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A. Edward Scherer
Manager of
Nuclear Regulatory Affairs

January 31, 2007

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

Subject: **Docket Nos. 50-361, 50-362**
Response to Request for Additional Information
Regarding Generic Letter 2006-02,
"Grid Reliability and the Impact on Plant Risk and
the Operability of Offsite Power"
San Onofre Nuclear Generating Station, Units 2 and 3

References:

1) Letter from C. Haney (NRC) to R. Rosenblum (SCE) dated December 5, 2006; Subject: Request for Additional Information Regarding Resolution of Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," (TAC Nos. MD0947 through MD1050).

2) Letter from B. Katz (SCE) to Document Control Desk (NRC) dated April 3, 2006; Subject: Docket Nos. 50-361, 50-362, Response to Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," San Onofre Nuclear Generating Station, Units 2 and 3.

Dear Sir or Madam:

By letter dated December 5, 2006, the NRC issued a request for additional information (Reference 1) regarding licensee's responses to GL 2006-02. Enclosed is Southern California Edison's (SCE's) response to Reference 1.

The NRC's request for additional information provided six questions and a table identifying which questions applied to each licensee. Questions 3, 4, 5, and 6 were identified as being applicable to the Generic Letter 2006-02 response (Reference 2) for San Onofre Units 2 and 3. The enclosure to this letter contains SCE's response to Questions 3, 4, 5, and 6 of Reference 1.

P.O. Box 128
San Clemente, CA 92672
949-368-7501
Fax 949-368-7575

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Should you have any questions, please contact Mr. Mark Morgan at 949-368-6745.

Sincerely,

Enclosure:

cc: B. S. Mallett, Regional Administrator, NRC Region IV
N. Kalyanam, NRC Project Manager, San Onofre Units 2 and 3
C. C. Osterholtz, NRC Senior Resident Inspector, San Onofre Units 2 and 3

Enclosure

Response to Request for Additional Information

Regarding Generic Letter 2006-02,

"Grid Reliability and the Impact on

Plant Risk and the Operability of Offsite Power

Some of the U.S. Nuclear Regulatory Commission's (NRC's) questions seek information regarding analyses, procedures, and activities concerning grid operation which San Onofre Nuclear Generating Station (SONGS) may not have first-hand knowledge of and/or are beyond the control of SONGS. The Transmission System Operator (TSO) was consulted during the preparation of the responses and although the TSO-based information is understood to be true and correct today, the TSO may institute changes in its operations in the future as deemed necessary and/or appropriate to perform its functions.

NRC Questions and SCE Responses

3. Verification of RTCA Predicted Post-Trip Voltage

   Your response to Question 2g indicates that you have not verified by procedure the voltages predicted by the online grid analysis tool (software program) with actual real plant trip voltage values. It is important that the programs used for predicting post-trip voltage be verified to be reasonably accurate and conservative. What is the range of accuracy for your GO's contingency analysis program? Why are you confident that the post-trip voltages calculated by the GO's contingency analysis program (that you are using to determine operability of the offsite power system) are reasonably accurate and conservative? What is your standard of acceptance?

Response:

Southern California Edison (SCE) does not use a Real Time Contingency Analysis (RTCA) program; the analysis tool the TSO [California Independent System Operator (ISO) and the SCE Grid Control Center (GCC)] uses is a nomogram to determine if a trip of a San Onofre Nuclear Generating Station (SONGS) operating unit would result in switchyard voltage below the required minimum (218kV). Note that the nomograms do not predict specific post-trip switchyard voltage values, but merely predict whether or not the post-trip switchyard voltage would be above or below 218 kV.

The limiting condition for the SONGS off-site power requirement occurs 2.5 seconds following trip of the remaining SONGS unit. Because this condition occurs in the transient time-frame of system response, off-line studies which include both transient and post-transient analyses must be used to define the pre-contingency conditions (in the form of a nomogram) that would result in acceptable post-contingency conditions as they relate to off-site power requirements. SONGS believes that the nomogram is appropriately accurate and conservative for the following reasons:

Nomograms used to assess/predict post-contingency system conditions are developed by SCE Grid Control Operating Engineering 1) using the most up-to-date system model approved by the Western Electricity Coordinating Council (WECC) and, 2) according to industry-accepted practices. The accuracy of any nomogram is a function of various factors, including the identification of the critical parameters that are most important in predicting post-contingency results, the study of the full range of those critical parameters as they may occur during the applicable conditions, the inclusion of those critical parameters into the make-up of the nomogram, and the ability to continually monitor the critical parameters as well as the relation of the operating point to the actual limit of the nomogram as they are all adjusted by real-time data. The SONGS nomogram includes seven critical parameters, is based on a comprehensive study performed using the most up-to-date system model adjusted to capture the full range of critical system conditions, and automatically adjusts to changing system conditions. The TSO has reviewed, endorsed and implemented the nomogram to predict post-trip voltage adequacy. The nomogram is reviewed annually for changes in the system and is updated as required to ensure that it accurately reflects the grid.

SONGS basis for acceptance for use of this nomogram is for the above reasons, i.e., the use of the approved system model, the high level of detail included in both the nomogram-development study as well as the real-time monitoring tool, the review and approval of the nomogram by the TSO and the annual review process established to update the tool as necessary.

4. Identification of Applicable Single Contingencies

   In response to question 3(a), you did not identify the loss of other critical transmission elements that may cause the offsite power system (OSP) to degrade, other than the loss of the nuclear unit. If it is possible for specific critical transmission elements (such as other generators, critical transmission line, transformers, capacitor banks, voltage regulators, etc.) to degrade the OSP such that inadequate post-trip voltage could result, have these elements been included in your N-1 contingency analysis? When these elements are included in your GO's contingency analysis model and failure of one of these transmission elements could result in actuation of your degraded voltage grid relay, is the offsite power declared inoperable? If not, what is your basis for not declaring the offsite power inoperable?

Response:

As described in SCE's response to Generic Letter 2006-02 dated April 3, 2006, the contingency analysis for SONGS Offsite Power System (OSP) is described in the SCE GCC Operating Procedure (OP) 13. As described in SCE's response to question 3(a), this analysis has determined that while both SONGS Unit 2 and Unit 3 are online and connected to the transmission system the remaining unit provides voltage support to the switchyard following a trip of the opposite unit. As such, there are no specific transmission elements which, if lost, could cause the OSP to be in a configuration in which a trip of one of the two operating units would cause degradation of the OSP resulting in actuation of the SONGS degraded voltage protection scheme. The analysis has also determined that when one SONGS unit is offline and one unit is online, there are certain critical transmission element(s) and limiting import levels that, if an outage occurs on one of these critical lines and the limiting imports are exceeded, the OSP would be below the degraded voltage setpoints when the remaining online unit trips.

There are no known losses single generators, transformers, capacitor banks, or voltage regulators that could combine with the conditions stated above to challenge SONGS' post-trip switchyard voltage. The specific critical transmission elements that could combine with the conditions stated above to challenge SONGS' post-trip switchyard voltage include transmission lines or combinations of lines, and one intertie. These specific critical transmission elements or combinations of elements are identified in OP-13 and are as follows:

Devers-Palo Verde line
Ellis-Johanna & Ellis-Santiago lines
Any two Lugo-Mira Loma lines
Mira Loma-Serrano No. 1 and 2 lines
Any Two Midway-Vincent lines
San Onofre-Serrano & San Onofre-Viejo lines
San Onofre-Serrano & Chino Viejo lines
Hassayampa-North Gila line
North Gila-Imperial Valley line
Imperial Valley-Miguel line
Imperial Valley-Miguel & Imperial Valley-La Rosita lines
Imperial Valley-Miguel & Miguel-Tijuana lines
Any Two San Onofre-San Luis Rey lines
San Luis Rey-Mission No. 1 and 2 lines
San Luis Rey-Encina-Escondido line
SCE/SDG&E tie at San Onofre

Loss of one of these critical transmission elements or combinations of these elements while one SONGS Unit is off line and one SONGS Unit is on line and during conditions where the limiting imports have been exceeded will prompt the Grid Control Center to notify SONGS Control Room to consider that the offsite power source is unavailable and thus Inoperable. The Control Room Operators will at that time, per Abnormal Operating Instruction SO23-13-4 "Operation During Major System Disturbances", declare the offsite sources Inoperable and enter the appropriate Action Statement.

5. <u>Seasonal Variation in Grid Stress (Reliability and Loss-of-Offsite Power (LOOP) Probability)</u>

   Certain regions during certain times of the year (seasonal variations) experience higher grid stress as is indicated in Electric Power Research

Institute (EPRI) Report 1011759, Table 4-7, Grid LOOP Adjustment Factor, and NRC NUREG/CR-6890. Do you adjust the base LOOP frequency in your probabilistic risk assessment (PRA) and Maintenance Rule evaluations for various seasons? If you do not consider seasonal variations in base LOOP frequency in your PRA and Maintenance Rule evaluations, explain why it is acceptable not to do so.

Response:

As described in SCE's response to Generic Letter 2006-02 dated April 3, 2006, stress on the grid is affected by several factors, including system demand, network configuration, and availability of reactive resources (including static devices in the form of capacitors, and dynamic facilities in the form of generators and static VAR compensators).

Loss of Offsite Power (LOOP) is related to stress on the grid inasmuch as higher system load (e.g., peak summer conditions), abnormal network conditions (e.g., transmission lines out due to maintenance activities, inclement weather, fires, etc.), and unavailability of reactive resources (e.g., generating units and shunt capacitors within electrical proximity to SONGS) all tend to exacerbate the risks for LOOP.

While stress on the grid is affected by each of these factors, deficiencies in one factor are typically counterbalanced by adjustments in the other factors. For example, during summer peak demand conditions the network is kept as normal as possible and all available generation is typically online. Conversely, during winter light demand conditions transmission outages are allowed for maintenance activities, and many of the generating units may be off due to maintenance or other reasons.

As such, there is no predictable seasonal variation to the LOOP frequency in the transmission region that supplies offsite power to SONGS.

Due to lack of sufficient SONGS-specific LOOP data, the base LOOP frequency in the SONGS Probabilistic Risk Assessment (PRA) is based on the actual industry-wide occurrences of LOOP events from all causes from 1980 through 2003 and includes the eight August 2003 Northeast grid blackout events. The LOOP average frequency used in the SONGS PRA and Safety Monitor (6.74E-2 per year) is conservative because it includes relevant LOOP events for all regions and not just the LOOP events in the Western region (i.e., WECC), which has experienced relatively few LOOP events. The LOOP national average frequency reported in NUREG/CR-6890, Vol. 1, "Reevaluation of Station Blackout Risk at Nuclear Power Plants – Analysis of Loss of Offsite Power Events: 1986 – 2004," dated December 2005, is 3.59E-2 per year (Table 3-3 in NUREG/CR-6890).

Although no explicit seasonal variability in the LOOP frequency is included in the SONGS Safety Monitor, its users (e.g., Work Control group, Shift Technical Advisors) can increase the average LOOP frequency (i.e., use more conservative values) to reflect any severe weather conditions being evaluated (e.g., tornado warning, external fires, tsunami warning) or any other condition that could result in degraded grid voltage. This is done by using various environmental factors available in the Safety Monitor. As stated in SCE's April 3, 2006 response to Generic Letter 2006-02, the environmental factor for High Impact Switchyard work is generally applied at all times, whether or not there is work being performed in the switchyard.

Generic Letter 2006-02 states in the Discussion section that,

> "Recent NRC studies that have found that since 1997, LOOP events have occurred more frequently during the summer (May through October) than before 1997, that the probability of a LOOP event due to a reactor trip has also increased during the summer months, and the durations of LOOP events have generally increased."

When it comes to seasonal variability in the LOOP frequency, there are different opinions and reports. For example, NUREG/CR-6890, Vol. 1, reports a national mean LOOP frequency of 3.59E-2 per year averaged over all months of the year (Table 3-3), 7.68E-2 per year for summer months, i.e., May through September (Table 3-4), and 9.70E-3 per year for non-summer months. i.e., October through April (Table 3-4) based on LOOP data for the period of 1997 to 2004. It is notable that the summer months LOOP frequency is very close to the average baseline LOOP frequency used in the SONGS Safety Monitor.

However, Electric Power Research Institute (EPRI) Report TR-1011759, "Frequency Determination Method for Cascading Grid Events," dated December 2005, has shown that there is no statistically significant seasonal variation in the recorded grid-centered LOOP events in any region (including the WECC) from 1997 to 2004 including the August 2003 Northeast grid blackout events (page 4-6 of TR-1011759). In this regard, the EPRI report states that: "The number of [North American Electric Reliability Council] regions involved in the Reference 2 list is broad, but because of the small number of events (14 grid-centered LOOPs), it has neither statistically significant regional nor seasonal dependencies." The cited Reference 2 is EPRI TR-1009889, "Losses of Off-Site Power at U. S. Nuclear Power Plants – Through 2003", dated March 2004.

The grid-LOOP adjustment factors reported in Table 4-7 of TR-1011759 for various Grid Regions and the four seasons are based on the Energy Information Agency (EIA) events, which mainly involve equipment failures and not necessarily LOOP events. EPRI report TR-1011759 also states that (page 4-9): "Because the EIA events have weak correlation to LOOPs, it appears to be best for purposes of nuclear power plant PRAs to choose a high weighting for LOOP events." The 160 EIA events were matched to only 2 LOOP events (1%) (page 4-13). Therefore, application of the proposed grid-LOOP adjustment factors in Table 4-7 of TR-1011759 to LOOP frequency in PRA is questionable.

Additionally, Table 4-7 in TR-1011759 does not contain any quantitative grid-LOOP adjustment factors that can be readily applied to the baseline LOOP frequency. The proposed method for application of the grid-LOOP adjustment factors (Table 4-8) is not well defined and requires the PRA analyst's judgment for counting some LOOP events in the site grid region that did not cause a LOOP at the site as 0.1 LOOP to 0.35 LOOP as well as making other subjective adjustments. This will introduce additional uncertainty in the LOOP frequency assessment and the PRA results.

Another difference between the LOOP seasonal data analysis and available results in the NUREG/CR-6890 and EPRI TR-1011759 is that the NRC's report does not discriminate among Grid Regions or specific seasons like the EPRI report. The EPRI summer months span over three months whereas the NRC summer months span over five months. This presents another source of variability when it comes to application of LOOP seasonal adjustment factors.

To summarize, while there are different opinions and reports regarding seasonal variability in the LOOP frequency, and while there is no predictable seasonal variation to the LOOP frequency in the transmission region that supplies offsite power to SONGS, the LOOP frequency adjustment factors for severe weather conditions and potential degraded grid voltage available in the SONGS Safety Monitor account for the potential variability in grid conditions including seasonal variability. Therefore, there is no need to introduce additional seasonal adjustment factors for the LOOP frequency in the Safety Monitor.

6. <u>Interface with Transmission System Operator During Extended Plant Maintenance</u>

   How do you interface with your GO when on-going maintenance at the nuclear power plant, that has been previously coordinated with your GO for a definite time frame, gets extended past that planned time frame?

Response:

There are 3 basic categories where the interface will occur; during Switchyard Restrictions (due to Higher Risk Evolutions (HREs) or Diesel Generator outage); during SONGS Test Technician relay testing; or for a Unit Outage return to service.

1. During Switchyard Restrictions, formal notice to the TSO is procedurally required when Switchyard Restrictions are no longer required. The

restrictions remain in place until lifted. If the plant maintenance activity is extended, courtesy verbal notification is normally made to the TSO, but the Switchyard Restrictions remain in place until formally lifted. SONGS will continue to restrain other work that could conflict with the extended Switchyard Restrictions via the disapproval methods discussed in SCE's response to Generic Letter 2006-02, until the extended restrictions are lifted.

2. During SONGS Test Technician relay testing, constant communication between the TSO and SONGS is in place during the testing, so real time communication is ongoing. Any conflicts due to extensions will continue to be restrained via SONGS disapproval of any requested conflicting activities.

3. Unit Outage return to service extensions are scripted to include a 72 hour advance notice to the SCE Generation Operations Center (GOC) and GCC any time the planned return to service date is extended.