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Fred Dacimo
Site Vice President
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April 3, 2006

Re: Indian Point Units 2 & 3
Dockets 50-247 & 50-286
NL-06-043

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
11555 Rockville Pike
Rockville, Maryland 20852

Subject: **Response to Generic Letter 2006-02, Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power**

Reference: 1. NRC Generic Letter 2006-02, *Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power*, dated February 1, 2006

Dear Sir or Madam:

The NRC issued Generic Letter 2006-02 (Reference 1) to request information for determining compliance with regulatory requirements governing electric power sources. Specifically, the NRC is requesting information regarding (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) including 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 Specification (TS); (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. The requested information is being provided under the requirements of 10 CFR 50.54(f).

Attachment 1 to this letter provides the Entergy Nuclear Operations, Inc. (ENO) response for Indian Point Unit 2 and 3 to Generic Letter 2006-02. Generic Letter 2006-02 discusses compliance with General Design Criterion (GDC) 17 and several other 10CFR50 requirements in several locations. The exact extent of the compliance of IP2 and IP3 to the GDC are described in each plant's Updated Final Safety Analysis Report.

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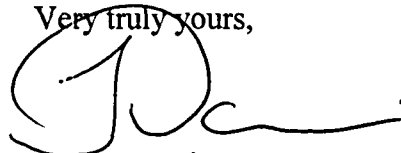
Some of the questions in Generic Letter 2006-02 seek information, procedures and activities concerning grid reliability which is provided by the TSO and/or ISO. ENO has not independently verified all information provided by:

- New York Independent System Operator
- Consolidated Edison Company of New York, Inc.

This letter contains no new commitments. Should you or your staff have any questions regarding this response, please contact Mr. Patric W. Conroy, Manager, Licensing at (914) 734-6668.

I declare under penalty of perjury that the foregoing is true and correct. Executed on April 3, 2006.

Very truly yours,



Fred R. Dacimo
Site Vice President
Indian Point Energy Center

Attachment 1: Response to Generic Letter 2006-02, Grid Reliability and the Impact On Plant Risk and the Operability of Offsite Power

cc:

Mr. Samuel J. Collins, Regional Administrator, Region I
Mr. John Boska, NRR Senior Project Manager
IPEC NRC Resident Inspector's Office, Indian Point Unit 2
IPEC NRC Resident Inspector's Office, Indian Point Unit 3
Mr. Paul Eddy, New York State Department of Public Service
Mr. Peter R. Smith, President NYSERDA

Attachment 1 to NL-06-043

**RESPONSE TO GENERIC LETTER 2006-02, GRID RELIABILITY AND THE IMPACT
ON PLANT RISK AND THE OPERABILITY OF OFFSITE POWER**

(26 Pages)

ENTERGY NUCLEAR OPERATIONS, INC.

**Indian Point Nuclear Generating Unit No. 2
Docket No. 50-247**

**Indian Point Nuclear Generating Unit No. 3
Docket No. 50-286**

Note The following provides a description of the IPEC off-site power system at Indian Point.

Unit 2: Offsite power is supplied from the offsite transmission network to the plant by two electrically and physically separated circuits (a 138kV circuit and a 13.8kV circuit). All offsite power enters the plant via 6.9kV buses Nos. 5 and 6 which are normally connected to the 138kV offsite circuit but have the ability to be connected to the 13.8kV offsite circuit. The 138kV offsite circuit satisfies the requirement in GDC 17 that at least one of the two required circuits can, within a few seconds, provide power to safety-related equipment following a loss-of-coolant accident. The 13.8kV offsite circuit is considered a delayed access circuit because operator action is normally required to supply offsite power to the plant using the 13.8kV offsite source.

Unit 3: Offsite power is supplied to the plant from the transmission network by two electrically and physically separated circuits, the 138kV or normal circuit and the 13.8kV or alternate circuit. Each of the offsite circuits from the Buchanan substation into the plant is required to be supported by a physically independent circuit from the offsite network into the Buchanan substation. All offsite power enters the plant via 6.9kV buses Nos. 5 and 6 which are connected to the 138kV (normal) offsite circuit and have the ability to be connected to the 13.8kV (alternate) offsite circuit. The arrangement satisfies the requirement that at least one of the two required circuits can within a few seconds; provide power to safety-related equipment following a loss-of-coolant accident. Operator action is required to supply offsite power to the plant using the 13.8kV (alternate) offsite source.

The key points to highlight here are as follows:

1. Both units' safeguards loads are powered from the 480V System. The connection to the offsite 138kV and 13.8kV circuits are via the six buses of the 6.9kV System. The arrangement of these six 6.9kV buses allows various alignments to both the 138kV and 13.8kV system and the 480V safeguards buses follow these alignments accordingly. Two of the six 6.9kV buses and consequently two of the associated 480V safeguards trains are directly connected to the 138kV offsite circuit, but can also be connected to the 13.8kV offsite circuit via manual transfer.
2. As described above, both units have two of the three available trains of safeguards loads connected directly to the preferred offsite circuit (138kV), via two of the six buses of the 6.9kV System, during normal operation and as such, there is no transfer action involved. Normal operation includes start-up, hot shutdown, cold shutdown, etc. The third train would be auto-transferred to the preferred offsite circuit during a unit trip from power operation (Mode 1) condition. Both plants design basis requires two of three safeguards trains to mitigate a loss of coolant accident.
3. There is no auto-transfer to the alternate 13.8kV offsite circuit from the 138kV circuit. This transfer, when needed, is manually performed at the 6.9kV System voltage level, and controlled by plant operating procedures. The procedures call for the Transmission Owner (TO) (i.e., ConEd) to be notified whenever the 13.8kV offsite circuit is to be used for plant operating load. This is because the 13.8kV offsite circuit is a local distribution circuit that also powers residential and commercial loads and the TO maintained voltage level is based on the load on the circuit. The higher the load, the higher the voltage that the TO maintains. The 13.8kV offsite circuit is controlled by a TO procedure and based on the load on the circuit, the circuit voltage is set accordingly. The lowest specified voltage permitted on this circuit is 13.4kV. TO notifications (to and from IPEC) are based on this value as well.

Both the 138kV and the 13.8kV circuits are monitored by both organizations through their station procedures. However only the 138kV offsite circuit is monitored by the On-line AC Contingency Monitoring Program. The 13.8kV offsite circuit is monitored by the TO from its Energy Control Center via a Real-time State Estimator (RT/SE) Voltage Profile display. This display provides voltage monitoring and alarming functions and the operations procedure contains the necessary notification responsibilities and notification voltages for both the 138kV and 13.8kV offsite circuits.

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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.

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

In the New York Reliability Coordinator Area the New York Independent System Operator (NYISO) has operational authority over the bulk power system. The Transmission Owners (TO) have operational authority over the non-bulk power system. The NYISO operates the bulk power system in accordance with NERC, NPCC and New York State Reliability Council (NYSRC) criteria. Established communications protocols are between the NYISO and the Transmission Owners (TO). Communications to the generating resources are through the TOs. The associated TO monitors the localized grid conditions and coordinates issues such as off site power operability with the NPP. In this document TSO refers to the TO.

Yes, IPEC has a number of formal agreements with the NYISO and TOs (which also performs the TSO function for IPEC as follows:

- IPEC Unit 3 Interconnection Agreement with the Consolidated Edison Company of New York, Inc. (Con Ed)
- IPEC Unit 2 Indian Point Continuing Site Agreement with Consolidated Edison Company of New York, Inc.
- The New York State Transmission Tariffs with the NYISO
- NYISO Customer & Guest Application Form of Service Agreement for NYISO Market Administration and Control Area Service Tariff
- Transaction Form between Entergy-IPEC and Con Edison for 138kV and 13.8kV monitoring and notification services

The NYISO and TSO agreements require all parties to operate per NYISO and/or TSO procedures and documents, therefore the NYISO and TSO procedures and documents are considered part of the formal agreements.

Compliance with GDC-17, as documented in the IPEC license basis and plant Technical Specifications, is not

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<p>1(b) Describe any grid conditions that would trigger a notification from the TSO to the NPP licensee and</p> <p>if there is a time period required for the notification</p>	<p>predicated on such an agreement.</p> <p>The TSO is required to notify IPEC as soon as practical per good utility practice whenever an impaired or potentially degraded grid condition is recognized by the TSO. Specific examples of known potentially degrading conditions identified in the agreement include:</p> <ol style="list-style-type: none"> 1. De-energizing, switching or in-service work on critical transmission lines 2. Potentially damaging inclement weather 3. Solar Magnetic Disturbances 4. Post-contingency voltage alarm for the 138kV transmission system after 30-minutes. 5. A real-time 13.8kV degraded voltage condition below a normal system schedule voltage after 30-minutes 6. Prior to any 138kV feeder, which could impact IPEC being removed or restored to service 7. When the TSO 138kV or 13.8kV monitoring and alarm capability are out of service and have not been restored after 30-minutes. 8. Other system or equipment conditions determine by the TSO to be of importance to IPEC.
<p>1(c) Describe any grid conditions that would cause the NPP licensee to contact the TSO.</p> <p>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.</p>	<p>Grid conditions and status are the primary responsibility of ISO and TSO.</p> <p>Relative to this question, "grid conditions" is assumed to be IPEC changes that impact the TSO real-time post contingency analysis capability. IPEC typically notified ISO and/or TSO for changes in the following grid conditions:</p> <ul style="list-style-type: none"> • Unit power capability changes • Unit Startup and Shutdown • Modifications resulting in changes to generator electrical characteristics • Breaker alignment and offsite voltage verification • MVAR Loading • Post-trip off-site voltage criteria • Changes in IPEC post trip station and accident loading • Loss of preferred 138KV Offsite Power Supply • Loss of 13.8KV Offsite Power Supply • Status of 13.8kv and 138kv • Maintenance activities directly affecting Switchyard components

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	<ul style="list-style-type: none"> • Method of voltage control, automatic or manual. • EDG Surveillance Testing • Load tap changer position / Auto-Manual Mode
<p>1(d) Describe how NPP operators are trained and tested on the use of the procedures or assessing grid conditions in question 1(c).</p>	<p>The Licensed Operators at IPEC have had training on site procedure that addresses offsite power continuous monitoring and notification. This procedure establishes monitoring, and notification responsibilities of the Buchanan Substation, as well as the interface between the IPEC and Con Edison's Energy Control Center. The most recent training occurred in Cycle 3 of 2005.</p> <p>Typically, IPEC operators are trained and tested, using procedures, on the following:</p> <ul style="list-style-type: none"> • LOOP • System Restoration <p>Typically, IPEC operators are trained, using procedures, on the following:</p> <ul style="list-style-type: none"> • LOOP • System Restoration • Degraded voltage conditions • Voltage (number for inadequate grid capacity) • VARs • Breaker status • Notification of the ISO and/or TSO of changed conditions.
<p>1(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.</p>	<p>As previously stated, IPEC does have a formal agreement with the TSO. Prompt notification from the TSO (after 30-minutes) and a pre-trip analysis of whether the post-trip voltage will be below acceptable values are included in Indian Point Energy Center Offsite Power Continuous Monitoring And Notification procedure. Additionally TSO procedure describes Con Edison responsibility to notify IPEC of low voltage issues as it relates to the 138kV and 13.8kV systems. The procedure requires the TSO to notify both IP2 & IP3 Control Rooms after 30-minutes if the real-time analysis tool determines the post IPEC trip voltage would be below the value specified by IPEC. In addition, the TSO will notify IPEC after 30-minutes if the 13.8kV system voltage is below the normal system voltage schedule.</p>

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<p>1(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)</p> <p>or</p> <p>LOOP after a trip of the reactor unit(s).</p>	<p>Compliance with GDC-17 (IP2 and IP3 are not a GDC plants, the FSARs describe to what extent IP2 and IP3 were reviewed to the draft GDCs or its equivalent is not predicated on this agreement).</p> <p>As previously stated, IPEC does have formal agreements with the TSO. These agreements require the TSO to notify IPEC as soon as practicable per good utility practice, upon receipt of a potential post-trip degraded voltage alarm.</p>
<p>1(g) Describe the low switchyard voltage conditions that would initiate operation of plant degraded voltage protection.</p>	<p>These are the Switchyard voltage conditions that will initiate operation of IPEC degraded voltage protection</p> <ul style="list-style-type: none"> i. 138 kv Offsite Power Source <133kv ii. 13.8kv Offsite Power Source <13.4kv <p>Note: The design of these systems is described in front of this attachment.</p>

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<p>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.</p>	
<p>2(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.</p>	<p>Yes. The TSO, uses a State Estimator and a Contingency Evaluation Program to analyze real time and contingency voltage levels and thermal loading for IPEC 138kV off-site sources.</p> <p>The 138kV transmission system program and related actions are summarized as follows:</p> <p>Real-Time Contingency Analysis Program: The program and related actions are summarized as follows; the program utilizes real-time transmission system information and nuclear generating unit specific shutdown loads and minimum voltage requirements. The program creates a model by combining real-time telemetry with the network model. The network model includes the nuclear power plant facilities. The State Estimator is then used to provide a consistent power flow that is used to run the contingencies. The contingency case assumes the simultaneous loss of the generator and the addition of load at the appropriate bus. An alarm is issued if the prescribed voltage limits are violated.</p> <p>The 13.8kV distribution system is monitored on a real-time voltage basis. If the voltage drops below a predetermined 13.8kV system voltage value, IPEC is notified. This approach is determined to be acceptable because the 13.8kV off-site source is a manually aligned supply and the predetermined notification value is at the lower limit of the 13.8kV systems normal voltage schedule. Therefore, the TSO will make all reasonable efforts to maintain the voltage schedule.</p>
<p>2(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?</p>	<p>Yes. The TSO uses the real-time analysis tool described in 2(a), in conjunction with procedures, as the basis for determining when conditions warrant IPEC notification of the 138kV system.</p> <p>As described above the TSO use real-time voltage monitoring, in conjunction with procedures, as basis for determining when conditions warrant IPEC notification of the 13.8kV system.</p>

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<p>2(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?</p> <p>If not, discuss how such a condition would be identified on the grid.</p>	<p>Yes. The TSO real-time analysis tool for the 138kV, in conjunction with IPEC plant load flow studies, have the capability to determine if the trip of their IPEC plants would result in a switchyard voltage which would actuate the associated unit's degraded voltage protection logic and initiate separation from the offsite power source.</p> <p>The 13.8kV source is a manually aligned distribution system, which the TSO has local resources available to adjust system voltage. Prior to IPEC aligning the 480VAC safety buses to the 13.8 kV system (via the 6.9 kV system), communication between the TSO and IPEC is required to ensure the adequacy of the 13.8 kV system voltage to support accident loads.</p>
<p>2(d) If your TSO uses an analysis tool, how frequently does the analysis tool program update?</p>	<p>The TSO 138kV real-time analysis tool presently resolves the IPEC Unit 2 and IPEC Unit 3 trip contingencies every minute for the steady state conditions.</p>
<p>2(e) Provide details of analysis tool-identified contingency conditions that would trigger an NPP licensee notification from the TSO.</p>	<p>The 138kV IPEC Unit 2 and IPEC Unit 3 contingencies results (see response to item 2(a)) are automatically compared to off-site post trip voltage limits. If any limit is violated, an alarm is generated and IPEC is notified if not cleared after 30 minutes</p>
<p>2(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?</p> <p>If so, how does the NPP licensee determine that the offsite power would remain operable when such a notification is received?</p>	<p>Yes. IPEC would be notified by the TSO when:</p> <ul style="list-style-type: none"> ▪ When all three 138 kV monitoring and alarm systems are out of service and have not been restored within 30 minutes. ▪ When the 13.8 kV monitoring and alarm systems are out of service and have not been restored within 30 minutes. <p>Loss of the voltage prediction tool alone has no impact on operability. If notified by the TSO that the Low Voltage Contingency Alarm is inoperable, then the IPEC Operators perform the following:</p> <ol style="list-style-type: none"> 1. Contact the TSO once per shift to verify imminent/expected degraded voltage conditions do not exist. 2. Minimize large electrical load changes

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	<ol style="list-style-type: none"> 3. Minimize maintenance and testing of the electrical distribution system. 4. Terminate maintenance or testing on critical components of the electrical distribution system as soon as possible. 5. Limit MVAR Output (IP2 only)
<p>2(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?</p>	<p>No. Verification of the post trip 138kV switchyard voltage real-time analysis results against actual post trip voltage is not performed. Since the real-time analysis tool uses real time system data and assumed worst case station loads a comparison of values would be difficult even if the real-time analysis predicted values were available which they are not.</p>
<p>2(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?</p>	<p>This question is not applicable to IPEC. The TSO has a real-time analysis tool presently in use for the 138kV system as discussed above.</p> <p>The TSO has no plans to install a real-time contingency monitor for the 13.8 kV off-site power source.</p>
<p>2(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?</p> <p>(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?</p> <p>(b) If the bounds of the analyses are exceeded, does this condition trigger the notification provisions discussed in question 1 above?</p>	<p>Not Applicable for the 138kV transmission lines, TSO uses real-time analysis tool as discussed above.</p> <p>IPEC performs periodic station load flow studies to ensure that the minimum 13.8kV scheduled voltage is adequate to support voltage requirements.</p>

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<p>2 (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.</p>	<p>Not applicable for 136kV and 13.8 kV Systems</p>

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<p>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.</p>	
<p>3(a) If the TSO notifies the NPP operator that</p> <ul style="list-style-type: none"> • a trip of the NPP, or • the loss of the most critical transmission line or • the largest supply to the grid <p>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)</p> <p>and</p> <p>would actuate plant degraded voltage protection,</p> <p>is the NPP offsite power system declared inoperable under the plant TSs? If not, why not?</p>	<p>IPEC would declare the 138kV off-site source "inoperable". The TSO has real-time monitor capability for the 138kV source and IPEC is notified by the TSO if the loss of the unit would result in an unacceptable off-site post-trip voltage. There are no identified system conditions where the loss of a transmission line or large supply would result in the trip of the generator.</p>
<p>3(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</p>	<p>IPEC is not designed for double sequencing events. LOCA with a Delayed LOOP is outside the design basis for both IP2 and IP3.</p>

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<p>result of responding to an emergency actuation signal during this condition, is the equipment considered inoperable? If not, why not?</p>	
<p>3(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).</p>	<p>Indian Point Units 2 and 3 are designed to a GDC that postulates a LOCA concurrent with a LOOP. Neither plant models a LOCA with Delayed LOOP scenario in its voltage profile and loading analyses, because this event is outside the design basis of both units.</p>
<p>3(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.</p>	<p>This condition is addressed by our site procedures. Under these circumstances we would enter the applicable site procedure for offsite power continuous monitoring and notification, a Technical Specification action statement would not be entered until an applicable system, structure or component was declared inoperable.</p>
<p>3(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.</p>	<p>Not applicable. Based on responses, we declare offsite power or applicable equipment inoperable under circumstances as described above.</p>
<p>3(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).</p>	<p>The Licensed Operators have been trained on the applicable site procedure for offsite power continuous monitoring and notification. This procedure contains the requirements for declaring off-site power inoperable and entering the appropriate Technical Specifications.</p> <p>For events such as LOCAs followed later by a LOOP event, the Operators continuing training includes the sequencing or manual loading of safeguards equipment. The</p>

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	requirement to manually load safeguards equipment is contingent on whether or not the Safeguards signal has been reset. The site's Westinghouse owner's group Emergency Operating Procedures address these situations. The licensed operators are tested on these procedures and in dynamic simulator evaluations, as applicable.

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4. Use of criteria and methodologies to assess whether the offsite power system will remain operable following a trip of your NPP.	
<p>4(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.</p>	<p>Yes, procedural guidance for abnormal situations related to this equipment is available to IPEC operators in Annunciator Response Procedures.</p> <p>The operators are trained and tested on systems such as the main generator voltage regulator and tap changers.</p>
<p>4(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.</p>	<p>Not applicable.</p>

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<p>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</p>	
<p>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.</p>	
<p>5. Performance of grid reliability evaluations as part of the maintenance risk assessments required by 10 CFR 50.65(a)(4).</p>	
<p>5(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?</p>	<p>Yes</p> <p>IPEC performs qualitative risks assessment as required by 10 CFR 50.65 and IPEC Plant Technical Specification. The program is implemented by IPECNPP On-Line Risk Assessment and Outage Risk Assessment procedures.</p> <p>These procedures require plant risk assessment before removing equipment from service for planned maintenance activities, or upon discovery of equipment out of service that is unplanned.</p> <p>The IPECNPP On-Line Risk Assessment procedure requires an evaluation of current and anticipated grid conditions before removing risk significant equipment from service.</p> <p>The Equipment Out of Service (EOOS) Monitor is a computer based program that is used to calculate Core Damage Frequency and conditional Core Damage Frequency for the plant equipment configuration and testing activities for both planned and unplanned configurations.</p> <p>The IPECNPP Work Management procedure requires a risk plan development for activities that would increase grid instability in combination with external events.</p>
<p>5(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</p>	<p>Yes</p>

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<p>grid-risk-sensitive maintenance?</p> <p>5(c) Is there a significant variation in the stress on the grid in the vicinity of your NPP site caused by</p> <p>seasonal loads</p> <p>or</p> <p>maintenance activities associated with critical transmission elements?</p> <p>Is there a seasonal variation (or the potential for a seasonal variation) in the LOOP frequency in the local transmission region?</p> <p>If the answer to either question is yes, discuss the time of year when the variations occur and their magnitude.</p>	<p>Yes</p> <p>The NYISO Reliability Coordination Area is a summer peaking area. Due to high intra area and inter area power flows, it would be expected that the grid would be stressed. However, this stress is managed through facility maintenance coordination. During the summer peak season scheduled transmission facility maintenance is avoided in June, July and August if possible.</p> <p>Anytime that maintenance is scheduled, the schedules are managed in order to maintain operation of the bulk power system within established operating criteria.</p> <p>No, based on the limited number of LOOP occurrences in the NYISO region over the past 10 years, no seasonal variation can be established. IPEC last experienced a transmission system related LOOP on August 14, 2003.</p>
<p>5(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?</p>	<p>No. However, Con Edison the TSO by procedure does not schedule feeder outages between May 1 and September 15 due to summer loading concerns. IPEC will not schedule maintenance activities during this time. IPEC will schedule emergent activities to address issues that could pose a threat to grid stability.</p>
<p>5(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?</p>	<p>Yes.</p> <p>TSO Communication contacts are available for assessment of grid conditions before and during the performance of grid-risk sensitive maintenance activities.</p>
<p>5(f) Describe any formal agreement or protocol that you have with your TSO to assure that you are promptly alerted to a</p>	<p>Site level procedures provide the guidance on scheduling. The procedure for performance of the offsite power continuous monitoring and notification contains guidelines for risk management of feeder outages. This would include the ability to</p>

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<p>worsening grid condition that may emerge during a maintenance activity.</p>	<p>restrict work on feeders or equipment due to maintenance on grid equipment. The Piant models grid feeder outage in the risk assessment Program EOOS.</p> <p>Notification occurs whether or not maintenance is on-going. The TSO is required to notify IPEC whenever an impaired or potentially degraded grid condition is recognized by the TSO. Specific examples of known potentially degrading conditions identified in the agreement include:</p> <ol style="list-style-type: none"> 1. De-energizing, switching or in-service work on critical transmission lines. 2. Potentially damaging inclement weather. 3. Solar Magnetic Disturbances. 4. Post-contingency voltage alarm for the 138kV transmission system after 30-minutes. 5. A real-time 13.8kV degraded voltage condition below a normal system schedule voltage after 30-minutes. 6. Prior to any 138kV feeder outage which could impact IPEC being removed or restored to service 7. When the TSO 138kV or 13.8kV monitoring and alarm capability are out of service and have not been restored after 30-minutes. 8. Other system or equipment conditions determine by the TSO to be of importance to IPEC.
<p>5(g) Do you contact your TSO periodically for the duration of the grid-risk-sensitive maintenance activities?</p>	<p>Yes. Additionally the TSO is contacted before the start of grid- risk sensitive maintenance activities and at the completion of the activity. Changes to grid conditions are communicated to IPEC as stated in 5(f).</p>
<p>5(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.</p>	<p>The formal agreement with the System Operator at IPEC is described in the offsite power continuous monitoring and notification station procedure. This procedure establishes monitoring, and notification responsibilities of the Buchanan Substation, as well as the interface between the IPEC and Con Edison's Energy Control Center. The Licensed Operators have had training on this procedure. The most recent training occurred in Cycle 3 of 2005.</p> <p>There was no testing associated with this training.</p>

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	Maintenance personnel do not have training on this agreement or procedure because Operations and Work Control assess the risk and conditions for performing maintenance activities.
5(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).	Not applicable.
5(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.	Not applicable
5(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.	Not applicable. No alternative actions required.

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<p>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).</p>	
<p>TSO does grid reliability evaluations; not NPPs. "grid reliability evaluations" Enter AP, if notified un-normality on grid.</p>	
<p>6(a) Does the TSO coordinate transmission system maintenance activities that can have an impact on the NPP operation with the NPP operator?</p>	<p>Yes. The TSO coordinates all scheduled work activities with the plant. The Process is described in site level procedures.</p>
<p>6(b) Do you coordinate NPP maintenance activities that can have an impact on the transmission system with the TSO?</p>	<p>Yes. IPEC coordinates all scheduled work activities with the TSO. The plant process is described in site procedures.</p>
<p>6(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?</p>	<p>Yes. IPEC will reschedule activities as required to prevent challenging the stability of the local Grid. This would include activities which would likely cause plant trip or loss of off site power. Guidance is described in site procedures. If the Grid voltage degrades to a point where it challenges the NPP, the TSO will immediately correct it or notify the IPEC Control room operators. IF emergent equipment outage occurs the TSO will notify the control room. The Switchyard coordinator or lead system engineer will be notified. A risk assessment evaluation will be performed and if applicable, restrict feeders as required.</p>
<p>6(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</p>	<p>Yes. Guidance is described in site procedures. The Switchyard coordinator or lead system engineer will be notified. A risk assessment evaluation will be performed and if applicable restrict feeders as required. Additionally, mitigative actions such as feeder restrictions and protected equipment will be implemented.</p>

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include alternate equipment protection and compensatory measures to limit or minimize risk.)	
6(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.	Emergent maintenance or declining grid condition guidance is described in site procedures. The operator will perform appropriate actions as required by Technical Specifications. The Switchyard Coordinator or Lead System Engineer will be notified. They will perform a risk evaluation and if applicable restrict feeders as required. The feeder or equipment outage will be run through the plant risk program. These actions are required by Procedure and must be performed.
6(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).	<p>The Licensed Operators and Work Control Personnel at IPEC were provided training on the applicable procedure that addresses Offsite Power Continuous Monitoring and Notification. This procedure establishes monitoring, and notification responsibilities of the Buchanan Substation, as well as the interface between the IPEC and Con Edison's Energy Control Center. The most recent training occurred in Cycle 3 of 2005.</p> <p>There was no testing associated with this training.</p>
6(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).	Not applicable
6(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.	Not applicable

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6(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).	Not applicable. No alternative actions required.

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<p>Offsite power restoration procedures in accordance with 10 CFR 50.63 as developed in Section 2 of RG 1.155</p>	
<p>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.</p>	
<p>7. Procedures for identifying local power sources¹ that could be made available to resupply your plant following a LOOP event.</p>	
<p>Note: Section 2, "Offsite Power," of RG 1.155 (ADAMS Accession No. ML003740034) states:</p> <p>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:</p> <ul style="list-style-type: none"> - Grid under-voltage and collapse - Weather-induced power loss - Preferred power distribution system faults that could result in the loss of normal power to essential switchgear buses 	
<p>7(a) Briefly describe any agreement made with the TSO to identify local power sources that could be made available to re-supply power to your plant following a LOOP event.</p>	<p>IPEC has no agreement with local power sources. The NYISO and the TSO have restoration plans which identify how power will be restored to the NPPs as a priority load. The TSO is responsible for coordinating the restoration of off-site power to the NPP. The NPP is considered a critical facility and restoration of power is a priority.</p>
<p>7(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.</p>	<p>Yes. Continuing Licensed Operator Re-qualification Training includes electrical bus and power supply training. Also included is training on applicable Abnormal Operating procedures, which address re-energizing plant electrical systems following a LOOP.</p>

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

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<p>7(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.</p>	<p>Not applicable.</p> <p>The NYISO has agreements with area black-start capable units in accordance with NYISO bulk power restoration plan. The NYISO restoration plan identifies restoring power to the NPPs as a priority, and the TSO is responsible for coordinating the restoration of off-site power to the NPP. The NPP is considered a critical facility and restoration of power is a priority.</p>

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<p>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</p>	
<p>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.</p>	
<p>8. Maintaining SBO coping capabilities in accordance with 10 CFR 50.63.</p>	
<p>8(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?</p>	<p>Yes, a LOOP caused by grid failure occurred during August 2003.</p>
<p>8(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?</p>	<p>No. See additional information in the response to Question 8(d) below.</p>
<p>8(c) If so, what were the results of this reevaluation, and did the initially determined coping duration for the NPP need to be adjusted?</p>	<p>Both Units 2 and 3 remain 8 hour coping plants.</p>
<p>8(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</p>	<p>Per RG 1.155 Table 4, Sites that expect to experience a total loss of offsite power caused by grid failures at a frequency equal to or greater than 20 site-years are considered to be an Offsite Power Design Characteristic Group "P3", unless the site has a procedure to recover AC power from reliable alternate (non-emergency) AC power sources within approximately one-half hour following a grid failure are considered.</p> <p>Both IP2 and IP3 are already considered as Offsite Power Design Characteristic "P3" with 8 hour coping duration. This classification already accounts for a frequency of grid related loss of offsite power events greater than once per 20 years. Therefore, no reevaluation of coping time for either plant is required as a result of a LOOP subsequent to existing evaluations.</p>

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50.63.	<p data-bbox="667 294 913 322">Indian Point Unit 2</p> <p data-bbox="667 327 1795 528">The IP-RTP-04-00811 Station Blackout Report (Tenera Report), dated March 1990 documents IP2 as Offsite Power Design Characteristic "P3" with an 8 hour coping duration. This is based on past loss of offsite experience at the site, the probabilities of severe weather, and the independence of offsite power supplies. The factor used for determining coping duration is the high EDG reliability. A target reliability of 0.95 gives IP2 a coping duration category of 8 hours.</p> <p data-bbox="667 566 913 594">Indian Point Unit 3</p> <p data-bbox="667 599 1837 697">NRC Letter Docket No 50-286, dated June 9, 1992 Supplemental Safety Evaluation (SSE) Station Blackout Rule 10 CFR 50.63 states IP3 is an Offsite Power Design Characteristic "P3" with a minimum required coping duration of 8 hours.</p>

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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.

Areas of non-compliance were entered in the Corrective Action Process and will drive the actions necessary to implement changes to bring the condition into compliance and will include a detailed schedule.

CR-IP2-2006-01450 was initiated to change operations procedure to give the Operators direct guidance that when notified by the TO of the Real-time Contingency Analysis (RTCA) alarm, the Offsite Power Supply will be Inoperable and TS actions will be entered. Additionally, the 133kV criteria will be deleted from the procedure.