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Appendix 3A-1a
Addendum 1 to the Interconnection Study Report

Appendix A – WDT1189

Wellhead Power Development, LLC

Stanton Energy Center

QUEUE CLUSTER 7 PHASE II REPORT

Addendum #1 to the Final Phase II Study Report

June 24, 2016

This study has been completed in coordination with the California Independent System Operator Corporation (CAISO) per CAISO Tariff Appendix DD Generator Interconnection and Deliverability Allocation Procedures (GIDAP)

Table of Contents

A. Introduction ... 1
B. Study Assumptions ... 4
C. Reliability Standards, Study Criteria and Methodology ... 5
D. Power Flow Reliability Assessment Results ... 5
E. Short Circuit Duty Results ... 5
F. Transient Stability Evaluation ... 7
G. Power Factor Requirements ... 7
H. Deliverability Assessment Results ... 7
I. In-Service Date and Commercial Operation Date Assessment ... 7
J. Timing of Full Capacity Deliverability Status, Interim Deliverability, Area Constraints, and Operational Information ... 10
K. Interconnection Facilities, Network Upgrades, and Distribution Upgrades ... 11
L. Cost and Construction Duration Estimates ... 11
M. SCE Technical Requirements ... 11
N. Sub Synchronous Interaction Evaluations ... 12
O. Environmental Evaluation, Permitting, and Licensing ... 12
P. Affected Systems Coordination ... 12
Q. Items not covered in this study ... 12

Attachments:

1. Interconnection Facilities, Network Upgrades and Distribution Upgrades
2. Escalated Cost and Time to Construct for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades
3. Not Used
4. Distribution Provider Interconnection Handbook
5. Short Circuit Calculation Study Results (see Appendix H of the Bulk Area Report)
6. Customer Provided Dynamic Data
7. Subtransmission Assessment Report – Barre 66 kV System

A. Introduction

Wellhead Power Development, LLC, the Interconnection Customer (IC), has submitted a completed Interconnection Request (IR) to Southern California Edison Company (SCE) for their proposed Stanton Energy Center (Project). The project requested a Point of Interconnection (POI) is Southern California Edison Company's (SCE) Barre 66 kV Switchrack located in Orange County, CA. The Project has a CAISO delivery point at Barre 220 kV Substation bus. The IC elected that the project be Option A with Full Capacity Deliverability Status, and desires an In-Service Date (ISD) and Commercial Operation Date (COD) of March 30, 2018 and June 1, 2018 respectively. Such dates are specified in the Project Attachment B. Actual ISD and COD will depend on design and construction requirements to interconnect for the Project.

In accordance with Federal Energy Regulatory Commission (FERC) approved CAISO Tariff Appendix DD Generator Interconnection and Deliverability Allocation Procedures (GIDAP) of Attachment I of SCE's Wholesale Distribution Access Tariff (WDAT), the Project was grouped with Queue Cluster 7 (QC7) Phase II projects to determine the impacts of the group.

Please note that the discussion related to the combined impacts at the Transmission and Subtransmission levels of the group resides in the SCE Metro Bulk Area and Barre Subtransmission Assessment Reports; both are included in the QC7 PII report package. This report focuses only on the impacts or impact contributions of the Project at the local Distribution system, and it is not intended to supersede any contractual terms or conditions specified in an Interconnection Agreement.

The report provides the following:

1. Transmission and/or Subtransmission system impacts caused by the Project;

2. System reinforcements necessary to mitigate the adverse impacts caused by the Project under various system conditions;

3. A list of required facilities and a good faith estimate of the Project's cost responsibility and time to construct[1] these facilities. Such information is provided in Attachment 1 and Attachment 2 as separate documents in the Appendix A Project report package.

All the equipment and facilities comprising the Project located in Stanton, California, as disclosed by the IC in its IR, as may have been amended during the Interconnection Study process, which consists of (i) three (3) synchronous generator units rated at 50.6 MW each for a combined output of 151.6 MW as measured at the generator terminals; (ii) the associated infrastructure and step-up transformers, (iii) meters and metering equipment, (iv) appurtenant equipment and (v) 1.8 MW of auxiliary load.

Based on the technical data provided for the main step-up transformer banks, internal generation facility losses were found to be 0.7 MW resulting in a net output, as measured at the high-side of the main transformer banks, of 149.3 MW when taking the auxilary loads and internal facility losses into account. Losses on the 0.34 mile 3000 copper XLP UG generation tie-line were found to be 0.1 MW resulting in an estimated capacity delivery of 149.2 MW at the Point of Interconnection.

The Project shall consist of the Generating Facility and the IC's Interconnection Facilities as illustrated below in Figure A-1. Similarly, the Project information is summarized in Table A.1 below The location of

[1] It should be noted that construction is only part of the duration of months specified in the study, includes final engineering, licensing, etc, and other activities required to bring such facilities into service. These durations are from the execution of the Interconnection Agreement, receipt of: all required information, funding, and written authorization to proceed from the IC as will be specified in the Interconnection Agreement to commence the work.

the Project was assumed as specified in the IR provided by the IC. The Project shall not exceed the total net output.

Figure A.1: Project IC Facilities One-Line Diagram

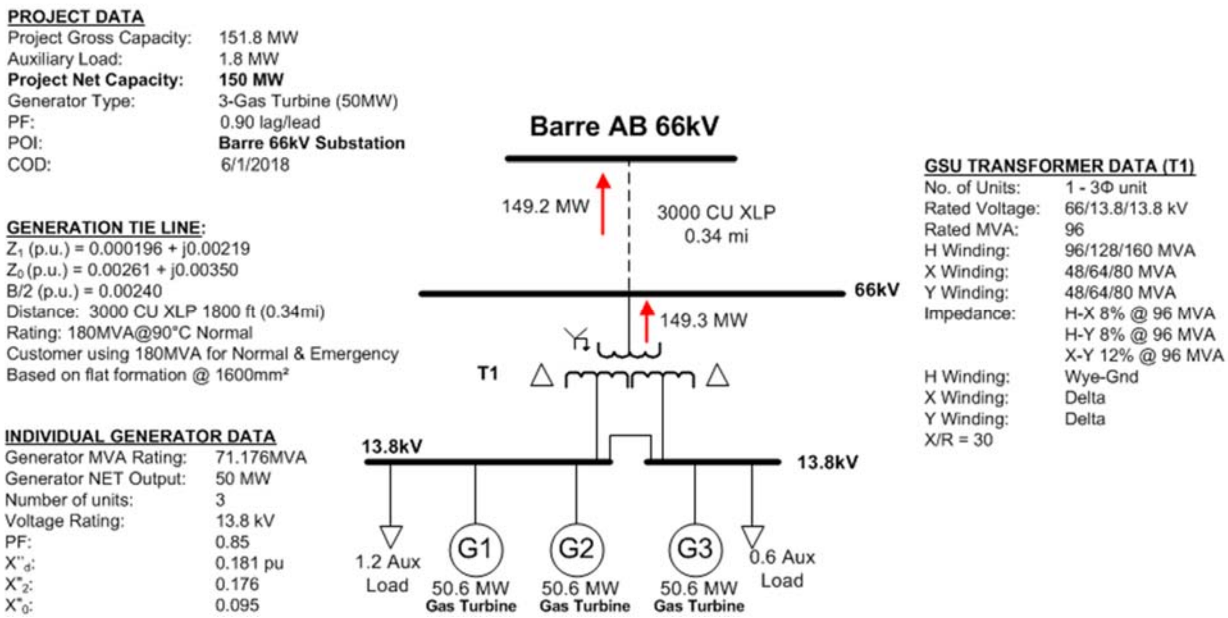


Figure A.2: Project IC Facilities Site Location

Table A.1: Project General Information

Project Location	10711 Dale Street Stanton, CA 90680 Orange County GPS Coordinates: Latitude: 33.807053, Longitude: -117.985299
Distribution Provider's Planning Area	SCE Metro Bulk system
Number and Types of Generators	3 Synchronous Generators (50.6 MW each)
Interconnection Voltage	66 kV
Maximum Generator Output (At Generator Terminals)	151.8 MW (gross)
Generator Auxiliary Load	1.8 MW
Internal Generation Facility Losses	0.7 MW
Maximum Net Output at Generation Facility (High-Side of Main Transformer)	149.3 MW
Power Factor Range	Lead 0.90 / Lag 0.90 at POI per interconnection application
Step-up Transformer(s)	Main Transformers (T1) 66/13.8/13.8 kV (YG-D-D), H-Winding: 96/128/160 MVA, X-Winding: 48/64/80 MVA, Y-Winding: 48/64/80 MVA, H-X Impedance Value: 8% @ 96 MVA H-Y Impedance Value: 8% @ 96 MVA X-Y Impedance Value 12% @ 96 MVA
Gen-Tie	0.34 miles, 3000 CU XLP
POI	Distribution Provider's Barre 66 kV Switchrack
Estimated Losses on Gen-Tie Facilities (All Gen-Tie Facilities used to deliver to POI)	0.1 MW
IC Requested COD	6/01/2018

B. Study Assumptions

For detailed assumptions regarding the group cluster delivery analysis, please refer to the applicable QC7 Phase II SCE Metro Area Deliverability Assessment and for detailed assumptions regarding the group cluster analysis at the Subtransmission level, please refer to the applicable QC7 Phase II Subtransmission Assessment Report. Below are the assumptions specific to the Project:

1. The following is the Plan of Service (POS) assumed for the Project in the Phase II Study:

   The project was modeled as via one 66 kV generation tie-line (gen-tie) to SCE's Barre 66 kV Substation.

2. The following facilities will be installed by SCE and **<u>are included</u>** in this Phase II Study:

   - The new 66 kV position at Barre Switchrack.
   - The segment of a 66 kV generation tie-line inside the Barre 66 kV substation property line.
   - The extensions of each of the two generator – owned fiber optic cables inside the Barre Substation property line.
   - Lightwave, channel banks and associated equipment at Barre Substation and at the Generating Facility.
   - The required retail load meters.

     NOTE: SCE installation does not include metering, voltage and current transformers, and metering cabinet. The SCE meters will be connected to the generator – owned voltage and current transformers to be installed for their CAISO metering.

3. The following facilities are to be installed by the Interconnection Customer and **<u>are not included</u>** in this Phase II Study:

   - The 66 kV generation tie-line from the Generating Facility to the last structure outside the Barre Substation property line.
   - The fiber optic cables to provide two diversely routed telecommunication paths required for the line protection relays.
   - The required CAISO metering equipment (voltage and current transformers and CAISO meters) and metering cabinet for SCE revenue meter.

     NOTE: The metering voltage and current transformers installed for the CAISO metering will also be used for the SCE owned retail meters.

   - The following 66 kV line protection relays to be installed at the Generating Facility end of the 66 kV generation tie-line:
     - One (1) G.E. L90 current differential relay with dual dedicated digital communication channels on diverse paths to Barre Substation.
     - One (1) SEL 311L current differential relay with dual dedicated digital communication channels on diverse paths to Barre Substation.

C. Reliability Standards, Study Criteria and Methodology

The generator interconnection studies will be conducted to ensure the CAISO-controlled grid is in compliance with the North American Electric Reliability Corporation (NERC) reliability standards, WECC regional criteria, and the CAISO planning standards. Refer to Section C of the Bulk Area Report for details of the applicable reliability standards, study criteria and methodology.

D. Power Flow Reliability Assessment Results

I. Steady State Power Flow Analysis Results – 220 kV and above

The study did not identify any power flow issues on the Bulk Electric System not addressed via the use of CAISO Congestion Management or via already approved transmission upgrades. Consequently, the Project is not allocated cost for any Network Upgrades identified to address power flow issues. The details of the power flow analysis are provided in Section D of the Metro Area Report.

II. Steady State Power Flow Analysis Results - 66 kV

1. Thermal Overloads

The study did not identify any power flow issues on the Barre 66 kV Subtransmission System. The details of the power flow analysis are provided in the Subtransmission Assessment Report.

2. Voltage Performance

The Project is required to provide power factor regulation capability (0.95 lead/lag at POI for asynchronous generation and 0.90 lagging to 0.95 leading at generator terminals for synchronous generators) to alleviate power flow non-convergence and maintain the Transmission transfer capability.

3. Required Mitigations

No power flow mitigations on the subtransmission system were identified to be required by the Project.

E. Short Circuit Duty Results

Short circuit studies were performed to determine the fault duty impact of adding the QC7 Phase II projects to the Transmission system and to ensure system coordination. The fault duties were calculated with and without the projects to identify any equipment overstress conditions. Once overstressed circuit breakers are identified, the fault current contribution from each individual project in QC7 Phase II is determined. Each project in the cluster will be responsible for its share of the upgrade cost based on the rules set forth in CAISO Tariff Appendix DD.

1. Short Circuit Duty Study Input Data

"Synchronous Gen" Data for each generation unit:

X"1 - positive sequence subtransient reactance: 0.181 PU
X"2 - negative sequence subtransient reactance: 0.176 PU
X"0 - zero sequence subtransient reactance: 0.095 PU

Generation tie-line:

Length:	1,800 feet
Conductor:	3000 CU XLP
Z1(p.u.) conductor impedance information:	0.000196 R, 0.00219 X, 0.0048 B
Z0(p.u.) conductor impedance information:	0.00261 R, 0.00350 X, 0.0048 B

Main Generation Step-Up Transformer

Technical details are provided above in Table A-1.

2. Short Circuit Duty Study Results

All bus locations where the QC7 Phase II projects increase the short-circuit duty by 0.1 kA or more and where duty was found to be in excess of 60% of the minimum breaker nameplate rating are listed in the Bulk Area Report (Appendix H). These values have been used to determine if any equipment is overstressed as a result of the inclusion of QC7 Phase II interconnections and corresponding network upgrades, if any.

As discussed in Section D.5.2 of the Area Report and Appendix I, short circuit duty at Barre 220 kV was found to exceed the maximum nameplate ratings of all existing 220 kV breakers. Physical upgrades would necessitate replacement of all circuit breakers with a currently non-SCE standard higher rated 220 kV breaker which will necessitate in excess of $70 million and require over 48 months to implement. Because the need is currently viewed as temporary in nature and is impacted by timing of the ultimate disposition of the existing OTC units, the recommended mitigation involves implementing an operating procedure which would restrict the number of generation units that can operate (i.e., "spin") to ensure duties at Barre 220 kV are maintained within the maximum Barre SCD ratings of 63 kA. Such restrictions may impact day-to-day operations of this project as well as those existing OTC units which provide significant short-circuit duty contribution to the Barre 220 kV bus.

The responsibility to finance short circuit related Reliability Network Upgrades identified through a Group Study shall be assigned to all Interconnection Requests in that Group Study pro rata on the basis of short circuit duty contribution of each Generating Facility.

Please refer to the QC7 Phase II Area Report for the QC7 Phase II breaker evaluation identified overstressed circuit breakers at the SCE buses, and Attachment 2 for the pro-rata allocation with corresponding estimated costs (if any) for the Project, based on SCD contribution at each location. Note that the list of Barre 66 kV circuit breakers shown in the QC7 Phase II Area Report has been adjusted as discussed in the Subtransmission Assessment Report (Queue Cluster 7 Phase II Attachment 8). In addition, the 2016 Reassessment Study efforts has determined that the need to upgrade fourteen (14) circuit breakers at Vista 220 kV Substation for short-circuit duty mitigation is no longer required.

3. SCE Substations with Ground Grids Duty Concerns

The short circuit studies flagged SCE-owned substations beyond the Project POI with ground grid duty concerns that necessitate a ground grid study. The Project's contribution to the Huntington Beach 220 kV, Lewis 220 kV, Apollo 66 kV, Bolsa 66 kV, Fullerton 66 kV, Gilbert 66 kV, Kindler 66 kV, La Palma 66 kV, Lampson 66 kV, Marion 66 kV, Shawnee 66 kV, Sunny Hills 66 kV, Team 66 kV, and Trask 66 kV Substations were found to be signification and will require the project to fund the cost of performing ground grid studies at these locations.

4. Preliminary Protection Requirements

   Protection requirements are designed and intended to protect the Distribution Provider's system only. The preliminary protection requirements were based upon the interconnection plan as shown in the one-line diagram depicted in line item #7 in Attachment 1.

   The IC is responsible for the protection of its own system and equipment and must meet the requirements in the Distribution Provider Interconnection Handbook provided in Attachment 4.

F. Transient Stability Evaluation

With the Project providing 0.95 power factor correction as measured at the POI and including the required mitigation identified above, transient stability performance was found to be acceptable. Refer to enclosed Bulk Area Report and Subtransmission Assessment Report in the QC7 Phase II report package, for the QC7 Phase II transient stability evaluation criteria and assessment results.

G. Power Factor Requirements

Based on the results of the Study, the Project will need to be designed to maintain a composite power delivery at continuous rated power at the POI at a power factor within the range of 0.95 lead/lag at POI for asynchronous generation and 0.90 lagging to 0.95 leading at generator terminals for synchronous generators. Additionally, the generation system must be designed to accommodate a VAR schedule provided by SCE. SCE will determine if the VAR schedule is necessary based on future re-arrangements of SCE's Transmission.

H. Deliverability Assessment Results

1. **On Peak Deliverability Assessment**

   The Project does not contribute to any deliverability constraint.

2. **Off Peak Deliverability Assessment**

   There is no wind generators in the study area. The off-peak deliverability assessment is not performed.

3. **Required Mitigations**

   No Delivery Network Upgrades are required.

I. In-Service Date and Commercial Operation Date Assessment

The latest information provided by the IC has indicated that the requested generator ISD is March 30, 2018 and a COD of June 1, 2018. To determine if these dates could be met, an In-Service Date and Commercial Operation Date Assessment was performed which considered both the QC7 Phase II process timelines as well as the following facilities needed to provide for reliable energy only interconnection of the Project. Timing of the upgrades required to provide for the requested Full Capacity Deliverability Status are discussed in the section below:

1. QC7 Interconnection Process Timelines

To enable physical interconnection, a Generation Interconnection Agreement (GIA) is required. As part of the QC7 interconnection process, a GIA is not scheduled to be tendered until after completion of the Reassessment and Transmission Planning Deliverability (TPD) Allocation Study Process which does not commence until late January or early February 2016. The TPD Allocation is scheduled to be completed by April and if no changes to scope requirements are identified, a letter is provided at the end of April outlining the TPD Allocation results. However, if changes are identified, updates to scope, costs and schedules are developed and updated reports are issued by the end of July. The GIA negotiations commences after either the issuance of the letter outlining the TPD allocation results at the end of April or upon issuance of the updated reports at the end of July. Provided the Project does not elect to Park, the letter or updated reports are used as the basis to proceed with the GIA negotiations. Assuming a three month timeframe for GIA negotiations, a GIA is not expected until either early August 2016 or early November 2016 depending on TPD study results and decision to Park or proceed.

2. System Upgrade Timelines for Reliable Interconnection

   The Operational Studies identified that the following facilities are required in order to provide for an energy only interconnection:

   a. Distribution Provider's Interconnection Facilities

      As described in Section 1.b of Attachment 1, line protection, telecomm, and SCE portion of 66 kV gen-tie among other items will be required to terminate the IC gen-tie at the SCE Johanna Substation. Preliminary durations estimated to install the Distribution Provider's Interconnection Facilities is 27 months.

   b. Reliability Network Upgrades – Short-Circuit Duty (SCD) Mitigation

      Short circuit duty operational mitigation was identified taking into account new generation projects which have executed GIAs, approved transmission system upgrades fully permitted and under construction, and new generation projects including QC7 Phase II Projects which do not yet have an executed GIA. The study results for these operational studies are provided in Section II of the Generation Sequencing Implementation (GSI) Short Circuit Duty evaluation (Appendix G). Based on the QC7 Phase II and taking into account 2016 Reassessment study results, the following upgrades/mitigation are required to be in place in order to enable energy only interconnection of this Project:

      - Reconfiguration of the system to operate one Mira Loma AA-Bank on the east side as normally open (requires simply opening AA-Bank so no duration identified)
      - Vincent 220 kV bus-split which has an estimated in-service date of July 2016

      In addition to the above mitigation requirements which already have established in-service dates, the following additional SCD mitigations may be needed in order to enable energy only interconnection. It is important to note that projects to undertake the work have not been initiated since the timing of need is dependent on development of queued generation projects, including QC7, which have not yet executed a GIA.

      - Replacement of four (4) Vincent 500 kV circuit breakers (triggered by QC3&4)
      - ~~Upgrade fourteen (14) Vista 220 kV circuit breakers by installing TRV Caps (triggered by QC7)~~

- o CAISO Operating Procedure which limits the number of generation units operating and "spinning" to ensure duties at Barre 220 kV are maintained within the maximum Barre SCD ratings of 63 kA (triggered by QC7)

The identification of need was based on the assumption that all queued generation projects actually materialize and are interconnected (as energy only). Timing to implement the first two SCD mitigations are currently estimated at 27 months from the date the need is identified. These additional SCD mitigations will be continuously evaluated as part of ongoing GIA negotiations and ongoing studies to properly define the time when actual need to undertake these mitigations is required based on the actual GIA negotiations with corresponding requested in-service dates. Once the actual need is triggered, project development will commence. Timing to implement the recommended CAISO Operating Procedure will depend on OTC unit operations and timing of actual development of the Stanton Energy Project.

c. Voltage Support Mitigation

No voltage support upgrades were identified to be required to enable this project to interconnect.

d. Distribution Upgrades

i. Plan of Service

As described in Section 3.b of Attachment 1, a new 66 kV line position equipped as a double-bus double-breaker configuration is required as the Distribution Plan of Service to interconnect the project to the SCE Barre Substation. Preliminary duration estimated to install the Distribution Provider's Distribution Upgrades is 27 months.

ii. Short-Circuit Duty Mitigation

The studies identified that several QC7 Phase II Projects, including this project, contributes to the overstressing of one (1) 66 kV circuit breaker at Villa Park and that this project alone would drive the need for replacement of twenty-eight (28) 66 kV circuit breakers at Barre under a conditions when the bus-sectionalizing 66 kV circuit breakers are closed. However, the number of CB's requiring replacement is reduced to twenty-one (21) with an operating procedure which to disconnect the Project (WDAT 1189) during the condition when the bus-sectionalizing breakers are closed as discussed in the Subtransmission Assessment Report (Queue Cluster 7 Phase II Attachment 8). Preliminary duration estimated to replace the 66 kV circuit breakers at Barre and Villa Park is 27 months.

3. Conclusion

Based on the standard timelines, the requested IC In-Service Date of March 30, 2018 cannot be met due to the following reasons:

- o The QC7 Interconnection Process Timelines will not yield a Generation Interconnection Agreement until either early August 2016 or early November 2016 depending on TPD study results which is beyond the requested IC In-Service Date.

- Timelines required to construct the Distribution Provider's Interconnection Facilities and Distribution Upgrades are estimated at 27 months from the date the GIA is executed, payments are made, and notice to proceed with interconnection is provided. Following the standard process, this would result in a best case in-service date of December 2018 or March 2019 depending on TPD study results. It should be noted that the ability to meet a best case in-service date is tied directly to the IC's timely execution of the Interconnection Agreement, submittal of payments, and notice to proceed.

- Potential need to replace four (4) Vincent 500 kV ~~and upgrade fourteen (14) Vista 220 kV~~ circuit breakers which would require an estimated 27 months to complete from the day a project is initiated to commence the upgrade~~ at each location~~.

It is also important to note that once interconnected, the ability to operate the unit (even in spinning reserve) is contingent on further developments and operating status of existing OTC units. With all OTC units currently in operating either as generator or synchronous condenser, the Barre 220 kV circuit breakers will be overstressed with the addition of this project. To address this issue, an Operating Procedure is recommended that will limit certain generation unit operations.

J. Timing of Full Capacity Deliverability Status, Interim Deliverability, Area Constraints, and Operational Information

The IC elected that the Project be Option A with Full Capacity Deliverability Status (FCDS). Timing of obtaining the requested FCDS is dependent on the completion of Delivery Network Upgrades. Until such time that the Delivery Network Upgrades are completed and placed into service, the Project may experience additional congestion exposure due to transmission limitations or may be granted Interim Deliverability Status based on annual system availability. The sections below provide a discussion of the timing of Full Capacity Deliverability Status, Interim Deliverability, Area Constraints, and Operational Information.

1. System Upgrades Required for Full Capacity Deliverability Status

   No upgrades have been identified to be required (either previously triggered or triggered with the addition of QC7 Projects) for this project to obtain the requested FCDS.

2. Interim Operational Deliverability Assessment for Information Only

   The operational deliverability assessment was performed for study years 2018 and 2020 by modeling the Transmission and generation in service in the corresponding study year. For details of the Transmission and generation assumption, refer to Section E.2 of the Area Report. There are no deliverability constraints identified. The Project will have the deliverability status as granted by the Transmission Plan Deliverability allocation.

3. Conclusion

   Since no upgrades have been identified to be required to obtain FCDS, the requested Full Capacity Deliverability Status could be achieved upon interconnection.

K. Interconnection Facilities, Network Upgrades, and Distribution Upgrades

Please see **Attachment 1** for the Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades and Distribution Upgrades allocated to the Project. Please note that SCE will not “reserve” the identified IF’s for the proposed POI. The identified scope/facilities will be allocated to the project upon the successful execution of the Generation Interconnection Agreement and SCE has completed the final design and engineering of the facilities according to tariff timelines.

L. Cost and Construction Duration Estimates

To determine the cost responsibility of each generation project in QC7 Phase II, the CAISO developed cost allocation factors (Attachment 3) for Reliability Network Upgrades, Local Delivery Network Upgrades and Area Delivery Network Upgrades. Attachment 2 provides the 'constant' 2014 dollars and their escalation to the estimated COD year for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades which the Project was allocated cost.

For the QC7 Phase II Study, the estimated COD is derived by assuming the duration of the work element will begin in December 2016, which accounts for the CAISO tariff scheduled completion date of the QC7 Phase II study plus: the TP Deliverability (TPD)[2] allocation, Annual Reassessment effort, and the interconnection agreement signing period and submittal of required funds by the IC.

The IC should note that any Local Delivery Network Upgrades and Area Delivery Network Upgrades allocated to the Project may be assessed 35% Income Tax Component of Contribution (ITCC) pending the results of the TPD allocation Process several months after the QC Phase II Study Reports are released, in addition to the 35% ITCC assessed for the IFs, DUs, and RNUs above the $60K/MW repayment cap allocated to the Project. For your information, Attachment 2 contains a potential ITCC estimate[3] based on the Phase I cost in this study. It does not represent the “maximum ITCC exposure” of the Project. Attachment 3 provides an estimated non-reimbursable RNU cost that would be subject to ITCC, taking into account the Network Upgrade maximum cost responsibility. The maximum ITCC warranted by the Project will be addressed, calculated, and included during the Interconnection Agreement development phase once the IC submits the TPD Affidavit confirming the acceptance, partial acceptance, or denial of awarded deliverability assigned to the Project.

M. SCE Technical Requirements

The IC is responsible for the protection of its own system and equipment and must meet the requirements in the Distribution Provider Interconnection Handbook provided in Attachment 4.

It is the IC’s responsibility to select, purchase, and install turbine/inverter based generators that are compatible with the series compensation in the area.

[2] Transmission Plan Deliverability: Deliverability supported by the CAISO’s Transmission Plan

[3] The maximum ITCC exposure applies ITCC (35%) to assigned IF and DU facilities, Network Upgrades that are not subject to transmission credits incremental to a repayment $/MW cap or an award of 0 MW TPD Allocation, and that SCE will own the facilities in question. The maximum ITCC exposure is calculated by applying the following formula: (IF*35%)+ ((RNU Costs – (Project MW * ($60k/MW)))*35%)+(LDNU*35%)+(ADNU*35%)+(DU*35%)

N. Sub Synchronous Interaction Evaluations

Certain generators or inverter based generators when interconnected within electrical proximity of series capacitor banks on the transmission system are susceptible to Sub-Synchronous Interaction (SI) conditions which must be evaluated. Subsynchronous Interaction evaluations include Subsynchronous Resonance (SSR) and Subsynchronous Torsional Interactions (SSTI) for conventional generation units, and Subsynchronous Control Instability (SSCI) for inverter based generators using power electronic devices (e.g. Solar PV and Wind Turbines).

For projects interconnecting at the 220 kV voltage level and above in close electrical proximity of series capacitor banks on the transmission system a study will need to be performed to evaluate the SI between generating facilities and the transmission system.

The IC is 100% responsible for any studies related to the SSR or SSTI. The only study that SCE will perform (at the IC's expense) is for SSCI; to ensure that the Project does not damage SCE's control systems.

The SSCI study will require that the IC provide a detailed PSCAD model of its Generating Facility and associated control systems, along with the manufacturer representative's contact information. The study will identify any mitigation(s) that will be required as part project execution and need to be completed prior to initial synchronization of the Generating Facility. The study and the proposed mitigation(s) shall be at the expense of the IC.

It is the IC's responsibility to select, purchase, and install turbine/inverter based generators that are compatible with the series compensation in the area.

O. Environmental Evaluation, Permitting, and Licensing

Please see Appendix K of the QC7 Phase II Bulk Area Report.

P. Affected Systems Coordination

Please see Section H of the QC7 Phase II Bulk Area Report.

Q. Items not covered in this study

1. Conceptual Plan of Service

   The results provided in this study are based on conceptual engineering and a preliminary Plan of Service and are not sufficient for permitting of facilities. The Plan of Service is subject to change as part of final engineering and design.

2. IC's Technical Data

   The study accuracy and results for the QC7 Phase II Study are contingent upon the accuracy of the technical data provided by the IC. Any changes from the data provided could void the study results.

3. Study Impacts on Neighboring Utilities

   Results or consequences of this QC7 Phase II Study may require additional studies, facility additions, and/or operating procedures to address impacts to neighboring utilities and/or regional forums. For example, impacts may include but are not limited to WECC Path Ratings, short circuit duties outside of the CAISO Controlled Grid, and sub-synchronous resonance (SSR).

Refer to Affected Systems Coordination section of the Bulk Area Report.

4. Use of Distribution Provider Facilities

   The IC is responsible for acquiring all property rights necessary for the IC's Interconnection Facilities, including those required to cross Distribution Provider facilities and property. This Interconnection Study does not include the method or estimated cost to the IC of Distribution Provider mitigation measures that may be required to accommodate any proposed crossing of Distribution Provider facilities. The crossing of Distribution Provider property rights shall only be permitted upon written agreement between Distribution Provider and the IC at Distribution Provider's sole determination. Any proposed crossing of Distribution Provider property rights will require a separate study and/or evaluation, at the IC's expense, to determine whether such use may be accommodated.

5. Distribution Provider Interconnection Handbook

   The IC shall be required to adhere to all applicable requirements in the Distribution Provider Interconnection Handbook. These include, but are not limited to, all applicable protection, voltage regulation, VAR correction, harmonics, switching and tagging, and metering requirements.

6. Western Electricity Coordinating Council (WECC) Policies

   The IC shall be required to adhere to all applicable WECC policies including, but not limited to, the WECC Generating Unit Model Validation Policy.

7. System Protection Coordination

   Adequate Protection coordination will be required between Distribution Provider-owned protection and generator-owned protection. If adequate protection coordination cannot be achieved, then modifications to the generator-owned facilities (i.e., Generation-tie or Substation modifications) may be required to allow for ample protection coordination.

8. Standby Power and Temporary Construction Power

   The QC7 Phase I Study does not address any requirements for standby power or temporary construction power that the Project may require prior to the In-Service Date of the Interconnection Facilities. Should the Project require standby power or temporary construction power from Distribution Provider prior to the In-Service Date of the Interconnection Facilities, the IC is responsible to make appropriate arrangements with Distribution Provider to receive and pay for such retail service.

9. Licensing Cost and Estimated Time to Construct Estimate (Duration)

   The estimated licensing cost and durations applied to this Project are based on the Project scope details presented in this study. These estimates are subject to change as Project environmental and real estate elements are further defined. Upon execution of the Interconnection Agreement, additional evaluation including but not limited to preliminary engineering, environmental surveys, and property right checks may enable licensing cost and/or duration updates to be provided.

10. Network/Non-Network Classification of Telecommunication Facilities

    The cost for telecommunication facilities that were identified as part of the IC's Interconnection Facilities was based on an assumption that these facilities would be sited, licensed, and constructed by the IC. The IC will own, operate, maintain, and construct diverse telecommunication paths associated with the IC's generation tie line, excluding terminal equipment at both ends. In addition, the telecommunication requirements for SPS were assumed based on tripping of the generator breaker as opposed to tripping the circuit breakers at the Distribution Provider substation. Due to uncertainties related to telecommunication upgrades for the numerous projects in queue ahead of QC7 Phase II, telecommunication upgrades for higher queued projects were not considered in this study. Depending on the outcome of interconnection studies for higher queued projects, the telecommunication upgrades identified for QC7 Phase II may be reduced. Any changes in these assumptions may affect the cost and schedule for the identified telecommunication facilities.

11. Ground Grid Analysis

    A detailed ground grid analysis will be required as part of the final engineering for the Project at the SCE substations whose ground grids were flagged with duty concerns.

12. Applicability

    This document has been prepared to identify the impact(s) contributions of the Project on the SCE electrical system; as well as establish the technical requirements to interconnect the Project to the POI that was evaluated in the QC7 Phase II Study for the Project. Nothing in this report is intended to supersede or establish terms/conditions specified in interconnection agreements agreed to by SCE, CAISO and the IC.

13. Process for synchronization/trial operations and commercial operations of the Project

    The IC is reminded that the CAISO has implemented a New Resource Implementation (NRI) process that ensures that a generation resource meets all requirements before synchronization/trial operations and commercial operations. The NRI uses a bucket system for deliverables from the IC that are required to be approved by the CAISO. The first step of this process is to submit an "ISO Initial Contact Information Request form" at least 7 months in advance of the planned initial synchronization. Subsequently an NRI project number will be assigned to the project for all future communications with the CAISO. The Distribution Providers have no involvement in this NRI process except to inform the IC of this process requirement. Further information on the NRI process can be obtained from the CAISO Website using the following links:

    New Resource Implementation webpage:
    http://www.caiso.com/participate/Pages/NewResourceImplementation/Default.aspx

    NRI Checklist:
    http://www.caiso.com/Documents/NewResourceImplementationChecklist.xls

    NRI Guide:
    http://www.caiso.com/Documents/NewResourceImplementationGuide.doc

14. Potential Changes in Cost Responsibility

    The IC hereby placed on notice that interconnection of its proposed generating facility may be dependent upon certain Network Upgrades which are currently the cost responsibility of projects ahead of the proposed generating facility in the interconnection application queue. Section 14.2.2 of the GIDAP provides that should Network Upgrades required for queued-ahead projects be included in an executed GIA (or unexecuted GIA filed at FERC) at the time of withdrawal of the earlier queued generating facility, and the upgrades are determined to still be needed by later queued generating facilities, the financial responsibility for such upgrades falls to the Distribution Provider. However, if the Network Upgrades required by earlier queued generating facilities are not subject to an executed GIA (or unexecuted GIA filed at FERC) the financial responsibility for such upgrades may fall to the IC. Section 14.2.2 also discusses how Network Upgrades required by interconnection customers selecting Option (B) might be required to be reapportioned among interconnection customers selecting Option (B) in the case of withdrawals of earlier queued generating facilities. Changes in costs allocated to the IC could also arise as the result of the CAISO's reassessment process described in Section 7.4 of the GIDAP. SCE encourages the IC to review Sections 7.4 and 14.2.2 of the GIDAP for the rules and processes under which the financial responsibility might be reapportioned to the IC. Potential changes in the IC's cost responsibility resulting from application of the provisions of these Sections of GIDAP are not included in this Phase II study, nor are the potential impacts to the IC's maximum cost responsibility outlined

15. Additional limitations may occur in the future under future base case overloads

16. Please note that SCE has made its best efforts to convey as much information possible based on information provided by the IC about its proposed project. The information contained herein may indicate to ICs that a project of its magnitude may be better suited to interconnect at higher voltage levels, or downsize as to not incur significant amount of restrictions. Any determination to change POIs or downsize is purely at the IC's discretion and would be subject to a SCE material modification review pursuant to the tariff.

Attachment 1

Interconnection Facilities, Network Upgrades and Distribution Upgrades

Please refer to separate document.

Queue Cluster 7 Phase II - Attachment 1
WDT1189– Stanton Energy Center Project
Interconnection Facilities, Network Upgrades and Distribution Upgrades

Addendum #1 to the Final Phase II Study Report

June 24, 2016

To determine the cost responsibility of each project in QC7, the California Independent System Operator Corporation (CAISO) developed cost allocation factors (Attachment 3) for Reliability Network Upgrades and Local Delivery Network Upgrades. The CAISO developed the $/MW cost rate for incremental Area Delivery Network Upgrades. The cost rate multiplied by the requested deliverable MW capacity provides the cost estimate for the Area Delivery Network Upgrades. The Interconnection Facilities are the sole cost responsibility of the Project. The Interconnection Facilities, Network Upgrades, and Distribution Upgrades allocated to the project are listed below[1].

1. Interconnection Facilities.

(a) **Interconnection Customer's Interconnection Facilities.** The Interconnection Customer shall:

(i) Install a substation with one (1) 66/13.8/13.8 kV main step-up transformer with H-X, H-Y, and X-Y windings with a 8, 8, and 12 percent impendences on a 95 MVA base.

(ii) Install a new underground 0.34 mile 66 kV generation tie-line from the Facility to a position designated by the Distribution Provider, outside of the Distribution Provider's Barre Substation, where Interconnection Customer shall install a structure designed and engineered in accordance with the Distribution Provider's specifications ("Last Structure"). This generation tie-line will be referred to as the Barre - WDT1189 66 kV Line. The right-of-way for Barre - WDT1189 66 kV Line shall extend up to the edge of the Barre Substation property line.

(Note: The Barre - WDT1189 66 kV Line name is subject to change by the Distribution Provider based upon its transmission line naming criteria. Should the Barre - WDT1189 66 kV Line name be changed, this GIA may be amended to reflect such change.)

(iii) The normal rating of the Interconnection Customer's 66 kV equipment that is part of the generation tie-line is 1574.59 A and the emergency rating is 1574.59 A.

(iv) Install appropriate single-mode fiber optic cable on Barre - WDT1189 66 kV Line to a point designated by the Distribution Provider near the Distribution Provider's Barre Substation to provide one of two telecommunication paths required for the line protection scheme, and the Remote Terminal Units ("RTU"). A minimum of eight (8) strands within the single-mode fiber optic cable shall be provided for the Distribution Provider's exclusive use into Barre Substation.

(v) Install appropriate fiber optic cable from the Facility to a point designated by the Distribution Provider near the Distribution Provider's Barre Substation to provide the second telecommunication path required for the line protection scheme. A minimum of eight (8) strands within the fiber

[1] Such descriptions are subject to modification to reflect the actual facilities that are constructed and installed following the Distribution Provider's final engineering and design, identification of field conditions, and compliance with applicable environmental and permitting requirements.

optic cable shall be provided for the Distribution Provider's exclusive use. The telecommunication path shall meet the Applicable Reliability Standards criteria for diversity.

(vi) Own, operate and maintain both telecommunication paths (including the fiber optic cables and appurtenant facilities), with the exception of the terminal equipment at both Barre Substation and at the Facility, which terminal equipment will be installed, owned, operated and maintained by the Distribution Provider.

(vii) Allow the Distribution Provider to review the Interconnection Customer's telecommunication equipment design and perform inspections to ensure compatibility with the Distribution Provider's terminal equipment and protection engineering requirements; allow the Distribution Provider to perform acceptance testing of the telecommunication equipment and the right to request and/or to perform correction of installation deficiencies.

(viii) Provide required data signals, make available adequate space, facilities, and associated dedicated electrical circuits within a secure building having suitable environmental controls for the installation of the Distribution Provider's RTU in accordance with the Interconnection Handbook.

(ix) Make available adequate space, facilities, and associated dedicated electrical circuits within a secure building having suitable environmental controls for the installation of the Distribution Provider's telecommunications terminal equipment in accordance with the Interconnection Handbook.

(x) Extend the fiber optic cables for the two telecommunication paths to an Interconnection Customer provided and installed patch panel located adjacent to the Distribution Provider's telecommunications terminal equipment specified above.

(xi) Install all required CAISO-approved compliant metering equipment at the Facility, in accordance with Section 10 of the CAISO Tariff.

(xii) Install a revenue and wholesale metering cabinet and revenue and wholesale metering equipment (typically, voltage and current transformers) at the Facility to meter the Facility revenue and wholesale load, as specified by the Distribution Provider. The metering cabinet must be placed at a location that would allow twenty-four hour access for the Distribution Provider's metering personnel.

(xiii) Allow the Distribution Provider to install, in the revenue and wholesale metering cabinet provided by the Interconnection Customer, revenue and wholesale meters and appurtenant equipment required to meter the revenue and wholesale load at the Facility.

(xiv) Install relay protection to be specified by the Distribution Provider to match the relay protection used by the Distribution Provider at Barre Substation, in order to protect the Barre - WDT1189 66 kV Line, as follows:

1. Two (2) current differential relays connected via diversely routed dedicated digital communication channels to Barre Substation. The make and type of current differential relays will be specified by the

Distribution Provider during final engineering of the Distribution Provider's Interconnection Facilities.

(xv) Install all equipment necessary to comply with the power factor requirements of Article 9.6.1 of the GIA, including the ability to automatically regulate the power factor to a schedule (VAR schedule) in accordance with the Interconnection Handbook.

(xvi) Install disconnect facilities in accordance with the Distribution Provider's Interconnection Handbook to comply with the Distribution Provider's switching and tagging procedures.

(b) **Distribution Provider's Interconnection Facilities.** The Distribution Provider shall**:**

(i) **Barre Substation.**

1. Install the interconnection facilities portion for a new 66 kV position to terminate the Barre - WDT1189 66 kV Line. This work includes the following:
   a. One (1) dead-end substation structure.
   b. Three (3) 66 kV potential transformers with steel pedestal support structures.
   c. Three (3) 66 kV line drops.
2. Install the following relays to protect the Barre - WDT1189 66 kV Line:
   a. Two (2) current differential relays connected via diversely routed dedicated digital communications channels to the Generating Facility.

(ii) **Barre - WDT1189 66 kV Line.**

Install an appropriate number of 66 kV sub-transmission structures including insulator/hardware assemblies between the Last Structure and the dead-end substation structure at Barre Substation. The actual number and location of the sub-transmission structures and spans of conductor will be determined by the Distribution Provider following completion of final engineering of the Distribution Provider's Interconnection Facilities. The Phase II Interconnection Study assumed two (2) sub-transmission TSP risers, approximately 600 feet of 954 SAC conductor, 12,000 feet of 3000 kcmil underground Cu cable, and 3 vaults.

(iii) **Telecommunications.**

1. Install all required lightwave, channel, and associated equipment (including terminal equipment), supporting protection and SCADA requirements at the Facility and Barre Substation for the interconnection of the Facility. Notwithstanding that certain telecommunication equipment, including the telecommunications terminal equipment, will be located on the Interconnection Customer's side of the Point of Change of Ownership, the Distribution Provider

shall own, operate and maintain such telecommunication equipment as part of the Distribution Provider's Interconnection Facilities.

2. Install appropriate length of fiber optic cable, including conduit and vaults, from the point designated by the Distribution Provider near the Distribution Provider's Barre Substation to extend the fiber optic cable into the communication room at Barre Substation. The actual location and length of fiber optic cable and conduit, and location and number of vaults, will be determined during final engineering of the Distribution Provider's Interconnection Facilities. The Phase II Interconnection Study assumed the installation of approximately 2,000 feet of underground fiber optic cable inside 5-inch conduit, and one (1) vault to extend the fiber optic cable into the communication room at Barre Substation.
3. Install appropriate length of fiber optic cable, including conduit and vaults, to extend the Interconnection Customer's diverse telecommunications from the point designated by the Distribution Provider near the Distribution Provider's Barre Substation into the communication room at Barre Substation. The actual location and length of fiber optic cable and conduit, and location and number of vaults, will be determined during final engineering of the Distribution Provider's Interconnection Facilities. The Phase II Interconnection Study assumed the installation of approximately 3,800 feet of underground fiber optic cable inside 5-inch conduit, and one (1) vault to extend the fiber optic cable into the communication room at Barre Substation.

(iv) **Real Properties, Transmission Project Licensing, and Corporate Environmental Health and Safety.**
Obtain easements and/or acquire land, obtain licensing and permits, and perform all required environmental activities for the installation of the Distribution Provider's Interconnection Facilities, including any associated telecommunication equipment for the Barre - WDT1189 66 kV Line.

(v) **Metering.**
Install revenue and wholesale meters and appurtenant equipment required to meter the revenue and wholesale load at the Facility. Notwithstanding that the meters and appurtenant equipment will be located on the Interconnection Customer's side of the Point of Change of Ownership, the Distribution Provider shall own, operate and maintain such facilities as part of the Distribution Provider's Interconnection Facilities.

(vi) **Power System Control.**
Install one (1) RTU at the Facility to monitor typical battery storage elements such as MW, MVAR, terminal voltage and circuit breaker status for the Facility and plant auxiliary load, and transmit the information received thereby to the Distribution Provider's grid control center.

Notwithstanding that the RTU will be located on the Interconnection Customer's side of the Point of Change of Ownership, the Distribution Provider shall own, operate and maintain the RTU as part of the Distribution Provider's Interconnection Facilities.

2. Network Upgrades.

(a) **Stand Alone Network Upgrades.**
None identified in the Phase II Study.

(b) **Other Network Upgrades.**

(i) **Distribution Provider's Reliability Network Upgrades.**

~~1. **Short Circuit Duty (SCD) Mitigation – (RNU)**~~
~~a. Vista 220 kV Substation~~
~~i. Upgrade fourteen (14) Circuit Breakers by installing fifteen (15) sets of TRV Capacitors.~~
~~ii. Perform ground grid study.~~
~~b. Real Properties, Transmission Project Licensing, and Corporate Environmental Health and Safety~~
~~Obtain easements and/or acquire land, obtain licensing and permits, and perform all required environmental activities for the installation of the TRV's.~~

2. **Ground grid studies.**
Perform ground grid studies at Huntington Beach 220 kV and Lewis 220 kV Substations.

(ii) **Distribution Provider's Delivery Network Upgrades See Area Report**
1. **Area Delivery Network Upgrades.**
None identified in the Phase II Study.
2. **Local Delivery Network Upgrades.**
None identified in the Phase II Study.

3. Distribution Upgrades. The Distribution Provider shall
(a) **Barre Substation.**
(i) Install the distribution facilities portion for a new 66 kV position to terminate the Barre - WDT1189 66 kV Line. This work includes the following:
a. Two (2) 66 kV circuit breakers.
b. Four (4) sets of 66 kV disconnect switches.
c. Perform ground grid study

(b) **Power Systems Controls.**

(i) Substation Automation System (SAS) point additions to the existing Barre SAS to accommodate new relay protection, status, and alarm.

(c) **Real Properties, Transmission Project Licensing, and Corporate Environmental Health and Safety.**

(i) Obtain easements and/or acquire land, obtain licensing and permits, and perform all required environmental activities for the installation of the Distribution Upgrades.

(d) **Short Circuit Duty (SCD) Mitigation – DU**

(i) Barre 66 kV Substation

a. Replace a total of twenty-one (21) Circuit Breakers and upgrade their bus positions accordingly.
b. Replace twelve (12) spans of 66 kV lines.
c. Perform ground grid study.
d. Real Properties, Transmission Project Licensing, and Corporate Environmental Health and Safety.
e. Obtain easements and/or acquire land, obtain licensing and permits, and perform all required environmental activities for replacement of the Circuit Breakers and Line Spans.

(ii) Villa Park 66 kV Substation

a. Replace ine Circuit Breaker.
b. Perform ground grid study.
c. Real Properties, Transmission Project Licensing, and Corporate Environmental Health and Safety.
d. Obtain easements and/or acquire land, obtain licensing and permits, and perform all required environmental activities for replacement of the Circuit Breaker.

(e) **Ground Grid Studies**

Perform ground grid studies at ~~Apollo 66 kV, Bolsa 66 kV,~~ Fullerton 66 kV, Gilbert 66 kV, Kindler 66 kV, La Palma 66 kV, Lampson 66 kV, Marion 66 kV and ~~, Shawnee 66 kV,~~ Sunny Hills 66 kV~~, Team 66 kV, and Trask 66 kV~~ Substations.

4. Affected System Upgrades

Not used.

5. Point of Change of Ownership.

(a) Barre - WDT1189 66 kV Line: The Point of Change of Ownership shall be the point where the conductors of the Barre - WDT1189 66 kV Line are attached to the Last Structure, which will be connected on the side of the Last Structure facing Barre Substation. The Interconnection Customer shall own and maintain the Last Structure, the conductors, insulators and jumper loops from such Last

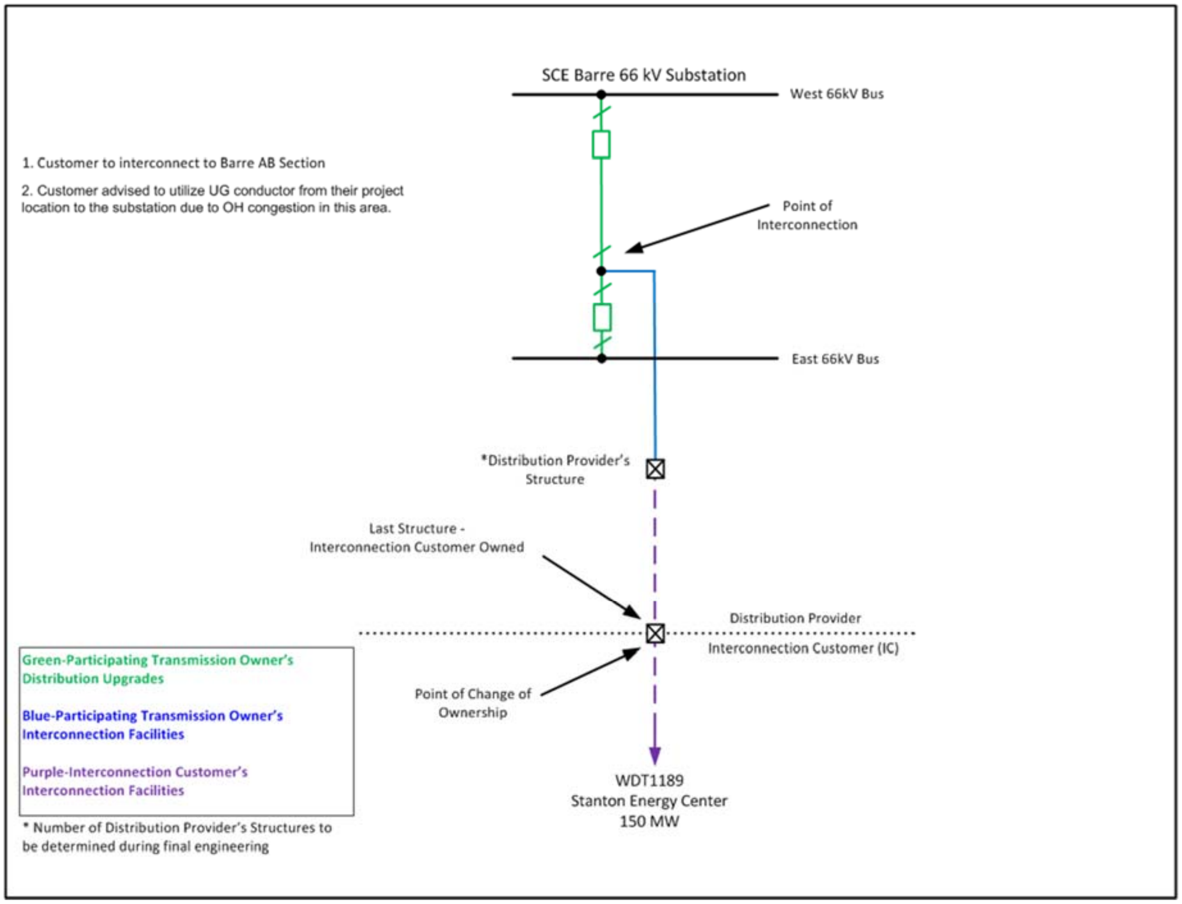
Structure to the Interconnection Customer's Facility. The Distribution Provider will own and maintain Barre Substation, as well as all circuit breakers, disconnects, relay facilities and metering within Barre Substation, together with the line drop, in their entirety, from the Last Structure to Barre Substation. The Distribution Provider will own the insulators that are used to attach the Distribution Provider-owned conductors to the Last Structure.

(b) Telecommunication single mode fiber optic cable: The Point of Change of Ownership shall be the point at a Distribution Provider owned vault, where the Interconnection Customer's fiber-optic cable is connected to the Distribution Provider's fiber optic cable.

(c) Telecommunication diverse fiber optic cable: The Point of Change of Ownership shall be the point at a Distribution Provider owned vault, where the Interconnection Customer's fiber-optic cable is connected to the Distribution Provider's fiber optic cable.

6. **Point of Interconnection.** The Distribution Provider's Barre 66 kV Substation at the 66 kV switchrack.

7. **One-Line Diagram of Interconnection to Barre 66 kV Substation.**



Attachment 2

Escalated Cost and Time to Construct for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades

Please refer to separate document.

Queue Cluster 7 Phase II - Attachment 2
Escalated Cost and Time to Construct for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades

Addendum #1 to the Final Phase II Study Report

June 24, 2016

QC7 Phase II Study Report Attachment #2

Escalated Cost and Time to Construct for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades

Project #: WDT1189

Cost Category	Costs per Category w/o ITCC (A)	One Time Costs (Note 1) (B)	Total Costs w/o ITCC (C=A+B)	Total Escalated Costs w/o ITCC	Estimated Time to Construct (Months)	COD Dollar Escalation Duration (Months)
	Constant 2016 Dollar in $1000s (Estimate)	Constant 2016 Dollar in $1000s (Estimate)	Constant 2016 Dollar in $1000s (Estimate)	Escalated to OD Year in $1000s	(Note 3,4,5, 9, & 10)	(Note 3,4,5, 9, & 10)
Interconnection Facilities						
Transmission	$0	$0	$0	$0	27	42
Sub-Transmission	$2,901	$0	$2,901	$3,295	27	42
Substation	$1,210	$0	$1,210	$1,374	27	42
Real Properties	$123	$0	$123	$140	27	42
Metering Services	$35	$0	$35	$40	27	42
Telecommunication	$725	$0	$725	$823	27	42
Edison Carrier Solutions	$168	$0	$168	$191	27	42
Corporate Environmental	$137	$0	$137	$156	27	42
Licensing	$0	$0	$0	$0	27	42
Power System Control	$74	$0	$74	$84	27	42
Interconnection Facilities Total	**$5,374**	**$0**	**$5,374**	**$6,103**	**27**	**42**
Reliability Network Upgrades						
Ground Grid Study						
Ground Grid Study for Bulk System(Huntington Beach and Lewis)	$0	$89	$89	$101	27	42
Reliability Network Upgrades Total	**$0**	**$89**	**$89**	**$101**	**27**	**42**
Distribution Upgrades						
Substation	$2,196	$45	$2,241	$2,545	27	42
Corporate Environmental	$57	$0	$57	$65	27	42
Power System Control	$0	$27	$27	$31	27	42
Short Circuit Duty Mitigation						
Barre 66 kV SCD	$16,397	$0	$16,397	$18,621	42	42
Villa Park 66 kV SCD	$397	$0	$397	$451	27	42
Ground Grid Study to support Barre 66 kV SCD	$0	$45	$45	$51	27	42
Ground Grid Study to support Villa Park 66 kV SCD	$0	$45	$45	$51	27	42
Ground Grid Study						
Ground Grid Study for Barre System (Apollo, Bolsa, Fullerton, Gilbert, Kindler, La Palma, Lampson, Marion, Shawnee, Sunny Hills, Team, Trask)	$0	$490	$490	$557	27	42
Distribution Upgrades Total	**$19,048**	**$651**	**$19,699**	**$22,370**	**42**	**42**

WDT1189	Project MW:	10
Income Tax Component of Contribution (ITCC) Potential		
Element	**ITCC @ 35% Constant Dollar in $1000s (2016)**	**ITCC @ 35% Escalated Dollar in $1000s (OD)**
IF (Calculation: (IF+SPS IF) * 35%)	**$1,881**	**$2,136**
RNU Refer to Note 11 below for Calculation	**$0**	**$0**
LDNU Refer to Note 12 below for ITCC treatment	**N/A**	**N/A**
DU (Calculation: DU* 35%)	**$6,667**	**$7,571**
ADNU Refer to Note 12 below for details on ITCC treatment	**N/A**	**N/A**

Max Duration for ITCC Calculation	**42**

Note 1: The one time costs item(s) will be treated as applicable per the specified upgrade classification. They may be reimburseable depending on their classification.

Note 2: Distribution upgrades are not reimbursable. Allocated costs may change if all projects responsible for these upgrades do not execute Generator Interconnection Agreements.

Note 3: The estimated licensing cost and durations applied to this project are based on the project scope details presented in this study. These estimates are subject to change as project environmental and real estate elements are further defined. Upon execution of the Interconnection Agreement, additional evaluation including but not limited to preliminary engineering, environmental surveys, and property right checks may enable licensing cost and/or duration updates to be provided.

Note 4: Each Upgrade category may contain multiple work element construction durations. The longest construction duration is shown under the C.O.D Dollar Duration column.

Note 5: SCE's Phase II cost estimating is done in 'constant' dollars 2016 and then escalated to the estimated O.D.year. For the QC7 study, the estimated C.O.D. Dollar is derived by assuming the duration of the work element will begin in December 2016, which is the CAISO tariff scheduled completion date of the QC7 Phase II study plus: the TPD Allocation, Annual Reassessment Effort , and the interconnection agreement signing period and submittal of required funds by the IC. For instance, if a work element is estimated to take a total of 24 months (final engineering, design, procurement, licensing and construction), then the estimated C.O.D. would be December 2018. If an IC's requested C.O.D. is beyond the estimated C.O.D. of a work element, the IC's requested C.O.D. is used. However, should the Generator Interconnection Agreement not be executed, or the necessary information, funding, and written authorization to proceed is not provided by the IC in time for the Participating TO to perform the work within these time frames, the information provided in Table above may be subject to change.

Note 6: Individual O&M charges for the above construction costs will be identified and communicated during the Interconnection Agreement process.

Note 7: The Estimated Time to Construct (duration in months) is the schedule for the PTO to complete final engineering, design, procurement, licensing, and construction, etc., and other activities needed to construct and bring the facilities into service. Such activities are from the execution of the Generator Interconnection Agreements, and receipt of: all required information, funding, and written authorization to proceed from the IC, as will be specified in the Interconnection Agreement, to commence work. The estimated schedule does not take into account unanticipated delays or difficulties securing necessary permits, licenses or other approvals; construction difficulties or potential delays in the project implementation process; or unanticipated delays or difficulties in obtaining and receiving necessary clearances for interconnection of the project to the transmission system.

Note 8: Estimated Time to Construct durations are from completion of any preceding facilities required.

Note 9: The C.O.D. Dollar for the IF and RNU/Dist. Plan of Service facilities was escalated using the requested Project C.O.D when the requested Project C.O.D was beyond the identified ETC of the IF and RNU/Dist. Plan of Service facilities. In such instances there is a different duration (months) in the ETC and C.O.D. Dollar escalation duration columns.

Note 10: RNUs are subject to ITCC on funds above the repayment maximum ($60 k/MW) of the Project.The ITCC corresponding to the RNUs, when applicable, was calculated by applying the following formula:
[Total Project allocated RNU Costs – {(Project MW Size)* ($60k)}]*35%

Note 11: LDNUs and ADNUs may be assessed 35% ITCC. However, presently the ITCC corresponding to LDNUs and ADNUs cannot be quantified due to their dependency on TPD allocation awarded to the Project and accepted by the Interconnection Customer ("IC") several months after the Phase II studies are complete. Consequently, the maximum ITCC warranted by the Project will be addressed, calculated, and included during the Interconnection Agreement development phase once the IC submits the TPD Affidavit confirming acceptance, waiver (parking), or denial of awarded deliverability to the Project.

Attachment 3

Not Used

Attachment 4

Distribution Provider Interconnection Handbook

Preliminary Protection Requirements for Interconnection Facilities are outlined in the Distribution Provider Interconnection Handbook.

Please refer to separate document.

Attachment 5

Short Circuit Calculation Study Results

Please refer to the Appendix H of the Bulk Area Report.

Attachment 6

Customer Provided Project Dynamic Data

The following data was submitted by the IC for Dynamic simulation:

genrou 96694 "WDT1189G " 13.80 "1 " : #9 mva=71.176 "tpdo" 9.67 "tppdo" 0.05 "tpqo" 2.95 "tppqo" 0.05 "h" 0.97 "d" 0.0 "ld" 2.35 "lq" 2.15 "lpd" 0.245 "lpq" 0.35 "lppd" 0.181 "ll" 0.13 "s1" 0.094 "s12" 0.507 "ra" 0.0053 "rcomp" 0 "xcomp" 0 "accel" 0.5

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genrou 96695 "WDT1189G2 " 13.80 "2 " : #9 mva=71.176 "tpdo" 9.67 "tppdo" 0.05 "tpqo" 2.95 "tppqo" 0.05 "h" 0.97 "d" 0.0 "ld" 2.35 "lq" 2.15 "lpd" 0.245 "lpq" 0.35 "lppd" 0.181 "ll" 0.13 "s1" 0.094 "s12" 0.507 "ra" 0.0053 "rcomp" 0 "xcomp" 0 "accel" 0.5

exac2 96695 "WDT1189G2 " 13.80 "2 " : #9 "tr" 0.028 "tb" 1.0 "tc" 1.0 "ka" 889.0 "ta" 0.02 "vamax" 166.0 "vamin" -166.0 "kb" 1.0 "vrmax" 41.5 "vrmin" 0.0 "te" 0.5 "kl" 1.51 "kh" 0.0 "kf" 0.0303 "tf" 1.0 "kc" 0.0 "kd" 0.0 "ke" 1.0 "vlr" 50.08 "e1" 1.5 "se1" 0.19 "e2" 2.0 "se2" 0.67 "limflg" 0.0

pss2a 96695 "WDT1189G2 " 13.80 "2 " : #9 "j1" 1 "k1" 0 "j2" 3 "k2" 0 "tw1" 2 "tw2" 2 "tw3" 2 "tw4" 0 "t6" 0 "t7" 2 "ks2" 1.03 "ks3" 1 "ks4" 1 "t8" 0.5 "t9" 0.1 "n" 1 "m" 5 "ks1" 10.0 "t1" 0.25 "t2" 0.04 "t3" 0.2 "t4" 0.03 "vstmax" 0.1 "vstmin" -0.1 "a" 1 "ta" 0 "tb" 0

ggov1 96695 "WDT1189G2 " 13.80 "2 " : #9 mwcap=51.0 "r" 0.05 "rselect" 1.0 "tpelec" 1.0 "maxerr" 0.023 "minerr" -0.023 "kpgov" 3.6 "kigov" 1.65 "kdgov" 0.0 "tdgov" 1.0 "vmax" 1.0 "vmin" 0.24 "tact" 0.4 "kturb" 2.7 "wfnl" 0.2587 "tb" 0.1 "tc" 0.0 "flag" 0.0 "teng" 0.0 "tfload" 0.3 "kpload" 1.0 "kiload" 3.3 "ldref" 1.0902 "dm" 0.0 "ropen" 99.0 "rclose" -99.0 "kimw" 0.0 "pmwset" 0.0 "aset" 99.0 "ka" 10.0 "ta" 0.1 "db" 0.0 "tsa" 1.0 "tsb" 1.0 "rup" 99.0 "rdown" -99.0

genrou 96695 "WDT1189G2 " 13.80 "3 " : #9 mva=71.176 "tpdo" 9.67 "tppdo" 0.05 "tpqo" 2.95 "tppqo" 0.05 "h" 0.97 "d" 0.0 "ld" 2.35 "lq" 2.15 "lpd" 0.245 "lpq" 0.35 "lppd" 0.181 "ll" 0.13 "s1" 0.094 "s12" 0.507 "ra" 0.0053 "rcomp" 0 "xcomp" 0 "accel" 0.5

exac2   96695 "WDT1189G2   " 13.80 "3 " : #9 "tr" 0.028 "tb" 1.0 "tc" 1.0 "ka" 889.0 "ta" 0.02 "vamax" 166.0 "vamin" -166.0 "kb" 1.0 "vrmax" 41.5 "vrmin" 0.0 "te" 0.5 "kl" 1.51 "kh" 0.0 "kf" 0.0303 "tf" 1.0 "kc" 0.0 "kd" 0.0 "ke" 1.0 "vlr" 50.08 "e1" 1.5 "se1" 0.19 "e2" 2.0 "se2" 0.67 "limflg" 0.0

pss2a   96695 "WDT1189G2   " 13.80 "3 " : #9 "j1" 1 "k1" 0 "j2" 3 "k2" 0 "tw1" 2 "tw2" 2 "tw3" 2 "tw4" 0 "t6" 0 "t7" 2 "ks2" 1.03 "ks3" 1 "ks4" 1 "t8" 0.5 "t9" 0.1 "n" 1 "m" 5 "ks1" 10.0 "t1" 0.25 "t2" 0.04 "t3" 0.2 "t4" 0.03 "vstmax" 0.1 "vstmin" -0.1 "a" 1 "ta" 0 "tb" 0

ggov1   96695 "WDT1189G2   " 13.80 "3 " : #9 mwcap=51.0 "r" 0.05 "rselect" 1.0 "tpelec" 1.0 "maxerr" 0.023 "minerr" -0.023 "kpgov"   3.6 "kigov"   1.65 "kdgov" 0.0 "tdgov" 1.0 "vmax"   1.0 "vmin" 0.24 "tact" 0.4 "kturb"   2.7 "wfnl" 0.2587 "tb" 0.1 "tc" 0.0 "flag" 0.0 "teng" 0.0 "tfload" 0.3 "kpload" 1.0 "kiload"   3.3 "ldref" 1.0902 "dm" 0.0 "ropen" 99.0 "rclose" -99.0 "kimw" 0.0 "pmwset" 0.0 "aset" 99.0 "ka" 10.0 "ta" 0.1 "db" 0.0 "tsa" 1.0 "tsb" 1.0 "rup" 99.0 "rdown" -99.0

Attachment 7

Subtransmission Assessment Report for Generation Reliability Study

Please refer to separate document.

Queue Cluster 7 Phase II

Attachment 7

Subtransmission Assessment Report

Addendum #1 to the Final Phase II Study Report

Barre 66 kV System

June 24, 2016

Table of Contents

1. Purpose 1

2. QC7 Phase II Generation Project Interconnection Information 2

3. System Assumptions 2

3.1 Planning Criteria 2

3.2 Load Assumptions 3

3.3 Generation Assumptions 6

3.4 Subtransmission System Assumptions 6

3.5 Study Methodology 6

4. Power Flow Results 8

4.1 Maximum Generation Coupled with Minimum Load Conditions 8

4.2 Maximum Energy Storage Coupled with Minimum Local Subtransmission Generation Conditions 8

4.3 Power Flow Study Observations, Notes, and Restriction to Energy Storage ... 8

4.4 Subtransmission Assessment Mitigations 8

5. Post Transient Voltage Stability Assessment Results 9

6. Short Circuit Duty Results 9

6.1 Application Queue 9

6.2 Sensitivity Study – Define Projects that Drive Need for SCD Mitigation at Barre 66 kV 10

6.3 Operational Study 12

6.4 Ground Grid Evaluation 15

7. Scope of Subtransmission Level Distribution Upgrades 15

8. Network Constraints 15

1. Purpose

Impacts of QC7 Projects on the CAISO controlled transmission grid are addressed in the Metro Area Group Report. Because one (1) QC7 project is seeking to interconnect to the Barre 66 kV AB bus section, which is not under CAISO control, additional analysis is required to evaluate the 66 kV subtransmission system performance. The Individual project details are provided in the project's corresponding Appendix A. This additional analyses focuses on the QC7 interconnection request in the Barre 66 kV Subtransmission System and considers minimum levels of load demand with maximum generation dispatch as this would represent the most stressed condition for the project seeking interconnection to the Barre 66 kV AB bus section.

The purpose of this study is to determine the adequacy of SCE's electrical subtransmission system to accommodate the interconnection request and to identify system limitations that would require Distribution Upgrades on the subtransmission system to mitigate any identified impacts. The study included all existing and queued ahead generation projects in the Barre 66 kV Subtransmission System, regardless of the in-service dates of such prior queued generation projects. Results of the study will be used as the basis to determine appropriate cost allocation for the identified Distribution Upgrades taking into account every project in this cluster. An operational study was also performed, as required, to determine timing need of any identified upgrade. Such timing need is directly related to actual projects moving forward as not all queued ahead generation projects have progressed towards project execution. It is important to note that withdrawals of projects in this cluster could result in reallocating costs among the remaining projects.

The accuracy of the subtransmission assessment results are contingent on the accuracy of the technical data provided as part of the interconnection request. Any changes from the data provided could void the study results. The study report provides detailed study assumptions and conditions of the Barre AB 66 kV Subtransmission System in which the study was performed. The single QC7 interconnection request seeking interconnection to subtransmission facilities served out of the Barre AB 66 kV Subtransmission System progressed into Phase II. This project consists of a gas turbine power plant requesting to interconnect to the Barre 66 kV AB bus section.

This Subtransmission study report provides the following:

- Subtransmission system impacts caused by the addition of the QC7 Phase II project requesting interconnection in the Barre AB 66 kV Subtransmission System;
- A good faith estimate of the cost of any identified subtransmission level Distribution Upgrades

To determine the system impacts caused by the QC7 Phase II project seeking interconnection in the Barre 66 kV AB Subtransmission System, the following studies were performed:

- Steady State Power Flow Analyses
- Subtransmission level Short Circuit Duty Analyses

2. QC7 Phase II Generation Project Interconnection Information

The single QC7 interconnection request, totaling 150 MW, seeking interconnection to the Barre 66 kV subtransmission system progressed into Phase II. Table 2 summarizes the new QC7 generator project with essential data obtained from the SCE WDAT Generation Queue.

Table 2: SCE QC7 Phase II Project at Barre 66 kV System

CAISO Queue	Point of Interconnection (CAISO Delivery Point)	Full Capacity Energy Only	Fuel	Max MW
WDT 1189	Barre AB 66 kV Switchrack	FC	Gas	150
			Total QC7 Generation	**150**

3. System Assumptions

3.1 Planning Criteria

The generator interconnection studies were conducted utilizing SCE's Reliability Planning Criteria. More specifically, the main criteria applicable to this study are as follows:

Power Flow Analysis

Since the QC7 interconnection request, totaling 150 MW, is seeking interconnection directly to the Barre AB 66 kV bus section, the only contingency applicable for this study is loss of a single 220/66 kV Transformer Bank (A-Bank) at the Barre Substation.

- Single Contingencies (N-1) – Loss of one line or one A-bank

The following reliability criteria was used to evaluate loss of A-Bank:

Subtransmission Lines 220/66 kV Transformer banks (A-banks)	Base Case	Limiting Component Normal Rating
	N-1 and N-2	Limiting Component Emergency Rating
	Base Case	Normal Loading Rating*
	Long Term Emergency Loading Limit (LTELL) & Short Term Emergency Loading Limit (STELL)	As defined by SCE Operating Bulletin

3.1.1. Normal Overloads

Normal overloads are those that exceed 100 percent of normal facility rating with all facilities in-service (base case). Mitigation will be required to address any identified normal overload triggered by the inclusion of QC7 Phase II projects.

3.1.2. Contingency Overloads

Contingency overloads are those that exceed 100 percent of emergency ratings under outage conditions. Mitigation will be required to address any identified contingency overload triggered by the inclusion of QC7 Phase II projects.

3.1.3. Voltage Criteria

Voltage performance under single and double outage conditions will be limited to 5 percent and 10 percent deviation respectively.

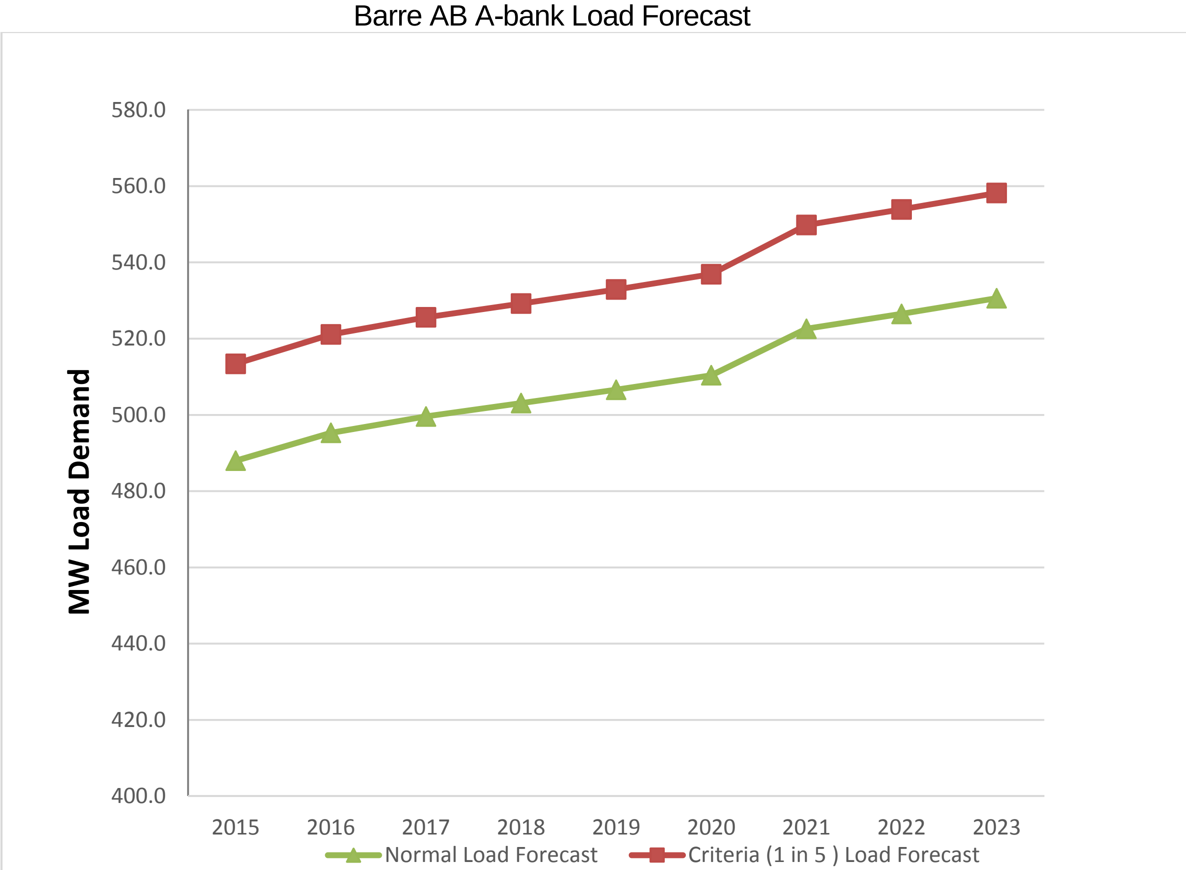
3.1.4. Power Factor Criteria

All projects will need to comply with SCE's Interconnection Handbook requirements.

3.2 Load Assumptions

The load assumptions used for local subtransmission system initially considered a 2019 load forecast. The 2019 load forecast was derived using SCE's Distribution Engineering A-bank Planning load forecast as well as the individual load serving substation (B-bank) load forecast for 2015-2023. Figure 3.2.1 below provides the local subtransmission load forecast values at the A-bank level under Normal (1-in-2 year) and Criteria (1-in-5 year) Planning assumptions.

Figure 3.2.1
Barre AB A-bank Load Forecast



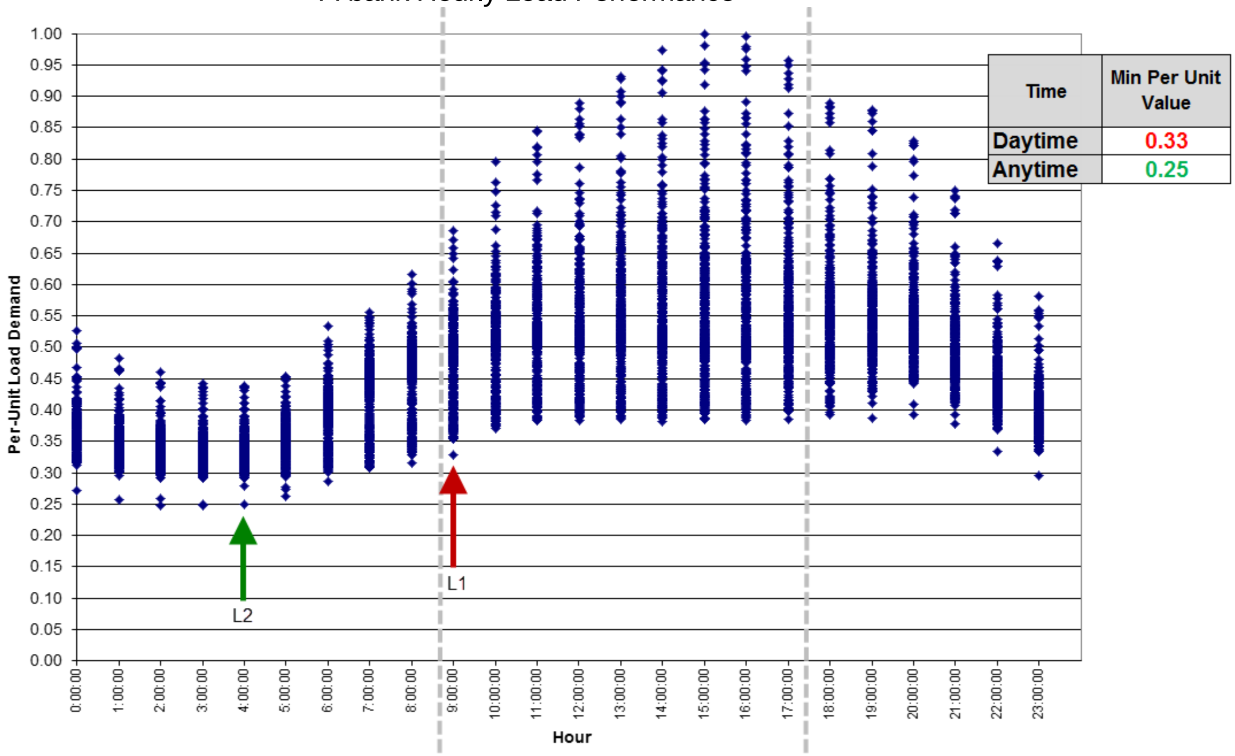
The A-bank Normal and Criteria load forecast was distributed to each individual B-bank substation (lower voltage substations served from the 220/66 kV substation) on a pro-rata basis. The resulting individual B-bank substation values are shown below in Table 3.2.1 and were used as the basis for evaluating subtransmission system performance.

Table 3.2.1
Local Subtransmission System Load Assumptions

Barre System Load Serving Substations	2019	
	Normal (1-in-2)	**Criteria (1-in-5)**
Barre 5&6 (D)	78.5	82.6
Ely (D)	68.2	71.8
Fullerton (D) 12kV	72.6	76.4
Fullerton (D) 4kV	5.0	5.2
Gilbert (D)	74.5	78.3
La Palma (D)	52.1	54.8
Lampson (D)	74.3	78.2
Marion (D)	77.0	81.0
Large Customers	4.4	4.7
Barre AB-Section Total	**506.6**	**532.9**

To model year 2019 hourly forecast load performance, historical year 2013 A-bank data was obtained and normalized (maximum historical load = 1.0). This was done in order to provide a means for scaling to reflect comparable hourly performance with a year 2019 load forecast. Shown below, Figure 3.2.2, is the normalized local subtransmission system A-bank hourly load performance as measured at the 220/66 kV transformer banks.

Figure 3.2.2
Normalized Local Subtransmission System
A-bank Hourly Load Performance



The assessment evaluating the most stressed system condition pertaining to maximum generation output. This condition involves identifying issues that arise under minimum load and maximum generation for the study. Utilizing the normalized hourly load performance shown above in Figure 3.2.2, the lowest per-unit load was applied to define two maximum generation output scenarios. The first scenario would use the minimum per-unit load during the daytime (shown as L1) while the second scenario would use the minimum value identified at any time of the day (shown as L2).

These per-unit values were used to define the specific load distribution assumptions at each load serving substation. These values were used in the base cases developed for each load scenario. The base cases multiplied the per-unit value identified for the respective load scenario, L1 and L2, with the “Normal” load distribution shown in Table 3.2.1. The resulting minimum load distribution used in the power flow study at each individual B-bank substation is provided below in Table 3.2.2.

Table 3.2.2
B-bank Load Distribution

Barre System Load Serving Substations	Minimum Load	
	0.33 PU	0.25 PU
	L1	L2
Barre 5&6 (D)	25.9	20.6
Ely (D)	22.5	17.9
Fullerton (D) 12kV	24.0	19.1
Fullerton (D) 4kV	1.6	1.3
Gilbert (D)	24.6	19.6
La Palma (D)	17.2	13.7
Lampson (D)	24.5	19.5
Marion (D)	25.4	20.2
Large Customers	1.4	1.2
Barre AB-Section Total Load	**167.2**	**133.2**

3.3 Generation Assumptions

There were no queued ahead generation projects in the Barre AB Subtransmission System.

3.4 Subtransmission System Assumptions

The QC7 Phase II Study modeled the existing Barre AB 66 kV Bus Section without any additional upgrades as no such upgrades have been triggered. The study considered existing system operating bulletins/procedures that transfer system load from bus one section to the adjacent bus section by closing the sectionalizing breaker under the loss of one A-Bank.

3.5 Study Methodology

3.5.1. Power Flow Study

While it is impractical to study all combinations of system load and generation levels during all seasons and at all times of the day, the base cases were developed to represent stressed scenarios of loading and generation conditions for the study group area. This assessment is comprised of power flow study scenarios that represents load conditions reflected in Table 3.2.2. A pre case without the inclusion of the QC7 projects and a Post-case with the inclusion of QC7 projects were modeled for each of the load conditions reflected in Table 3.2.2. Mitigation measures will be recommended for any power flow criteria violation identified to be triggered with the inclusion of QC7 projects. The outage conditions evaluated are provided below in Table 3.5.1.

Table 3.5.1
List of Contingencies Evaluated

#	Contingency Type	Contingency Description
1	Base Case	No Outage
2	N-1	Loss of Barre 1A 230/66 kV
3	N-1	Loss of Barre 3A 230/66 kV

The contingency study did not consider loss of lines internal to the Barre 66 kV System as the project does not impact flows on these lines since it is connected directly to the source bus.

3.5.2. Post Transient Voltage Study

The power flow study voltage results were used as a screen to identify those contingencies that may require additional post-transient voltage studies. Contingencies identified in the power flow to have a voltage drop in excess of 5% were selected for post-transient voltage analysis. The Post-transient voltage studies compare voltage deviations to the reliability requirements for single and double contingency outages on the subtransmission system. Mitigation measures will be recommended for any criteria violation identified to be triggered with the inclusion of QC7 projects.

3.5.3. Short Circuit Duty Study

To determine the impact on short-circuit duty within the subtransmission system after inclusion of all QC7 projects (application queue), the study calculated the maximum symmetrical three-phase-to-ground (3PH) and single-line-to-ground (SLG) short-circuit duties. Generation and transformer data represented in the generator and transformer data sheets provided by the customers were utilized. Bus locations where short-circuit duty is increased with the inclusion of all QC7 projects by at least 0.1 kA and the duty is in excess of 60% of the minimum breaker nameplate rating are flagged for further review. Upon completion of the detailed circuit breaker review, circuit breakers exposed to fault currents in excess of 100 percent of their interrupting capacities will need to be replaced or upgraded, whichever is appropriate. Cost for breaker upgrades or replacements will be allocated to QC7 projects if the study identifies QC7 as the triggering entity. It is important to note that costs for upgrades triggered by queued ahead projects may ultimately be allocated if the triggering entity ultimately withdraws and the need for the upgrades is still required and triggered by QC7 following any such withdrawals. Additional review was performed which evaluated the potential use of operating scheme and/or procedure to disconnect the Project anytime the Barre 66 kV sectionalizing bus breakers are closed. Such procedure will result in excluding Project SCD impacts on the Barre C 66 kV circuit breakers.

In addition to the application queue short-circuit duty study, an operational short-circuit duty study is performed, as required, as a means to identify timing of any identified circuit breaker upgrades or replacements. The operational studies will involve short-circuit duty review of the following scenarios:

- Years 2015/2016, 2017, and 2018 with inclusion of all new generation projects that have an executed interconnection agreement and which are scheduled to be in-service during those timeframes;

- All other generation projects will be modeled as energy only under a 2019 base case. Any identified distribution and network upgrade needed to enable physical energy-only interconnection and allow flow of energy to reach the CAISO point of delivery will also be assumed to be in place as part of this scenario

- A final short-circuit duty review will be perform which adds all network upgrades identified to be triggered for Full Capacity Deliverability Status (FCSD) and which are not yet under development or which will be placed into service after year 2019.

The short circuit studies also identified substations within the subtransmission where the QC7 Phase II projects increased the substation ground grid duty by 0.25 kA or more.

4. Power Flow Results

4.1 Maximum Generation Coupled with Minimum Load Conditions

Based on the assumptions listed above, the addition of the QC7 Phase II project did not trigger any base case or single contingency subtransmission overloads under maximum generation with minimum load study conditions.

4.2 Maximum Energy Storage Coupled with Minimum Local Subtransmission Generation Conditions

No QC7 projects in this system involve energy storage. As such there is no identified subtransmission assessment mitigation

4.3 Power Flow Study Observations, Notes, and Restriction to Energy Storage

(a) Metro Bulk Area Export Limits

Please refer to the Metro Bulk Area Report Section for impacts on the CAISO controlled system

(b) N-1-1 Outages

Loss of two A-Banks is beyond planning criteria. However, under such conditions, the ability continue to operate will depend on real-time operating conditions. It is important to note that under such potential conditions, curtailment of generation output will be implemented under real-time operation of the system, if required, in advance of the second outage to ensure potential overload is properly mitigated. Because all interconnection agreements contain a provision to enable such generation curtailment, no additional physical upgrades were identified to be required under such outage conditions.

(c) Energy Storage

No energy storage projects in this section.

4.4 Subtransmission Assessment Mitigations

(a) Maximum Generation Coupled with Minimum Load Conditions

There were no impacts identified to the Barre AB Subtransmission System that would necessitate mitigation.

(b) Maximum Energy Storage Coupled with Minimum Local Subtransmission Generation Conditions

There were no QC7 Projects in this system that involved energy storage.

5. Post Transient Voltage Stability Assessment Results

Review of the power flow study results identified that no voltage deviation exceeded the criteria discussed above. As a result,, no further post-transient voltage stability analysis was performed. Please refer to the Metro Bulk Area Report for the post-transient analysis performed on the bulk system.

6. Short Circuit Duty Results

6.1 Application Queue

The application queue three-phase-to-ground and single-phase-to-ground fault currents for the Barre 66 kV AB Subtransmission System are shown below in Table 6.1.1 and Table 6.1.2 respectively.

Table 6.1.1
Application Queue Three-Phase-To-Ground Short-Circuit Duty Results
Barre AB Subtransmission System

Bus Name	Bus kV	Pre-Case			Post-Case			Delta kA
		X/R	kA	Eff kA	X/R	kA	Eff kA	
~~Apollo (D)~~	~~66~~	~~8.8~~	~~12.7~~	~~12.7~~	~~8.1~~	~~14~~	~~14.0~~	~~1.3~~
Barre (D)	66	50.4	26.0	32.5	53.5	32.3	40.7	8.2
~~Bolsa (D)~~	~~66~~	~~6.9~~	~~11.2~~	~~11.2~~	~~6.4~~	~~12.2~~	~~12.2~~	~~1.0~~
Ely (D)	66	9.5	15.3	15.3	8.6	17.2	17.2	1.9
Fullerton (D)	66	6.2	13.2	13.2	5.7	14.6	14.6	1.4
Gilbert (D)	66	5.8	11.1	11.1	5.4	12.1	12.1	1.0
Kinder (C)	66	4.4	7.7	7.7	4.2	8.2	8.2	0.5
La Palma (D)	66	12.6	17.0	17.9	11.5	19.5	20.5	2.6
Lampson (D)	66	4.8	9.9	9.9	4.5	10.7	10.7	0.8
Marion (D)	66	12.2	16.3	17.1	11.1	17.6	18.5	1.4
Peaker (D)	66	23.7	25.0	27.5	21.0	30.7	32.8	5.3
~~Shawnee (D)~~	~~66~~	~~12.2~~	~~15.6~~	~~15.6~~	~~11.1~~	~~17.6~~	~~17.6~~	~~2.0~~
Sunnyhills (C)	66	5.7	9.3	9.3	5.3	10.0	10.0	0.7
~~Team (D)~~	~~66~~	~~7.4~~	~~10.8~~	~~10.8~~	~~6.9~~	~~11.7~~	~~11.7~~	~~0.9~~
~~Trask (D)~~	~~66~~	~~14.9~~	~~18.2~~	~~18.2~~	~~13.5~~	~~21.1~~	~~21.1~~	~~2.9~~

Table 6.1.2
End-of-Queue Single-Phase-To-Ground Short-Circuit Duty Results
Barre AB Subtransmission System

Bus Name	Bus kV	Pre-Case			Post-Case			Delta kA
		X/R	kA	Eff kA	X/R	kA	Eff kA	
~~Apollo (D)~~	~~66~~	~~8.7~~	~~9.5~~	~~9.5~~	~~8.1~~	~~10.2~~	~~10.2~~	~~0.7~~
Barre (D)	66	40.5	23.5	28.4	34.2	33.2	39.2	10.8
~~Bolsa (D)~~	~~66~~	~~7.8~~	~~10.0~~	~~10.0~~	~~7.3~~	~~10.7~~	~~10.7~~	~~0.7~~
Ely (D)	66	10.3	10.7	11.1	9.2	12.0	12.5	1.4
Fullerton (D)	66	6.9	8.1	8.1	6.3	9.0	9.0	0.9
Gilbert (D)	66	6.6	6.8	6.8	6.1	7.3	7.3	0.5
Kinder (C)	66	4.8	4.8	4.8	4.6	5.1	5.1	0.3
La Palma (D)	66	10.4	11.2	11.6	9.3	12.9	13.4	1.8
Lampson (D)	66	5.1	6.3	6.3	4.7	6.8	6.8	0.5
Marion (D)	66	10.7	11.4	12.0	9.5	13.1	13.8	1.8
Peaker (D)	66	21.4	22.8	24.4	15.2	31.7	31.7	7.3
~~Shawnee (D)~~	~~66~~	~~10.6~~	~~11.6~~	~~11.6~~	~~9.6~~	~~13.0~~	~~13.0~~	~~1.4~~
Sunnyhills (C)	66	6.5	5.4	5.4	6.1	5.8	5.8	0.4
~~Team (D)~~	~~66~~	~~6.8~~	~~7.6~~	~~7.6~~	~~6.4~~	~~8.1~~	~~8.1~~	~~0.5~~
~~Trask (D)~~	~~66~~	~~13.3~~	~~15.6~~	~~15.6~~	~~11.7~~	~~17.9~~	~~17.9~~	~~2.3~~

The QC7 Phase II breaker evaluations identified that the inclusion of QC7 projects triggers the need for SCD mitigation at the Barre 66 kV. The corresponding mitigation ~~is~~ shown in the Metro Area Bulk Report includes identification of 66 kV circuit breakers on the Barre C Section under an assumption that the Barre 66 kV sectionalizing circuit breakers were closed (during loss of A-Bank) with the Project in-service and operational. The total number of 66 kV circuit breaker upgrades triggered by the inclusion is reduced to twenty-one (21) breakers located on the Barre AB Section with the use of an Operating Procedure to disconnect the Project anytime the Barre 66 kV sectionalizing bus breakers are closed. The circuit breakers outlined in Section F.5.1.i of the Metro Area Bulk Report that are no longer required circuit breaker upgrades, with this operating procedure, includes CB5, CB6, CB51, CB52, CB61, CB62, and CB65. Project cost allocations are shown in Appendix G of the Metro Area Bulk Report. Section D.5.2 and Section F.5.1.i of

6.2 Sensitivity Study – Define Projects that Drive Need for SCD Mitigation at Barre 66 kV

A sensitivity study was performed to properly identify the QC7 Phase II project(s) which materially drive the need for the Barre 66 kV breaker upgrades. The sensitivity study considered two additional scenarios beyond Application Queue analysis. The first scenario modeled every QC7 Phase II project except for those projects seeking interconnection to distribution facilities served out of the Barre 66 kV Subtransmission System. The second scenario modeled those QC7 Phase II projects seeking interconnection to distribution facilities served out of the Barre 66 kV Subtransmission System without the rest of the QC7 Phase II projects.

6.2.1 Scenario 1: QC7 Phase II Projects External to Barre 66 kV System excluding QC7 Phase II Projects Internal to Barre 66 kV System

The three-phase-to-ground and single-phase-to-ground fault currents for the Barre 66 kV Subtransmission System under Scenario 1 resulted in no identified substations within the Barre System where SCD contribution was increased by at least 0.1 kA where the resulting SCD required a need for short-circuit duty mitigation. Such finding results in the conclusion that the need for circuit breaker upgrades internal to the Barre 66 kV Subtransmission System are completely driven by the addition of QC7 Projects seeking interconnection to distribution served by the Barre 66 kV Subtransmission System.

6.2.2 Scenario 2: QC7 Phase II Projects Internal to Barre 66 kV System excluding QC7 Phase II Projects External to Barre 66 kV System

The three-phase-to-ground and single-phase-to-ground fault currents for the Barre 66 kV Subtransmission System under Scenario 2 are shown below in Table 6.2.1.1 and Table 6.2.1.2 respectively.

Table 6.2.2.1
Three-Phase-To-Ground Short-Circuit Duty Results
QC7 Phase II Projects Excluding QC7 Phase II Projects External to Barre 66 kV System

Bus Name	Bus kV	Pre-Case			Post-Case			Delta kA
		X/R	kA	Eff kA	X/R	kA	Eff kA	
~~Apollo (D)~~	~~66~~	~~8.8~~	~~12.7~~	~~12.7~~	~~8.1~~	~~14.0~~	~~14.0~~	~~1.3~~
Barre (D)	66	50.4	26.0	32.5	53.5	32.2	40.6	8.1
~~Bolsa (D)~~	~~66~~	~~6.9~~	~~11.2~~	~~11.2~~	~~6.4~~	~~12.2~~	~~12.2~~	~~1.0~~
Ely (D)	66	9.5	15.3	15.3	8.6	17.2	17.2	1.9
Fullerton (D)	66	6.2	13.2	13.2	5.7	14.6	14.6	1.4
Gilbert (D)	66	5.8	11.1	11.1	5.4	12.1	12.1	1.0
Kinder (C)	66	4.4	7.7	7.7	4.2	8.2	8.2	0.5
La Palma (D)	66	12.6	17.0	17.9	11.5	19.5	20.5	2.6
Lampson (D)	66	4.8	9.9	9.9	4.5	10.7	10.7	0.8
Marion (D)	66	12.2	16.3	17.1	11.1	17.6	18.5	1.4
Peaker (D)	66	23.7	25.0	27.5	21.0	30.7	32.8	5.3
~~Shawnee (D)~~	~~66~~	~~12.2~~	~~15.6~~	~~15.6~~	~~11.1~~	~~17.6~~	~~17.6~~	~~2.0~~
Sunnyhills (C)	66	5.7	9.3	9.3	5.3	10.0	10.0	0.7
~~Team (D)~~	~~66~~	~~7.4~~	~~10.8~~	~~10.8~~	~~6.9~~	~~11.7~~	~~11.7~~	~~0.9~~
~~Trask (D)~~	~~66~~	~~14.9~~	~~18.2~~	~~18.2~~	~~13.5~~	~~21.1~~	~~21.1~~	~~2.9~~

Table 6.2.2.2
Single-Phase-To-Ground Short-Circuit Duty Results
QC7 Phase II Projects Excluding QC7 Phase II Projects External to Barre 66 kV System

Bus Name	Bus kV	Pre-Case			Post-Case			Delta kA
		X/R	kA	Eff kA	X/R	kA	Eff kA	
~~Apollo (D)~~	~~66~~	~~8.7~~	~~9.5~~	~~9.5~~	~~8.1~~	~~14.0~~	~~14~~	~~4.5~~
Barre (D)	66	40.5	23.5	28.4	53.5	32.3	40.7	12.3
~~Bolsa (D)~~	~~66~~	~~7.8~~	~~10.0~~	~~10.0~~	~~6.4~~	~~12.2~~	~~12.2~~	~~2.2~~
Ely (D)	66	10.3	10.7	11.1	8.6	17.2	17.9	6.8
Fullerton (D)	66	6.9	8.1	8.1	5.7	14.6	14.6	6.5
Gilbert (D)	66	6.6	6.8	6.8	5.4	12.1	12.0	5.2
Kinder (C)	66	4.8	4.8	4.8	4.2	8.2	8.2	3.4
La Palma (D)	66	10.4	11.2	11.6	11.5	19.5	20.2	8.6
Lampson (D)	66	5.1	6.3	6.3	4.5	10.7	10.7	4.4
Marion (D)	66	10.7	11.4	12.0	11.1	17.6	18.5	6.5
Peaker (D)	66	21.4	22.8	24.4	21.0	30.7	32.8	8.4
~~Shawnee (D)~~	~~66~~	~~10.6~~	~~11.6~~	~~11.6~~	~~11.1~~	~~17.6~~	~~17.6~~	~~6.0~~
Sunnyhills (C)	66	6.5	5.4	5.4	5.3	10.0	10.0	4.6
~~Team (D)~~	~~66~~	~~6.8~~	~~7.6~~	~~7.6~~	~~6.9~~	~~11.7~~	~~11.7~~	~~4.1~~
~~Trask (D)~~	~~66~~	~~13.3~~	~~15.6~~	~~15.6~~	~~13.5~~	~~21.1~~	~~21.1~~	~~5.5~~

Based on the study results, the inclusion of all application queue projects except the eighteen QC7 Phase II projects external to the Barre 66 kV Subtransmission System resulted in a need for breaker upgrades at the 66 kV voltage level. Such conclusion indicates that the single project seeking interconnection to distribution facilities served out of the Barre 66 kV Subtransmission System drives the need for the circuit breaker upgrades at Barre 66 kV Subtransmission System identified in the Metro Area Group Report.

6.3 Operational Study

Based on the conclusion that the need for Barre 66 kV breaker upgrades is directly linked to the development of the single project seeking interconnection to distribution facilities served out of the Barre 66 kV Subtransmission System, an operational study was performed to determine timing of need for such circuit breaker upgrades. The operational study evaluated the impacts associated with the incremental addition of generation units from the single project seeking interconnection to distribution facilities served out of the Barre 66 kV Subtransmission System.

6.3.1 Addition of one unit from WDT1189

The operational three-phase-to-ground and single-phase-to-ground fault currents for the Barre 66 kV Subtransmission System with the addition of only one unit from WDT1189 are shown below in Table 6.2.3.1 and Table 6.2.3.2 respectively.

Table 6.3.1.1
Three-Phase-To-Ground Short-Circuit Duty Results
QC7 Phase II Projects Excluding QC7 Phase II Projects External to Barre 66 kV System

Bus Name	Bus kV	Pre-Case			Post-Case			Delta kA
		X/R	kA	Eff kA	X/R	kA	Eff kA	
~~Apollo (D)~~	~~66~~	~~8.8~~	~~12.7~~	~~12.7~~	~~8.5~~	~~13.3~~	~~13.3~~	~~0.6~~
Barre (D)	66	50.4	26.0	32.5	54.0	28.8	36.6	4.1
~~Bolsa (D)~~	~~66~~	~~6.9~~	~~11.2~~	~~11.2~~	~~6.7~~	~~11.7~~	~~11.7~~	~~0.5~~
Ely (D)	66	9.5	15.3	15.3	9.1	16.2	16.2	0.9
Fullerton (D)	66	6.2	13.2	13.2	6.0	13.9	13.9	0.7
Gilbert (D)	66	5.8	11.1	11.1	5.6	11.6	11.6	0.5
Kinder (C)	66	4.4	7.7	7.7	4.3	8.0	8.0	0.3
La Palma (D)	66	12.6	17.0	17.9	12.1	18.1	19.0	1.1
Lampson (D)	66	4.8	9.9	9.9	4.6	10.3	10.3	0.4
Marion (D)	66	12.2	16.3	17.1	11.8	17.3	18.2	1.1
Peaker (D)	66	23.7	25.0	27.5	22.8	27.5	30.0	2.5
~~Shawnee (D)~~	~~66~~	~~12.2~~	~~15.6~~	~~15.6~~	~~11.7~~	~~16.5~~	~~16.5~~	~~0.9~~
Sunnyhills (C)	66	5.7	9.3	9.3	5.5	9.7	9.7	0.4
~~Team (D)~~	~~66~~	~~7.4~~	~~10.8~~	~~10.8~~	~~7.2~~	~~11.3~~	~~11.3~~	~~0.5~~
~~Trask (D)~~	~~66~~	~~14.9~~	~~18.2~~	~~18.2~~	~~14.3~~	~~19.5~~	~~19.5~~	~~1.3~~

Table 6.3.1.2
Single-Phase-To-Ground Short-Circuit Duty Results
QC7 Phase II Projects Excluding QC7 Phase II Projects External to Barre 66 kV System

Bus Name	Bus kV	Pre-Case			Post-Case			Delta kA
		X/R	kA	Eff kA	X/R	kA	Eff kA	
~~Apollo (D)~~	~~66~~	~~8.7~~	~~9.5~~	~~9.5~~	~~8.2~~	~~10.0~~	~~10.0~~	~~0.5~~
Barre (D)	66	40.5	23.5	28.4	35.3	30.7	36.2	7.8
~~Bolsa (D)~~	~~66~~	~~7.8~~	~~10.0~~	~~10.0~~	~~7.5~~	~~10.4~~	~~10.4~~	~~0.4~~
Ely (D)	66	10.3	10.7	11.1	9.5	11.6	12.1	1.0
Fullerton (D)	66	6.9	8.1	8.1	6.4	8.8	8.8	0.7
Gilbert (D)	66	6.6	6.8	6.8	6.2	7.2	7.2	0.4
Kinder (C)	66	4.8	4.8	4.8	4.6	5.0	5.0	0.2
La Palma (D)	66	10.4	11.2	11.6	9.5	12.5	13.0	1.4
Lampson (D)	66	5.1	6.3	6.3	4.8	6.7	6.7	0.4
Marion (D)	66	10.7	11.4	12.0	9.7	12.7	13.3	1.3
Peaker (D)	66	21.4	22.8	24.4	16.2	29.4	29.7	5.3
~~Shawnee (D)~~	~~66~~	~~10.6~~	~~11.6~~	~~11.6~~	~~9.9~~	~~12.6~~	~~12.6~~	~~1.0~~
Sunnyhills (C)	66	6.5	5.4	5.4	6.2	5.7	5.7	0.3
~~Team (D)~~	~~66~~	~~6.8~~	~~7.6~~	~~7.6~~	~~6.5~~	~~8.0~~	~~8.0~~	~~0.4~~
~~Trask (D)~~	~~66~~	~~13.3~~	~~15.6~~	~~15.6~~	~~12.2~~	~~17.1~~	~~17.1~~	~~1.5~~

Results corresponding to the addition of one unit from WDT1189 indicates that short-circuit duty values at Barre increase beyond duty capability of a number of existing circuit breakers. Such results conclude that the breaker upgrades at the Barre 66 kV need to be in place prior to allowing synchronization of the first unit from WDT1189.

6.3.2 Addition of two units from WDT1189

The operational three-phase-to-ground and single-phase-to-ground fault currents for the Barre 66 kV Subtransmission System with the addition of two units from WDT1189 are shown below in Table 6.2.3.1 and Table 6.2.3.2 respectively.

Table 6.3.2.1
Three-Phase-To-Ground Short-Circuit Duty Results
QC7 Phase II Projects Excluding QC7 Phase II Projects External to Barre 66 kV System

Bus Name	Bus kV	Pre-Case			Post-Case			Delta kA
		X/R	kA	Eff kA	X/R	kA	Eff kA	
~~Apollo (D)~~	~~66~~	~~8.8~~	~~12.7~~	~~12.7~~	~~8.3~~	~~13.7~~	~~13.7~~	~~1.0~~
Barre (D)	66	50.4	26.0	32.5	54.3	30.8	39.1	6.6
~~Bolsa (D)~~	~~66~~	~~6.9~~	~~11.2~~	~~11.2~~	~~6.5~~	~~12.0~~	~~12.0~~	~~0.8~~
Ely (D)	66	9.5	15.3	15.3	8.8	16.8	16.8	1.5
Fullerton (D)	66	6.2	13.2	13.2	5.8	14.3	14.3	1.1
Gilbert (D)	66	5.8	11.1	11.1	5.5	11.9	11.9	0.8
Kinder (C)	66	4.4	7.7	7.7	4.3	8.1	8.1	0.4
La Palma (D)	66	12.6	17.0	17.9	11.8	18.9	19.8	1.9
Lampson (D)	66	4.8	9.9	9.9	4.5	10.5	10.5	0.6
Marion (D)	66	12.2	16.3	17.1	11.4	17.2	18.1	1.0
Peaker (D)	66	23.7	25	27.5	21.9	29.3	31.6	4.1
~~Shawnee (D)~~	~~66~~	~~12.2~~	~~15.6~~	~~15.6~~	~~11.4~~	~~17.2~~	~~17.2~~	~~1.6~~
Sunnyhills (C)	66	5.7	9.3	9.3	5.4	9.9	9.9	0.6
~~Team (D)~~	~~66~~	~~7.4~~	~~10.8~~	~~10.8~~	~~7.0~~	~~11.5~~	~~11.5~~	~~0.7~~
~~Trask (D)~~	~~66~~	~~14.9~~	~~18.2~~	~~18.2~~	~~13.8~~	~~20.4~~	~~20.4~~	~~2.2~~

Table 6.3.2.2
Single-Phase-To-Ground Short-Circuit Duty Results
QC7 Phase II Projects Excluding QC7 Phase II Projects External to Barre 66 kV System

Bus Name	Bus kV	Pre-Case			Post-Case			Delta kA
		X/R	kA	Eff kA	X/R	kA	Eff kA	
~~Apollo (D)~~	~~66~~	~~8.7~~	~~9.5~~	~~9.5~~	~~8.1~~	~~10.1~~	~~10.1~~	~~0.6~~
Barre (D)	66	40.5	23.5	28.4	34.8	32.2	38.0	9.6
~~Bolsa (D)~~	~~66~~	~~7.8~~	~~10.0~~	~~10.0~~	~~7.4~~	~~10.6~~	~~10.6~~	~~0.6~~
Ely (D)	66	10.3	10.7	11.1	9.3	11.8	12.3	1.2
Fullerton (D)	66	6.9	8.1	8.1	6.3	8.9	8.9	0.8
Gilbert (D)	66	6.6	6.8	6.8	6.1	7.3	7.3	0.5
Kinder (C)	66	4.8	4.8	4.8	4.6	5.1	5.1	0.3
La Palma (D)	66	10.4	11.2	11.6	9.4	12.7	13.2	1.6
Lampson (D)	66	5.1	6.3	6.3	4.7	6.8	6.8	0.5
Marion (D)	66	10.7	11.4	12.0	9.6	12.9	13.5	1.5
Peaker (D)	66	21.4	22.8	24.4	15.6	30.7	30.7	6.3
~~Shawnee (D)~~	~~66~~	~~10.6~~	~~11.6~~	~~11.6~~	~~9.7~~	~~12.8~~	~~12.8~~	~~1.2~~
Sunnyhills (C)	66	6.5	5.4	5.4	6.1	5.7	5.7	0.3
~~Team (D)~~	~~66~~	~~6.8~~	~~7.6~~	~~7.6~~	~~6.5~~	~~8.1~~	~~8.1~~	~~0.5~~
~~Trask (D)~~	~~66~~	~~13.3~~	~~15.6~~	~~15.6~~	~~11.9~~	~~17.6~~	~~17.6~~	~~2.0~~

Results corresponding to the addition of two units from WDT1189 are for information purposes only as circuit breaker upgrades at Barre are required to be in place prior to allowing synchronization of the first unit from WDT1189.

6.4 Ground Grid Evaluation

As shown above in Table 6.1.2, the addition of the QC7 Phase II projects seeking interconnection to distribution facilities served out of the Barre 66 kV Subtransmission System were found to significantly increase single line-to-ground short circuit duty. The study identified the following SCE Substations served out of the Barre System where the single line-to-ground fault contribution from the QC7 projects increased duty in excess of 0.25 kA and exceeded the currently documented ground grid single line-to-ground short circuit duty value (excludes Ely and Johanna as current documentation indicates no issues).

- ~~Apollo~~
- Barre
- ~~Bolsa~~
- Fullerton
- Gilbert
- Kinder
- La Palma
- Lampson
- Marion
- ~~Shawnee~~
- Sunnyhills
- ~~Team~~
- ~~Trask~~

These locations will require a detailed ground grid analysis to be performed in support of projects seeking interconnection to distribution facilities served out of the Barre 66 kV Subtransmission System. The approximate one-time cost for such study is $35k per substation. These costs will be allocated to the generation projects identified to significantly increase SCD contributions and are identified in the appropriate Appendix A

7. Scope of Subtransmission Level Distribution Upgrades

Please refer to the Attachment 1 of the applicable Appendix A report for the scope of any subtransmission upgrades

8. Network Constraints

Please refer to the Metro Area Bulk Report for information pertaining to any network related constraints.