PSEG Nuclear LLC
P.O. Box 236, Hancocks Bridge, New Jersey 08038-0236

APR 0 3 2006

PSEG Nuclear LLC

LR-N06-0132

United States Nuclear Regulatory Commission
Document Control Desk
Washington, DC 20555

RESPONSE TO NRC GENERIC LETTER 2006-02
"GRID RELIABILITY AND THE IMPACT ON PLANT RISK AND THE OPERABILITY OF OFFSITE POWER"
HOPE CREEK GENERATING STATION
FACILITY OPERATING LICENSE NPF-57
DOCKET NO. 50-354

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 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 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;

A123

(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.

Attachment 1 provides the PSEG Nuclear, LLC (PSEG) response to the Generic Letter for Hope Creek Generating Station.

Some of the questions in GL 2006-02 seek information about analyses, procedures, and activities concerning grid reliability of which PSEG does not have first-hand knowledge and which are beyond the control of PSEG. In providing information responsive to such questions, PSEG makes no representation as to the accuracy or completeness of the information.

Certain values (i.e., 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.

No regulatory commitments made are being made in this document by PSEG.

Should you have any questions concerning this letter, please contact Mr. Paul Duke at (856) 339-1466.

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

Executed on 4/3/06
(date)

George P. Barnes
George P. Barnes
Site Vice President
Hope Creek Generating Station

Attachment (1)

C Mr. S. Collins, Administrator - Region I
U. S. Nuclear Regulatory Commission
475 Allendale Road
King of Prussia, PA 19406

U. S. Nuclear Regulatory Commission
Mr. S. Bailey, Project Manager - Hope Creek
Mail Stop 08B1
Washington, DC 20555-0001

USNRC Senior Resident Inspector - Hope Creek (X24)

Mr. K. Tosch, Manager IV
Bureau of Nuclear Engineering
PO Box 415
Trenton, New Jersey 08625

HOPE CREEK GENERATING STATION
FACILITY OPERATING LICENSE NPF-57
DOCKET NO. 50-354
RESPONSE TO 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 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).

The PSEG Nuclear, LLC (PSEG) response to the Generic Letter for Hope Creek Generating Station (HCGS) is provided below.

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 systems 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 systems under plant TS.*

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

   Response:
   Yes. Hope Creek Generating Station (HCGS) is located in the service territory of PJM Interconnection, LLC (PJM). PJM is the Transmission System Operator (TSO) for HCGS. The Transmission Owner (TO) providing interconnection services for HCGS is Public Service Electric and Gas (PSE&G). PSE&G is a member of PJM.

   All members of PJM execute the "Operating Agreement of PJM Interconnection, LLC," (Reference 1) which 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 are required to follow.

PSE&G (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 entitled "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 M-3, "Transmission Operations," Section 3, (Reference 4).

In addition to the agreements delineated in the PJM Operating Agreement and the PJM Manuals, HCGS has an Interconnection Agreement with the TO (i.e., PSE&G) that provides for interconnection service (Reference 14). The Interconnection Agreement contains the requirement for the TO to monitor the NPP offsite source voltages and notify HCGS 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:
PJM Manual M3, (Reference 4) requires PJM to initiate notification to HCGS 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 HCGS by the 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 HCGS and PJM (TSO) are generally through the Transmission Owner (TO) providing the interconnection service. HCGS 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
- Main generator VAR swings
- Switchyard alarms

In addition to alarm response procedures for the above applicable conditions, TSO/TO notifications are controlled by Operating Procedures and Abnormal Operating Procedures.

HCGS contacts the TSO/TO during the grid restoration process to obtain grid status in preparation for returning the plant buses to the offsite source.

HCGS also notifies the TSO/TO of switchyard equipment deficiencies identified by NPP personnel. Jointly approved interface agreements/procedures between the HCGS and TO identify the communication protocols for station identified switchyard deficiencies. PSEG procedure SH.OP-DD.ZZ-0001(Z), "Electric System Emergency Operations and Electric System Operator Interface" (Reference 15) provides guidelines to ensure the required communication protocol is maintained between PSEG Nuclear, the Electrical Systems Operations Center (ESOC) and PSEG Energy Resources & Trade (ER&T).

In addition, HCGS notifies the TSO/TO of NPP configurations that potentially impact grid conditions. SH.OP-DD.ZZ-0001(Z) identifies the requirements for

communication to the ESOC of the conditions listed below:

- Emergency downpowers
- Conditions that derate the units
- Ramp up/down schedules
- NPP Main generator voltage regulator not in "Automatic" mode

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

Response:
HCGS 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. Among 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," (and associated addendum) are captured in the Licensed Operator Requalification (LOR) Program. These topics, in varying detail based upon the SAT process, are reviewed periodically with HCGS 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. A formal agreement exists for HCGS.

(f) *If you have an existing formal interconnection agreement or protocol that ensures adequate communication and coordination between the NPP licensee 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 unit(s).*

Response:
PJM Manual M3 (Reference 4) requires PJM to initiate notification to HCGS through its respective TO'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 the NPP is one of the contingencies analyzed by PJM. PJM analyzes the HCGS switchyard contingency voltages to the voltage limits provided by HCGS. The voltage limits provided for HCGS 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 minimum value required to maintain Class 1E bus voltage above the setpoint of the degraded voltage relay 110.5 volts (3868 volts on a 4.16 kV basis) will cause a trip of the preferred power source after a time delay of approximately 20 seconds. The relation between the switchyard voltage and the Class 1E bus voltage is dependent on the loading of the auxiliary power system and preferred power source configuration. Under design basis accident (i.e., large break LOCA) conditions, the maximum loading is known and contained in the HCGS calculations of record. A switchyard voltage of 493 kV ensures all safety related loads have sufficient voltage for proper operation. This value has been transmitted to the TSO for the real time contingency analysis alarm setpoint.

In other conditions, the loading on the station service transformers supplying the Class 1E buses is less than the LOCA loading and will vary considerably depending on which loads are needed to support unit conditions. Under these conditions, the required HCGS 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 one minute and analyzes approximately 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., HCGS).

In addition, PSE&G (i.e., the TO) possesses a similar system that also calculates post-contingency voltage limit violations. One of the contingencies analyzed by PSE&G is the trip of the HCGS 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., HCGS) in accordance with PJM Manual M3, Section 3 (Reference 4).

PSE&G (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., HCGS) 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 HCGS. The voltage limits provided by HCGS are based on the plant's design basis analysis as discussed in the response to question 1(g).

PSE&G (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 one minute. In addition, PSE&G (i.e., the TO) possesses a Security Analysis application that updates approximately every five minutes.

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

Response:
PJM notifies HCGS through the TO (i.e., PSE&G) control center whenever actual or post-contingency voltages are determined to be below the HCGS 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. HCGS unit trip contingency voltage calculations are performed by the PJM EMS and the TO (i.e., PSE&G) Security Analysis application. The PJM EMS consists of a primary and backup system. If the PJM EMS fails, the PSE&G Security Analysis application continues to analyze the HCGS unit trip contingency voltage. HCGS will be notified if the real time contingency analysis capabilities of PJM and the TO (i.e., PSE&G) are lost simultaneously in accordance with PJM Manual M01 (Reference 3), Section 2.

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

(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., PSE&G) Security Analysis applications.

PJM provided the following information to PSEG 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. HCGS's TSO (i.e., PJM) has an analysis tool.

(i) If an analysis tool is not available, does your TSO perform periodic 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. HCGS's 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. HCGS's 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. HCGS's 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. HCGS's TSO (i.e., PJM) has an analysis tool. In addition, the applicable contingency voltage results are made available to HCGS 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 HCGS that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., HCGS) is below the pre-determined notification value, HCGS 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 HCGS is based on the HCGS 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 HCGS at this time. If the TSO (i.e., PJM) notifies HCGS of a predicted contingency voltage violation resulting from the postulated trip of a transmission facility, HCGS 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 GDC 17 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., HCGS).

   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., HCGS). 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 in the HCGS current licensing and design basis as documented in the HCGS Updated Final Safety Analysis Report (UFSAR). HCGS has not been explicitly analyzed for all issues associated with double sequencing. Onsite safety-related equipment (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 13), which provides NRC guidance on responding to this issue, a review of the loading logic for the diesel generators as well as the safety related breakers' anti-pumping logic was performed for HCGS. The review concluded that onsite safety-related equipment (i.e., emergency diesel generators or safety-related motors) is not lost as a result of diesel block loading or 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 HCGS is discussed in the response to question 3(c) below.

(c) *Describe your evaluation of onsite safety-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 HCGS current licensing and design basis as documented in the HCGS UFSAR. HCGS 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 the HCGS 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 HCGS's 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 question 3(a), if the TSO (i.e., PJM) notifies HCGS that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., HCGS) is below the pre-determined notification value, HCGS 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 HCGS is based on the HCGS degraded voltage design basis analysis.

If PJM notifies HCGS that the actual offsite power source voltage is less than the pre-determined notification value, HCGS 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 HCGS is based on the HCGS 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 HCGS declaring the offsite power source inoperable in accordance with TSs.

- If the TSO (i.e., PJM) notifies HCGS that the predicted contingency offsite power source voltage following a trip of the NPP (i.e., HCGS) is below the pre-determined notification value, HCGS 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 HCGS is based on the HCGS degraded voltage design basis analysis.

- If the TSO (i.e., PJM) notifies HCGS that the actual offsite power source voltage is less than the pre-determined notification value, HCGS 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 HCGS is based on the HCGS 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 effecting 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 HCGS (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 HCGS current licensing and design basis as documented in the HCGS UFSAR. HCGS 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:
HCGS 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, 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 regulators, 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. HCGS 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 station service transformer (SST) load tap changers. PSEG procedures provide guidance for notification of the TSO/TO (i.e., PJM/PSE&G) when the voltage regulator is not in automatic.

HCGS 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., PSE&G) of the failure.

Hope Creek Operators are given specific guidance in plant procedures (HC.OP-DL.ZZ-0002, HC.OP-DL.ZZ-0003) with respect to transformer automatic load tap changers. Operators are instructed to monitor Class 1E bus voltages and adjust

the voltages into acceptable limits or else declare the offsite power source(s) inoperable and enter TS 3.8.1.1.a action statement.

The operation of the main generator voltage regulators does not have any direct impact on the operability of the offsite sources. The HCGS offsite sources are not directly connected to the main generator output, but only connected together via the switchyard buses. The TSO is notified whenever the voltage regulators are taken from automatic to manual operation.

HCGS 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. Among 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, 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.

<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. 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 HCGS by June 30, 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 HCGS through its Transmission Owner (i.e., PSE&G) of emergent grid conditions as discussed in the response to question 1(b) above. In addition, PSE&G (i.e., the TO) is also performing similar monitoring and evaluation. Existing PSEG 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:
No. The base Probabilistic Risk Assessment (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 HCGS, 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 PSEG 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 [PJM] are in the maintenance seasons with a lot of equipment out of service can cause the most severe challenges.
>
> We [PJM] are aware of the existence of the NERC [North American Electric Reliability Council] 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?*

<u>Response:</u>
No. While time related variations are not factored into the base PRA model for HCGS, 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 question 1(b). Work is coordinated based on anticipated conditions and planned maintenance in accordance with PSEG work management procedures and PSEG's guideline for communication with the PSE&G Electrical Systems Operations Center (ESOC).

As stated in the response to question 1(b), communication is shared between the TSO (i.e., PSE&G) and HCGS 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:
As stated in the response to question 1(a), HCGS is located in the service territory of PJM. PJM is the TSO for HCGS. The TO providing interconnection services for HCGS is PSE&G. PSE&G is a member of PJM.

All members of PJM execute the PJM Operating Agreement (Reference 1) which 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 question 1(b), PJM Manual, M13 (Reference 5) identifies a series of alerts, warnings, and actions that PJM issues to its members depending on the identified grid condition. The PJM message is communicated to HCGS 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 HCGS 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. Communication takes place between the TSO (i.e., PJM) through the TO (i.e., PSE&G) and HCGS as detailed in the response to question 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 HCGS 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:
HCGS maintenance, operations, and work management personnel associated with schedule development or communicating with the TO (i.e., PSE&G) 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 rely on communication with 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 question 2(a), grid status is continually evaluated by PJM using the Security Analysis application. PJM notifies HCGS through the TO (i.e., PSE&G) of emergent grid conditions. In addition, PSE&G (i.e., the TO) possesses a similar system and is also monitoring and evaluating grid conditions. Existing PSEG 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., HCGS) with HCGS.

   (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., HCGS) 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 (i) 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 online 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 get 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. PSE&G (i.e., the TO) is a member of PJM. In addition, PJM has computerized tools to track the process throughout its evolution, so that PJM, PSE&G and PSEG 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). 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., PSE&G) is performing similar monitoring and evaluation. PJM notifies the NPP (i.e., HCGS) through the TO's control center, as discussed in the response to question 1(b).

Interface with the TO (i.e., PSE&G) is defined in accordance with PSEG procedure SH.OP-DD.ZZ-0001 (Reference 15).

Actions described in questions 6(c) and 6(d) are specified in Exelon Work Management procedure WC-AA-101, "On-Line Work Control Process" (Reference 7), which is applicable to PSEG.

(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:
HCGS 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 PSE&G (i.e., the TO) and HCGS is identified in accordance with PSEG procedure SH.OP-DD.ZZ-0001 (Reference 15).

(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 proceduralized and implemented during the conditions described above.

(i) *You may, as an 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 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[2] 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*

---

[2] 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:
HCGS is located in the service territory of PJM. PJM is the Transmission System Operator (TSO) for HCGS. The Transmission Owner (TO) providing interconnection services for HCGS is PSE&G. PSE&G is a member 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.

PSE&G (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. PSE&G (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., HCGS) in the PJM service territory. The TSO (i.e., PJM) and the TO (i.e., PSE&G) 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.

HCGS has an Interconnection Agreement with PSE&G (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 HCGS offsite power circuit back to an operable status (Reference 14).

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

The PJM Restoration Manual (M36) [(Reference 9)] 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, "Pre-Scheduling 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:

HCGS operators are not specifically trained and tested on identifying and using local power sources to resupply HCGS following a LOOP event. The identification and use of local power sources for the NPP are under the control of the TSO and TO in accordance with the procedures and interface agreements described in the response to question 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 HCGS following a LOOP event are under the control of PJM (i.e., the TSO) and PSE&G (i.e., the TO) in accordance with the procedures and interface agreements described in the response to question 7(a). Due to the myriad of possible restoration scenarios, no specific power sources to resupply HCGS 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 PSE&G.

Note that, as detailed in the response to question 7(a), both PSE&G (i.e., the TO) and PJM (i.e., the TSO) have stated that restoring offsite power to a NPP (i.e., HCGS) is a priority.

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 HCGS operating procedures and training, since they are outside of HCGS'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 for 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:
HCGS has not experienced a total LOOP caused by grid failure since the coping duration was initially determined under 10 CFR 50.63. A review of the station Licensee Event Report (LER) database starting from July 1988, when the Station Blackout Rule 10CFR 50.63 was added, was used to make this determination.

This determination is consistent with the data presented in NUREG/CR-6890, Volume 1, "Revaluation 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 describe what actions you intend to take to ensure that the NPP maintains its SBO coping capabilities in accordance with 10 CFR 50.63. Actions to ensure compliance*

Response:
Not applicable

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:
There are no further actions required to bring Hope Creek into compliance with NRC regulatory requirements, including TSs, GDC 17, 10 CFR 50.65(a)(4), 10CFR 50.63, 10 CFR 55.59 or 10 CFR 50.120

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. NRC IN 93-17, "Safety Systems Response to Loss of Coolant and Loss of Offsite Power"

13. 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'"

14. "Interconnection Agreement By and Among The Hope Creek Station Owner and The Hope Creek Switching Station Owner, Dated August 2000, for the Hope Creek Generating Station," PJM Interconnection LLC Service Agreement No. 537 Under FERC Electric Tariff, Fifth Revised Volume No. 1

15. PSEG procedure SH.OP-DD.ZZ-0001, "Electric System Emergency Operations and Electric System Operator Interface," Revision 3