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PG&E Letter DCL-06-042

U.S. Nuclear Regulatory Commission
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Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
60-Day Response to NRC Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power"

Dear Commissioners and Staff:

NRC Generic Letter (GL) 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated February 1, 2006, was issued to request information from its licensees in four areas:

(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 (TS). (The TSO, ISO, or RA/RC is responsible for preserving the reliability of the local transmission system. In this GL the term TSO is used to denote these entities);

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

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

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

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GL 2006-02 required that within 60 days, licensees submit a response to the questions in the GL. Pacific Gas and Electric Company's (PG&E's) response for Diablo Canyon Power Plant (DCPP) is provided in Enclosure 1.

GL 2006-02 implies that a "formal agreement" between PG&E and the grid operator is essential to ensure compliance with 10 CFR 50, Appendix A, General Design Criterion 17 (GDC-17), "Electric Power Systems." Compliance with GDC-17, as documented in the DCPP license basis and plant TS, is not predicated on such an agreement. Although DCPP has such an agreement, the enclosed responses do not make any commitments in this matter.

This response does not contain any commitments.

In accordance with the provisions of Section 182a of the Atomic Energy Act of 1954, as amended, and 10 CFR 50.54(f), PG&E is submitting this letter under oath and affirmation.

If you have questions regarding this response, please contact Mr. Stan Ketelsen at (805) 545-4720.

Sincerely,

DJacobs

Donna Jacobs
Vice President – Nuclear Services

kjse/4328 A0659036
Enclosure
cc: Edgar Bailey, DHS
Terry W. Jackson, Senior Resident Inspector
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UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of PACIFIC GAS AND ELECTRIC COMPANY	Docket No. 50-275 Facility Operating License No. DPR-80
Diablo Canyon Power Plant Units 1 and 2	Docket No. 50-323 Facility Operating License No. DPR-82

AFFIDAVIT

Donna Jacobs, being of lawful age, first being duly sworn upon oath states that she is Vice President – Nuclear Services of Pacific Gas and Electric Company; that she has executed this response to NRC Generic Letter 2006-02 on behalf of said company with full power and authority to do so; that she is familiar with the content thereof; and that the facts stated therein are true and correct to the best of her knowledge, information, and belief

Donna Jacobs
Vice President – Nuclear Services

Subscribed and sworn to before me this 31st day of March, 2006, by Donna Jacobs, personally known to me or proved to me on the basis of satisfactory evidence to be the person who appeared before me.

Notary Public
County of San Luis Obispo
State of California

CHUCK MACKEY
Commission # 1397547
Notary Public - California
San Luis Obispo County
My Comm. Expires Feb 1, 2007

PG&E Response to Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power"

In Generic Letter (GL) 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated February 1, 2006, the NRC requested that each licensee provide answers to the following questions and provide information to determine if compliance is being maintained with respect to grid reliability and the impact on plant risk and the operability of offsite power. Pacific Gas and Electric Company's (PG&E's) responses are provided below.

GL 2006-02 uses the term "Operable/Operability" throughout the document. According to NRC Regulatory Issue Summary (RIS) 2005-20, the term "Operable/Operability" is defined in the Technical Specifications (TS) and only applies to TS structures, systems, and components (SSC). Therefore, as applied to the responses below, the term "Operable/Operability" only applies to the offsite power circuits. As defined in the Diablo Canyon Power Plant (DCPP) Units 1 and 2 TS, the offsite power circuits consist of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network (i.e., the switchyards) to the onsite Class 1E busses. The offsite power system (i.e., grid) is not a TS SSC; therefore, it is defined to be either functional or nonfunctional.

NRC Question 1:

Use of protocols between the nuclear power plant (NPP) licensee and the transmission system operator (TSO), independent system operator (ISO), or reliability coordinator/authority (RC/RA) to assist the NPP licensee in monitoring grid conditions to determine the operability of offsite power systems under plant TS.

General Design Criteria (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).

NRC Question 1(a):

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

PG&E Response:

Yes. PG&E does have a formal agreement with the TSO for DCPP. The agreement is documented in Appendix E, "Nuclear Protocols," dated January 1, 2003, to the Transmission Control Agreement (TCA) between the California Independent System Operator (CAISO) and the various transmission owners, including PG&E. It should be noted, however, that the DCPP personnel communicate primarily with the Electric System Operations (ESO) Department of

the Energy Delivery division of PG&E and only rarely communicate directly with the CAISO. It is the responsibility of PG&E ESO Department personnel to communicate with the CAISO.

It should also be noted that compliance with GDC-17, as documented in the DCPP licensing basis and plant TS, is not predicated on such an agreement.

NRC Question 1(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.

PG&E Response:

The TCA requires "...that impaired or potentially degraded grid conditions are recognized, assessed, and immediately communicated to the DCPP operating staff..." Specific examples of potentially degrading conditions can fall into two categories:

1. normal day to day operational communications associated with topics such as:
   a. work coordination (e.g., clearances)
   b. switching
   c. generation dispatch
   d. planning

2. infrequent or off-normal communications associated with topics such as:
   a. loss of any 500kV outlet line (three total)
   b. loss of a Los Padres Area (i.e., the area in the vicinity of DCPP) 230kV critical transmission element.
   c. DCPP 500kV switchyard voltages outside the specified range
   d. DCPP 230kV switchyard voltages outside the specified range
   e. grid conditions determined by the ESO to be more severe with respect to DCPP switchyard voltages or otherwise unanalyzed
   f. TSO Energy Emergency Alerts
   g. TSO Restricted Maintenance Operation (RMO) notification

The occurrence of a grid condition that impacts DCPP requires immediate DCPP notification. The ESO procedure defines "immediate" as within ten minutes.

NRC Question 1(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.

PG&E Response:

Grid conditions and status are the primary responsibility of the TSO.

The grid parameters observable to a DCPP control room operator include only generator voltage and frequency, real and reactive power output, output breaker status, and certain switchyard alarm points.

Relative to this question, "grid conditions" are assumed to be DCPP changes that impact the ESO analysis of the grid interface. A DCPP operator notifies the ESO for changes in the following grid conditions:

- DCPP power uprate and derate design changes (both real and reactive power)
- design modifications resulting in changes to generator electrical characteristics
- changes in DCPP post-trip offsite power minimum required switchyard voltage or loading
- change in status of DCPP offsite power voltage regulating devices (such as load tap changers (LTCs) in manual versus auto)
- high-voltage equipment problems that could impact DCPP output, stability, or availability (i.e., large power transformer problems, main generator problems, isophase bus problems, etc.)
- other notifications associated with internal plant electrical or equipment alignments are also made when applicable; however, these are not related to "grid conditions"
- diesel generator maintenance schedules
- planned changes in generation output (e.g., startup, shutdown, and curtailments)

Procedures associated with these communications are:

- Operations Policy B-1, "Communications with Generation and Transmission Organizations"
- Operating Procedure OP J-2:VIII, "Guidelines for Reliable Transmission Service for DCPP"
- Operating Procedure OP J-5:II, "Transferring 12kV Banks"
- Operating Procedure OP J-6A:II, "Transferring 4160 Volt Banks"

- Abnormal Operating Procedure OP AP-26, "Loss of Offsite Power"
- Emergency Operating Procedure ECA-0.0, "Loss of All Vital AC Power"
- Annunciator Response PK20-24, "230kV SWYD"
- Annunciator Response PK20-25, "500kV SWYD"

The primary ESO procedure is O-23, "Operating Instructions for Reliable Transmission Service to DCPP." The ESO provides copies of this procedure to the TSO, in addition to DCPP.

NRC Question 1(d):

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

PG&E Response:

As part of simulator training, DCPP operators are faced with Loss-of-Offsite-Power (LOOP) scenarios requiring the restoration of busses either from offsite power or cross-tying busses utilizing emergency diesel generators (EDG's) for power. This condition is included in some simulator exam scenarios and is tested on a recurring basis, typically more often than annually.

In January through February of 2004, all licensed DCPP operators were trained in offsite power circuit operability. This included training on voltage conditions required for operability, line configurations required for operability, and communications with electrical system operators on changes to DCPP system status. Included in the training was a written test.

Operators have been trained on the total power output limits established for lines being out of service, either tripped or intentionally removed from service for maintenance.

Operations Policy B-1 is updated following every refueling outage and the changes are communicated to the operating crew via a shift order. This maintains the DCPP operator's awareness of the required communication between the plant operators, ESO, and the TSO.

As part of the normal training process DCPP operators are trained on the procedures listed in the response to Question 1(c).

NRC Question 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.

PG&E Response:

Not applicable. PG&E does have a formal agreement with the TSO for DCPP.

Compliance with GDC-17 is not predicated on such an agreement. Modification of the existing TCA is not necessary for compliance with GDC-17. As defined in the DCPP license basis, offsite power circuit capacity and capability issues are limited to the "connection" from the offsite system (i.e., the transmission network/grid) to the onsite distribution busses and not the grid itself.

Separately, beyond GDC-17 compliance:

- The ESO grid analysis of DCPP offsite power interface addresses multiple grid contingencies, not just the loss of any generator, large load block, or the most critical transmission line (i.e., single contingencies).
- The TSO is required by the Western Electricity Coordination Council (WECC) to perform periodic studies to ensure compliance with their grid stability criteria and planning standards. These criteria include limits on the maximum allowable voltage deviation and duration of transients for a given grid disturbance. This provides additional DCPP offsite power assurance beyond that required by GDC-17.
- The North American Electricity Reliability Council (NERC) has drafted a new standard identifying TSO requirements unique to nuclear power plants. This standard will expand TSO interface requirements beyond stability to address offsite power circuit operation in addition to "sizing" the nuclear power plant connection. NERC is planning tentative adoption of this standard in May, 2006. This standard will ensure that TSO's address the unique requirements associated with nuclear power plants.

NRC Question 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 technical specification (TS) nominal trip setpoint value

requirements; including NPP licensees using allowable value in its TSs) or loss of offsite power (LOOP) after a trip of the reactor unit(s).

PG&E Response:

As previously stated in the response to Question 1(a), PG&E has a TCA for DCPP. The agreement requires immediate DCPP notification of postulated post-trip voltages below acceptable limits. The ESO initiates the notification and their procedure defines "immediate" as within ten minutes.

NRC Question 1(g):

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

PG&E Response:

For the 230kV startup source: The issue for DCPP is the resultant voltage drop due to the DCPP post-trip load addition to the system, and not the absolute switchyard voltage. This source has a transformer equipped with a LTC with a tap range of 165-243kV. Since this interface has voltage regulation capability, there is no single switchyard low voltage limit regarding DCPP degraded voltage detection. The degraded voltage protective function may initiate if the DCPP post-trip load addition results in a voltage drop in excess of 21kV (The actual analysis is based on the Thevenin equivalent impedance looking back into the 230kV System. The limiting impedance is 18 percent on a 100 megavolt-ampere base). Under these conditions, the LTC does not have sufficient time to adjust (16.1 second limit).

For the 500kV auxiliary source: The nominal voltage of this interface is 525kV. Post-trip voltages below 510kV may initiate the degraded voltage protective function for the worst case plant loading condition.

The NRC Temporary Instruction (TI) TI-2515/156, Attachment B, definition of "Loss of Offsite Power" (LOOP) is inconsistent with GDC-17. The TI reads "the simultaneous loss of electrical power to all unit safety buses (the non-essential busses will also be de-energized as a result of this), requiring all emergency diesel generators to start and supply power to the safety buses." GDC-17 defines a LOOP as "the loss of power from the transmission network." The difference is that one of the two DCPP offsite circuits is a delayed access source, as allowed by GDC-17. The loss of the immediate offsite circuit, coincident with a unit trip, would result in the starting and loading of the diesel generators. However, this is not synonymous with a LOOP since the delayed source may be available.

NRC Question 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.

NRC Question 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.

PG&E Response:

Yes. The ESO makes use of analysis tools to determine grid conditions that would make the DCPP offsite power circuits inoperable and to assist DCPP operators in determining offsite power capability. The tools include a grid state estimator and an energy management Supervisory Control and Data Acquisition (SCADA) monitoring system, in conjunction with periodic studies involving a large number of contingencies specific to DCPP and implementing procedures.

The ESO analysis is based on bounding transmission planning studies, in conjunction with the monitoring of critical parameters. As long as the grid state is within that allowed by the procedures, adequate grid stability, including DCPP offsite power capability, is assured. Specific case studies are also performed as needed to support planned grid configurations when not clearly bounded by existing studies.

A brief description of the process methodology is as follows:

i) ESO computes switchyard voltages due to loss of generation resulting from a unit trip (periodic study)

ii) DCPP personnel compute the plant post-trip grid loading for input to the ESO grid model (periodic study)

iii) ESO computes the maximum pre-load the local grid can support for a given DCPP post-trip loading (periodic study)

iv) ESO computes the minimum pre-trip voltage, necessary to comply with TSO criteria, for input to DCPP personnel (periodic study)

v) ESO computes the grid Thevenin equivalent impedance at the DCPP switchyard for input to DCPP (periodic study)

vi) DCPP personnel perform dynamic voltage analysis of plant electrical response for the range of grid Thevenin impedances, at the minimum

pre-trip voltage, to ensure that the degraded voltage protective function does not actuate (periodic study)

vii) the critical grid parameters are monitored twenty-four hours per day and seven days per week by the ESO switchyard operator (i.e., grid configuration, including status of other generation, voltage, and local grid loading) (SCADA)

viii) ESO switchyard operator notifies the DCPP control room operator of any grid configuration change, switchyard voltage levels below established pre-trip minimums, and local grid loading in excess of established maximums (procedural)

ix) DCPP control room operator verifies correct LTC controller output voltage (procedural)

x) DCPP control room operator determines operability and notifies the ESO switchyard operator of conclusion (procedural)

In addition to the analysis tools in use at this time, both the TSO and the ESO are introducing real-time contingency analyses (RTCA) capability. RTCA systems are predictive analysis computer programs. Real time grid data are processed via a grid state estimator computer system to develop a complete and detailed snapshot of the transmission system. The output of the grid state estimator is fed into the RTCA. The RTCA, using the state estimator results as initial conditions, then sequentially analyzes a list of pre-defined contingencies and predicts the resultant steady state grid condition after each contingency. These results can be compared to system acceptance limits and flagged for TSO review as appropriate. The initial application of the RTCA in California is for marketing purposes only (i.e., power exchanges and generation dispatch).

The application of RTCA contingency analysis to support DCPP license requirements is not feasible at this time. The RTCA predicts final steady state grid conditions. It accomplishes this with limited input data from DCPP. The DCPP input to the grid state estimator is limited to generation (i.e., megawatt, megavolt-ampere reactive, and kV) and auxiliary power consumption. In order to reasonably predict sufficient offsite power capability, so as to preclude actuation of the degraded grid undervoltage protective function, requires a dynamic analysis capability. The present state-of-the-art RTCA system cannot support this. Additionally, the existing RTCA systems are unaware of critical real time DCPP Electrical Distribution System data necessary to make an operability assessment. These data include bus alignment; the status, capability, and dynamic response of plant voltage regulating devices; and post-unit trip/loss-of-coolant accident (LOCA) plant load profiles including compensatory actions invoked by the plant. Because of these restrictions, an automated RTCA based system is not being pursued to support DCPP offsite operability determinations at this time.

NRC Question 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?

PG&E Response:

Yes. The ESO uses the analysis tools described in response to Question 2(a) as the basis for determining if existing conditions warrant DCPP personnel notification so that DCPP personnel can determine operability.

Notification is via voice communication from the ESO switchyard operator.

NRC Question 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? If not, discuss how such a condition would be identified on the grid.

PG&E Response:

Yes. The ESO analysis tool, in conjunction with DCPP plant analysis, identifies conditions which could result in actuation of the DCPP degraded voltage protection logic and subsequent separation from an offsite power source immediately (i.e., during safety bus load sequencing) or long-term (i.e., steady state) upon a DCPP trip.

NRC Question 2(d):

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

PG&E Response:

The update interval of the ESO SCADA system varies depending on the variable. A typical update interval for the ESO switchyard operator is less than 15 seconds. The ESO periodic analysis is reviewed annually and updated as necessary. The DCPP/TSO agreement requires prior DCPP notification regarding planned changes to the grid local to DCPP. Since PG&E is the transmission owner, the ESO provides the subject notifications. DCPP personnel can request updates at this time also.

NRC Question 2(e):

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

PG&E Response:

The notification from the ESO is based upon the predicted post-trip overall system performance, given predetermined bounding studies of numerous grid and plant configurations.

Conditions that would trigger a DCPP notification from the ESO switchyard operator include:

- switchyard voltages below the pre-trip minimum established for the current grid configuration
- Los Padres Area (i.e., the area in the vicinity of DCPP) 230kV loading in excess of the maximum established for the current grid configuration
- change in the current grid configuration such as loss of a transmission element, change in status of voltage regulating devices, change in status of other local generation (more than 80 different configurations are predefined)
- ESO transmission planning analysis results regarding WECC stability compliance issues local to DCPP (note: this is included for completeness as it is acknowledged that grid stability is not within the scope of GL 2006-02)

NRC Question 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? If so, how does the NPP licensee determine that the offsite power would remain operable when such a notification is received?

PG&E Response:

Yes. The TCA specifically requires DCPP notification for periods of time when grid functionality is indeterminate. This notification requirement is implemented via ESO procedure.

Grid conditions that are more severe with respect to DCPP voltage requirements or otherwise unanalyzed, require DCPP notification and DCPP operations would declare the offsite circuit inoperable.

NRC Question 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?

PG&E Response:

No. The ESO has procedurally required reporting requirements to the TSO and WECC; however, these are generally triggered by load interruptions and not necessarily the loss of generation. The ESO does have a method for validating the grid state estimator. However, this process does not specifically include DCPP unit trips since they are too infrequent. A unit trip as a consequence of a major grid disturbance would be included in a post event investigation.

The ESO model used to define the critical parameter limits in the periodic study updates is based on the current WECC model. DCPP is not knowledgeable on how that model is validated.

DCPP procedures do not require verification of the predicted analysis tool switchyard voltages. This task is not feasible by DCPP personnel. Verification of the analysis tool switchyard voltages would require access to extensive amounts of grid data not available to DCPP personnel and expertise beyond that necessary to analyze nuclear power plant SSCs. DCPP personnel do perform an assessment of the in-plant electrical distribution system, including bus transfers and voltage responses prior to restart per Operating Procedure OP1.DC1.

NRC Question 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?

PG&E Response:

Not applicable. Analysis tools are available and in use by the ESO.

NRC Question 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?

PG&E Response:

Not applicable. Analysis tools are available and in use by the ESO. However, as stated in response to Question 2(a), periodic studies are an integral part of the process; therefore, responses to Questions 2(i)(a) and 2(i)(b) are provided.

NRC Question 2(i)(a):

(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?

PG&E Response:

Yes. Key assumptions and parameters are translated into ESO procedural guidance.

NRC Question 2(i)(b):

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

PG&E Response:

Yes. Grid operation outside the bounds of the key assumptions and parameters does trigger DCPP notification.

NRC Question 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.

PG&E Response:

Not applicable. The ESO utilizes analysis tools and communicates the applicable results and conclusions.

See the response to Question 1(e) regarding compliance with GDC-17.

NRC Question 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.

NRC Question 3(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?

PG&E Response:

Yes. The DCPP operator declares the applicable offsite power circuit inoperable, if after an analysis (operational decision-making) of a contingent DCPP unit trip, it is determined that the offsite power system (i.e., the grid) is nonfunctional.

If notified that a DCPP trip would drive voltage below the degraded voltage protection setpoint, the DCPP operator would enter TS Limiting Condition for Operation 3.8.1 Action (A).

The DCPP operator does not declare the offsite power circuits inoperable for other postulated grid facility losses.

Postulated contingencies on the transmission grid are not used as a basis for functional determinations since:

- such events are only postulated and have not actually occurred,
- the offsite power circuits remain capable of effecting a safe shutdown and mitigating the effects of an accident, and
- the GDC-17 criterion discussed in GL 2006-02 is still met (i.e., loss of power from the transmission network would not occur as a result of loss of power generated by DCPP).

If the ESO notified the control room and requested a backdown of DCPP generation in order to preclude instability elsewhere in the system due to postulated "N-1" TSO contingencies, DCPP would backdown in accordance with procedures, but would not declare offsite power circuits inoperable. Similarly, if the TSO declares a "restricted maintenance or no touch" day or a Stage 3 grid emergency (i.e., energy deficiency), the expectation is that the TSO will adjust generation and load (initiate rolling blackouts) to ensure system voltage and

frequency remain within limits. Therefore, the grid would remain functional and the offsite power circuits would be operable.

- There is no industry-wide precedent that requires NPPs to monitor the postulated effects of transmission line trips. There is no assessment of the probability of a particular line tripping to allow an informed risk determination. There has been no industry dialog on what "preparatory actions," if any, would be necessary or appropriate if such a notification were received. Based on a nominal grid, a single transmission line trip would not result in the loss of an offsite power circuit.

NRC Question 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 result of responding to an emergency actuation signal during this condition, is the equipment considered inoperable? If not, why not?

PG&E Response:

Yes. If safety-related equipment is lost for any reason, as governed by plant TS, then the equipment is declared inoperable.

As stated in PG&E Letter DCL-97-074 to the NRC, "License Amendment Request 97-05: Revision of Technical Specification 3/4.7.3.1," dated May 22, 1997, the DCPP licensing basis requires postulation of a LOOP only at the initiation of an event. The assumption of a design basis accident with a nonconcurrent LOOP is beyond the licensing basis of DCPP. The 230kV offsite power circuit is the "immediately available" source for DCPP. The basis for operability is having sufficient capacity to preclude actuation of the degraded voltage protective function upon a postulated LOCA/unit trip. Therefore, by definition double sequencing as a result of a postulated unit trip/LOCA will not occur when the startup source is operable.

The double sequencing concern this question is alluding to is related more to the TS offsite circuit completion time than a delayed LOOP. A delayed LOOP is only one possible initiator of double sequencing. The definition of a LOOP is the loss of *both* offsite power circuits. Double sequencing can also result from a unit trip if only the "immediate access" offsite power circuit (i.e., 230kV for DCPP) has insufficient capacity. An operable "delayed access" offsite power source (i.e., 500kV for DCPP) would not constitute a LOOP. If it has been determined that double sequencing can adversely impact a required safety function, the concern is the basis for the TS offsite circuit completion time may be nonconservative if other LCO's are applicable concurrently.

DCPP previously identified such a situation regarding the containment fan cooler unit (CFCU) containment heat removal safety function and the component cooling water system (CCW). A modification was made (i.e., CCW pressurization system) to eliminate the double sequencing vulnerability for the CCW system. However, should the CCW system pressurization function be inoperable coincident with postulated insufficient 230kV startup capacity, Equipment Control Guideline 14.1, "CCW Surge Tank Pressurization System," requires that TS 3.0.3 is immediately applied. Item E8.1 of NRC Inspection Report 50-275/96023 and 50-323/96023, dated January 17, 1997, contains an evaluation of double sequencing at DCPP.

NRC Question 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).

PG&E Response:

DCPP has evaluated the interaction of the CFCU's and the CCW system as stated in the response to Question 3(b), above. The concerns identified as part of that evaluation have been resolved. The evaluation for the CFCU and CCW system also concluded that this phenomenon was a generic issue. Therefore, other systems were reviewed for similar vulnerabilities as part of DCPP nonconformance report N0001977 and no other vulnerabilities were identified. This action resolved the double sequencing issue for DCPP. This conclusion was confirmed in Item E8.1 of NRC Inspection Report 50-75/96023 and 50-323/96023.

NRC Question 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.

PG&E Response:

No. TS are not entered for grid conditions that might occur. The DCPP operator declares the applicable offsite circuit inoperable when the predicted voltage following a DCPP trip is low enough to cause actuation of the degraded voltage relays and a consequential separation from the offsite power circuit.

Postulated contingencies on the transmission grid are not used as a basis for functionality determinations since:

- such events are only postulated and have not actually occurred,

- the offsite power circuits remain capable of effecting a safe shutdown and mitigating the effects of an accident, and
- the GDC-17 criterion is still met (i.e., loss of power from the transmission network would not occur as a result of loss of power generated by DCPP).

NRC Question 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.

PG&E Response:

Not applicable. DCPP declares offsite power circuits and safety-related equipment inoperable if the conditions required for operability are not met, as stated in the response to Questions 3(a) and 3(b).

NRC Question 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).

PG&E Response:

Not applicable. DCPP does not invoke compensatory actions to alleviate the effects of an inoperable offsite power circuit.

NRC Question 4:

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

NRC Question 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.

PG&E Response:

Yes. Procedural guidance is available to DCPP operators.

The training program includes training on Operating Procedure J-2:VIII, which addresses manual operation of the startup power LTC and the compensatory measures that are required to maintain startup power operable while the tap changer is in manual. Operating Procedure J-2:VIII training also includes training on when the transmission system capacitor banks are required to be in operation for offsite circuit operability. Operating procedures for transferring 4kV and 12kV buses between auxiliary and startup power direct operators to refer to OP J-2:VIII for operability limitations when operating the LTC in manual (as required to perform bus transfers). OP C-3:III, "Main Unit Turbine – At Power Operations," provides instruction (precautions) regarding main generator voltage and load restrictions during 500kV line outages in order to optimize grid stability during this time. This training is evaluated via the weekly written licensed operator continuing training test.

NRC Question 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.

PG&E Response:

Not applicable. DCPP operators are provided the requisite procedural guidance.

NRC Question 5:

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.

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

NRC Question 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?

PG&E Response:

Yes. A qualitative assessment is performed. Regulation 10 CFR 50.65(a)(4) requires performance of a risk assessment prior to maintenance activities. Maintenance is defined broadly and would include surveillances, post maintenance testing, and preventive and corrective maintenance. Relative to increasing the initiating event frequency, such as the frequency of a plant trip, the industry guidance, NUMARC 93-01 (endorsed without exception by NRC Regulatory Guide (RG) 1.182), states in Section 11.3.2.2 that the following should be considered:

- the likelihood of an initiating event or accident that would require the performance of the affected safety function
- the likelihood that the maintenance activity will significantly increase the frequency of a risk-significant initiating event (e.g., by an order of magnitude or more as determined by each licensee, consistent with its obligation to manage maintenance-related risk)

The consideration of likelihood of an initiating event or accident is generally met by using the Probabilistic Risk Assessment (PRA) and associated configuration risk management tools, which explicitly consider initiating event frequencies for transients and accidents. LOOP sequences are important elements of PRA, and are thoroughly modeled and assessed during plant peer reviews. Risk management personnel are sensitized to the importance of these sequences.

For the consideration for a maintenance activity, if a maintenance activity is expected to increase the likelihood of an initiating-event by an order of magnitude, then it should be considered in the assessment. Otherwise, the baseline initiating event frequencies may be used. These frequencies are based on generic data updated with plant specific data, and would take into account the plant specific LOOP and trip frequencies.

DCPP Administrative Procedure AD7.DC6, "On-Line Maintenance Risk Management," addresses the evaluation of risk from external events. For example, the following external risk examples are classified as High Trip Risks:

- offsite power system induced trip risks:
    - peak power demand (i.e., TSO stage 3 or higher grid emergencies)
    - fires threatening offsite power source lines
    - storms (i.e., wind, rain, etc.)
- direct trip risk from storms:
    - high ocean swell warning (refer to OP O-28, "Intake Management")
    - lightning strikes, etc.
- seismic risk factors:
    - Parkfield Level A earthquake prediction
    - tsunami warning

NRC Question 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 grid-risk-sensitive maintenance?

PG&E Response:

Yes. Procedure MA1.DC11, "Risk Assessment," is performed each and every time additional activities are scheduled as required by Procedure AD7.DC6, "On-Line Maintenance Risk Management." The ESO, via the Diablo Canyon Control Center (DCCC) switchyard operators, monitors grid status and communicates status updates to the DCPP operators accordingly. DCPP personnel are required, as part of the work control and risk management process, to re-assess risk on a real-time basis. Per AD7.DC6, the DCPP Shift Foreman (SFM) "shall evaluate and manage the risk of all activities or conditions based on the current plant state;" this includes "as soon as possible when an external or internal event or condition is recognized." Grid status falls under "external" events or conditions per Procedure AD7.DC6.

NUMARC 93-01 does not define "grid-risk-sensitive maintenance," so there is no unique guidance for such activities. The following guidance is included in Section 11.3.2.8 of NUMARC 93-01:

"Emergent conditions may result in the need for action prior to conduct of the assessment, or could change the conditions of a previously performed assessment. Examples include plant configuration or mode changes, additional SSCs out of service due to failures, or significant changes in external conditions

(weather, offsite power availability). The following guidance applies to this situation:

- The safety assessment should be performed (or re-evaluated) to address the changed plant conditions on a reasonable schedule commensurate with the safety significance of the condition. Based on the results of the assessment, ongoing or planned maintenance activities may need to be suspended or rescheduled, and SSCs may need to be returned to service.
- Performance (or re-evaluation) of the assessment should not interfere with, or delay, the operator and/or maintenance crew from taking timely actions to restore the equipment to service or take compensatory actions.
- If the plant configuration is restored prior to conducting or re-evaluating the assessment, the assessment need not be conducted, or re-evaluated if already performed."

Note that emergent conditions are defined as "significant" changes to conditions assumed in the original risk assessment. How the plant determines whether grid conditions are changed, or whether these changes are significant enough to warrant re-assessment, are not prescribed in the NRC endorsed guidance. Plant procedures would address these issues.

NRC Question 5(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.

PG&E Response:

No. There is not a significant variation in the stress on the grid in the vicinity of the DCPP site (i.e., lines to/from the DCPP switchyards) caused by seasonal loads or maintenance activities associated with critical transmission elements based on the GL 2006-02 definition of grid stress. The "vicinity" of DCPP is interpreted to be the Los Padres Division of the PG&E service territory. The Los Padres area load is definitely a factor in determining DCPP offsite power circuit operability and it is monitored. However, the Los Padres area load is not the determining factor for TSO alert notifications in the context of NERC Standard EOP-002-0.

It is acknowledged that maximum grid loading (California including Los Padres area) occurs during the summer. Consequently, grid "stress" during the summer can be associated with capacity limitations. This is also when TSO resource alert notifications are most likely to occur. However, grid stress is a function of more than just load as defined in GL 2006-02. During other periods of the year, although the load may be less, changes in the grid dynamics can result in stability being the limiting factor. For DCPP, light winter loading conditions are the most restrictive. Therefore, since each season may be associated with a stressed grid, it is concluded that there is no significant seasonal variation with respect to grid functionality.

The local transmission elements critical to supplying DCPP offsite power are not typically operated at, or near their respective thermal limits. DCPP generation feeds into the 500kV pacific intertie at two different locations between "Path 15" and "Path 26." The 500kV pacific intertie has numerous remedial action schemes (RAS), including Paths 15 and 26, for the purpose of relieving stress and maintaining overall grid reliability. A RAS is a transmission protective function designed to detect abnormal grid conditions and take preplanned, corrective action (other than the isolation of faulted elements) to provide acceptable grid performance. These schemes are functional all year. However, the DCPP switchyards and associated transmission lines are not part of the 500kV pacific intertie. Additionally, the loss of a DCPP output line does not require initiation of a Path 15 or 26 RAS scheme.

The TSO maintains a stable grid in the event of a major disturbance and or during energy deficiencies. Load management procedures are in place to ensure continued grid reliability. The DCPP offsite power interface is identified as a continuous requirement and is not subject to interruption relative to grid load management. Hence, the grid is maintained to be continuously functional.

The maintenance outage scheduling of generators and transmission facilities are coordinated by the TSO. Tools for fully evaluating the reliability and economic impacts of these outages are not yet fully developed (see response to Question 2(a) regarding RTCA). At times, scheduled outages may have to be changed due to reliability concerns in the day ahead or current day. Since this is a potential reliability problem for the TSO, it may require changes in scheduled generation to maintain overall reliability of the grid. DCPP is located in a very temperate coastal climate and consequently ESO maintenance of local transmission elements may be performed any time during the year if system loading conditions permit.

There is not a seasonal variation in the expected LOOP frequency. Within the context of GL 2006-02, the phrase "*expected* LOOP frequency" means *actual* LOOP frequency based on SECY 05-0219, dated December 2, 2005, Table 3, "Bin 3", "Comment M-6." DCPP has not experienced a grid initiated LOOP, consequently there is no LOOP data available to indicate a seasonal variation.

Additionally, EPRI report T-1011759, dated December 2005, concludes that there is no statistically significant seasonal variation in recorded LOOP events in any region from 1997 to 2004. Utilizing station blackout (SBO) classifications per RG 1.155, DCPP is classified "SW Group 1" (i.e., the lowest); therefore, severe weather is not a significant seasonal factor. ESO operating procedures also ensure continuous compliance with transmission criteria year round.

NRC Information Notice IN 2006-06, "Loss of Offsite Power and Station Blackout are More Probable During Summer Periods," was issued on March 3, 2006, and PG&E is evaluating this separately.

NRC Question 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?

PG&E Response:

No. The time-related variations in the probability of a LOOP at DCPP are not considered in the grid-risk-sensitive maintenance evaluation. As stated in response to Question 5(c), it is believed that there is no known significant variation in the stress on the grid in the vicinity of the DCPP site or seasonal variations in the frequency of a LOOP at DCPP.

The grid condition, however, is qualitatively factored in as part of the DCPP risk management as addressed in the response to Question 5(a).

NRC Question 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?

PG&E Response:

Yes. The ESO contact is the DCCC switchyard operator. DCPP Operations Policy B-1, "Communications with Generation and Transmission Organizations," outlines the communication channels between organizations and ESO procedure O-23, "General Operating Instructions for Reliable Transmission at DCPP," establishes ESO switchyard operator instructions for insuring adequate and reliable transmission to and from DCPP. ESO procedure O-23 is available to DCPP operators as an attachment to DCPP Operating Procedure OP J-2:VIII, "Guidelines for Reliable Transmission Service for DCPP." DCPP Operating Procedure OP J-2:VIII contains instructions for DCPP operators to determine

operability of the offsite power sources and directs the DCPP operators to obtain information needed from DCCC to make an operability determination.

NRC Question 5(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.

PG&E Response:

The TCA referred to in the response to Question 1(a) requires the TSO "to ensure that various system operating conditions, including multiple contingency events, are evaluated and understood, such that impaired or potentially degraded grid conditions are recognized, assessed and immediately communicated to the DCPP operating staff for Operability determination." Conditions that may emerge during maintenance activities are included in this requirement. The ESO implementing procedure requires the ESO switchyard operator to notify the DCCP operator as soon as possible after a forced outage of transmission equipment critical to DCPP offsite power or generation.

DCPP has a documented Operations Policy, B-1, "Communications With Generation and Transmission Organizations." This policy addresses:

- forecasting unit generation,
- TSO emergencies,
- restricted maintenance operations,
- "stage 3" emergency declarations,
- 500kV voltage control, and
- DCPP backdown/fast ramp capabilities.

This policy is typically updated after every refueling outage and distinctly identifies responsible organizations and associated telephone numbers.

NRC Question 5(g):

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

PG&E Response:

Yes. When performing scheduled maintenance at DCPP the ESO is generally notified daily to update progress.

NRC Question 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.

PG&E Response:

As part of licensed operator continuing training, operators are trained on the protocols described in Operating Procedure J-2:VIII, Operations Policy B-1, and ESO transmission Operating Procedure O-23. This formal classroom training is augmented with on the job training by those that routinely utilize these protocols. That group includes Senior Reactor Operators (SROs) assigned to the control room staff and SROs assigned to the position of work week manager (WWM).

NRC Question 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).

PG&E Response:

Not applicable. The DCPP grid reliability evaluation does rely on communication with the ESO as part of the maintenance risk assessment required by 10 CFR 50.65 (a)(4). These risks assessments are performed as part of DCPP Administrative Procedure AD7.ID4, "On-Line Maintenance Scheduling," Administrative Procedure AD7.DC6, "On-Line Maintenance Risk Management," Operating Procedure OP J-2:VIII, "Guidelines for Reliable Transmission Service for DCPP," and DCPP Operations Policy B-1, "Communications with Generation and Transmission Organizations." These procedures address maintenance risk for both planned maintenance and real-time grid conditions.

NRC Question 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.

PG&E Response:

Not applicable. Risk is assessed by procedures addressed in response to Question 5(i) above.

NRC Question 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.

PG&E Response:

Not applicable. Risk is assessed by procedures addressed in response to Question 5(i) above.

NRC Question 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).

NRC Question 6(a):

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

PG&E Response:

Yes. The ESO communicates with DCPP using a formal work request process that involves the power plant's local switchyard and the work control group at DCPP. These work requests are sent many weeks in advance to the work control group who, then incorporate this proposed work into the master work schedule as long as there are no conflicts with the schedule.

NRC Question 6(b):

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

PG&E Response:

Yes. An electronic work request form similar to the one mentioned in response to Question 6(a) is filled out weeks in advance by the DCPP work control group and then sent electronically to the transmission and distribution section for approval and incorporation into their schedule.

NRC Question 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?

PG&E Response:

Yes. The operations department and work control group utilize an on-line risk management procedure that re-evaluates planned maintenance activities when it is discovered that an increased "external risk" to the power plant exists. The TSO uses a tiered notification system based on level of severity of degradation of the grid. DCPP maintenance activities may be rescheduled if there is a significant conflict with the maintenance and the grid condition (e.g., TSO RMO).

Although rescheduling is not in the Maintenance Rule definitions, the risk informed Maintenance Rule allows many choices. Maintenance that has an associated trip risk is performed when the on-shift DCPP personnel conclude that the risk of the work is small compared to the safety benefit. When the maintenance work is done in response to a TS, the risk assessment is informative for sequencing tasks, but not controlling. Maintenance that has an associated trip risk would be activities such as the following:

- reactor protection system calibrations
- anticipated transient without scram mitigation system testing
- control rod drive testing
- main turbine control testing

Emergent issues with the grid are managed to maintain a high level of plant safety. At times appropriate management means rescheduling activities, at other times the shift manager will order the on-shift DCPP staff to back-out of the task and restore the safety-related function of the equipment.

NRC Question 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 include alternate equipment protection and compensatory measures to limit or minimize risk.)

PG&E Response:

Yes. Risk management actions would include maximizing equipment availability that is not directly affected by the maintenance activity. Alternate equipment is protected by placing "no work" signs at the entrances to areas containing

protected equipment as well as physical barriers across these entrances. Other actions include preplanning and staging necessary equipment to complete the maintenance, dry-run training sessions for maintenance personnel for jobs seldom performed, management oversight of the maintenance activities, 24 hours per day work schedule until the maintenance activity is complete, tail boarding all affected personnel, and increased monitoring of in service protected equipment to ensure no work is performed on or near the equipment that may compromise its availability. Although rescheduling is not in the Maintenance Rule definitions, the risk informed Maintenance Rule allows many choices. Maintenance that has an associated trip risk is performed when the on-shift DCPP personnel conclude that the risk of the work is small compared to the safety benefit. When the maintenance work is done in response to a TS, the risk assessment is informative for sequencing tasks, but not controlling.

NRC Question 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.

PG&E Response:

The actions associated with each question are as described in the applicable response to Questions 6(a) through 6(d). The actions will be consistently accomplished since they are required by the procedures. The governing procedures are as follows:

6(a) The procedure reference is Operations Policy B-1. Other references are AD7.DC6; "On Line Maintenance Risk Management" and AD7.ID4; "On Line Maintenance Scheduling."

6(b) The procedure references for Question 6(b) are the same as for Question 6(a).

6(c) The procedure reference is AD7.DC6; "On Line Maintenance Risk Management." This procedure evaluates the risk, both qualitatively and quantitatively, and involves senior operations management if the risk surpasses a conservative threshold.

6(d) Risk management actions are typically described in individual procedures that remove from service a certain piece of equipment. For example, if a startup transformer is removed from service for maintenance, Operating Procedure OP J-2:III takes actions to protect remaining equipment and gives instructions on notifications and approvals necessary as well as oversight requirements. Guidance for risk management actions while the

unit is on line is provided by Administrative Procedure AD7.DC6. Guidance for risk management actions during a planned or forced unit outage is provided by Administrative Procedure AD8.DC55, "Outage Safety Scheduling."

Operations Policy B-1, Attachment 3 details DCPP on-line maintenance/risk management during a grid TSO stage 3 emergency (critical operating reserve shortfall). Actions during a TSO stage 3 emergency include: (1) trip mitigation equipment/systems will be worked on a 24-hour/around-the-clock basis; (2) for risk evaluations during this period, the 500kV system is considered an external trip risk and the 230kV system degraded; and (3) compensatory measures are established commensurate with the duration and risk significance of planned maintenance.

NRC Question 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).

PG&E Response:

Both work control and clearance coordination are functions of the operations department. The operations department has the responsibility for making operability determinations.

The risk management program was taught to operations personnel when it was first implemented and again when it was modified. The training included the need to consider offsite risk and events (including what is going on in the power grid) when removing equipment from service. This was tested via written test.

The work control process and risk process is taught in initial license class including on-the-job training to reinforce expectations on the use of risk management and the procedures involved.

Maintenance personnel are not specifically trained regarding this matter as they are a "customer" of the operations work control process.

NRC Question 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).

PG&E Response:

Not applicable. There is effective coordination of maintenance activities.

NRC Question 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.

PG&E Response:

Not applicable. As discussed in the responses to Questions 6(a) through 6(d), DCPP effectively implements appropriate risk management actions.

NRC Question 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).

PG&E Response:

Not applicable. As discussed in Questions 6(a) through 6(d), DCPP effectively implements appropriate risk management actions.

NRC Question 7:

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.

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

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

Procedures should include the actions necessary to restore offsite power and use nearby power sources when offsite power is unavailable. As a minimum, the following potential causes for loss of offsite power should be considered:

- *Grid undervoltage and collapse*
- *Weather-induced power loss*
- *Preferred power distribution system faults that could result in the loss of normal power to essential switchgear buses*

NRC Question 7(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.

PG&E Response:

Pursuant to 10 CFR 50.63, each DCPP unit relies on an onsite "Alternate AC" (AAC) power source to comply with station blackout requirements. The TCA referred to in the response to Question 1(a) addresses the restoration of offsite power, but it does not identify specific power sources. The agreement does require: (1) that the highest possible priority shall be given to restoring power to the DCPP switchyards; (2) should incoming lines to the DCPP switchyards be damaged, highest priority shall be assigned to repair and restore at least one line into the DCPP switchyards; (3) that repair crews engaging in power restoration activities for DCPP shall be given the highest priority for manpower, equipment, and materials; and (4) that formal procedures shall be in place to effect these requirements.

The TSO, as required by the TCA, directs the ESO to maintain system restoration guidelines. The ESO guidelines identify multiple sources of power, including black start units, and connection paths to the DCPP switchyards.

NRC Question 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.

PG&E Response:

Not applicable. Local power sources (see response to Question 7(a)) are not a DCPP SSC and therefore, not subject to DCPP operator training. See the response to Question 1(d) regarding training on the restoration of the offsite power circuits.

The ESO grid operators train on the grid restoration process annually per NERC training requirements.

NRC Question 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.

PG&E Response:

Not applicable. The TCA referred to in the response to Question 1(a) establishes the priority regarding the resupply of power to DCPP. The TSO/ESO restoration guidelines identify multiple sources of potential power, including black start units, and connection paths to the DCPP switchyards.

The DCPP methods of compliance with 10 CFR 50.63 have been reviewed and accepted by the NRC. Although DCPP utilizes RG 1.155 as guidance, the licensing basis does not commit to it. Additionally, 10 CFR 50.63 does not require the use of "nearby power sources."

Solely relying on nearby power sources would not be practical. DCPP has no jurisdiction or control over "nearby" units; therefore, even if such plants were procedurally identified, the allowance for other alternatives would be critical. The establishment of priority with TSO is paramount and is consistent with the 10 CFR 50.63 requirements regarding the timely restoration of offsite power. The TSO would know the extent of the transmission outage and therefore would be best suited to identify available sources and connection paths to the DCPP switchyards. The DCPP LOOP procedures deal with getting power from the switchyard to the plant busses.

DCPP does not believe any additional actions are warranted for compliance with 10 CFR 50.63.

NRC Question 8:

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

Maintaining SBO coping capabilities in accordance 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.

NRC Question 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?

PG&E Response:

Not applicable. DCPP is classified as an AAC plant where onsite AC power can be available within ten minutes. The evaluation of station blackout capability for DCPP did not rely on a coping duration analysis. Each DCPP unit relies on an AAC power source to cope with a station blackout. The onsite AAC source for each DCPP unit meets the requirements of 10 CFR 50.63(c)(2) since it is demonstrated by test to be available to power the shutdown busses within ten minutes of the onset of the station blackout. Therefore, in accordance with 10 CFR 50.63(c)(2) no coping analysis is required.

In the response to TI 2515/156, DCPP reported one grid centered LOOP event for both DCPP units. This event occurred on August 10, 1996. This was a major grid event that originated outside of California. Although it resulted in a DCPP dual unit trip, the offsite power system of both units functioned as designed. That is, electrical power automatically transferred from the unit auxiliary feeds to the startup feeds (i.e., 500kV to 230kV) and the diesel generators did not load. Subsequent to the unit trips, the startup source was declared inoperable for conservatism. Although the startup source was declared inoperable, it remained functional and continued to power plant loads. Therefore, this input to TI 2515/156 is incorrect and DCPP has not experienced a grid initiated LOOP.

Although a coping analysis is not required, the initial DCPP assessment concluded that the coping duration would be 4 hours. In conclusion, DCPP has not experienced a grid centered LOOP event since the plant's coping duration was initially determined.

NRC Question 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?

PG&E Response:

Not applicable. See response to Question 8(a).

NRC Question 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?

PG&E Response:

Not applicable. See response to Question 8(a).

NRC Question 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 50.63.

PG&E Response:

Not applicable. See response to Question 8(a).

NRC Question 9:

Actions to ensure compliance.

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.

PG&E Response:

Not applicable. No noncompliance with NRC regulatory requirements has been determined as a result of this response to GL 2006-02.