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PG&E Letter DCL-09-066

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
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Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
Meeting to Discuss Basis for Request for Technical Specification Interpretation Regarding 230kV System Operability

Dear Commissioners and Staff:

References:
1. PG&E Letter DCL-09-010, Request for Technical Specification Interpretation Regarding 230kV System Operability, dated February 23, 2009.
2. Summary of July 22, 2009, Meeting With Pacific Gas and Electric Company on Technical Specification (TS) Interpretation of 230kV Offsite Power System (TAC Nos. ME0711 and ME0712), dated August 18, 2009.

On July 22, 2009, PG&E met with the NRC to discuss the basis for its request for a technical specification interpretation submitted February 23, 2009 (Reference 1). PG&E had requested NRC concurrence with PG&E's position regarding the basis for operability of the 230kV offsite power system as controlled by TS 3.8.1, "AC Sources – Operating," and TS 3.8.2, "AC Sources – Shutdown." PG&E agreed to provide responses to several questions asked by the NRC staff at the meeting (Reference 2). The responses are included in the enclosure to this letter.

The meeting summary stated that PG&E agreed that the current TS Bases would not support its interpretation of operability for TS 3.8.1 and TS 3.8.2. PG&E made that statement regarding the basis for operability when operating with the offsite circuits in an off-normal cross-tied configuration (i.e., an off-normal configuration with both units aligned to the 230kV offsite power system through a single startup transformer). The statement was not made in reference to the normal configuration of the offsite circuits. The current TS would support PG&E's interpretation of operability for TS 3.8.1 and TS 3.8.2.

If you have further questions, or require additional information, please contact Larry Parker at (805) 545-3386.

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NRR

Sincerely,

James R. Becker
Site Vice President

tcg/DA50085862
Enclosure
cc: Elmo E. Collins, NRC Region IV
Alan B. Wang, NRC Project Manager
Diablo Distribution
cc/enc: Michael S. Peck, NRC Senior Resident Inspector

Responses to Questions from July 22, 2009 PG&E/NRC Meeting –
Request for Technical Specification Interpretation
Regarding 230kV Offsite Power System Operability

NRC Question 1:

What sequences the ESF loads on?

PG&E Response:

The following conditions will auto start the required engineered safety feature (ESF) loads (Reference Final Safety Analysis Report (FSAR) 8.3.1.1.9 and Drawing 458863 [typical of each vital bus]):

- Bus auto transfer to the 230kV startup source without a safety injection (SI) signal (Auxiliary Saltwater (ASW) Pump and Containment Fan Cooler only)
- Bus auto transfer to the onsite diesel generator source without a SI signal (ASW, Auxiliary Feedwater (AFW) Pump, Charging Pump, Component Cooling Water Pump, and Containment Fan Cooler only)
- SI signal transfer to the 230kV startup source (ESF loads that were running are automatically transferred and energized. All ESF loads are given a start signal in sequence.)
- SI signal transfer to the onsite diesel generator source (All ESF loads are given a start signal in sequence.)

NRC Question 2:

Do the second level undervoltage relays (SLURS) meet the Branch Technical Position?

PG&E Response:

The DCPP degraded grid voltage protection was designed and approved by the NRC prior to the issuance of Branch Technical Position (BTP) PSB-1 in July 1981. The design meets the position provided in NRC Letter to PG&E dated November 22, 1977. The NRC review is documented in Supplement to Safety Evaluation Report 9 dated June 1980.

NRC Question 3:

Is a dual unit trip an Anticipated Operational Occurrence (AOO)?

PG&E Response:

A dual unit trip is not an AOO; however, a dual unit trip could be the consequence of an AOO.

As defined in 10 CFR 50, Appendix A, an AOO is a condition of normal operation that is expected to occur one or more times during the life of the nuclear power unit and includes but is not limited to loss of power to all recirculation pumps, tripping of the turbine generator set, isolation of the main condenser, and loss of all offsite power. Other examples of AOOs are provided in Regulatory Guide (RG) 1.70 and Standard Review Plan (SRP) 15.0. AOOs are also known as Condition II and III events as addressed in SRP 15.0.

A station loss of offsite power event would result in a dual unit trip; however, offsite power would be lost as part of the initiating event, and not as a consequence of the dual unit trip. Therefore, for the purposes of this question, a dual unit trip is considered to be the simultaneous automatic or manual actuation of the Reactor Protection Systems (RPS) of both DCPP operating units such that the auxiliary loads of both units are simultaneously transferred to the 230kV system or the emergency diesel generators. Thus, simultaneous actuation of the RPS on both units is not expected to occur absent an external event of a nature that independently results in exceeding an RPS actuation condition on both units. Potential events that could result in actuation of the RPS on both units include:

Grid Disturbances – A grid disturbance of sufficient magnitude could result in an interruption of power either to or from DCPP. These events are considered AOOs and are analyzed as Condition II events in Chapter 15 of the FSAR Update as follows:

Loss of external electrical load and/or turbine trip – For this event, the unit is evaluated for a complete loss of steam load from full power without a direct reactor trip. A grid disturbance could result in a loss of load via separation of the generator from the grid (i.e., generator output breakers open). The reactor is not tripped until conditions in the RCS result in a trip. This event is analyzed in FSAR Update Section 15.2.7. Relative to grid-induced loss of external load events, various DCPP stability studies (performed by the Transmission System Provider (TSP)) and the plant operating experience have not revealed any plant stability problems related to its operation with all three 500kV lines in service or following a loss of a single 500kV component (a line or a unit). The plant performance in such situations is in compliance with the NERC/WECC Planning Standards. Specifically, NERC/WECC Category A and B events should not initiate a dual unit trip. However, it is recognized that the potential of instability and a dual unit trip increases if one of the 500kV lines is out-of-service. The TSP has installed a "Special Protection Scheme" (SPS) to detect and preclude a dual unit trip for these indentified conditions. When the SPS protection is out-of-service, DCPP reduces the station net output to preclude postulated dual unit trips (Reference DCPP Operating Procedure OP J-2:VIII, Attachment 9.6, Page 11). Multi-contingency grid events, NERC/WECC Category C and D events are bounded by the loss of offsite power event (FSAR Update Section 15.2.9).

Loss of offsite power and main generator power to the station auxiliaries – A severe grid disturbance could result in a grid (i.e., all voltage levels including 230kV and 500kV) collapse (NERC/WECC Category D event). This would be reflected at DCPP as a loss of offsite power to station auxiliaries and would result in a simultaneous actuation of the RPS on both units. As described in FSAR Update, Section 15.2.9, the loss of offsite power would result in starting and loading of the emergency diesel generators (EDGs) as necessary to achieve a safe shutdown.

Ocean Debris Loading of Intake Screens – These events are characterized by uneven accumulation of debris on the intake screens of the two units. Due to the physical design configuration of the DCPP intake, the accumulation of debris on the Unit 2 circulating water screens typically occurs at a faster rate than on Unit 1. Although the accumulation of ocean debris could result in a reactor trip on both units, they would not be expected to occur simultaneously. Past ocean debris events exhibited this behavior. On October 28, 1999, Unit 1 and Unit 2 were manually tripped within a period of one minute due to heavy debris loading of the traveling screens during a Pacific Ocean storm. The auxiliary loads of both units successfully transferred to startup. However, prior to the unit trips one circulating water pump on each unit was tripped. When the units were tripped, the other circulating water pump in each unit was tripped. Thus, no circulating water pumps transferred to startup power.

Significant Seismic Event – Each unit has an independent seismic trip system. The setpoint of the seismic trip actuation is a ground acceleration of 0.35g. Offsite power is not expected to be available immediately following a seismic event of the magnitude that would result in actuation of the seismic trip system. In this event, the emergency diesel generators would be relied upon to power the vital busses as necessary to achieve a safe shutdown.

General design criterion (GDC) 2 requires that structures, systems, and components important to safety be designed to withstand the effects of natural phenomena such as earthquakes, tornadoes, hurricanes, floods, tsunami, and seiches without loss of capability to perform their safety functions. For offsite power systems, compliance with GDC 2 requires that nuclear power plant structures, systems, and components important to safety be designed to withstand the effects of natural phenomena such as high and low atmospheric temperatures, high wind, rain, lightning discharges, ice and snow conditions, and weather events causing regional effects without loss of capability to perform their intended safety function. The effects of earthquakes are specifically excluded. (SRP 8.2)

Therefore, the offsite power system is not relied on to power the minimum required safety functions following an earthquake.

Thus, although a dual unit trip is not in itself an AOO, its occurrence as a result of an external event is bounded by the AOOs analyzed as Condition II events in Chapter 15 of the FSAR Update.

NRC Question 4:

Verify the 023 analysis does not assume any operation from 2 units.

PG&E Response:

The offsite power load flow analysis does not credit any DCPP generation to the grid.

NRC Question 5:

What is the operational impact of assuming a "concurrent" versus "orderly" shutdown of the second unit?

PG&E Response:

DCPP is designed for concurrent shutdown of both units. A shutdown is not a trip. For the purposes of responding to this question, it is assumed that the "concurrent" shutdown referred to in the question is a concurrent trip of the second unit. The operational impact on the second level undervoltage degraded grid protective function would result in a decrease in margin and could have operational/maintenance impacts on both DCPP and the TSP. The decrease in margin would result in entering the TS Action more frequently and for longer periods, potentially resulting in TS required shutdowns, or requiring licensing action. The operational/maintenance impacts would result in deferred maintenance, potentially resulting in reduced reliability of the preferred power supply and/or the grid network.

A. Margin

1. Compressing the timing interval of bus transfers resulting from automatic actions associated with a concurrent unit trip of the nonaccident unit versus those of an operator-controlled orderly shutdown will reduce the available grid margin, particularly during summer peak loading.

2. The necessity of TSP compensatory measures not presently credited may complicate grid operation.

3. Compensatory measures by DCPP to reduce the magnitude of the auxiliary loads transferred for off-normal grid configurations may be required more frequently. The increased unavailability of balance of plant equipment (e.g., block standby condensate trains automatic start) could increase the plant trip risk and/or complicate the shutdown process should a trip occur.

4. If a concurrent trip of the nonaccident unit must be assumed, the present analysis assumptions regarding the establishment of the initial load tap changer tap position (i.e., prior to the postulated events) could result in overly conservative results relative to the degraded grid second level undervoltage integrated analysis (i.e., overall performance of the grid, the preferred power supply, and the onsite distribution system). An alternative, less conservative, approach may be necessary to compensate for the dual unit trip margin loss.

B. Maintenance

1. Certain 230kV grid maintenance could be restricted to DCPP refueling outages (i.e., one unit offline), impacting TSP maintenance planning.

2. Startup transformer maintenance requiring the transformer be deenergized for a duration greater than the TS completion time would require a unit shutdown.

C. Operation

1. Emergent grid configuration changes could result in more frequent TS condition entry and TS required shutdowns. This would force the transfer of the DCPP auxiliary loads to the degraded source in order to shut down the unit.

2. It may become necessary for the TSP, for off normal grid configurations, to develop compensatory measures to ensure standby voltage support for DCPP.

3. DCPP operations would have an increased reliance on TSP real-time grid monitoring and reporting for area loading and system operating voltage.

D. TSP Upgrades

1. Previously identified TSP upgrade projects may need to be accelerated.

2. Additional TSP upgrades may be necessary.

E. Grid Stability

1. There would be no impact to grid stability since the TSP presently considers a DCPP dual unit trip in accordance with NERC/WECC requirements and the PG&E/California Independent System Operator transmission control agreement. The primary purpose is to ensure that the uncontrolled successive loss of grid elements is not triggered (i.e. cascading outages). This also assures grid availability to DCPP following such an event.