UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Southern California Edison Company  )  Docket No. RC15-1-000

PREPARED SUPPLEMENTAL TESTIMONY OF
JONATHAN M. SHEARER
ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

(EXHIBIT SCE-16)

JUNE 2, 2015
Q. Please state your name and business address for the record.

A. My name is Jonathan M. Shearer, and my business address is 3 Innovation Way, Pomona, California 91768.

Q. Are you the same Jonathan M. Shearer who previously submitted direct testimony in this docket?

A. Yes, I am.

Q. Have you reviewed the Motion to Intervene and Comments of the North American Electric Reliability Corporation and Western Electricity Coordinating Council ("NERC/WECC Comments") filed May 18, 2015 in this docket?

A. Yes, I have, and my Supplemental Testimony will respond to the NERC/WECC Comments. More specifically, I will respond to the requests for additional information on pages 8-9 therein.

Q. Do you have any opening remarks?

A. Yes. I appreciate NERC and WECC’s interest and involvement in this proceeding. SCE is committed to the safe and reliable operation of the integrated transmission network and
distribution systems alike, and we appreciate NERC and WECC’s attention to this process.

Q. **Please summarize the Comments and your response.**

A. The Comments set out a list of the “information that NERC and WECC believe SCE should provide before the Commission makes a determination of the impact of the Facilities at issue on the reliability of the BPS and their status as local distribution.” In general, these concerns may be valid questions and “other factors” if SCE were seeking to remove facilities from the BES by way of an Exception Request for Exclusion of facilities previously considered part of the Bulk Electric System. However, SCE is not pursuing a NERC Exception at this time, but is only seeking to confirm the existing local distribution status of the indicated Facilities through its direct Application to FERC. Thus, the questions are only useful towards further understanding the uniqueness of SCE’s system design and operation given the procedure which SCE availed itself through its Application. By responding to the additional questions posed, we believe they further support our assertions and supporting justification contained in our Application and ensure the continued reliability of the integrated transmission network.

Q. **Aside from this, do you have any other concerns with the Comments?**

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1 The 115 kV Facilities at issue in the Application are currently not classified as transmission and are not under operational control of the CAISO. Additional detail about the location, design, and function of each facility can be found in attachments Exhibit SCE-2 through Exhibit SCE-10.

2 Application for Factual Determination That the Indicated 115 kV Facilities Are Used In Local Distribution (“Application”).
Yes. SCE’s Application includes all of the technical information necessary to support its filing. SCE’s examination of the Seven Factor Test, Mansfield test, and other Commission precedent that formed its analysis of the Facilities already included an inquiry into the effect of these 115 kV Facilities on the BPS. The relevant information is discussed in Section VIII of Exhibit SCE-1 and reported in Exhibit SCE-13. The question is whether SCE has provided sufficient information to support its conclusion. I am very confident that we have.

Q. What information is requested in the Comments?

A. NERC and WECC contend that the following technical questions, at a minimum, should be answered:\(^3\):

1. A demonstration of the current fault contributions to the BPS from the systems for which SCE is requesting the local distribution designation.

2. A discussion of the potential reliability impact on the BPS for the failure of the local network protection systems, particularly, the protection systems associated with the 500/115 kV and 230/115 kV transformers connected to these networks.

3. An explanation of how the generation and reactive devices (shunt capacitors) are used to provide voltage support or control of the BPS. In Order No. 773, the Commission stated that, if the generator is necessary for the operation of the interconnected transmission network, it is appropriate also to include the

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\(^3\) NERC/WECC Comments at pp. 8-9.
generator interconnection facility operating at or above 100 kV that delivers the
generation to the BES.

4. The study assumptions SCE uses in selecting the power flow base cases, system
conditions, path transfers, as related to the associated facility ratings and
nomograms, seasonal conditions, inertia requirements, and emergency ratings,
etc., with an explanation of how those assumptions affect the study results and
conclusions.

5. Whether SCE used the WECC composite load model in the power flow and
stability analyses, and if not, why. At least one of the local areas concerned is
susceptible to fault-induced delayed voltage recovery (“FIDVR”), and the
composite load model is a better assumption to use in such areas.

6. Whether SCE conducted post-transient studies or voltage stability studies, with an
explanation of whether these local systems could become VAR deficient when
generator operators do not dispatch local traditional generation resources due to
economic conditions.

7. An explanation of how voltages can be controlled in these areas under light-load
conditions, light transfers across the BPS lines in the area, and high renewable
generation levels.

8. A discussion of the potential effect of the magnitude of the load, on end-use
customers (~600,000 people) all served through one substation.

Q. Please respond to number 1, relating to current fault contributions to the BPS from
radial 115 kV systems.
A. Fault contribution from SCE’s radial 115 kV systems are attributed to local generation and ground sources, including grounded transformer banks, internal to the 115 kV system. The table below provides the corresponding three-phase and single-phase-to-ground short circuit duty contributions to the BPS from the systems or facilities for which SCE is requesting the local distribution designation.

Table 1

<table>
<thead>
<tr>
<th>Radial 115 kV System or Facility</th>
<th>Total Bus Fault SCD (Amps)</th>
<th>Radial 115 kV System Contribution (Amps)</th>
<th>Other System Contributions* (Amps)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>3Ph</td>
<td>SLG</td>
<td>3Ph</td>
</tr>
<tr>
<td>Control 115 kV</td>
<td>4,428</td>
<td>5,284</td>
<td>797</td>
</tr>
<tr>
<td>Coolwater 115 kV</td>
<td>7,635</td>
<td>9,085</td>
<td>0</td>
</tr>
<tr>
<td>El Casco 230 kV</td>
<td>11,714</td>
<td>10,194</td>
<td>0</td>
</tr>
<tr>
<td>Devers 230 kV</td>
<td>40,186</td>
<td>46,479</td>
<td>1,737</td>
</tr>
<tr>
<td>Inyokern 115 kV</td>
<td>7,017</td>
<td>7,296</td>
<td>411</td>
</tr>
<tr>
<td>Kramer 115 kV</td>
<td>18,078</td>
<td>15,529</td>
<td>3,696</td>
</tr>
<tr>
<td>Mirage 230 kV</td>
<td>18,442</td>
<td>16,421</td>
<td>0</td>
</tr>
<tr>
<td>Valley 500 kV</td>
<td>18,805</td>
<td>19,331</td>
<td>252</td>
</tr>
<tr>
<td>Victor 115 kV</td>
<td>23,858</td>
<td>20,855</td>
<td>1,800</td>
</tr>
<tr>
<td>Vista 230 kV</td>
<td>46,032</td>
<td>41,223</td>
<td>4,213</td>
</tr>
</tbody>
</table>

*Other system values are comprised of BES contributions, contributions from radial gen-ties directly connected to the bus serving the radial 115 kV system, and other non-BES contributions (contributions from 66 kV, 33 kV, and 12 kV)

Not shown on Table 1 are fault contributions to the BES from the Coso 115 kV and Randsburg 115 kV substations as the BES connection of these two substations is directly to BES 115 kV lines depicted in Exhibit SCE-10. Three-phase fault contributions to the BES from both the Coso and Randsburg substation is zero while single-line-ground fault contribution from Coso and Randsburg is zero and 624 amps respectively.

Q. Please respond to number 2, relating to the failure of the local network protection systems.
A. Potential reliability impacts on the BPS for the failure of the local network protection systems is dependent on the substation design serving the radial 115 kV system or facilities. The substations serving the Devers, El Casco, Kramer, Mirage, Valley, and Victor radial 115 kV systems all have a 115 kV bus configuration that involves breaker-and-a-half arrangement while the substation serving the Vista 115 kV system has a 115 kV bus configuration that involves a double-bus-double-breaker arrangement. The primary protection for the transformers are transformer differential protection systems to quickly isolate the faulted transformer. As a back-up for failure of the primary protection system, such as a stuck breaker, the local breaker failure protection will isolate the electrically adjacent elements to the stuck breaker. In a double-bus configuration, this leaves the other bus in service keeping the lines and other transmission elements energized, resulting in minimal disruption to the BPS. In the event of a stuck tie breaker, the result would be loss of the transformer and the line connected in the same position. Both of these bus configurations result in no impact to the reliability of the BPS upon a failure of the local network protection systems. The generic one-line diagrams for these two 115-kV bus configurations below illustrate what would happen under failed primary protection.
The design for the Control and Inyokern 115 kV substations is referred to as a double-bus-single-breaker arrangement. These two substations do not have either a
500/115 kV or 230/115 kV transformer connected to them. Remote protection would involve isolating fault conditions on radial 115 kV facilities by disconnecting the operating bus which is connected to the line where the primary protection system failed. Such operation does not have an adverse impact to the reliability of the BPS as analysis of BES facilities and the sectionalizing breakers already evaluates contingencies that result in the same operation.

Q. Please respond to number 3, regarding voltage support and control of the BPS.

A. SCE does not rely on generation and reactive devices connected to its local distribution facilities to address voltage support or control of the BPS. In fact, SCE assumes the opposite in its Planning Assessments used for compliance with NERC TPL Reliability Standards. The local distribution reactive power loads are adjusted so that the high side of SCE’s 220/115 kV and 500/115 kV transformers represent the local distribution facilities drawing VARs from the BPS. SCE plans sufficient reactive support on its local distribution facilities to have zero VAR flow on the high side of transformer banks and SCE uses this conservative assumption in its system planning process in order to insure the reliability of the integrated transmission network.

SCE’s zero VAR flow planning criteria for local distribution facilities and the planning assumption of VAR draw from the BPS for planning the BPS ensures that the BPS is not relying on generation and reactive devices on SCE’s local distribution facilities to provide voltage support or control of the BPS.
Q. Please respond to number 4, relating to SCE’s immaterial impact study assumptions.

A. The power flow base cases used for the technical analysis starts with SCE’s annual assessment cases that are used as a compliance tool with the NERC TPL Reliability Standards. These base cases were then modified to include the detailed representation of all of SCE’s 115 kV local distribution facilities. Transmission and generation projects, as well as load and generation assumptions are detailed in Exhibit SCE-13 (SCE’s Study Report) of the Application filing. SCE explains in its prior testimony how the varying combinations of generation and load patterns encompass the full range of reasonable results. Since the local distribution facilities are all radial from the integrated transmission network, path transfers and other external assumptions did not need to be maximized. Given the low electrical relationship between the radial facilities and the integrated transmission network, the inclusion of extremely high transfer path levels outside of these local systems do not help address the impact to the BPS. The objective of this assessment was to demonstrate that the SCE local distribution facilities at issue have no adverse impact on the BPS. Furthermore, no local distribution facility at issue is included in any WECC-defined transfer path. Lastly, the ratings used to calculate the delta flow pre- and post-contingency were based on the element’s continuous rating in accordance with the screening methodology described in Exhibit SCE-1. The further analysis of potential impact to the BPS used emergency ratings of BPS Elements in accordance with NERC’s FAC-008-3 Reliability Standard. The emergency ratings of the local distribution facilities are inconsequential when the objective is identifying impact to reliability of the BPS.
Q. Please respond to number 5, relating to the composite load model and FIDVR.

A. SCE did not use the composite load model for the analysis of impact to the BPS. The screening of Elements for possible impact was conducted via power flow analysis. A power flow analysis cannot use the composite load model since the model is strictly used for dynamic simulations.

If an Element was flagged for further analysis by the screening process, SCE’s more detailed analysis included a dynamic stability assessment. The composite load model, however, is being implemented in two phases. The first phase intentionally disables the stalling of single phase air conditioners which is the major cause of the cited FIDVR events. Using the approved phase one model will not capture the results of AC stalling. The second phase which includes this AC stalling feature is not yet approved for use by WECC so consequently it was not used by SCE. The report referenced by NERC and WECC uses the phase two unapproved model. SCE would also like to note that none of the system Elements referred to in the question (Valley 115 kV System Elements) were identified through the power flow screening process for further dynamic analysis.

Lastly, SCE did not use the composite load model in its dynamic stability assessment because the WECC Performance Criteria has not yet been updated by WECC to reflect the better system representation. WECC’s drafting team on Project WECC-0100 is responsible for updating the WECC Performance Criteria and the drafting team has not yet finalized the criteria revision. While SCE agrees that the composite load model may more accurately reflect load behavior in response to disturbances in the dynamic time frame, SCE needed an approved and useful threshold to analyze the potential dynamic stability impact.
Q. Please respond to number 6, relating to voltage performance and VAR sufficiency.

A. As referenced in my initial testimony and study report, SCE conducted voltage analysis in the post-transient timeframe for the TPL-like assessment and those local systems in which the aggregate generation exceeds 75 MVA (i.e., Devers, North of Lugo, and Vista). After thorough analysis of the specific Elements which were flagged for further analysis and analysis of these three (3) local systems, SCE’s found that there are no VAR deficiencies nor performance violations on the BPS.

Voltage stability analysis in the Western Interconnection involves increasing the transfer path flow or the study area load by 5% and 2.5% for Category B and Category C contingencies respectively. Using a forecasted 2017 load for each radial local distribution study area, as SCE did, exceeds the 5% load increase that would normally have been considered when performing a voltage stability analysis on 2015 loads.

Voltage stability analysis requires simulation convergence for demonstrated acceptable performance. All simulations converged in SCE’s screening of the Facilities which demonstrates acceptable voltage stability performance.

Further, as noted in SCE’s the response to No. 3 above, SCE does not rely on generation and reactive devices connected on its local distribution facilities to address voltage support or control of the BPS.

Q. Please respond to number 7, relating to light loads, BPS voltage, and high BPS transfers.

A. The integrated transmission network is planned and designed to maintain BPS voltages within the California ISO’s required steady-state operating limits. The voltage on the
BPS is controlled through reactive power devices connected on the BPS such as series capacitors, line reactors, shunt capacitor and reactor banks, shunt reactors on BPS transformer bank tertiary windings, and two Static VAR Compensators directly connected to the BPS. As mentioned earlier, SCE does not rely on generation or reactive devices connected to the local distribution facilities to address voltages or control voltages on the BPS.

Interconnection Requirements under SCE’s FERC-approved Wholesale Distribution Access Tariff and Transmission Owner Tariff require leading and lagging power factor correction for generation customers at the point of interconnection. The local voltage impact from renewable generation output in the applicable 115 kV systems or facilities is managed locally via the interconnection process. BPS voltages are controlled by BPS devices as stated before in SCE’s response to Question 3 which is noted on page 9 of this supplemental testimony.

Q. Please respond to number 8, relating to the quantity of affected customers versus BPS reliability.

A. SCE currently has one substation which serves a large magnitude of load involving approximately 600,000 people. However, this substation functions as two separate 115 kV substations serving the area since the 115 kV system is served through two sections of the substation, as depicted in Exhibit SCE-7, that are not operated in parallel. Each bus section is connected to the BES by two 500/115 kV transformer banks and a spare transformer bank can be switched to either bus section in the event of a loss of one transformer bank since this spare transformer bank is on site and energized.
Additionally, compliance with the NERC TPL Reliability Standards requires an assessment of Extreme Contingencies. In the case of the Valley 115 kV system in its entirety, loss of the entire station would necessitate either loss of three 500 kV transmission lines (two lines routed along common corridor to the east and one line routed in a different direction to the west) or loss of a 500 kV bus while the other 500 kV bus is already out of service. As part of SCE’s Annual Transmission Planning Assessment, this scenario is evaluated and study results have not identified an adverse impact on the BES that necessitates mitigation at this time.

Q. Does this conclude your supplemental testimony?

A. Yes.
AFFIDAVIT of AUTHENTICATION

State of California )
County of Los Angeles ) ss

Jonathan Shearer, being first duly sworn, on oath says that he is the Jonathan Shearer identified in the foregoing prepared direct testimony; that the answers therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers would, under oath, be the same.

Jonathan Shearer

Subscribed and sworn to (or affirmed) before me on this 2nd day of June, 2015, by Jonathan Shearer, proved to me on the basis of satisfactory evidence to be the person who appeared before me.

ANA A. CALDERON
Notary Public for the State of California