offsite power since there is no way to accurately predict the extent and characteristics of a specific blackout. The TSO and TO have multiple options available to restore offsite power and these would not be limited to local power sources.

The Interconnection Agreement between the NPP (i.e., PBAPS) and PECO (i.e., the TO) reinforces the importance and priority of restoring the NPP offsite power source (Reference 18). In addition, PBAPS has an Affiliate Level Arrangement Agreement (ALA) with PECO (Reference 17) to apply "best efforts" to restore to service the facilities that they own or control in order to restore the PBAPS offsite power circuit back to an operable status.

PJM provided the following information to EGC regarding this response in a letter from PJM to all PJM nuclear owners (Reference 6).

"The PJM Restoration Manual (M36) details the process to be followed during a system restoration. The process reiterates the specific offsite power requirements for NPPs:

> 'Offsite power should be restored as soon as possible to nuclear units, both units that had been operating and those that were already offline prior to the system disturbance, without regard to using these units for restoring customer load.'

However, due to the myriad of possible restoration scenarios, no specific power sources to resupply NPPs are identified. The PJM restoration process allows for the fact that the blacked out area may or may not be separated from the remainder of the system. Regardless of the scenario, there is a clear recognition of the importance of restoring an NPP offsite power source.

PJM Manual M36 further states: 'Transmission Owners and Nuclear Power Plants must effectively communicate to keep the Nuclear Power Plant apprised of the anticipated restoration time for offsite power.' The manual also states that for PJM Restoration Drills the objectives should include 'Ensure that all nuclear units have been provided with one offsite source within 4 hours,' and that the PJM Nuclear Generation Owner/Operator Users Group should be debriefed on the drill results.

In support of the restoration objectives outlined in the PJM Restoration Manual (M36), there are generating units designated as critical black-start units electrically close to each of the NPPs. These black start units are required to provide black start capability whenever necessary. The adequacy of black-start resources to support system restoration is managed through a process contained in PJM Manual M10, "PreScheduling Operations," (Reference 16), Section 2. The process ensures the continuous availability of black start units to support the restoration needs of the NPPs even when a designated black start unit is on a planned outage."

(b) Are your NPP operators trained and tested on identifying and using local power sources to resupply your plant following a LOOP event? If so, describe how.

<u>Response</u>

No

PBAPS operators are not specifically trained and tested on identifying and using local power sources to resupply the NPP (i.e., PBAPS) following a LOOP event. The identification and use of local power sources for PBAPS are under the control of PJM (i.e., the TSO) and PECO (i.e., the TO) in accordance with the procedures and interface agreements described in the response to 7(a). The response to this question does not address the operation of the PBAPS alternate AC source established under 10 CFR 50.63, "Loss of all alternating current power," (i.e., Station Blackout (SBO) Rule), for which PBAPS operators are trained and tested to identify and use under SBO conditions.

(c) If you have not established an agreement with your plant's TSO to identify local power sources that could be made available to resupply power to your plant following a LOOP event, explain why you believe you comply with the provisions of 10 CFR 50.63, or describe what actions you intend to take to establish compliance.

Response

The identification and use of local power sources for restoration of offsite power to PBAPS following a LOOP event are under the control of PJM (i.e., the TSO) and PECO (i.e., the TO) in accordance with the procedures and interface agreements described in the response to 7(a). Due to the myriad of possible restoration scenarios, no specific power sources to resupply PBAPS are identified. The procedures identified by RG 1.155, "Station Blackout," (Reference 11) that include the actions necessary to restore offsite power and the use of nearby power sources are also under the control of PJM and PECO.

Note that, as detailed in the response to 7(a), both PECO (i.e., the TO) and PJM (i.e., the TSO) have stated that restoring offsite power to a NPP (i.e., PBAPS) is a priority.

The identification and use of local power sources that could be made available to resupply power to the NPP following a LOOP event are not part of the current PBAPS operating procedures and training since they are outside of PBAPS's direct control.

Losses of offsite power caused by grid failures at a frequency of equal to or greater than once in 20 site-years in accordance with Table 4 of Regulatory Guide 1.155 for complying with 10 CFR 50.63.

Pursuant to 10 CFR 50.63, the NRC requires that each NPP licensed to operate be able to withstand an SBO for a specified duration and recover from the SBO. NRC RG 1.155 gives licensees guidance on developing their approaches to complying with 10 CFR 50.63.

8. Maintaining SBO coping capabilities in accordance with 10 CFR 50.63.

(a) Has your NPP experienced a total LOOP caused by grid failure since the plant's coping duration was initially determined under 10 CFR 50.63?

Response

Yes

PBAPS Units 2 and 3 have experienced one grid related LOOP event as defined in NRC Inspection Manual TI 2515/165, "Offsite Power System Operational Readiness," (Reference 9), Attachment B, "LOOP Events." The PBAPS event occurred on September 15, 2003. This event is consistent with data presented in NUREG/CR-6890, Volume 1, "Reevaluation of Station Blackout Risk at Nuclear Power Plants – Analysis of Offsite Power Events: 1986-2004," (Reference 10), Appendix A, "LOOP Event Database," Section A-2, "Data Tables," Table A -1, "Loop Events for 1986-2004, sorted by plant."

A review of PBAPS records including LERs since Reference 10 was issued has concluded that there were no additional grid failure based LOOP events.

(b) If so, have you reevaluated the NPP using the guidance in Table 4 of RG 1.155 to determine if your NPP should be assigned to the P3 offsite power design characteristic group?

Response

Yes

(c) If so, what were the results of this reevaluation, and did the initially determined coping duration for the NPP need to be adjusted?

Response

The below review was performed to confirm that both Peach Bottom Units 2 and 3 have been subjected to only one LOOP event, (i.e., the event on September 15, 2003), since commissioning.

The original evaluation that determined the offsite power design characteristic of P2 was performed in accordance with NUMARC-8700, "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors," (Reference 12). RG 1.155, "Station Blackout," (Reference 11) states that NUMARC-8700 provides acceptable guidance for conformance to 10 CFR 50.63, "Loss of all alternating current power," (i.e., Station Blackout (SBO) Rule).

A review was performed of the basis for the original NUMARC-8700 Section 3 evaluation as documented in a letter to the NRC (Reference 28) to determine if a change from the original P2 to the P3 offsite power design characteristic group is required as a result of the September 15, 2003 event. The basis for the P2 determination is not changed from what was previously reported in Reference 28 since the expected frequency of grid-related LOOPs does not exceed once per 20 years. A review of PBAPS events using NUREG/CR 6890 (Reference 10), for the years 1986-2004; NUREG-1032, "Evaluation of Station Blackout Accidents at Nuclear Power Plants," (Reference 14), for the years1973-1983; and all PBAPS LERs for 1984, 1985, 2005 and 2006; determined that there has only been one grid related LOOP event at PBAPS (i.e., September 15, 2003). Therefore, the frequency of LOOP(s) at PBAPS since original plant operation is once in 31+ site-years of operation. This is bounded by the once per 20-year frequency assumption considered in Reference 28. Therefore, the original coping duration calculated in accordance with NUMARC-8700 Table 3-8 remains unchanged at 8 hours.

(d) If your NPP has experienced a total LOOP caused by grid failure since the plant's coping duration was initially determined under 10 CFR 50.63 and has not been reevaluated using the guidance in Table 4 of RG 1.155, explain why you believe you comply with the provisions of 10 CFR 50.63 as stated above, or described what actions you intend to take to ensure that the NPP maintains its SBO coping capabilities in accordance with 10 CFR 50.63.

Response

Not applicable

Actions to ensure compliance

9. *If you determine that any action is warranted to bring your NPP into compliance with NRC regulatory requirements, including TSs, GDC 17, 10 CFR 50.65(a)(4), 10 CFR 50.63, 10 CFR 55.59 or 10 CFR 50.120, describe the schedule for implementing it.*

Response

Not applicable

References

1. "Operating Agreement of PJM Interconnection, LLC," revised through February 6. 2006

2. "Consolidated Transmission Owners Agreement," effective March 19, 2006

3. PJM Manual 01, "Control Center Requirements," Revision 10, effective February 7, 2006

4. PJM Manual 3, "Transmission Operations," Revision 20, effective February 10, 2006

5. PJM Manual 13, "Emergency Operations," Revision 24, effective February 22, 2006

6. 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

7. EGC procedure WC-AA-8000, "Interface Procedure between Exelon Energy Delivery (ComEd/PECO) and Exelon Generation (Nuclear/Power) for Construction and Maintenance Activities," Revision 0

8. EGC procedure WC-AA-101, "On-Line Work Control Process," Revision 11

9. NRC Inspection Manual TI 2515/165, "Offsite Power System Operational Readiness," issued April 29, 2004

10. NUREG/CR-6890, Volume 1, "Reevaluation of Station Blackout Risk at Nuclear Power Plants – Analysis of Offsite Power Events: 1986-2004," Revision 0

11. Regulatory Guide 1.155, "Station Blackout," Revision 0

12. NUMARC-8700, "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors," Revision 0

13. EGC procedure OP-AA-108-107-1002, "Interface Agreement between Exelon Energy Delivery and Exelon Generation for Switchyard Operations," Revision 2

14. NUREG-1032, "Evaluation of Station Blackout Accidents at Nuclear Power Plants," dated June 1988

15. PJM Manual 36, "System Restoration," Revision 2, effective November 1, 2005

16. PJM Manual 10, "Pre-Scheduling Operations," Revision 18, effective August 10, 2005

17. "Affiliate Level Arrangement ('ALA') by and among Exelon Energy Delivery Groups of PECO and Exelon Generation Company, LLC," effective January 1, 2006

18. "Interconnection Service Agreement among PJM, Exelon Generation Company, LLC, PSEG Nuclear LLC, and PECO Energy Company," dated December 12, 2003

19. NRC Information Notice IN 93-17, "Safety Systems Response to Loss of Coolant and Loss of Offsite Power," Revision 1, dated March 25, 1994

20. SECY-05-0219, "Issuance of Nuclear Regulatory Commission Generic Letter 2005-XX, 'Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power,'" dated December 2, 2005

21. EGC procedure OP-AA-108-107-1001, "Station Response to Grid Capacity Conditions," Revision 1

22. PBAPS Special Event Procedure SE-11, "Loss of Offsite Power"

23. PBAPS Special Event Procedure SE-16, "Grid Emergency"

24. EGC procedure WC-AA-107, "Seasonal Readiness," Revision 2

25. SOER 99-1, "Loss of Grid," December 27, 1999

26. SOER 99-1, "Loss of Grid – Addendum," December 9, 2004

27. Jennifer Sterling, Exelon Transmission Planning, "NRC Generic Letter – Draft responses to questions 1 and 2," February 14, 2006, personal email to John Gyrath, Exelon Nuclear, (February 14, 2006)

28. Letter from D. R. Helwig (Philadelphia Electric Company) to USNRC, "Peach Bottom Atomic Power Station, Units 2 and 3, 10 CFR 50.63, 'Loss of All Alternating Current Power,' Revised Station Blackout Analysis," dated April 24, 1991

ATTACHMENT 9

60-day Response to NRC Generic Letter 2006-02

THREE MILE ISLAND NUCLEAR STATION, Unit 1

FOL No. DPR-50

ATTACHMENT 9
60-day Response to NRC Generic Letter 2006-02,
THREE MILE ISLAND NUCLEAR STATION, Unit 1

On February 1, 2006, the NRC issued Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power." 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 Generic Letter requested that licensees answer the following questions and provide the information to the NRC with respect to each of their Nuclear Power Plants (NPPs).

Use of protocols between the NPP licensee and the TSO, ISO, or RC/RA and the use of analysis tools by TSOs to assist NPP licensee in monitoring grid conditions to determine the operability of offsite power system under plant TS.

GDC 17, 10 CFR Part 50, Appendix A, requires that licensees minimize the probability of the loss of power from the transmission network given a loss of the power generated by the nuclear power unit(s).

1. *Use of protocols between the NPP licensee and the TSO, ISO, or RC/RA to assist the NPP licensee in monitoring grid conditions to determine the operability of offsite power system under plant TS.*

   (a) Do you have a formal agreement or protocol with your TSO?

   Response

   Yes

   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 1 is FirstEnergy Corporation (FirstEnergy). AmerGen Energy Company, LLC (AmerGen) and FirstEnergy are both members of PJM.

   All members of PJM execute the "Operating Agreement of PJM Interconnection, LLC," (Reference 1) that details the obligations and responsibilities of both PJM and the PJM members. In the Operating Agreement, each member agrees to abide by the requirements contained in the PJM Manuals. The PJM Manuals contain the specific operational requirements that PJM and each member is required to follow.

   FirstEnergy (i.e., the TO) is also a signatory on the "PJM Consolidated Transmission Owners Agreement (PJM TOA)," (Reference 2). Section 4.5 of the PJM TOA requires the TOs to operate and maintain their transmission facilities in accordance with the PJM Manuals.

   The PJM Operating Agreement requires PJM to, "Incorporate the grid reliability requirements applicable to nuclear generating units in the PJM Region planning and operating principles and practices." PJM Manual M01, "Control Center Requirements," Attachment B, "Nuclear Plant Communication Protocol," (Reference 3), provides the roles and responsibilities of nuclear stations, TOs, and PJM with regard to communications both in normal and emergency circumstances. The nuclear power plant (NPP) notification requirements are contained in PJM Manual M3, "Transmission Operations," Section 3 (Reference 4).

In addition to the agreements delineated in the PJM Operating Agreement and the PJM Manuals, TMI 1 has an Interconnection Agreement with the TO (i.e., FirstEnergy) that provides for interconnection service. The Interconnection Agreement contains the requirement for the TO to monitor the NPP offsite source voltages and notify TMI 1 of any limit violations (Reference 12).

Note that FirstEnergy is synonymous with Metropolitan Edison Company as documented in Reference 12.

(b) Describe any grid conditions that would trigger a notification from the TSO to the NPP licensee and if there is a time period required for the notification.

Response

PJM Manual M3 (Reference 4) requires PJM to initiate notification to TMI 1 through the TO's control center if PJM identifies a switchyard voltage violation. PJM Manual M3 states: "This notification should occur within 15 minutes for voltage contingency violations and immediately for actual voltage violations. To the extent practical, PJM shall direct operations such that the violation is remedied within 30 minutes."

In addition, PJM Manual M13, "Emergency Operations," (Reference 5) identifies a series of alerts, warnings, and actions that PJM issues to PJM members depending on the identified grid condition. The PJM message is communicated to TMI 1 by their generation dispatcher for a variety of system conditions including the following:

Capacity Emergencies
- Maximum Emergency Generation Loading
- Load Management Curtailment
- Manual Load Dump Warning

Light Load Emergencies
- Minimum Generation Emergency
- Local Minimum Generation Emergency

Weather/Environmental Emergencies
- Hot/Cold Weather Alerts
- Thunderstorms and Tornadoes
- Solar Magnetic Disturbances

Sabotage/Terrorism Emergencies

(c) Describe any grid conditions that would cause the NPP licensee to contact the TSO. Describe the procedures associated with such a communication. If you do not have procedures, describe how you assess grid conditions that may cause the NPP licensee to contact the TSO.

Response

As required by PJM Manuals, communications between TMI 1 and PJM (TSO) are generally through the Transmission Owner (TO) providing the interconnection service.

TMI 1 will contact the TSO/TO for grid conditions that have parameters that are observable at the NPP. These conditions include the following:

- Loss of Offsite Power (LOOP)
- Abnormal switchyard voltage
- Automatic (protective) switchyard circuit breaker operation
- Switchyard alarms
- Grid disturbances (observable frequency or voltage fluctuations)

In addition to any alarm response procedures for the above applicable conditions, TSO/TO notifications are controlled by operating procedures, (e.g., 1107-11, "TMI Grid Operations," 1102-4, "Power Operation," OP-TM-108-107-1002, "TMI Switchyard Operations"), Abnormal Operating Procedures, (e.g., OP-TM-AOP-022, "Load Rejection," OP-TM-AOP-020, "Loss of Station Power"), and Emergency Operating Procedures, (e.g., OP-TM-EOP-001, "Reactor Trip").

TMI 1 will contact the TSO/TO during a grid restoration process to obtain grid status in preparation for returning the plant buses to the offsite source.

TMI 1 also notifies the TSO/TO of switchyard equipment deficiencies identified by NPP personnel. Procedures OP-TM-108-107-1002, "TMI Switchyard Operations," (Reference 13) identifies the communication protocols between TMI 1 and the TO for station identified switchyard deficiencies.

In addition, TMI 1 will notify the TSO/TO of NPP configurations that potentially impact grid conditions. Procedures OP-TM-108-107-1002 (Reference 13) and 1107-11, "TMI Grid Operations," (Reference 14) identify the requirements for communication between TMI 1 and the TO of the conditions listed below:

- NPP MVAR limitations
- NPP Main generator voltage regulator not in "Automatic" mode
- NPP inability to provide the MVARs requested by the TSO/TO

Note that any TMI 1 MW limitations or limitations on the rate at which the NPP power may be raised or lowered are communicated to the generation dispatcher.

(d) Describe how NPP operators are trained and tested on the use of the procedures or assessing grid conditions in question 1(c).

Response

TMI 1 licensed operators are trained and tested in accordance with the Systematic Approach to Training (SAT). Procedures and policies are routinely reviewed for training through this process for improvement of operator performance. The items considered for training include Operating Procedures, Annunciator Response Procedures, Abnormal Operating Procedures, and Emergency Operating Procedures that require interface with the TSO in accordance with the established protocol. These procedures may be utilized based on various grid, switchyard, or plant symptoms to assess, respond to or mitigate off-normal plant and grid conditions. Additionally, SOER 99-01, "Loss of Grid," (Reference 23) and SOER 99-01, "Loss of Grid – Addendum," (Reference 24) specifically are captured in the Licensed Operator Requalification Training Program (LORT) Long Range Training Program. These topics, in varying detail based upon the SAT process or as part of implementing EGC procedure WC-AA-107, "Seasonal Readiness," (Reference 22) are reviewed periodically with TMI 1 operators. Testing is commensurate with the material presented and any performance issues are identified for inclusion in future training.

(e) If you do not have a formal agreement or protocol with your TSO, describe why you believe you continue to comply with the provisions of GDC 17 as stated above, or describe what actions you intend to take to assure compliance with GDC 17.

Response

Not applicable. Formal agreements exist for TMI 1.

(f) If you have an existing formal interconnection agreement or protocol that ensures adequate communication and coordination between the NPP license and the TSO, describe whether this agreement or protocol requires that you be promptly notified when the conditions of the surrounding grid could result in degraded voltage (i.e., below TS nominal trip setpoint value requirements; including NPP licensees using allowable value in its TSs) or LOOP after a trip of the reactor units(s).

Response

PJM Manual M3 (Reference 4) requires PJM to initiate a notification to TMI 1 through its respective transmission owner's control center if PJM identifies a NPP switchyard voltage violation. PJM Manual M3 states: "This notification should occur within 15 minutes for voltage contingency violations and immediately for actual voltage violations. To the extent practical, PJM shall direct operations such that the violation is remedied within 30 minutes." The trip of a NPP is one of the contingencies analyzed by PJM. PJM analyzes the TMI 1 switchyard contingency voltages to the voltage limits provided by TMI 1. The voltage limits provided for TMI 1 are based on the existing design basis analysis.

(g) Describe the low switchyard voltage conditions that would initiate operation of plant degraded voltage protection.

Response

Switchyard voltage below a value maintaining emergency bus voltage above the maximum reset value of the degraded voltage relay (3727 volts) will cause a trip of the preferred power source after a time delay of approximately 10 seconds. The relation between the switchyard voltage and the emergency bus voltage is dependent on the loading of the auxiliary transformer two secondary windings, the auxiliary transformer impedance and the tap setting of the automatic load tap changer. Under design basis accident (i.e., Large Break LOCA) conditions, the maximum loading is known and contained in the TMI 1 calculations of record. The design basis maximum loading and the degraded voltage relay reset voltage were used to determine the switchyard voltage needed for the system to remain connected to the offsite power source. This corresponds to a switchyard voltage of 207.11 kV for normal two transformer operation and 217.49 kV for one engineered safeguard bus and 218.89 kV for the other engineered safeguard bus under single transformer operation.

In other conditions, the loading is less than the expected LOCA loading and will vary considerably depending on which loads are needed to support unit conditions. Under these conditions the required TMI 1 switchyard voltage will be less than that required to support LOCA loading.

2. *Use of criteria and methodologies to assess whether the offsite power system will become inoperable as a result of a trip of your NPP.*

(a) Does your NPP's TSO use any analysis tools, an online analytical transmission system studies program, or other equivalent predictive methods to determine the grid conditions that would make the NPP offsite power system inoperable during various contingencies? If available to you, please provide a brief description of the analysis tool that is used by the TSO.

Response

Yes

The PJM Energy Management System (EMS) includes a Security Analysis application which runs approximately every 1 minute and analyzes ~4,000 contingencies on the PJM system (Reference 6). The analysis provides results with respect to thermal, voltage, and voltage drop limit violations. One of the contingencies analyzed by the PJM EMS is the trip of a NPP (i.e., TMI 1).

In addition, FirstEnergy (i.e., the TO) possesses a similar system that also calculates post-contingency voltage limit violations. One of the contingencies analyzed by FirstEnergy is the trip of TMI 1.

(b) Does your NPP's TSO use an analysis tool as the basis for notifying the NPP licensee when such a condition is identified? If not, how does the TSO determine if conditions on the grid warrant NPP licensee notification?

Response

Yes

The results of the PJM Security Analysis application contain the specific contingency of the NPP tripping as the contingent element. Violation of the unit trip contingency voltage limit would result in notification of the NPP (i.e., TMI 1) in accordance with PJM Manual M3, Section 3 (Reference 4).

FirstEnergy (i.e., the TO) also possesses similar capability to monitor the same condition.

(c) If your TSO uses an analysis tool, would the analysis tool identify a condition in which a trip of the NPP would result in switchyard voltages (immediate and/or long-term) falling below TS nominal trip setpoint value requirements (including NPP licensees using allowable value in its TSs) and consequent actuation of plant degraded voltage protection? If not, discuss how such a condition would be identified on the grid.

Response

Yes

The trip of the NPP (i.e., TMI 1) is one of the contingencies analyzed by the PJM Security Analysis application. PJM analyzes the NPP switchyard contingency voltages to the voltage limits provided by TMI 1. The voltage limits provided by TMI 1 are based on the plant's design basis analysis as discussed in the response to 1(g).

FirstEnergy (i.e., the TO) also possesses similar capability to monitor the same condition.

(d) If your TSO uses an analysis tool, how frequently does the analysis tool program update?

Response

The PJM EMS includes a Security Analysis application that currently updates approximately every 1-minute. In addition, FirstEnergy (i.e., the TO) possesses a Security Analysis application that updates approximately every 2 minutes (Reference 25).

(e) Provide details of analysis tool-identified contingency conditions that would trigger an NPP licensee notification from the TSO.

Response

PJM notifies TMI 1 through the TO (i.e., FirstEnergy) control center whenever actual or post-contingency voltages are determined to be below the TMI 1 switchyard voltage limits. This requirement applies to all contingencies involving the tripping of the NPP or any transmission facility as the contingent element. The notification is required even if the voltage limits are the same as the standard PJM voltage limits in accordance with PJM Manual M3 (Reference 4).

(f) If an interface agreement exists between the TSO and the NPP licensee, does it require that the NPP licensee be notified of periods when the TSO is unable to determine if offsite power voltage and capacity could be inadequate? If so, how does the NPP licensee determine that the offsite power would remain operable when such a notification is received?

Response

Yes

TMI 1 unit trip contingency voltage calculations are performed by the PJM EMS and the TO (i.e., FirstEnergy) Security Analysis application. The PJM EMS consists of a primary and backup system. If the PJM EMS fails, the FirstEnergy Security Analysis application continues to analyze the TMI 1 unit trip contingency voltage. TMI 1 will be notified if the real time contingency analysis capability of PJM and the TO (i.e., FirstEnergy) are lost simultaneously in accordance with PJM Manual M01, Section 2 (Reference 3).

If TMI 1 is notified that PJM and FirstEnergy (i.e., the TO) have both lost their real time contingency analysis capability, TMI 1 would request PJM and FirstEnergy to provide an assessment of the current condition of the grid based on the tools that PJM and FirstEnergy have available. The determination of the operability of the offsite sources would consider the assessment provided by PJM and FirstEnergy and whether the current condition of the grid is bounded by the grid studies previously performed for TMI 1.

(g) After an unscheduled inadvertent trip of the NPP, are the resultant switchyard voltages verified by procedure to be bounded by the voltages predicted by the analysis tool?

Response

No

There is presently no formal process for comparing the actual post-trip voltages to the post-trip contingency voltage results calculated by the PJM and the TO (i.e., FirstEnergy) Security Analysis applications.

PJM provided the following information to AmerGen regarding this response in a letter from PJM to all PJM nuclear owners (Reference 6).

"Because the PJM transmission owning member companies have similar Security Analysis programs to PJM, there are many opportunities to compare the results of the respective Security Analysis programs. In this manner, there is a high confidence that the Security Analysis results are accurate within the precision of the calculations.

PJM retains the EMS results for a period of approximately 3 weeks after real time. It is possible to use those saved EMS results to repeat the Security Analysis calculations and compare them to the actual voltages from a unit trip. However, the NPP trips occur so infrequently that it would take a number of data points to verify the accuracy with any statistical significance. This process could take years if the process is limited to a comparison of only NPP trips."

(h) If an analysis tool is not available to the NPP licensee's TSO, do you know if there are any plans for the TSO to obtain one? If so, when?

Response

Not applicable. TMI 1 TSO (i.e., PJM) has an analysis tool.

(i) If an analysis tool is not available, does your TSO perform period studies to verify that adequate offsite power capability, including adequate NPP post-trip switchyard voltages (immediate and/or long-term), will be available to the NPP licensee over the projected timeframe of the study?

Response

Not applicable. TMI 1 TSO (i.e., PJM) has an analysis tool.

(a) Are the key assumptions and parameters of these periodic studies translated into TSO guidance to ensure that the transmission system is operated within the bounds of the analyses?

Response

Not applicable. TMI 1 TSO (i.e., PJM) has an analysis tool.

(b) If the bounds of the analyses are exceeded, does this condition trigger the notification provisions discussed in question 1 above?

Response

Not applicable. TMI 1 TSO (i.e., PJM) has an analysis tool.

(j) If your TSO does not use, or you do not have access to the results of an analysis tool, or your TSO does not perform and make available to you periodic studies that determine the adequacy of offsite power capability, please describe why you believe you comply with the provisions of GDC 17 as stated above, or describe what compensatory actions you intend to take to ensure that the offsite power system will be sufficiently reliable and remain operable with high probability following a trip of your NPP.

Response

Not applicable. TMI 1 TSO (i.e., PJM) has an analysis tool. In addition the applicable contingency voltage results are made available to TMI 1 as needed.

3. *Use of criteria and methodologies to assess whether the NPP's offsite power system and safety-related components will remain operable when switchyard voltages are inadequate.*

   (a) If the TSO notifies the NPP operator that a trip of the NPP, or the loss of the most critical transmission line or the largest supply to the grid would result in switchyard voltages (immediate and/or long-term) below TS nominal trip setpoint value requirements (including NPP licensees using allowable value in its TSs) and would actuate plant degraded voltage protection, is the NPP offsite power system declared inoperable under the plant TSs? If not, why not?

Response

If the TSO (i.e., PJM) notifies TMI 1 that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., TMI 1) is below the pre-determined notification value, TMI 1 will review the applicability to the plant operating configuration in accordance with Technical Specification (TS) 3.7, "Unit Electric Power System," action statement 3.7.2.h. The notification value provided to PJM by TMI 1 is based on the TMI 1 degraded voltage design basis analysis.

Predicted contingency voltages following the loss of a transmission facility (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 for TMI 1 at this time. If the TSO (i.e., PJM) notifies TMI 1 of a predicted contingency voltage violation resulting from the postulated trip of a transmission facility, TMI 1 will perform a risk analysis of in progress and scheduled plant work and will take action as appropriate.

The NPP unit trip contingency can be caused by plant-centered events. The use of the NPP unit trip contingency as the contingency element upon which offsite power operability is based is consistent with the final paragraph of General Design Criterion (GDC) 17, "Electric power systems," of 10 CFR Part 50 Appendix A, "General Design Criteria for Nuclear Power Plants," which requires provisions be included to minimize the probability of the loss of power from the transmission network given a loss of the power generated by the NPP (i.e., TMI 1).

Postulated contingencies on the transmission system are currently not used as the basis for offsite source operability determinations since loss of power from the transmission network would not occur as a result of loss of power generated by a NPP unit (i.e., TMI 1). Such events (e.g., loss of a transmission line) are only postulated and have not actually occurred, and the offsite power sources remain capable of supporting a safe shutdown and mitigating the effects of an accident. Loss of power from the transmission network would not occur as a result of loss of power generated by a NPP unit and therefore the GDC 17 provision discussed in GL 2006-02 is met.

(b) If onsite safety-related equipment (e.g., emergency diesel generators or safety-related motors) is lost when subjected to a double sequencing (LOCA with delayed LOOP event) as a result of the anticipated system performance and is incapable of performing its safety functions as a result of responding to an emergency actuation signal during this condition, is the equipment considered inoperable? If not, why not?

Response

Although some features have been incorporated into the plant design, requirements for analysis and design considerations for double sequencing are not included within the TMI 1 current licensing and design basis as documented in the TMI 1 Updated Final Safety Analysis Report (UFSAR). TMI 1 has not been explicitly analyzed for all issues associated with double sequencing. Onsite safety-related equipment at TMI 1 (e.g., emergency diesel generators or safety-related motors) is not declared inoperable as a result of a TSO (i.e., PJM) unit trip contingency voltage notification.

Based on Enclosure 2 of SECY-05-0219, "Issuance of Nuclear Regulatory Commission Generic Letter 2005-XX, 'Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power,'" (Reference 17) which provided NRC guidance on responding to this issue, a review was performed for TMI 1 of the loading logic for the diesel generators as well as the safety-related breakers' anti-pumping logic. This review concluded that onsite safety-related equipment (i.e., emergency diesel generators or safety-related motors) is not lost as a result of diesel generator block loading and breaker lockout from anti-pump circuitry when subjected to a double sequencing event resulting from inadequate post unit trip voltages. The scope of the review performed for TMI 1 is discussed in the response to question 3(c) below.

(c) *Describe your evaluation of onsite-related equipment to determine whether it will operate as designed during the condition described in question 3(b).*

Response

Although some features have been incorporated into the plant design, requirements for analysis and design considerations for double sequencing are not included within the TMI 1 current licensing and design basis as documented in the TMI 1 UFSAR. TMI 1 has not been explicitly analyzed for all issues associated with double sequencing. However, using the NRC clarification provided in Enclosure 2 of SECY-05-0219 as guidance, a review was performed for the purpose of addressing question 3(b).

This review examined the effects of a double sequencing event on diesel generator block loading and the potential for breaker lockout from the anti-pump circuitry. The review assumed that following a LOCA initiation, separation occurred as a result of degraded voltage relay operation triggered by the loss of TMI 1. The review examined the diesel generator loading logic and determined that the logic is reset by the LOOP event. The second sequence is consistent with that described in the TMI 1 UFSAR for a LOOP/LOCA event. Loads are shed as a result of the LOOP signal and the loads are not block (i.e., bulk) loaded onto the diesel generator.

The review also examined the potential for breaker lockout due to the anti-pumping circuitry. This review determined that there was sufficient time between the two sequences such that the breaker charging springs would re-charge and the second closure would be successful. To ensure that a breaker lockout would not occur, the breaker closing logics were also examined to assure that the trip signals were cleared before the second close signal was initiated.

(d) *If the NPP licensee is notified by the TSO of other grid conditions that may impair the capability or availability of offsite power, are any plant TS action statements entered? If so, please identify them.*

Response

As discussed in the response to 3(a), if the TSO (i.e., PJM) notifies TMI 1 that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., TMI 1) is below the pre-determined notification value, TMI 1 will review the applicability to the plant operating configuration and will declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by TMI 1 is based on the TMI 1 degraded voltage design basis analysis.

If PJM notifies TMI 1 that the actual offsite power source voltage is less than the pre-determined notification value, TMI 1 will review the applicability to the plant operating configuration and would declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by TMI 1 is based on the TMI 1 degraded voltage design basis analysis.

If PJM notifies TMI 1 that less than two 230 kV lines are supplying the switchyard, the TMI 1 TS require that one Emergency Diesel Generator shall be started and run continuously until two transmission lines are restored.

(e) *If you believe your plant TSs do not require you to declare your offsite power system or safety-related equipment inoperable in any of these circumstances, explain why you believe you comply with the provisions of GDC 17 and your plant TSs, or describe what compensatory actions you intend to take to ensure that the offsite power system and safety-related components will remain operable when switchyard voltages are inadequate.*

Response

The following notifications from the TSO (i.e., PJM) will result in TMI 1 declaring the offsite power source inoperable in accordance with TSs.

- If the TSO (i.e., PJM) notifies TMI 1 that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., TMI 1) is below the pre-determined notification value, TMI 1 will review the applicability to the plant operating configuration in accordance with Technical Specification (TS) 3.7, "Unit Electric Power System," action statement 3.7.2.h. The notification value provided to PJM by TMI 1 is based on the TMI 1 degraded voltage design basis analysis.

- If the TSO (i.e., PJM) notifies TMI 1 that the actual offsite power source voltage is less than the pre-determined notification value, TMI 1 will review the applicability to the plant operating configuration and would declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by TMI 1 is based on the TMI 1 degraded voltage design basis analysis.

Predicted contingency voltages following the loss of a transmission facility (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. If the TSO notifies the NPP of a predicted contingency voltage violation resulting from the postulated trip of a transmission facility, the NPP performs a risk analysis of in-progress and scheduled plant work and takes action as appropriate.

The NPP unit trip contingency can be caused by plant-centered events. The use of the NPP unit trip contingency as the contingency element upon which offsite power operability is based is consistent with the final paragraph of GDC 17 which requires provisions to minimize the probability of the loss of power from the transmission network given a loss of the power generated by the NPP.

Postulated contingencies on the transmission system are not used as the basis for offsite source operability determinations since loss of power from the transmission network would not occur as a result of loss of power generated by the NPP unit. Such events (e.g., loss of a transmission line) are only postulated and have not actually occurred, and the offsite power sources remain capable of affecting a safe shutdown and mitigating the effects of an accident. The GDC 17 provision discussed in the Generic Letter is still met; loss of power from the transmission network would not occur as a result of loss of power generated by the NPP unit.

Onsite safety-related equipment at TMI 1 (e.g., emergency diesel generators or safety-related motors) is not declared inoperable as a result of a TSO (i.e., PJM) unit trip contingency voltage notification. Although some features have been incorporated into the plant design, requirements for analysis and design considerations for double sequencing are not included within the TMI 1 current licensing and design basis as documented in the TMI 1 UFSAR. TMI 1 has not been explicitly analyzed for all issues associated with double sequencing.

(f) Describe if and how NPP operators are trained and tested on the compensatory actions mentioned in your answers to questions 3(a) through (e).

Response

TMI 1 licensed operators are trained and tested in accordance with the Systematic Approach to Training (SAT). Equipment operability, as defined by TS, including normal and emergency power, offsite circuits, and safety-related components, is under continuous review. Procedures are in place to provide operator guidance and required actions necessary during predicted or actual degraded grid voltage conditions based on information provided by the TSO/TO in accordance with established protocol or as observed by the NPP operator. As part of initial training, requalification training, and annual operating tests, licensed operators are subjected to written examinations, dynamic learning activities, static and/or simulator examinations, Job Performance Measures (JPMs), and evaluated simulator scenarios incorporating topics including the actual or predicted switchyard voltage issues and its effect on AC Source operability. Testing is commensurate with the material presented and any performance issues are identified for inclusion in future training.

4. *Use of criteria and methodologies to assess whether the offsite power system will remain operable following a trip of your NPP.*

   (a) Do the NPP operators have any guidance or procedures in plant TS bases sections, the final safety analysis report, or plant procedures regarding situations in which the condition of plant-controlled or monitored equipment (e.g., voltage regulator, auto tap changing transformers, capacitors, static VAR compensators, main generator voltage regulators) can adversely affect the operability of the NPP offsite power system? If so, describe how the operators are trained and tested on the guidance and procedures.

Response

Yes

TMI 1 plant controlled or monitored equipment that can adversely affect the operability of the offsite power system is limited to the main generator voltage regulators and the 1A and 1B auxiliary transformer automatic load tap changers (LTCs). EGC and plant specific procedures provide guidance for notification of the TSO/TO (i.e., PJM/FirstEnergy) when the voltage regulator is not in automatic.

TMI 1 procedures direct operator actions to control excitation in manual or other mitigating actions to control excitation. Operator actions on a loss of automatic control of the voltage regulator include the requirement to notify the TO (i.e., FirstEnergy) of the failure. The TSO is notified whenever the voltage regulators are taken from automatic to manual operation.

TS 3.7, "Unit Electric Power System," TS 3.7.1.a and TS 3.7.1.b require two 230 KV lines in service and one 230 KV bus in service to be critical. TS 3.7.2.a (i) and TS 3.7.2.a (ii) require that two 230 KV lines are in service to provide auxiliary power to Unit 1 and that the voltage on the 230 KV grid is sufficient to power the safety-related ES loads.

The offsite sources are not declared inoperable if the load tap changer is not in automatic. This guidance is written in TMI 1 procedures. The TMI 1 procedures require that the low side voltages on the 1A and 1B auxiliary transformers be controlled within a specified voltage band to support offsite source operability.

TMI 1 licensed operators are trained and tested in accordance with the Systematic Approach to Training (SAT). Procedures and policies are routinely reviewed for training through this process for improvement of operator performance. The items considered for training include Annunciator Response Procedures, Abnormal Operating Procedures, and Emergency Operating Procedures that require interface with the TSO/TO in accordance with the established protocol. In addition as part of initial training, requalification training, and annual operating tests, licensed operators are subjected to written examinations, static and/or simulator examinations, Job Performance Measures (JPMs), and evaluated simulator scenarios. These evaluations may incorporate topics including the loss of the main generator voltage regulator and actions to mitigate the effect of the failure. Testing is commensurate with the material presented and any performance issues are identified for inclusion in future training.

(b) If your TS bases sections, the final safety analysis report, and plant procedures do not provide guidance regarding situations in which the condition of plant-controlled or monitored equipment can adversely affect the operability of the NPP offsite power system, explain why you believe you comply with the provisions of GDC 17 and the plant TSs, or describe what actions you intend to take to provide such guidance or procedures.

Response

Not applicable

Use of NPP licensee/TSO protocols and analysis tool by TSOs to assist NPP licensees in monitoring grid conditions for consideration in maintenance risk assessments.

The Maintenance Rule (10 CFR 50.65(a)(4)) requires that licensees assess and manage the increase in risk that may result from proposed maintenance activities before performing them.

5. *Performance of grid reliability evaluations as part of the maintenance risk assessments required by 10 CFR 50.65(a)(4).*

   (a) Is a quantitative or qualitative grid reliability evaluation performed at your NPP as part of the maintenance risk assessment required by 10 CFR 50.65(a)(4) before performing grid-risk-sensitive maintenance activities? This includes surveillances, post-maintenance testing, and preventive and corrective maintenance that could increase the probability of a plant trip or LOOP or impact LOOP or SBO coping capability, for example, before taking a risk-significant piece of equipment (such as an EDG, a battery, a steam-driven pump, an alternate AC power source) out-of-service?

   Response

   Yes

   Risk is assessed using a process that combines quantitative results from a probabilistic risk assessment (PRA) with a qualitative defense-in-depth model. During the planning and scheduling of work and prior to the execution of work, many factors are assessed for risk including the effect of weather/time of year and grid instability. The combination of unavailable Systems, Structures and Components (SSCs) and planned activities is then assessed in the risk assessment tool. Currently, a procedure update is being implemented to provide additional detail for how to factor grid reliability into the risk assessment tool before taking equipment out of service for planned maintenance. These procedure changes are currently scheduled to be in place at TMI 1 by May 15, 2006.

   (b) Is grid status monitored by some means for the duration of the grid-risk-sensitive maintenance to confirm the continued validity of the risk assessment and is risk reassessed when warranted? If not, how is the risk assessed during grid-risk-sensitive maintenance?

   Response

   Yes

   Grid status is continually evaluated by PJM using the Security Analysis application. PJM notifies TMI 1 through its Transmission Operator, (i.e., FirstEnergy), of emergent grid conditions as discussed in the response to 1(b) above. In addition, FirstEnergy (i.e., the TO) is also performing similar monitoring and evaluation. Existing EGC procedures require evaluation of the risk of scheduled online maintenance activities based on conditions such as power grid stability, weather forecast, and current plant system conditions.

(c) Is there a significant variation in the stress on the grid in the vicinity of your NPP site caused by seasonal loads or maintenance activities associated with critical transmission elements? Is there a seasonal variation (or the potential for a seasonal variation) in the LOOP frequency in the local transmission region? If the answer to either question is yes, discuss the time of year when the variations occur and their magnitude.

Response

The base PRA model reflects the yearly average LOOP frequency because seasonal variations that would cause changes to the frequency of a LOOP cannot be accurately predicted. While time related variations are not factored into the base PRA model for TMI 1, symptoms of grid stress such as maximum generation conditions, low grid voltage, or severe weather conditions require identification of such dynamic conditions should they occur, and risk management actions are then taken to mitigate the risk or reschedule the work as appropriate.

PJM provided the following information to AmerGen regarding this response in a letter from PJM to all PJM nuclear owners (Reference 6).

"Stress on the grid is manifested in a number of ways. Stress can mean 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.

Regarding the seasonal variability of the stress causers, each has a seasonal component. For example, peak load levels occur at the peak seasons of the summer and winter seasons. While the specific days cannot be predicted, it is known roughly when they will occur. Consequently, maintenance during these times of the year is avoided.

From a transmission system operations perspective, it is the simultaneous combination of stress causers that results in the most difficult operational challenges. For example, experiencing very hot (or cold) weather when we (i.e., PJM) are in the maintenance seasons with a lot of equipment out of service can cause the most severe challenges.

We (i.e., PJM) are aware of the existence of the North American Electric Reliability Council (NERC) and NRC data regarding LOOP frequency. However, it is difficult to assign differential risks to any seasonal variation because of the complexity of the various competing factors, as explained above."

(d) Are known time-related variations in the probability of a LOOP at your plant site considered in the grid-risk-sensitive maintenance evaluation? If not, what is your basis for not considering them?

Response

No

While time related variations are not factored into the base PRA model for TMI 1, symptoms of grid stress such as maximum generation conditions, low grid voltage, or severe weather conditions require identification of such dynamic conditions should they occur, and risk management actions are then taken to mitigate the risk or reschedule the work as appropriate.

(e) Do you have contacts with the TSO to determine current and anticipated grid conditions as part of the grid reliability evaluation performed before conducting grid-risk-sensitive maintenance activities?

Response

Yes

The protocol for NPP notification of actual or anticipated grid conditions is outlined in the response to 1(b). Any work performed on the grid risk sensitive equipment is evaluated for risk using these current or anticipated conditions as part of the evaluation prior to performance. Specific contacts for the TSO/TO (i.e., PJM/FirstEnergy) are identified within site specific risk management and assessment procedures. Repeated contact is made at prescribed intervals during scheduling process for grid sensitive activities. Further discussion describing 10 CFR 50.65(a)(4) Maintenance Rule implementation requirements for TMI 1 is documented in a letter from AmerGen to FirstEnergy dated January 19, 2005 (Reference 15).

As stated in the response to 1(b), communication is shared between the TSO (i.e., PJM) and TMI 1 if grid conditions deteriorate from an acceptable level.

(f) Describe any formal agreement or protocol that you have with your TSO to assure that you are promptly alerted to a worsening grid condition that may emerge during a maintenance activity.

Response

As stated in the response to 1(a), TMI 1 is located in the service territory of PJM. PJM is the TSO for TMI 1. The TO providing interconnection services for TMI 1 is FirstEnergy. AmerGen and FirstEnergy are both members of PJM.

All members of PJM execute the PJM Operating Agreement (Reference 1) that details the obligations and responsibilities of both PJM and the PJM members. In the Operating Agreement, each member agrees to abide by the requirements contained in the PJM Manuals. The PJM Manuals contain the specific operational requirements that PJM and each member is required to follow.

As stated in the response to 1(b), PJM Manual M13 (Reference 5) identifies a series of alerts, warnings, and actions that PJM issues to PJM members depending on the identified grid condition. The PJM message is communicated to TMI 1 by their generation dispatcher for a variety of system conditions including capacity emergencies, light load emergencies, weather/environmental emergencies or sabotage/terrorism emergencies.

PJM Manual M3 (Reference 4) requires PJM to initiate notification to TMI 1 through the TO's control center if PJM identifies a switchyard voltage violation. PJM Manual M3 states: "This notification should occur within 15 minutes for voltage contingency violations and immediately for actual voltage violations. To the extent practical, PJM shall direct operations such that the violation is remedied within 30 minutes."

(g) Do you contact your TSO periodically for the duration of the grid-risk sensitive maintenance activities?

Response

No

Communications take place between the TSO (i.e., PJM) through the TO (i.e., FirstEnergy) and TMI 1 as detailed in the response to 1(b) above if grid conditions deteriorate from an acceptable level. At this time there is no periodic mandated contact between the TSO/TO and TMI 1 during the duration of grid-risk-sensitive maintenance activities.

(h) If you have a formal agreement or protocol with your TSO, describe how NPP operators and maintenance personnel are trained and tested on this formal agreement or protocol.

Response

TMI 1 maintenance, operations, and work management personnel associated with schedule development or communicating with the TO (i.e., FirstEnergy) are briefed on TSO/TO interface requirements and expectations but are not formally tested on knowledge retention in this area.

OP-TM-108-107-1002 (Reference 13) outlines the requirements and restrictions associated with work in the switchyard at the station. Operations personnel have been trained on this procedure but are not specifically tested on its content.

(i) If your grid reliability evaluation, performed as part of the maintenance risk assessment required by 10 CFR 50.65(a)(4), does not consider or rely on some arrangement for communication with the TSO, explain why you believe you comply with 10 CFR 50.65(a)(4).

Response

Not applicable

The methods used to integrate grid risk into the quantitative risk evaluation prior to taking equipment out of service for planned maintenance at TMI 1 rely on communication with the TSO/TO.

(j) If risk is not assessed (when warranted) based on continuing communication with the TSO throughout the duration of grid-risk-sensitive maintenance activities, explain why you believe you have effectively implemented the relevant provisions of the endorsed industry guidance associated with the maintenance rule.

Response

Not applicable

As detailed in the response to 2(a), grid status is continually evaluated by PJM using the Security Analysis application. PJM notifies TMI 1 through the TO (i.e., FirstEnergy) of emergent grid conditions. In addition, FirstEnergy (i.e., the TO) possesses a similar system and is also monitoring and evaluating grid conditions. Existing EGC procedures require evaluation of the risk of scheduled on line maintenance activities based on conditions such as power grid stability, weather forecast, and current plant system conditions.

(k) With respect to questions 5(i) and 5(j), you may, as an alternative, describe what actions you intend to take to ensure that the increase in risk that may result from proposed grid-risk-sensitive activities is assessed before and during grid-risk-sensitive maintenance activities, respectively.

Response

Not applicable

6. *Use of risk assessment results, including the results of grid reliability evaluations, in managing maintenance risk, as required by 10 CFR 50.65(a)(4).*

(a) Does the TSO coordinate transmission system maintenance activities that can have an impact on the NPP operation with the NPP operator?

Response

Yes

The TSO/TO coordinates transmission system maintenance activities that can have an impact on the NPP (i.e., TMI 1) with TMI 1.

(b) Do you coordinate NPP maintenance activities that can have an impact on the transmission system with the TSO?

Response

Yes

The NPP (i.e., TMI 1) coordinates maintenance activities that can have an impact on the transmission system with the TSO/TO.

(c) Do you consider and implement, if warranted, the rescheduling of grid-risk-sensitive maintenance activities (activities that could (1) increase the likelihood of a plant trip, (ii) increase LOOP probability, or (iii) reduce LOOP or SBO coping capability) under existing, imminent, or worsening degraded grid reliability conditions?

Response

Yes

Existing procedures require deferring work that would render AC power sources unavailable if severe weather is expected. Risk of scheduled on line work is evaluated based on grid conditions, the weather forecast, and current plant systems status. If the risk analysis determines that risk exceeds a predetermined level, then that configuration is not voluntarily entered and schedule changes are made to reduce the risk to an acceptable level.

(d) If there is an overriding need to perform grid-risk-sensitive maintenance activities under existing or imminent conditions of degraded grid reliability, or continue grid-risk-sensitive maintenance when grid conditions worsen, do you implement appropriate risk management actions? If so, describe the actions that you would take. (These actions could include alternate equipment protection and compensatory measures to limit or minimize risk.)

Response

Yes

When any risk significant SSC is made unavailable, actions are taken to protect redundant or diverse SSCs commensurate with the risk significance of the work being performed in accordance with approved procedures.

(e) Describe the actions associated with questions 6(a) through 6(d) above that would be taken, state whether each action is governed by documented procedures and identify the procedures, and explain why these actions are effective and will be consistently accomplished.

Response

The outage coordination process is documented in the PJM Manuals and agreed to by PJM (i.e., the TSO) and the members. AmerGen and FirstEnergy (i.e., the TO) are both members of PJM. In addition, PJM has computerized tools to track the process throughout its evolution, so that PJM, FirstEnergy and AmerGen are clear what the status is and what the expectations are.

Planned transmission outages are coordinated in accordance with a process detailed in PJM Manual M3, Section 4 (Reference 4). The process requires advanced notice and subsequent PJM approval for all outages to ensure grid reliability. On the outage start day, the system is analyzed one last time by PJM before permitting the equipment to be switched out of service.

Once the equipment is switched out of service, grid status is continually evaluated by the PJM Security Analysis application. In addition, the TO (i.e., FirstEnergy), is performing similar monitoring and evaluation. PJM notifies the NPP through the TO's control center, as discussed in the response to 1(b).

Interface with the TO (i.e., FirstEnergy) is identified in accordance with TMI 1 site specific procedure OP-TM-108-107-1002 (Reference 13).

Actions specified in 6(c) and 6(d) are specified in the EGC Work Management procedure WC-AA-101 (Reference 7) and is applicable to TMI 1.

(f) Describe how NPP operators and maintenance personnel are trained and tested to assure they can accomplish the actions described in your answers to question 6(e).

Response

TMI 1 Maintenance, Operations, and Work Management personnel associated with schedule development and/or risk assessment are briefed on procedure expectations but are not formally tested on knowledge retention in this area.

(g) If there is no effective coordination between the NPP operator and the TSO regarding transmission system maintenance or NPP maintenance activities, please explain why you believe you comply with the provisions of 10 CFR 50.65(a)(4).

Response

Not applicable

Effective coordination is directed by PJM (i.e., the TSO) procedures and interface between FirstEnergy (i.e., the TO) and TMI 1 is identified in accordance with OP-TM-108-107-1002 (Reference 13).

(h) If you do not consider and effectively implement appropriate risk management actions during the conditions described above, explain why you believe you effectively addressed the relevant provisions of the associated NRC-endorsed industry guidance.

Response

Not applicable

Effective and appropriate risk management actions are described in plant procedures and implemented during the conditions described above.

(i) You may, as alternative to questions 6(g) and 6 (h) describe what actions you intend to take to ensure that the increase in risk that may result from grid-risk-sensitive maintenance activities is managed in accordance with 10 CFR 50.65(a)(4).

Response

Not applicable

Offsite power restoration procedures in accordance with 10 CFR 50.63 as developed in Section 2 of RG 1.155.

Pursuant to 10 CFR 50.63, the NRC requires that each NPP licensed to operate to be able to withstand an SBO for a specified duration and recover from the SBO. NRC RG 1.155 gives licensees guidance on developing their approaches for complying with 10 CFR 50.63.

7. *Procedures for identifying local power sources[1] that could be made available to resupply your plant following a LOOP event.*

   Note: Section 2, "Offsite Power," of RG 1.155 (ADAMS Accession No. ML003740034) states:

   > *Procedures should include the actions necessary to restore offsite power and use nearby power sources when offsite power is unavailable. As a minimum, the following potential causes for loss of offsite power should be considered:*
   >
   > - *Grid undervoltage and collapse*
   > - *Weather-induced power loss*
   > - *Preferred power distribution system faults that could result in the loss of normal power to essential switchgear buses*

   (a) Briefly describe any agreement made with the TSO to identify local power sources that could be made available to resupply power to your plant following a LOOP event.

Response

TMI 1 is located in the service territory of PJM. PJM is the Transmission System Operator (TSO) for TMI 1. The Transmission Owner (TO) providing interconnection services for TMI 1 is FirstEnergy. AmerGen and FirstEnergy are both members of PJM.

All members of PJM execute the "Operating Agreement of PJM Interconnection, LLC," (Reference 1) that details the obligations and responsibilities of both PJM and the PJM members. In the Operating Agreement, each member agrees to abide by the requirements contained in the PJM Manuals. The PJM Manuals contain the specific operational requirements that PJM and each member is required to follow.

FirstEnergy (i.e., the TO) is also a signatory on the "PJM Consolidated Transmission Owners Agreement (PJM TOA)," (Reference 2). Section 4.5 of the PJM TOA requires the TOs to operate and maintain their transmission facilities in accordance with the PJM Manuals.

PJM (i.e., the TSO) is responsible for coordinating restoration of all or parts of the bulk power system in the PJM service territory. FirstEnergy (i.e., the TO) is responsible for cooperating and coordinating with PJM and other PJM members during the restoration of all or parts of the bulk power system in the PJM service territory.

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[1] *This includes items such as nearby or onsite gas turbine generators, portable generators, hydro generators, and black-start fossil power plants.*

PJM Manual M36, "System Restoration," (Reference 9) gives priority to the restoration of offsite power to NPPs (i.e., TMI 1) in the PJM service territory. The TSO (i.e., PJM) and the TO (i.e., FirstEnergy) will utilize the best power sources and transmission paths available based on the specific event to restore offsite power since there is no way to accurately predict the extent and characteristics of a specific blackout. The TSO and TO have multiple options available to restore offsite power and these would not be limited to local power sources.

TMI 1 has an Interconnection Agreement with FirstEnergy (i.e., the TO) that requires use of "best efforts" to restore to service the facilities that they own or control in order to restore the TMI 1 offsite power circuit back to an operable status (Reference 12).

PJM provided the following information to AmerGen regarding this response in a letter from PJM to all PJM nuclear owners (Reference 6).

"The PJM Restoration Manual (M36) details the process to be followed during a system restoration. The process reiterates the specific offsite power requirements for NPPs:

> 'Offsite power should be restored as soon as possible to nuclear units, both units that had been operating and those that were already offline prior to the system disturbance, without regard to using these units for restoring customer load.'

However, due to the myriad of possible restoration scenarios, no specific power sources to resupply NPPs are identified. The PJM restoration process allows for the fact that the blacked out area may or may not be separated from the remainder of the system. Regardless of the scenario, there is a clear recognition of the importance of restoring an NPP offsite power source.

PJM Manual M36 further states: 'Transmission Owners and Nuclear Power Plants must effectively communicate to keep the Nuclear Power Plant apprised of the anticipated restoration time for offsite power.' The manual also states that for PJM Restoration Drills the objectives should include 'Ensure that all nuclear units have been provided with one offsite source within 4 hours,' and that the PJM Nuclear Generation Owner/Operator Users Group should be debriefed on the drill results.

In support of the restoration objectives outlined in the PJM Restoration Manual (M36), there are generating units designated as critical black-start units electrically close to each of the NPPs. These black start units are required to provide black start capability whenever necessary. The adequacy of black-start resources to support system restoration is managed through a process contained in PJM Manual M10, "PreScheduling Operations," (Reference 10), Section 2. The process ensures the continuous availability of black start units to support the restoration needs of the NPPs even when a designated black start unit is on a planned outage."

(b) Are your NPP operators trained and tested on identifying and using local power sources to resupply your plant following a LOOP event? If so, describe how.

Response

No

TMI 1 operators are not specifically trained and tested on identifying and using local power sources to resupply the NPP (i.e., TMI 1) following a LOOP event. The identification and use of local power sources for TMI 1 are under the control of PJM (i.e., the TSO) and FirstEnergy (i.e., the TO) in accordance with the procedures and interface agreements described in the response to 7(a). The response to this question does not address the operation of the TMI 1 alternate AC source established under 10 CFR 50.63, "Loss of all alternating current power," (i.e., Station Blackout (SBO) Rule), for which TMI 1 operators are trained and tested to identify and use under SBO conditions.

(c) If you have not established an agreement with your plant's TSO to identify local power sources that could be made available to resupply power to your plant following a LOOP event, explain why you believe you comply with the provisions of 10 CFR 50.63, or describe what actions you intend to take to establish compliance.

Response

The identification and use of local power sources for restoration of offsite power to TMI 1 following a LOOP event are under the control of PJM (i.e., the TSO) and FirstEnergy (i.e., the TO) in accordance with the procedures and interface agreements described in the response to 7(a). Due to the myriad of possible restoration scenarios, no specific power sources to resupply TMI 1 are identified. The procedures identified by RG 1.155, "Station Blackout," (Reference 11) that include the actions necessary to restore offsite power and the use of nearby power sources are also under the control of PJM and FirstEnergy.

Note that, as detailed in the response to 7(a), both FirstEnergy (i.e., the TO) and PJM (i.e., the TSO) have stated that restoring offsite power to a NPP (i.e., TMI 1) is a priority.

The identification and use of local power sources that could be made available to resupply power to the NPP following a LOOP event are not part of the current TMI 1 operating procedures and training since they are outside of TMI 1's direct control.

Losses of offsite power caused by grid failures at a frequency of equal to or greater than once in 20 site-years in accordance with Table 4 of Regulatory Guide 1.155 for complying with 10 CFR 50.63.

Pursuant to 10 CFR 50.63, the NRC requires that each NPP licensed to operate be able to withstand an SBO for a specified duration and recover from the SBO. NRC RG 1.155 gives licensees guidance on developing their approaches to complying with 10 CFR 50.63.

8. Maintaining-SBO coping capabilities in accordance with 10 CFR 50.63.

(a) Has your NPP experienced a total LOOP caused by grid failure since the plant's coping duration was initially determined under 10 CFR 50.63?

Response

TMI 1 has not experienced a total LOOP caused by grid failure since the coping duration was initially determined under 10 CFR 50.63, "Loss of all alternating current power," (i.e., Station Blackout (SBO) Rule). A review of TMI 1 records including the Licensee Event Report (LER) database from July 1988, when the SBO Rule was added, was performed to make this determination.

This determination is consistent with the data presented in NUREG/CR-6890, Volume 1, "Reevaluation of Station Blackout Risk at Nuclear Power Plants – Analysis of Offsite Power Events: 1986-2004," (Reference 8), Appendix A, "LOOP Event Database," Section A-2, "Data Tables," Table A –1, Loop Events for 1986-2004, sorted by plant."

In addition, the review of LERs since Reference 8 was issued to present has concluded that there were no additional grid failure based LOOP events during this period.

(b) If so, have you reevaluated the NPP using the guidance in Table 4 of RG 1.155 to determine if your NPP should be assigned to the P3 offsite power design characteristic group?

Response

Not applicable

(c) If so, what were the results of this reevaluation, and did the initially determined coping duration for the NPP need to be adjusted?

Response

Not applicable

(d) If your NPP has experienced a total LOOP caused by grid failure since the plant's coping duration was initially determined under 10 CFR 50.63 and has not been reevaluated using the guidance in Table 4 of RG 1.155, explain why you believe you comply with the provisions of 10 CFR 50.63 as stated above, or described what actions you intend to take to ensure that the NPP maintains its SBO coping capabilities in accordance with 10 CFR 50.63.

Response

Not applicable

Actions to ensure compliance

9. *If you determine that any action is warranted to bring your NPP into compliance with NRC regulatory requirements, including TSs, GDC 17, 10 CFR 50.65(a)(4), 10 CFR 50.63, 10 CFR 55.59 or 10 CFR 50.120, describe the schedule for implementing it.*

Response

Not applicable

References

1. "Operating Agreement of PJM Interconnection, LLC," revised through February 6, 2006

2. "Consolidated Transmission Owners Agreement," effective March 19, 2006

3. PJM Manual 01, "Control Center Requirements," Revision 10, effective February 7, 2006

4. PJM Manual 3, "Transmission Operations," Revision 20, effective February 10, 2006

5. PJM Manual 13, "Emergency Operations," Revision 24, effective February 22, 2006

6. 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

7. EGC procedure WC-AA-101, "On-Line Work Control Process," Revision 11

8. NUREG/CR-6890, Volume 1, "Reevaluation of Station Blackout Risk at Nuclear Power Plants – Analysis of Offsite Power Events: 1986-2004," Revision 0

9. PJM Manual 36, "System Restoration," Revision 2, effective November 1, 2005

10. PJM Manual 10, "Pre-Scheduling Operations," Revision 18, effective August 10, 2005

11. Regulatory Guide 1.155, "Station Blackout," Revision 0

12. "Interconnection Agreement by and among AmerGen Energy Company, LLC and Metropolitan Edison Company for the Three Mile Island Unit 1 Nuclear Generating Station," dated October 15, 1998

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

14. TMI procedure 1107-11, "TMI Grid Operations"

15. Letter from G. E. Chick (TMI Plant Manager, AmerGen Energy Company, LLC) to D. Trump (FirstEnergy Corporation), "Update to TMI-230 kV Switchyard," dated January 19, 2005

16. NRC Information Notice IN 93-17, "Safety Systems Response to Loss of Coolant and Loss of Offsite Power," Revision 1, dated March 25, 1994

17. SECY-05-0219, "Issuance of Nuclear Regulatory Commission Generic Letter 2005-XX, 'Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power,'" dated December 2, 2005

18. TMI operating procedure 1102-4, "Power Operation"

19. TMI Abnormal Operating Procedure OP-TM-AOP-022, "Load Rejection"

20. TMI Abnormal Operating Procedure OP-TM-AOP-020, "Loss of Station Power"

21. TMI Emergency Operating Procedure OP-TM-EOP-001, "Reactor Trip"

22. EGC procedure WC-AA-107, "Seasonal Readiness," Revision 2

23. SOER 99-1, "Loss of Grid," December 27, 1999

24. SOER 99-1, "Loss of Grid – Addendum," December 9, 2004

25. Jeffrey J. Mackauer, Manager – Transmission Operation Services, FirstEnergy Corporation, "Exelon Nuclear – NRC Generic Letter Response," March 9, 2006, personal email to John Gyrath, Exelon Nuclear, (March 9, 2006)

ATTACHMENT 10

60-day Response to NRC Generic Letter 2006-02

QUAD CITIES NUCLEAR POWER STATION, Units 1 and 2

Renewed FOL Nos. DPR-29 and DPR-30

On February 1, 2006, the NRC issued Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power." 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 Generic Letter requested that licensees answer the following questions and provide the information to the NRC with respect to each of their Nuclear Power Plants (NPPs).

Use of protocols between the NPP licensee and the TSO, ISO, or RC/RA and the use of analysis tools by TSOs to assist NPP licensee in monitoring grid conditions to determine the operability of offsite power system under plant TS.

GDC 17, 10 CFR Part 50, Appendix A, requires that licensees minimize the probability of the loss of power from the transmission network given a loss of the power generated by the nuclear power unit(s).

1. *Use of protocols between the NPP licensee and the TSO, ISO, or RC/RA to assist the NPP licensee in monitoring grid conditions to determine the operability of offsite power system under plant TS.*

    (a) Do you have a formal agreement or protocol with your TSO?

    Response

    Yes

    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.

    All members of PJM execute the "Operating Agreement of PJM Interconnection, LLC," (Reference 1) that details the obligations and responsibilities of both PJM and the PJM members. In the Operating Agreement, each member agrees to abide by the requirements contained in the PJM Manuals. The PJM Manuals contain the specific operational requirements that PJM and each member is required to follow.

    ComEd (i.e., the TO) is also a signatory on the "PJM Consolidated Transmission Owners Agreement (PJM TOA)," (Reference 2). Section 4.5 of the PJM TOA requires the TOs to operate and maintain their transmission facilities in accordance with the PJM Manuals.

    The PJM Operating Agreement requires PJM to, "Incorporate the grid reliability requirements applicable to nuclear generating units in the PJM Region planning and operating principles and practices." PJM Manual M01, "Control Center Requirements," Attachment B, "Nuclear Plant Communication Protocol," (Reference 3), provides the roles and responsibilities of nuclear stations, TOs, and PJM with regard to communications both in normal and emergency circumstances. The nuclear power plant (NPP) notification requirements are contained in PJM Manual M3, "Transmission Operations," Section 3 (Reference 4).

In addition to the agreements delineated in the PJM Operating Agreement and the PJM Manuals, EGC has jointly approved interface procedures with the TO that address the monitoring of the offsite source voltages and the notification protocols. EGC procedure OP-AA-108-107-1002, "Interface Agreement between Exelon Energy Delivery and Exelon Generation for Switchyard Operations," (Reference 10) outlines the responsibilities and required work interfacing activities.

(b) Describe any grid conditions that would trigger a notification from the TSO to the NPP licensee and if there is a time period required for the notification.

Response

PJM Manual M3 (Reference 4) requires PJM to initiate notification to QCNPS through the TO's control center if PJM identifies a switchyard voltage violation. PJM Manual M3 states: "This notification should occur within 15 minutes for voltage contingency violations and immediately for actual voltage violations. To the extent practical, PJM shall direct operations such that the violation is remedied within 30 minutes."

In addition, PJM Manual M13, "Emergency Operations," (Reference 5) identifies a series of alerts, warnings, and actions that PJM issues to PJM members depending on the identified grid condition. The PJM message is communicated to QCNPS by their generation dispatcher through the EGC Nuclear Duty Officer (NDO) for a variety of system conditions including the following:

Capacity Emergencies
- Maximum Emergency Generation Loading
- Load Management Curtailment
- Manual Load Dump Warning

Light Load Emergencies
- Minimum Generation Emergency
- Local Minimum Generation Emergency

Weather/Environmental Emergencies
- Hot/Cold Weather Alerts
- Thunderstorms and Tornadoes
- Solar Magnetic Disturbances

Sabotage/Terrorism Emergencies

(c) Describe any grid conditions that would cause the NPP licensee to contact the TSO. Describe the procedures associated with such a communication. If you do not have procedures, describe how you assess grid conditions that may cause the NPP licensee to contact the TSO.

Response

As required by PJM Manuals, communications between QCNPS and PJM (TSO) are generally through the Transmission Owner (TO) providing the interconnection service.

QCNPS will contact the TSO/TO for grid conditions that have parameters that are observable at the NPP. These conditions include the following:

- Loss of Offsite Power (LOOP)
- Abnormal switchyard voltage
- Automatic (protective) switchyard circuit breaker operation
- Switchyard alarms
- Grid disturbances (observable frequency or voltage fluctuations)

In addition to any alarm response procedures for the above applicable conditions, TSO/TO notifications are controlled by operating procedures, (e.g., OP-AA-108-107-1001, "Station Response to Grid Capacity Conditions"), and Abnormal Operating Procedures, (e.g., QCOA 6100-03, "Loss of Offsite Power," QCOA 6100-04, "Station Blackout," QCOA 6000-03, "Low Switchyard Voltage," and QCOA 6000-02, "Main Generator Abnormal Operation").

QCNPS will contact the TSO/TO during a grid restoration process to obtain grid status in preparation for returning the plant buses to the offsite source.

QCNPS also notifies the TSO/TO of switchyard equipment deficiencies identified by NPP personnel. Jointly approved interface agreements/procedures between EGC and the TO identify the communication protocols for station identified switchyard deficiencies. EGC procedures OP-AA-108-107-1002 (Reference 10) and WC-AA-8000 (Reference 7) outline the responsibilities and required work interfacing activities.

In addition, QCNPS will notify the TSO/TO of NPP configurations that potentially impact grid conditions. A jointly approved interface agreement/procedure, OP-AA-108-107-1002 (Reference 10), between EGC and the TO identifies the requirements for communication of the conditions listed below:

- NPP MVAR limitations
- NPP Main generator voltage regulator not in "Automatic" mode
- NPP inability to provide the MVARs requested by the TSO/TO

Note that any QCNPS MW limitations or limitations on the rate at which the NPP power may be raised or lowered are communicated to the generation dispatcher.

(d) Describe how NPP operators are trained and tested on the use of the procedures or assessing grid conditions in question 1(c).

Response

QCNPS licensed operators are trained and tested in accordance with the Systematic Approach to Training (SAT). Procedures and policies are routinely reviewed for training through this process for improvement of operator performance. The items considered for training include Operating Procedures, Annunciator Response Procedures, Abnormal Operating Procedures, and Emergency Operating Procedures that require interface with the TSO in accordance with the established protocol. These procedures may be utilized based on various grid, switchyard, or plant symptoms to assess, respond to or mitigate off-normal plant and grid conditions. Additionally, SOER 99-01, "Loss of Grid," (Reference 25) and SOER 99-01, "Loss of Grid – Addendum," (Reference 26) specifically are captured in the Licensed Operator Requalification Training Program (LORT) Long Range Training Program. These topics, in varying detail based upon the SAT process or as part of implementing EGC procedure WC-AA-107, "Seasonal Readiness," (Reference 24) are reviewed periodically with QCNPS operators. Testing is commensurate with the material presented and any performance issues are identified for inclusion in future training.

(e) If you do not have a formal agreement or protocol with your TSO, describe why you believe you continue to comply with the provisions of GDC 17 as stated above, or describe what actions you intend to take to assure compliance with GDC 17.

Response

Not applicable. Formal agreements exist for QCNPS.

(f) If you have an existing formal interconnection agreement or protocol that ensures adequate communication and coordination between the NPP license and the TSO, describe whether this agreement or protocol requires that you be promptly notified when the conditions of the surrounding grid could result in degraded voltage (i.e., below TS nominal trip setpoint value requirements; including NPP licensees using allowable value in its TSs) or LOOP after a trip of the reactor units(s).

Response

PJM Manual M3 (Reference 4) requires PJM to initiate a notification to QCNPS through its respective transmission owner's control center if PJM identifies a NPP switchyard voltage violation. PJM Manual M3 states: "This notification should occur within 15 minutes for voltage contingency violations and immediately for actual voltage violations. To the extent practical, PJM shall direct operations such that the violation is remedied within 30 minutes." The trip of a NPP (i.e., trip of a QCNPS unit) is one of the contingencies analyzed by PJM. PJM analyzes the QCNPS switchyard contingency voltages to the voltage limits provided by QCNPS. The voltage limits provided for QCNPS are based on the existing design basis analysis.

(g) Describe the low switchyard voltage conditions that would initiate operation of plant degraded voltage protection.

Response

Switchyard voltage below a value maintaining emergency bus voltage above the maximum reset value of the degraded voltage relay (3969 volts) will cause a trip of the preferred power source after a time delay of approximately 7 seconds with a Loss of Coolant Accident (LOCA) signal present. The relation between the switchyard voltage and the emergency bus voltage is dependent on the system auxiliary transformer impedance and the winding load. Under design basis accident (i.e., Large Break LOCA) conditions, the maximum loading is known and contained in the QCNPS calculations of record. The design basis maximum loading and the degraded voltage relay reset voltage were used to determine the switchyard voltage needed for the system to remain connected to the offsite power source. For QCNPS, this corresponds to a switchyard voltage of approximately 352.9 kV.

In other conditions, the loading is less than the expected LOCA loading and will vary considerably depending on which loads are needed to support unit conditions. Under these conditions the required QCNPS switchyard voltage will be less than that required to support LOCA loading.

2. *Use of criteria and methodologies to assess whether the offsite power system will become inoperable as a result of a trip of your NPP.*

(a) Does your NPP's TSO use any analysis tools, an online analytical transmission system studies program, or other equivalent predictive methods to determine the grid conditions that would make the NPP offsite power system inoperable during various contingencies? If available to you, please provide a brief description of the analysis tool that is used by the TSO.

Response

Yes

The PJM Energy Management System (EMS) includes a Security Analysis application which runs approximately every 1 minute and analyzes ~4,000 contingencies on the PJM system (Reference 6). The analysis provides results with respect to thermal, voltage, and voltage drop limit violations. One of the contingencies analyzed by the PJM EMS is the trip of a NPP (i.e., trip of a QCNPS unit).

In addition, ComEd (i.e., the TO) possesses a similar system that also calculates post-contingency voltage limit violations. One of the contingencies analyzed by ComEd is the trip of a QCNPS unit.

(b) Does your NPP's TSO use an analysis tool as the basis for notifying the NPP licensee when such a condition is identified? If not, how does the TSO determine if conditions on the grid warrant NPP licensee notification?

Response

Yes

The results of the PJM Security Analysis application contain the specific contingency of the NPP tripping as the contingent element. Violation of the unit trip contingency voltage limit would result in notification of the NPP (i.e., QCNPS) in accordance with PJM Manual M3, Section 3 (Reference 4).

ComEd (i.e., the TO) also possesses similar capability to monitor the same condition.

(c) If your TSO uses an analysis tool, would the analysis tool identify a condition in which a trip of the NPP would result in switchyard voltages (immediate and/or long-term) falling below TS nominal trip setpoint value requirements (including NPP licensees using

allowable value in its TSs) and consequent actuation of plant degraded voltage protection? If not, discuss how such a condition would be identified on the grid.

Response

Yes

The trip of the NPP (i.e., trip of a QCNPS unit) is one of the contingencies analyzed by the PJM Security Analysis application. PJM analyzes the NPP switchyard contingency voltages to the voltage limits provided by QCNPS. The voltage limits provided by QCNPS are based on the plant's design basis analysis as discussed in the response to 1(g).

ComEd (i.e., the TO) also possesses similar capability to monitor the same condition.

(d) If your TSO uses an analysis tool, how frequently does the analysis tool program update?

Response

The PJM EMS includes a Security Analysis application that currently updates approximately every 1-minute. In addition, ComEd (i.e., the TO) possesses a Security Analysis application that updates approximately every 6 minutes (Reference 27).

(e) Provide details of analysis tool-identified contingency conditions that would trigger an NPP licensee notification from the TSO.

Response

PJM notifies QCNPS through the TO (i.e., ComEd) control center whenever actual or post-contingency voltages are determined to be below the QCNPS switchyard voltage limits. This requirement applies to all contingencies involving the tripping of the NPP or any transmission facility as the contingent element. The notification is required even if the voltage limits are the same as the standard PJM voltage limits in accordance with PJM Manual M3 (Reference 4).

(f) If an interface agreement exists between the TSO and the NPP licensee, does it require that the NPP licensee be notified of periods when the TSO is unable to determine if offsite power voltage and capacity could be inadequate? If so, how does the NPP licensee determine that the offsite power would remain operable when such a notification is received?

Response

Yes

QCNPS unit trip contingency voltage calculations are performed by the PJM EMS and the TO (i.e., ComEd) Security Analysis application. The PJM EMS consists of a primary and backup system. If the PJM EMS fails, the ComEd Security Analysis application continues to analyze the QCNPS unit trip contingency voltage. QCNPS will be notified if the real time contingency analysis capability of PJM and the TO (i.e., ComEd) are lost simultaneously in accordance with PJM Manual M01, Section 2 (Reference 3).

If QCNPS is notified that PJM and ComEd (i.e., the TO) have both lost their real time contingency analysis capability, QCNPS would request PJM and ComEd to provide an assessment of the current condition of the grid based on the tools that PJM and ComEd have available. The determination of the operability of the offsite sources would consider the assessment provided by PJM and ComEd and whether the current condition of the grid is bounded by the grid studies previously performed for QCNPS.

(g) After an unscheduled inadvertent trip of the NPP, are the resultant switchyard voltages verified by procedure to be bounded by the voltages predicted by the analysis tool?

Response

No

There is presently no formal process for comparing the actual post-trip voltages to the post-trip contingency voltage results calculated by the PJM and the TO (i.e., ComEd) Security Analysis applications.

PJM provided the following information to EGC regarding this response in a letter from PJM to all PJM nuclear owners (Reference 6).

"Because the PJM transmission owning member companies have similar Security Analysis programs to PJM, there are many opportunities to compare the results of the respective Security Analysis programs. In this manner, there is a high confidence that the Security Analysis results are accurate within the precision of the calculations.

PJM retains the EMS results for a period of approximately 3 weeks after real time. It is possible to use those saved EMS results to repeat the Security Analysis calculations and compare them to the actual voltages from a unit trip. However, the NPP trips occur so infrequently that it would take a number of data points to verify the accuracy with any statistical significance. This process could take years if the process is limited to a comparison of only NPP trips."

(h) If an analysis tool is not available to the NPP licensee's TSO, do you know if there are any plans for the TSO to obtain one? If so, when?

Response

Not applicable. QCNPS TSO (i.e., PJM) has an analysis tool.

(i) If an analysis tool is not available, does your TSO perform period studies to verify that adequate offsite power capability, including adequate NPP post-trip switchyard voltages (immediate and/or long-term), will be available to the NPP licensee over the projected timeframe of the study?

Response

Not applicable. QCNPS TSO (i.e., PJM) has an analysis tool.

(a) Are the key assumptions and parameters of these periodic studies translated into TSO guidance to ensure that the transmission system is operated within the bounds of the analyses?

Response

Not applicable. QCNPS TSO (i.e., PJM) has an analysis tool.

(b) If the bounds of the analyses are exceeded, does this condition trigger the notification provisions discussed in question 1 above?

Response

Not applicable. QCNPS TSO (i.e., PJM) has an analysis tool.

(j) If your TSO does not use, or you do not have access to the results of an analysis tool, or your TSO does not perform and make available to you periodic studies that determine the adequacy of offsite power capability, please describe why you believe you comply with the provisions of GDC 17 as stated above, or describe what compensatory actions you intend to take to ensure that the offsite power system will be sufficiently reliable and remain operable with high probability following a trip of your NPP.

Response

Not applicable. QCNPS TSO (i.e., PJM) has an analysis tool. In addition the applicable contingency voltage results are made available to QCNPS as needed.

3. *Use of criteria and methodologies to assess whether the NPP's offsite power system and safety-related components will remain operable when switchyard voltages are inadequate.*

(a) If the TSO notifies the NPP operator that a trip of the NPP, or the loss of the most critical transmission line or the largest supply to the grid would result in switchyard voltages (immediate and/or long-term) below TS nominal trip setpoint value requirements (including NPP licensees using allowable value in its TSs) and would actuate plant degraded voltage protection, is the NPP offsite power system declared inoperable under the plant TSs? If not, why not?

Response

If the TSO (i.e., PJM) notifies QCNPS that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., trip of a QCNPS unit) is below the pre-determined notification value, QCNPS will review the applicability to the plant operating configuration and will declare the offsite power source inoperable in accordance with Technical Specifications (TSs) if appropriate. The notification value provided to PJM by QCNPS is based on the QCNPS degraded voltage design basis analysis.

Predicted contingency voltages following the loss of a transmission facility (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 for QCNPS at this time. If the TSO (i.e., PJM) notifies QCNPS of a predicted contingency voltage violation resulting from the postulated trip of a transmission facility, QCNPS will perform a risk analysis of in-progress and scheduled plant work and will take action as appropriate.

The NPP unit trip contingency can be caused by plant-centered events. The use of the NPP unit trip contingency as the contingency element upon which offsite power operability is based is consistent with the final paragraph of General Design Criterion (GDC) 17, "Electric power systems," of 10 CFR Part 50 Appendix A, "General Design Criteria for Nuclear Power Plants," which requires provisions be included to minimize the probability of the loss of power from the transmission network given a loss of the power generated by the NPP (i.e., a QCNPS unit).

Postulated contingencies on the transmission system are currently not used as the basis for offsite source operability determinations since loss of power from the transmission network would not occur as a result of loss of power generated by a NPP unit (i.e., a QCNPS unit). Such events (e.g., loss of a transmission line) are only postulated and have not actually occurred, and the offsite power sources remain capable of supporting a safe shutdown and mitigating the effects of an accident. Loss of power from the transmission network would not occur as a result of loss of power generated by a NPP unit and therefore the GDC 17 provision discussed in GL 2006-02 is met.

(b) If onsite safety-related equipment (e.g., emergency diesel generators or safety-related motors) is lost when subjected to a double sequencing (LOCA with delayed LOOP event) as a result of the anticipated system performance and is incapable of performing its safety functions as a result of responding to an emergency actuation signal during this condition, is the equipment considered inoperable? If not, why not?

Response

Although some features have been incorporated into the plant design, requirements for analysis and design considerations for double sequencing are not included within the QCNPS current licensing and design basis as documented in the QCNPS Updated Final Safety Analysis Report (UFSAR). QCNPS has not been explicitly analyzed for all issues associated with double sequencing. Onsite safety-related equipment at QCNPS (e.g., emergency diesel generators or safety-related motors) is not declared inoperable as a result of a TSO (i.e., PJM) unit trip contingency voltage notification.

Based on Enclosure 2 of SECY-05-0219, "Issuance of Nuclear Regulatory Commission Generic Letter 2005-XX, 'Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power,'" (Reference 18) which provided NRC guidance on responding to this issue, a review was performed for QCNPS of the loading logic for the diesel generators as well as the safety-related breakers' anti-pumping logic. This review concluded that onsite safety-related equipment (i.e., emergency diesel generators or safety-related motors) is not lost as a result of diesel generator block loading and breaker lockout from anti-pump circuitry when subjected to a double sequencing event resulting from inadequate post unit trip voltages. The scope of the review performed for QCNPS is discussed in the response to question 3(c) below.

(c) Describe your evaluation of onsite-related equipment to determine whether it will operate as designed during the condition described in question 3(b).

Response

Although some features have been incorporated into the plant design, requirements for analysis and design considerations for double sequencing are not included within the QCNPS current licensing and design basis as documented in the QCNPS UFSAR. QCNPS has not been explicitly analyzed for all issues associated with double sequencing. However, using the NRC clarification provided in Enclosure 2 of SECY-05-0219 as guidance, a review was performed for the purpose of addressing question 3(b).

This review examined the effects of a double sequencing event on diesel generator block loading and the potential for breaker lockout from the anti-pump circuitry. The review assumed that following a LOCA initiation, separation occurred as a result of degraded voltage relay operation triggered by the loss of a QCNPS unit. The review examined the diesel generator loading logic and determined that the logic is reset by the LOOP event. The second sequence is consistent with that described in the QCNPS UFSAR for a LOOP/LOCA event. Loads are shed as a result of the LOOP signal and the loads are not block loaded onto the diesel generator.

The review also examined the potential for breaker lockout due to the anti-pumping circuitry. This review determined that there was sufficient time between the two sequences such that the breaker charging springs would re-charge and the second closure would be successful. To ensure that a breaker lockout would not occur, the breaker closing logics were also examined to assure that the trip signals were cleared before the second close signal was initiated.

(d) If the NPP licensee is notified by the TSO of other grid conditions that may impair the capability or availability of offsite power, are any plant TS action statements entered? If so, please identify them.

Response

As discussed in the response to 3(a), if the TSO (i.e., PJM) notifies QCNPS that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., trip of a QCNPS unit) is below the pre-determined notification value, QCNPS will review the applicability to the plant operating configuration and will declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by QCNPS is based on the QCNPS degraded voltage design basis analysis.

In addition, if PJM notifies QCNPS that the actual offsite power source voltage is less than the pre-determined notification value, QCNPS will review the applicability to the plant operating configuration and would declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by QCNPS is based on the QCNPS degraded voltage design basis analysis.

(e) If you believe your plant TSs do not require you to declare your offsite power system or safety-related equipment inoperable in any of these circumstances, explain why you believe you comply with the provisions of GDC 17 and your plant TSs, or describe what

compensatory actions you intend to take to ensure that the offsite power system and safety-related components will remain operable when switchyard voltages are inadequate.

Response

The following notifications from the TSO (i.e., PJM) will result in QCNPS declaring the offsite power source inoperable in accordance with TSs.

- If the TSO (i.e., PJM) notifies QCNPS that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., trip of a QCNPS unit) is below the pre-determined notification value, QCNPS will review the applicability to the plant operating configuration and will declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by QCNPS is based on the QCNPS degraded voltage design basis analysis.

- If the TSO (i.e., PJM) notifies QCNPS that the actual offsite power source voltage is less than the pre-determined notification value, QCNPS will review the applicability to the plant operating configuration and would declare the offsite power source inoperable in accordance with TSs if appropriate. The notification value provided to PJM by QCNPS is based on the QCNPS degraded voltage design basis analysis.

Predicted contingency voltages following the loss of a transmission facility (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. If the TSO notifies the NPP of a predicted contingency voltage violation resulting from the postulated trip of a transmission facility, the NPP performs a risk analysis of in-progress and scheduled plant work and takes action as appropriate.

The NPP unit trip contingency can be caused by plant-centered events. The use of the NPP unit trip contingency as the contingency element upon which offsite power operability is based is consistent with the final paragraph of GDC 17 which requires provisions to minimize the probability of the loss of power from the transmission network given a loss of the power generated by the NPP.

Postulated contingencies on the transmission system are not used as the basis for offsite source operability determinations since loss of power from the transmission network would not occur as a result of loss of power generated by the NPP unit. Such events (e.g., loss of a transmission line) are only postulated and have not actually occurred, and the offsite power sources remain capable of affecting a safe shutdown and mitigating the effects of an accident. The GDC 17 provision discussed in the Generic Letter is still met; loss of power from the transmission network would not occur as a result of loss of power generated by the NPP unit.

Onsite safety-related equipment at QCNPS (e.g., emergency diesel generators or safety-related motors) is not declared inoperable as a result of a TSO (i.e., PJM) unit trip contingency voltage notification. Although some features have been incorporated into the plant design, requirements for analysis and design considerations for double sequencing are not included within the QCNPS current licensing and design basis as documented in the QCNPS UFSAR. QCNPS has not been explicitly analyzed for all issues associated with double sequencing.

(f) Describe if and how NPP operators are trained and tested on the compensatory actions mentioned in your answers to questions 3(a) through (e).

Response

QCNPS licensed operators are trained and tested in accordance with the Systematic Approach to Training (SAT). Equipment operability, as defined by TS, including normal and emergency power, offsite circuits, and safety-related components, is under continuous review. Procedures are in place to provide operator guidance and required actions necessary during predicted or actual degraded grid voltage conditions based on information provided by the TSO/TO in accordance with established protocol or as observed by the NPP operator. As part of initial training, requalification training, and annual operating tests, licensed operators are subjected to written examinations, dynamic learning activities, static and/or simulator examinations, Job Performance Measures (JPMs), and evaluated simulator scenarios incorporating topics including the actual or predicted switchyard voltage issues and its effect on AC Source operability. Testing is commensurate with the material presented and any performance issues are identified for inclusion in future training.

4. *Use of criteria and methodologies to assess whether the offsite power system will remain operable following a trip of your NPP.*

(a) Do the NPP operators have any guidance or procedures in plant TS bases sections, the final safety analysis report, or plant procedures regarding situations in which the condition of plant-controlled or monitored equipment (e.g., voltage regulator, auto tap changing transformers, capacitors, static VAR compensators, main generator voltage regulators) can adversely affect the operability of the NPP offsite power system? If so, describe how the operators are trained and tested on the guidance and procedures.

Response

Yes

QCNPS plant controlled or monitored equipment that can adversely affect the operability of the offsite power system is limited to the main generator voltage regulators. EGC and plant specific procedures provide guidance for notification of the TSO/TO (i.e., PJM/ComEd) when the voltage regulator is not in automatic.

QCNPS procedures direct operator actions to control excitation in manual or other mitigating actions to control excitation. Operator actions on a loss of automatic control of the voltage regulator include the requirement to notify the TO (i.e., ComEd) of the failure.

EGC is planning on installing new transformers with automatic load tap changers (LTCs) that provide offsite power to QCNPS Units 1 and 2. Following installation and NRC approval of a License Amendment Request for automatic operation of the LTCs (Reference 14), procedures addressing operation will be implemented at QCNPS.

QCNPS licensed operators are trained and tested in accordance with the Systematic Approach to Training (SAT). Procedures and policies are routinely reviewed for training through this process for improvement of operator performance. The items considered for training include Annunciator Response Procedures, Abnormal Operating Procedures, and Emergency Operating Procedures that require interface with the TSO/TO in accordance with the established protocol. In addition as part of initial training, requalification training, and annual operating tests, licensed operators are subjected to written examinations, static and/or simulator examinations, Job Performance Measures (JPMs), and evaluated simulator scenarios. These evaluations may incorporate topics including the loss of the main generator voltage regulator and actions to mitigate the effect of the failure. Testing is commensurate with the material presented and any performance issues are identified for inclusion in future training.

(b) If your TS bases sections, the final safety analysis report, and plant procedures do not provide guidance regarding situations in which the condition of plant-controlled or monitored equipment can adversely affect the operability of the NPP offsite power system, explain why you believe you comply with the provisions of GDC 17 and the plant TSs, or describe what actions you intend to take to provide such guidance or procedures.

Response

Not applicable

Use of NPP licensee/TSO protocols and analysis tool by TSOs to assist NPP licensees in monitoring grid conditions for consideration in maintenance risk assessments.

The Maintenance Rule (10 CFR 50.65(a)(4)) requires that licensees assess and manage the increase in risk that may result from proposed maintenance activities before performing them.

5. *Performance of grid reliability evaluations as part of the maintenance risk assessments required by 10 CFR 50.65(a)(4).*

(a) Is a quantitative or qualitative grid reliability evaluation performed at your NPP as part of the maintenance risk assessment required by 10 CFR 50.65(a)(4) before performing grid-risk-sensitive maintenance activities? This includes surveillances, post-maintenance testing, and preventive and corrective maintenance that could increase the probability of a plant trip or LOOP or impact LOOP or SBO coping capability, for example, before taking a risk-significant piece of equipment (such as an EDG, a battery, a steam-driven pump, an alternate AC power source) out-of-service?

Response

Yes

Risk is assessed using a process that combines quantitative results from a probabilistic risk assessment (PRA) with a qualitative defense-in-depth model. During the planning and scheduling of work and prior to the execution of work, many factors are assessed for risk including the effect of weather/time of year and grid instability. The combination of unavailable Systems, Structures and Components (SSCs) and planned activities is then assessed in the risk assessment tool. Currently, a procedure update is being implemented to provide additional detail for how to factor grid reliability into the risk assessment tool before taking equipment out of service for planned maintenance. These procedure changes are currently scheduled to be in place at QCNPS by May 15, 2006.

(b) Is grid status monitored by some means for the duration of the grid-risk-sensitive maintenance to confirm the continued validity of the risk assessment and is risk reassessed when warranted? If not, how is the risk assessed during grid-risk-sensitive maintenance?

Response

Yes

Grid status is continually evaluated by PJM using the Security Analysis application. PJM notifies QCNPS through its Transmission Operator, (i.e., ComEd), of emergent grid conditions as discussed in the response to 1(b) above. In addition, ComEd (i.e., the TO) is also performing similar monitoring and evaluation. Existing EGC procedures require evaluation of the risk of scheduled online maintenance activities based on conditions such as power grid stability, weather forecast, and current plant system conditions.

(c) Is there a significant variation in the stress on the grid in the vicinity of your NPP site caused by seasonal loads or maintenance activities associated with critical transmission elements? Is there a seasonal variation (or the potential for a seasonal variation) in the LOOP frequency in the local transmission region? If the answer to either question is yes, discuss the time of year when the variations occur and their magnitude.

Response

The base PRA model reflects the yearly average LOOP frequency because seasonal variations that would cause changes to the frequency of a LOOP cannot be accurately predicted. While time related variations are not factored into the base PRA model for QCNPS, symptoms of grid stress such as maximum generation conditions, low grid voltage, or severe weather conditions require identification of such dynamic conditions should they occur, and risk management actions are then taken to mitigate the risk or reschedule the work as appropriate.

PJM provided the following information to EGC regarding this response in a letter from PJM to all PJM nuclear owners (Reference 6).

"Stress on the grid is manifested in a number of ways. Stress can mean 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.

Regarding the seasonal variability of the stress causers, each has a seasonal component. For example, peak load levels occur at the peak seasons of the summer and winter seasons. While the specific days cannot be predicted, it is known roughly when they will occur. Consequently, maintenance during these times of the year is avoided.

From a transmission system operations perspective, it is the simultaneous combination of stress causers that results in the most difficult operational challenges. For example, experiencing very hot (or cold) weather when we (i.e., PJM) are in the maintenance seasons with a lot of equipment out of service can cause the most severe challenges.

We (i.e., PJM) are aware of the existence of the North American Electric Reliability Council (NERC) and NRC data regarding LOOP frequency. However, it is difficult to assign differential risks to any seasonal variation because of the complexity of the various competing factors, as explained above."

(d) Are known time-related variations in the probability of a LOOP at your plant site considered in the grid-risk-sensitive maintenance evaluation? If not, what is your basis for not considering them?

Response

No

While time related variations are not factored into the base PRA model for QCNPS, symptoms of grid stress such as maximum generation conditions, low grid voltage, or severe weather conditions require identification of such dynamic conditions should they occur, and risk management actions are then taken to mitigate the risk or reschedule the work as appropriate.

(e) Do you have contacts with the TSO to determine current and anticipated grid conditions as part of the grid reliability evaluation performed before conducting grid-risk-sensitive maintenance activities?

Response

Yes

The protocol for NPP notification of actual or anticipated grid conditions is outlined in the response to 1(b). Any work performed on the grid risk sensitive equipment is evaluated for risk using these current or anticipated conditions as part of the evaluation prior to performance. Work is coordinated based on anticipated conditions and planned maintenance during bi-monthly interface meetings between the transmission operator (i.e., ComEd) and the EGC NPPs (i.e., QCNPS).

As stated in the response to 1(b), communication is shared between the TSO (i.e., PJM) and QCNPS if grid conditions deteriorate from an acceptable level. If contingencies are anticipated (e.g., the predicted post NPP trip offsite source voltage less than required) the TSO will provide QCNPS with a one day look ahead notice.

(f) Describe any formal agreement or protocol that you have with your TSO to assure that you are promptly alerted to a worsening grid condition that may emerge during a maintenance activity.

Response

As stated in the response to 1(a), QCNPS is located in the service territory of PJM. PJM is the TSO for QCNPS. The TO providing interconnection services for QCNPS is ComEd. EGC and ComEd are both members of PJM.

All members of PJM execute the PJM Operating Agreement (Reference 1) that details the obligations and responsibilities of both PJM and the PJM members. In the Operating Agreement, each member agrees to abide by the requirements contained in the PJM Manuals. The PJM Manuals contain the specific operational requirements that PJM and each member is required to follow.

As stated in the response to 1(b), PJM Manual M13 (Reference 5) identifies a series of alerts, warnings, and actions that PJM issues to PJM members depending on the identified grid condition. The PJM message is communicated to QCNPS by their generation dispatcher through the EGC NDO for a variety of system conditions including capacity emergencies, light load emergencies, weather/environmental emergencies or sabotage/terrorism emergencies.

PJM Manual M3 (Reference 4) requires PJM to initiate notification to QCNPS through the TO's control center if PJM identifies a switchyard voltage violation. PJM Manual M3 states: "This notification should occur within 15 minutes for voltage contingency violations and immediately for actual voltage violations. To the extent practical, PJM shall direct operations such that the violation is remedied within 30 minutes."

(g) Do you contact your TSO periodically for the duration of the grid-risk sensitive maintenance activities?

Response

No

Communications take place between the TSO (i.e., PJM) through the TO (i.e., ComEd), the NDO and QCNPS as detailed in the response to 1(b) above if grid conditions deteriorate from an acceptable level. If contingencies (e.g., the post trip voltages for QCNPS are predicted to be below the required limit) are anticipated, the TSO/TO will provide QCNPS with a one day look ahead notice. At this time there is no periodic mandated contact between the TSO/TO and QCNPS during the duration of grid-risk-sensitive maintenance activities.

(h) If you have a formal agreement or protocol with your TSO, describe how NPP operators and maintenance personnel are trained and tested on this formal agreement or protocol.

Response

QCNPS maintenance, operations, and work management personnel associated with schedule development or communicating with the TO (i.e., ComEd) are briefed on TSO/TO interface requirements and expectations but are not formally tested on knowledge retention in this area.

(i) If your grid reliability evaluation, performed as part of the maintenance risk assessment required by 10 CFR 50.65(a)(4), does not consider or rely on some arrangement for communication with the TSO, explain why you believe you comply with 10 CFR 50.65(a)(4).

Response

Not applicable

The methods used to integrate grid risk into the quantitative risk evaluation prior to taking equipment out of service for planned maintenance at QCNPS rely on communication with the TSO/TO.

(j) If risk is not assessed (when warranted) based on continuing communication with the TSO throughout the duration of grid-risk-sensitive maintenance activities, explain why you believe you have effectively implemented the relevant provisions of the endorsed industry guidance associated with the maintenance rule.

Response

Not applicable

As detailed in the response to 2(a), grid status is continually evaluated by PJM using the Security Analysis application. PJM notifies QCNPS through the TO (i.e., ComEd) of emergent grid conditions. In addition, ComEd (i.e., the TO) possesses a similar system and is also monitoring and evaluating grid conditions. Existing EGC procedures require evaluation of the risk of scheduled on line maintenance activities based on conditions such as power grid stability, weather forecast, and current plant system conditions.

(k) With respect to questions 5(i) and 5(j), you may, as an alternative, describe what actions you intend to take to ensure that the increase in risk that may result from proposed grid-risk-sensitive activities is assessed before and during grid-risk-sensitive maintenance activities, respectively.

Response

Not applicable

6. *Use of risk assessment results, including the results of grid reliability evaluations, in managing maintenance risk, as required by 10 CFR 50.65(a)(4).*

(a) Does the TSO coordinate transmission system maintenance activities that can have an impact on the NPP operation with the NPP operator?

Response

Yes

The TSO/TO coordinates transmission system maintenance activities that can have an impact on the NPP (i.e., QCNPS) with QCNPS.

(b) Do you coordinate NPP maintenance activities that can have an impact on the transmission system with the TSO?

Response

Yes

The NPP (i.e., QCNPS) coordinates maintenance activities that can have an impact on the transmission system with the TSO/TO.

(c) Do you consider and implement, if warranted, the rescheduling of grid-risk-sensitive maintenance activities (activities that could (1) increase the likelihood of a plant trip, (ii) increase LOOP probability, or (iii) reduce LOOP or SBO coping capability) under existing, imminent, or worsening degraded grid reliability conditions?

Response

Yes

Existing procedures require deferring work that would render AC power sources unavailable if severe weather is expected. Risk of scheduled on line work is evaluated based on grid conditions, the weather forecast, and current plant systems status. If the risk analysis determines that risk exceeds a predetermined level, then that configuration is not voluntarily entered and schedule changes are made to reduce the risk to an acceptable level.

(d) If there is an overriding need to perform grid-risk-sensitive maintenance activities under existing or imminent conditions of degraded grid reliability, or continue grid-risk-sensitive maintenance when grid conditions worsen, do you implement appropriate risk management actions? If so, describe the actions that you would take. (These actions could include alternate equipment protection and compensatory measures to limit or minimize risk.)

Response

Yes

When any risk significant SSC is made unavailable, actions are taken to protect redundant or diverse SSCs commensurate with the risk significance of the work being performed in accordance with approved procedures.

(e) Describe the actions associated with questions 6(a) through 6(d) above that would be taken, state whether each action is governed by documented procedures and identify

the procedures, and explain why these actions are effective and will be consistently accomplished.

Response

The outage coordination process is documented in the PJM Manuals and agreed to by PJM (i.e., the TSO) and the members. EGC and ComEd (i.e., the TO) are both members of PJM. In addition, PJM has computerized tools to track the process throughout its evolution, so that PJM, ComEd and EGC are clear what the status is and what the expectations are.

Planned transmission outages are coordinated in accordance with a process detailed in PJM Manual M3, "Transmission Operations," Section 4 (Reference 4). This process requires advanced notice and subsequent PJM approval for all outages to ensure grid reliability. On the outage start day, the system is analyzed one last time by PJM before permitting the equipment to be switched out of service.

Once the equipment is switched out of service, grid status is continually evaluated by the PJM Security Analysis application as detailed in the response to 2(a). In addition, the TO (i.e., ComEd) is performing similar monitoring and evaluation. PJM notifies the NPP (i.e., QCNPS) through the TO's control center, as discussed in the response to 1(b).

An 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," (Reference 7) directs that schedule coordination meetings are held bi-monthly between the TSO/TO and the NPPs (i.e., QCNPS) to coordinate maintenance activities that can have mutual impact.

Actions specified in questions 6(c) and 6(d) are specified in the EGC Work Management procedure, WC-AA-101, "On-Line Work Control Process," (Reference 8) and is applicable to QCNPS.

(f) Describe how NPP operators and maintenance personnel are trained and tested to assure they can accomplish the actions described in your answers to question 6(e).

Response

QCNPS Maintenance, Operations, and Work Management personnel associated with schedule development and/or risk assessment are briefed on procedure expectations but are not formally tested on knowledge retention in this area.

(g) If there is no effective coordination between the NPP operator and the TSO regarding transmission system maintenance or NPP maintenance activities, please explain why you believe you comply with the provisions of 10 CFR 50.65(a)(4).

Response

Not applicable

Effective coordination is directed by PJM (i.e., the TSO) procedures and jointly approved interface procedures between ComEd (i.e., the TO) and EGC.

(h) If you do not consider and effectively implement appropriate risk management actions during the conditions described above, explain why you believe you effectively addressed the relevant provisions of the associated NRC-endorsed industry guidance.

Response

Not applicable

Effective and appropriate risk management actions are described in plant procedures and implemented during the conditions described above.

(i) You may, as alternative to questions 6(g) and 6 (h) describe what actions you intend to take to ensure that the increase in risk that may result from grid-risk-sensitive maintenance activities is managed in accordance with 10 CFR 50.65(a)(4).

Response

Not applicable

Offsite power restoration procedures in accordance with 10 CFR 50.63 as developed in Section 2 of RG 1.155.

Pursuant to 10 CFR 50.63, the NRC requires that each NPP licensed to operate to be able to withstand an SBO for a specified duration and recover from the SBO. NRC RG 1.155 gives licensees guidance on developing their approaches for complying with 10 CFR 50.63.

7. *Procedures for identifying local power sources[1] that could be made available to resupply your plant following a LOOP event.*

Note: Section 2, "Offsite Power," of RG 1.155 (ADAMS Accession No. ML003740034) states:

> *Procedures should include the actions necessary to restore offsite power and use nearby power sources when offsite power is unavailable. As a minimum, the following potential causes for loss of offsite power should be considered:*
>
> - *Grid undervoltage and collapse*
> - *Weather-induced power loss*
> - *Preferred power distribution system faults that could result in the loss of normal power to essential switchgear buses*

(a) Briefly describe any agreement made with the TSO to identify local power sources that could be made available to resupply power to your plant following a LOOP event.

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[1] *This includes items such as nearby or onsite gas turbine generators, portable generators, hydro generators, and black-start fossil power plants.*

Response

QCNPS is located in the service territory of PJM. PJM is the Transmission System Operator (TSO) for QCNPS. The Transmission Owner (TO) providing interconnection services for QCNPS is ComEd. EGC and ComEd are both members of PJM.

All members of PJM execute the "Operating Agreement of PJM Interconnection, LLC," (Reference 1) that details the obligations and responsibilities of both PJM and the PJM members. In the Operating Agreement, each member agrees to abide by the requirements contained in the PJM Manuals. The PJM Manuals contain the specific operational requirements that PJM and each member is required to follow.

ComEd (i.e., the TO) is also a signatory on the "PJM Consolidated Transmission Owners Agreement (PJM TOA)," (Reference 2). Section 4.5 of the PJM TOA requires the TOs to operate and maintain their transmission facilities in accordance with the PJM Manuals.

PJM (i.e., the TSO) is responsible for coordinating restoration of all or parts of the bulk power system in the PJM service territory. ComEd (i.e., the TO) is responsible for cooperating and coordinating with PJM and other PJM members during the restoration of all or parts of the bulk power system in the PJM service territory.

PJM Manual M36, "System Restoration," (Reference 11) gives priority to the restoration of offsite power to NPPs (i.e., QCNPS) in the PJM service territory. The TSO (i.e., PJM) and the TO (i.e., ComEd) will utilize the best power sources and transmission paths available based on the specific event to restore offsite power since there is no way to accurately predict the extent and characteristics of a specific blackout. The TSO and TO have multiple options available to restore offsite power and these would not be limited to local power sources.

The Interconnection Agreement between the NPP (i.e., QCNPS) and ComEd (i.e., the TO) reinforces the importance and priority of restoring the NPP offsite power source (Reference 15). In addition, QCNPS has an Affiliate Level Arrangement Agreement (ALA) with ComEd (Reference 16) to apply "best efforts" to restore to service the facilities that they own or control in order to restore the QCNPS offsite power circuit back to an operable status.

PJM provided the following information to EGC regarding this response in a letter from PJM to all PJM nuclear owners (Reference 6).

"The PJM Restoration Manual (M36) details the process to be followed during a system restoration. The process reiterates the specific offsite power requirements for NPPs:

> 'Offsite power should be restored as soon as possible to nuclear units, both units that had been operating and those that were already offline prior to the system disturbance, without regard to using these units for restoring customer load.'

However, due to the myriad of possible restoration scenarios, no specific power sources to resupply NPPs are identified. The PJM restoration process allows for the fact that the blacked out area may or may not be separated from the remainder of the system.

Regardless of the scenario, there is a clear recognition of the importance of restoring an NPP offsite power source.

PJM Manual M36 further states: 'Transmission Owners and Nuclear Power Plants must effectively communicate to keep the Nuclear Power Plant apprised of the anticipated restoration time for offsite power.' The manual also states that for PJM Restoration Drills the objectives should include 'Ensure that all nuclear units have been provided with one offsite source within 4 hours,' and that the PJM Nuclear Generation Owner/Operator Users Group should be debriefed on the drill results.

In support of the restoration objectives outlined in the PJM Restoration Manual (M36), there are generating units designated as critical black-start units electrically close to each of the NPPs. These black start units are required to provide black start capability whenever necessary. The adequacy of black-start resources to support system restoration is managed through a process contained in PJM Manual M10, "PreScheduling Operations," (Reference 12), Section 2. The process ensures the continuous availability of black start units to support the restoration needs of the NPPs even when a designated black start unit is on a planned outage."

(b) Are your NPP operators trained and tested on identifying and using local power sources to resupply your plant following a LOOP event? If so, describe how.

Response

No

QCNPS operators are not specifically trained and tested on identifying and using local power sources to resupply the NPP (i.e., QCNPS) following a LOOP event. The identification and use of local power sources for QCNPS are under the control of PJM (i.e., the TSO) and ComEd (i.e., the TO) in accordance with the procedures and interface agreements described in the response to 7(a). The response to this question does not address the operation of the QCNPS alternate AC source established under 10 CFR 50.63, "Loss of all alternating current power," (i.e., Station Blackout (SBO) Rule), for which QCNPS operators are trained and tested to identify and use under SBO conditions.

(c) If you have not established an agreement with your plant's TSO to identify local power sources that could be made available to resupply power to your plant following a LOOP event, explain why you believe you comply with the provisions of 10 CFR 50.63, or describe what actions you intend to take to establish compliance.

Response

The identification and use of local power sources for restoration of offsite power to QCNPS following a LOOP event are under the control of PJM (i.e., the TSO) and ComEd (i.e., the TO) in accordance with the procedures and interface agreements described in the response to 7(a). Due to the myriad of possible restoration scenarios, no specific power sources to resupply QCNPS are identified. The procedures identified by RG 1.155, "Station Blackout," (Reference 13) that include the actions necessary to restore offsite power and the use of nearby power sources are also under the control of PJM and ComEd.

Note that, as detailed in the response to 7(a), both ComEd (i.e., the TO) and PJM (i.e., the TSO) have stated that restoring offsite power to a NPP (i.e., QCNPS) is a priority.

The identification and use of local power sources that could be made available to resupply power to the NPP following a LOOP event are not part of the current QCNPS operating procedures and training since they are outside of QCNPS's direct control.

Losses of offsite power caused by grid failures at a frequency of equal to or greater than once in 20 site-years in accordance with Table 4 of Regulatory Guide 1.155 for complying with 10 CFR 50.63.

Pursuant to 10 CFR 50.63, the NRC requires that each NPP licensed to operate be able to withstand an SBO for a specified duration and recover from the SBO. NRC RG 1.155 gives licensees guidance on developing their approaches to complying with 10 CFR 50.63.

8. Maintaining SBO coping capabilities in accordance with 10 CFR 50.63.

(a) Has your NPP experienced a total LOOP caused by grid failure since the plant's coping duration was initially determined under 10 CFR 50.63?

Response

QCNPS has not experienced a total LOOP caused by grid failure since the coping duration was initially determined under 10 CFR 50.63, "Loss of all alternating current power," (i.e., Station Blackout (SBO) Rule). A review of QCNPS records including the Licensee Event Report (LER) database from July 1988, when the SBO Rule was added, was performed to make this determination.

This determination is consistent with the data presented in NUREG/CR-6890, Volume 1, "Reevaluation of Station Blackout Risk at Nuclear Power Plants – Analysis of Offsite Power Events: 1986-2004," (Reference 9), Appendix A, "LOOP Event Database," Section A-2, "Data Tables," Table A -1, "Loop Events for 1986-2004, sorted by plant."

In addition, the review of LERs since Reference 9 was issued to present has concluded that there were no additional grid failure based LOOP events during this period.

(b) If so, have you reevaluated the NPP using the guidance in Table 4 of RG 1.155 to determine if your NPP should be assigned to the P3 offsite power design characteristic group?

Response

Not applicable

(c) If so, what were the results of this reevaluation, and did the initially determined coping duration for the NPP need to be adjusted?

Response

Not applicable

(d) If your NPP has experienced a total LOOP caused by grid failure since the plant's coping duration was initially determined under 10 CFR 50.63 and has not been reevaluated using the guidance in Table 4 of RG 1.155, explain why you believe you comply with the provisions of 10 CFR 50.63 as stated above, or described what actions you intend to take to ensure that the NPP maintains its SBO coping capabilities in accordance with 10 CFR 50.63.

Response

Not applicable

Actions to ensure compliance

9. If you determine that any action is warranted to bring your NPP into compliance with NRC regulatory requirements, including TSs, GDC 17, 10 CFR 50.65(a)(4), 10 CFR 50.63, 10 CFR 55.59 or 10 CFR 50.120, describe the schedule for implementing it.

Response

Not applicable

References

1. "Operating Agreement of PJM Interconnection, LLC," revised through February 6. 2006
2. "Consolidated Transmission Owners Agreement," effective March 19, 2006
3. PJM Manual 01, "Control Center Requirements," Revision 10, effective February 7, 2006
4. PJM Manual 3, "Transmission Operations," Revision 20, effective February 10, 2006
5. PJM Manual 13, "Emergency Operations," Revision 24, effective February 22, 2006
6. 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
7. EGC procedure WC-AA-8000, "Interface Procedure between Exelon Energy Delivery (ComEd/PECO) and Exelon Generation (Nuclear/Power) for Construction and Maintenance Activities," Revision 0
8. EGC procedure WC-AA-101, "On-Line Work Control Process," Revision 11
9. NUREG/CR-6890, Volume 1, "Reevaluation of Station Blackout Risk at Nuclear Power Plants – Analysis of Offsite Power Events: 1986-2004," Revision 0

10. EGC procedure OP-AA-108-107-1002, "Interface Agreement between Exelon Energy Delivery and Exelon Generation for Switchyard Operations," Revision 2

11. PJM Manual 36, "System Restoration," Revision 2, effective November 1, 2005

12. PJM Manual 10, "Pre-Scheduling Operations," Revision 18, effective August 10, 2005

13. Regulatory Guide 1.155, "Station Blackout," Revision 0

14. Letter from P. R. Simpson (Exelon Generation Company, LLC) to U.S. NRC, "Request for License Amendment Regarding Automatic Operation of Transformer Load Tap Changers," dated January 25, 2006

15. "Facilities, Interconnection and Easement Agreement among ComEd Generation Company LLC, Exelon Generation Company, LLC and Commonweatlh Edison Company," Quad Cities Nuclear Power Station Final Form, dated January 12, 2001

16. "Affiliate Level Arrangement ('ALA') by and among Exelon Energy Delivery Groups of ComEd and Exelon Generation Company, LLC," effective January 1, 2006

17. NRC Information Notice IN 93-17, "Safety Systems Response to Loss of Coolant and Loss of Offsite Power," Revision 1, dated March 25, 1994

18. SECY-05-0219, "Issuance of Nuclear Regulatory Commission Generic Letter 2005-XX, 'Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power,'" dated December 2, 2005

19. EGC procedure OP-AA-108-107-1001, "Station Response to Grid Capacity Conditions," Revision 1

20. QCNPS Abnormal Operating Procedure QCOA 6100-03, "Loss of Offsite Power"

21. QCNPS Abnormal Operating Procedure QCOA 6100-04, "Station Blackout"

22. QCNPS Abnormal Operating Procedure QCOA 6000-03, "Low Switchyard Voltage"

23. QCNPS Abnormal Operating Procedure QCOA 6000-02, "Main Generator Abnormal Operation"

24. EGC procedure WC-AA-107, "Seasonal Readiness," Revision 2

25. SOER 99-1, "Loss of Grid," December 27, 1999

26. SOER 99-1, "Loss of Grid – Addendum," December 9, 2004

27. Jennifer Sterling, Exelon Transmission Planning, "NRC Generic Letter – Draft responses to questions 1 and 2," February 14, 2006, personal email to John Gyrath, Exelon Nuclear, (February 14, 2006)