Southern California Edison Company

[redacted]

WDT1382

WDAT
INTERCONNECTION SYSTEM IMPACT STUDY

09/29/2016

SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL Company

Prepared by:
Maricel Calma
Distribution Engineer

Approved by:
Roger Salas
Distribution Region Manager

SOUTHERN CALIFORNIA EDISON COMPANY

Contents

I. INTRODUCTION

Southern California Edison Company (Interconnection Customer) applied to Southern California Edison Company ("SCE") for interconnection service for its proposed [redacted] Project ("Project") pursuant to SCE's Wholesale Distribution Access Tariff ("WDAT").

SCE performed an Interconnection System Impact Study (as requested by the Interconnection Customer for a 12 kV interconnection from an existing 12 kV distribution line [redacted] The Point of Interconnection is at the Interconnection Customer-owned 12 kV switchgear, which will be located approximately [redacted] from Estrella Substation. The Point of Interconnection will take place on the [redacted] out of SCE's Estrella 66/12 kV Substation. The generated power would be delivered to the California Independent System Operator ("CAISO") grid at the 220 kV bus of SCE's Santiago Substation.

The request is for a WDAT Export battery ("inverter-based") generation facility with a total capacity of 3.0 MW. The Interconnection Customer's initial request is for service to commence by September 01, 2017.[1]

The new generation, consisting of [redacted] will receive interconnection service from SCE's existing 12 kV circuitry on the [redacted] out of Estrella Substation. To accomplish this, a 12 kV primary underground line extension from existing circuit will need to be installed.

The purpose of this study is to determine the impact of the proposed generation addition on the SCE Distribution System and to identify the Interconnection Facilities, Distribution Upgrades, additions or modifications, or other facilities required to provide the requested service. This study was performed for historic year 2015-2016 peak load conditions as well as low demand conditions.

[1] Date as requested in the application. Actual In-Service Date depends on design and construction requirements.

Proposed Plan of Service

II. INTERCONNECTION SYSTEM IMPACT STUDY CONDITIONS & METHODOLOGY

Planning Criteria

The Project shall not cause the thermal rating of any conductor, connector, or apparatus to exceed 100% of its normal rated capacity with all facilities in service (base case).

The Project shall not cause the thermal rating of any conductor, connector, or apparatus to exceed 100% of its emergency rating under N-1 conditions. However, SCE may deem it necessary to isolate this project until the Distribution System returns to normal conditions.

Operational flexibility and reliability of the Distribution System shall be maintained at all times.

Circuit voltage profiles should be maintained to comply within CPUC's Rule 2 requirements.

System Conditions

Per the WDAT, the new generating facility will need to be able to operate at up to 0.95 lagging or leading. The base case analyzed the new generation at a power factor of 1.0.

The generation system must be designed to accommodate a VAR Schedule provided by SCE.

The generation system will be required to consume reactive power (VAR) during high voltage conditions.

Expected loading on the Distribution System as projected by the SCE 2016-2026 plan year was used.

Distributed generation resources connected to the Distribution System were analyzed offline and online during peak load and minimum load conditions during the day as to determine worst case scenario.

The short circuit contribution from the inverter systems was determined using a worst case scenario of 1.74 pu.

The Interconnection Customer's generating facility will have equipment, software, and the appropriate controls in-place to be able to control the generation output rates of change, as specified by SCE, in order to maintain appropriate voltage levels under all conditions including, but not limited to, the conditions identified above. Upon execution of the appropriate Interconnection Agreement, SCE will provide the Interconnection Customer the required ramp rate control parameters. The ramp rate controls will be a function of the generation penetration on the Distribution System as well as SCE's Distribution System configuration, but other parameters may be considered. Therefore, changes to the ramp rate control scheme may be required from time-to-time as required by increases in generation, changes in the Distribution System topology, or other changes in the Distribution System.

III. INTERCONNECTION SYSTEM IMPACT STUDY RESULTS

The study showed that the addition of the WDT1382 SCE 3.00 MW Project:

- Did not result in a violation of SCE's thermal loading criteria under base case conditions for the SCE Distribution System for peak load and daytime minimum load conditions. Under emergency (N-1) conditions (loss of B-Bank or circuit), SCE may deem it necessary to isolate this project until the Distribution System returns to normal conditions.

- Did not result in a voltage rise exceeding allowable Rule 2 limits during peak load conditions.

- Did not result in a voltage rise exceeded allowable Rule 2 limits during daytime minimum load conditions.

- Did not result in the need for additional protection requirements.

- The Project did result in the increase of three-phase short-circuit duties of 0.1 kA or more at a distribution substation. The circuit breaker interrupting capabilities were reviewed at these substations and it was determined that zero (0) circuit breakers will be required to be upgraded under this project.

Short Circuit Analysis

Using the short circuit models from the inverter systems being utilized in this battery storage generation system, the short circuit contribution at the 12 kV substation bus was calculated. This resulted in an increase of three-phase and/or single-line-ground short-circuit duties that did exceed 0.1 kA. The circuit breaker interrupting capabilities were reviewed at this substation and it was determined that zero (0) circuit breakers will be required to be upgraded under this project.

System Protection Considerations

With this proposed plan of service, no changes to the protection system of the SCE electrical system are currently required.

Thermal Loading

The line section between the Interconnection Customer's facility and the 12 kV Point of Interconnection is expected to experience a reverse power flow of [redacted] during daytime minimum loading. Of that [redacted] there will be [redacted] of reverse power flow back to the 12 kV bus at Estrella 12/66 kV substation during daytime minimum loading. No thermal overloads are calculated due to this reverse power flow under base case.

Under emergency (N-1) conditions (loss of circuit or B-bank), SCE may deem it necessary to isolate this project during N-1 conditions until the Distribution System returns to normal conditions.

Distribution Voltage Control

The [redacted] is not expected to exceed Rule 2 Voltage requirements under the generating facilities conditions of maximum generation, unity power factor, and daytime minimum load conditions. Therefore, this project will be required to accommodate a VAR schedule to be provided by SCE if necessary. The generator will need to consume VARs during high voltage conditions.

Harmonic Impact

The harmonic impact of the subject inverter based generation was not studied, however, despite the relatively low Total Harmonic Distortion (THD) (< 3%) of the equipment, impacts on voltage distortion levels are believed to be possibly significant due to the high penetration level of the generation facility with respect to the local distribution grid strength. As with all equipment connected to the SCE Distribution System, the installation with be subject to the provisions of Rule

2.E, allowing SCE to require Interconnection Customer mitigation of interference with SCE service, including harmonic impacts, should interference occur. The provided THD values are for individual inverters and not for the total generation requested. In order to better establish whether mitigation will be required in this case, a harmonic impact study is required to be provided to SCE by the Interconnection Customer. The Interconnection Customer shall commission such a study, discuss study structure with SCE prior to commencing study, and provide results to SCE with adequate lead time for SCE to direct any needed mitigation prior to detailed project design and construction.

SCE notes that the allowed harmonic voltage distortion limits on the Distribution System are the product of the impacts of all Interconnection Customers' equipment, not the limit to be applied to each individual installation.

IV. GENERAL DESCRIPTION OF IDENTIFIED UPGRADES

Distribution Upgrades

Distribution upgrades will be required to interconnect the system. The distribution upgrades include the installation of a pad-mounted gas switch and duct bank systems.

Interconnection Facilities

Interconnection Facilities will be required to interconnect the system. The interconnection facilities include the installation of an RCSG Automation, approximately [redacted] service transformer and associated wiring, activities to support Real Properties, and Corporate Environmental Services review.

Telemetry Requirements

Real-time telemetry will be required.

Interconnection Customer Equipment

The interface protection will be provided by the Interconnection Customer and will include a 12 kV circuit breaker, which is to be installed in an Interconnection Customer-owned 12 kV switchgear. The Interconnection Customer's protection must be coordinated with SCE's protective device(s) to provide adequate protection for the distribution system. The relay settings are subject to SCE approval prior to setting and certified timed trip testing report results using primary injection will need to be provided to SCE to verify relay and circuit breaker performance prior to energizing the service.

The Interconnection Customer owned switchgear must meet SCE's published Electrical Service Requirements ("ESR") to the extent applicable. Drawings required by the ESR shall be submitted, reviewed, and approved by SCE prior to release for fabrication/purchase of the equipment. Each medium voltage service is an individually engineered application at SCE.

Interconnection Customer's generation interconnection equipment must comply with SCE's Interconnection Handbook in regards to generation protection and lockable, visible open disconnecting means at the point of interconnection. Additionally, the Interconnection Customer shall be responsible for the installation and costs of certain underground facilities (i.e. ducts, structures, etc.) to the extent required by the final design. The construction of the underground facilities will be as per SCE's project drawings.

Interconnection Facilities Study

An Interconnection Facilities Study is required to determine the detailed scope and cost of facilities required to interconnect the Project.

V. NON-BINDING ORDER OF MAGNITUDE COST ESTIMATE

Non-binding order of magnitude cost estimates for the required Interconnection facilities and Distribution Upgrades are as follows:

Cost Estimate

Distribution Upgrades • [redacted] • Approximately [redacted]	$ 106.0 K
Interconnection Facilities • [redacted] • Approximately [redacted] • [redacted] • [redacted] • [redacted] • Storage Management System[2]	$ 108.6 K[3]
Corporate Environmental Services	$ 13.5 K
Real Properties	$ 24.9 K
Interconnection Facilities One Time Cost • Telemetry	$ 6.6 K[1]
Subtotal	$ 259.6 K
ITCC (0%)	$ 0.0 K
Total non-binding order of magnitude cost estimate	**$ 259.6 K**

[1] Cost Estimate based on centralized RTU method; the cost and scope of telemetry may significantly increase to include a dedicated RTU as required by SCE's Interconnection Handbook with an approximate cost of $140,000 in the event that Centralized RTU method is not feasible for this project.

[2] The Storage Management System is purely conceptual at this time. At minimum, the Storage Management System may require participation in SCE's Netcom System, and the following equipment, RFIs, packet radio, and a remote telemetry unit, which will be used to transmit the various data points to each participating Interconnection Customer. The preliminary cost estimate for the Storage Management System is approximately $600,000.

[3] This estimate does not include the cost for the Storage Management System

VI. GENERATION INTERCONNECTION AGREEMENT

The Interconnection Customer shall provide payments in accordance with the Generation Interconnection Agreement (GIA) as agreed to by the parties. The GIA will be developed using the scope of work, design, and construction requirements for the Project.

VII. DESIGN OF DISTRIBUTION UPGRADES & INTERCONNECTION FACILITIES

Design of the Distribution Upgrades and Interconnection Facilities is expected to be completed within **three (3) months** from receipt of the following deliverables:

- Execution of the Generation Interconnection Agreement, and Project Payment is received.
- Approved panel drawings in compliance with SCE's Electrical Service Requirements (ESR): http://www.sce.com/AboutSCE/Regulatory/distributionmanuals/esr.htm
- Interconnection Customer information sheet
- Street improvement plans (if available)
- **Unique address** assigned by the Authority Having Jurisdiction for the Generating Facility Meter location (required for all New-Services)
- Public right-of-way (street) base maps, as required by the interconnection
- Site plot plan on a 30:1 scale or digital file
    - Easement/lease agreement(s)
    - Grading plan(s)
    - Sewer and storm plot plan(s)
    - Landscape, Sprinkler, Pedestal Location(s)

However, schedules may change due to number of projects approved and release dates. Stacked projects may impact resources, system outage availability, and environmental windows of construction. The schedule is projected and preliminary.

VIII. CONSTRUCTION OF DISTRIBUTION UPGRADES & INTERCONNECTION FACILITIES

Construction of the Distribution Upgrades and Interconnection Facilities are expected to be completed within **twenty four (24) months** from receipt of the following deliverables:

- Completion of SCE's final design
- Interconnection Customer provides payment of any remaining balance in accordance with the Generation Interconnection Agreement
- All underground civil construction is to be performed by the Interconnection Customer in accordance with SCE Electrical Design Standards and released by SCE underground inspectors

However, schedules and duration may change due to number of projects approved and release dates. Stacked projects may impact resources, system outage availability, and environmental windows of construction. The schedule is projected and preliminary.

IX. ADDITIONAL DETAILS AND ASSUMPTIONS

The Interconnection System Impact Study Report showed:

- Interconnection service pursuant to the WDAT would be expected to commence approximately **twenty seven (27) months** from the execution of a Generator Interconnection Agreement. However, schedules and duration may change due to number of projects approved and release dates. Stacked projects may impact resources, system outage availability, and environmental windows of construction.

- Upgrades identified are general and preliminary descriptions only. The costs indicated are non-binding order of magnitude only. The schedule is projected and preliminary.

- Interconnection Customer is responsible for the installation of underground structures and conduits needed for the interconnection.

- An Interconnection Facilities Study detailing required scope and cost of the identified upgrades for the Project can be performed at the Interconnection Customer's request.

- This Interconnection System Impact Study is based on various technical data previously provided by the Interconnection Customer. If any of that information changes significantly, as determined by SCE, the results of this study may no longer be appropriate and may necessitate a new study.

- The final design of the proposed plan of service in this report may change to comply with the updated distribution design standards.

- This study does not include analysis related to the power output rate of change that may occur due to the following or other conditions;

    1. System morning start up for solar systems. That is when each morning the generating facility commences to generate and export electrical energy to the Distribution System.
    2. Cloud cover. Solar generating facilities have significant generation output variation (Variability) which can have an impact on Distribution System voltage profiles.

  The study assumes the Interconnection Customer's generating facility will have equipment, software and the appropriate controls in place to be able to control the generation output rates of change as specified by SCE in order to maintain appropriate voltage levels under all conditions including, but not limited to, the conditions identified above. Upon execution of the appropriate Generation Interconnection Agreement, SCE will provide the Interconnection Customer the required ramp rate control parameters. The ramp rate controls will be a function

of the generation penetration on the Distribution System as well as SCE's Distribution System configuration but other parameters may be considered. Therefore, changes to the ramp rate control scheme may be required from time to time as required by increases in generation, changes in the Distribution System topology, or other changes in the Distribution System.

- This study does not consider potential milestone setbacks that could result from the local jurisdiction requiring underground construction of distribution facilities. SCE encourages the Interconnection Customer to consult with the local jurisdiction to identify existing underground ordinance to reduce the risk of complication associated with said ordinance.

- Applicable to projects requesting primary service: This study does not include analysis related to coordination of system protection equipment. A coordination study will be required during final engineering. The coordination study may identify additional interconnection requirements such as installing new protection equipment, reprogramming and/or relocating existing protection equipment. The additional scope of work may have an effect on the Interconnection Customer's requested In-Service Date.

- The Corporate Environmental Services (CES) estimate assumes that SCE's scope of work would not require a California Public Utilities Commission license. That estimate also assumes that CES will act as the environmental liaison between SCE's team and Interconnection Customer's team, and the lead for regulatory agency communication. The estimate includes, but is not limited to the following CES activities, as applicable:

    a. Collaborate with the Interconnection Customer during the environmental study phase on proposed study methodologies and finding, as studies are being planned and performed for SCE's scope of work
    b. Review Interconnection Customer's California Environmental Quality Act (CEQA) and National Environmental Policy Act (NEPA) documents, technical studies, surveys, and other environmental documentation addressing SCE's scope of work (Interconnection Customer to include SCE's scope of work in their environmental document)
    c. Review of internal (SCE/CES) existing technical documents when available
    d. Regulatory agency communication, consultation, and reporting
    e. Permit of license acquisition
    f. Support SCE team in developing the project description, including scope changes during permitting/pre-construction or construction
    g. Communicate scope changes to Interconnection Customer's environmental team, discuss/approved subsequent actions including new surveys as necessary
    h. Prepare Environmental Requirements for Construction Clearance
    i. Develop communication plan
    j. Construction monitoring oversight
    k. General Order 131-D Consistency Determination and Environmental Evaluation
    l. Environmental Awareness/Worker Environmental Awareness Program (WEAP) training
    m. Preconstruction coordination field visit
    n. Construction and post-construction site assessments

- The estimate assumes the Interconnection Customer performs all environmental studies and prepares draft environmental permit applications related to the installation of SCE's Interconnection Facilities and Upgrades. Prior to commencing work and during execution of work, the Interconnection Customer must collaborate and obtain CES concurrence on all work outlined above. Should the Interconnection Customer-performed environmental studies, surveys, or monitoring not meet the Federal or State industry standards in accordance with Applicable Laws and Regulations, as determined by CES, the Interconnection Customer shall be obligated to remedy deficiencies under SCE/CES's direction, or CES shall undertake additional environmental studies, surveys, or monitoring at the sole expense of the Interconnection Customer. If these scenarios occur, the cost estimate must be updated to reflect the changes to the assumptions. The Interconnection Customer's responsibilities include, but are not limited to:
    a. Notifications to the Native American Heritage Commission (NAHC) and follow up notifications to the tribes and individuals in the NAHC contact list
    b. Performing cultural and paleontological resources records searches, performing cultural resources inventories (survey and recording), performing testing and evaluation and/or data recovery of archaeological sites as applicable, and providing the appropriate documentation in the form of inventory reports, research design and/or data recovery reports as applicable
    c. Cultural and paleontological monitoring during construction, when/if required
    d. Arranging curation agreements for artifacts and fossil specimens collected
    e. Performing a California Natural Diversity Database search
    f. Performing a habitat assessment
    g. Performing protocol or focused surveys for species with the potential of occurring in identified suitable habitat
    h. Conducting jurisdictional delineations for wetlands or other regulated waters
    i. Preparing draft environmental permit applications
    j. Performing pre-construction biological resource surveys
    k. Performing biological resource monitoring during construction
    l. Mitigation costs including, but not limited to, offsite/compensatory mitigation and onsite restoration and developing mitigation plans
    m. Developing environmental reports or submittals, if required

ATTACHMENT A

A1 - System without Proposed Project

A2 - System with Proposed Plan of Service

ATTACHMENT B

Subtransmission Assessment

Subtransmission Assessment Report

WDT1382

[redacted]

September 26, 2016

Table of Contents

1. Purpose

One (1) project, WDT1382, is seeking to interconnect to 12 kV distribution facilities served out of the Santiago 66 kV Subtransmission System, which is not under CAISO control, via the Independent Study Process (ISP). Impacts of the Project on the 12 kV distribution facilities are addressed in the SCE Field Engineering (FE) Report. Identification of impacts to the Santiago 66 kV Subtransmission System involved additional analysis which considered various levels of load demand with maximum generation dispatch. In addition, maximum charging of energy storage facilities was evaluated under a minimal generation within the local subtransmission system coupled with maximum levels of load demand.

The purpose of this study is to determine the adequacy of SCE's Santiago 66 kV Subtransmission System (non-CAISO controlled) to accommodate the Project 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 Santiago 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 the cost allocation for the identified Distribution Upgrades. An operational study if required is performed to determine the 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 execution of a generator interconnection agreement. It is important to note that withdrawals of any queued ahead projects could result in reallocating cost of any previously identified Distribution Upgrades.

The accuracy of the subtransmission assessment results are contingent on the accuracy of the technical data provided as part of the Interconnection Request (IR). Any changes from the data provided could void the study results and would need to be evaluated as part of a Material Modification Assessment (MMA) to determine if such change results in a material impact to queued-behind generation requests. The modifications would only be allowed if the MMA determines no material impacts to queued-behind generation requests. The study report provides detailed study assumptions and conditions of the Santiago 66 kV Subtransmission System in which the study was performed.

This Subtransmission Assessment Report provides the following:

- Subtransmission system impacts caused by the addition of the Project requesting interconnection within the Santiago 66 kV Subtransmission System.
- Subtransmission system impacts associated with energy storage projects seeking interconnection modeled as operating in charge mode.

To determine the system impacts caused by the Project seeking interconnection in the Santiago 66 kV Subtransmission System, the following studies were performed:

- Steady State Power Flow Analyses
- Post Transient Voltage Stability Analysis
- Subtransmission and Distribution voltage level Short-Circuit Duty Analyses

2. Project Interconnection Information

The WDT1382 Project is seeking interconnection to the Santiago 66 kV Subtransmission System. The Project consist of 5 MWs of energy storage. Please refer to the FE Report for specific Project details.

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

The following contingencies are considered for subtransmission lines and 220/66 kV transformer banks ("A-Banks"):

- Single Contingencies (N-1) – Loss of one line or one A-Bank
- Double Contingencies (N-2) – Common-mode loss of two lines

The following reliability criteria are used:

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

* Please note that Normal and Emergency Ratings are reduced to reflect 95% of rating for charging cases.

3.1.1. Normal Overloads

Normal overloads are those that exceed 100 percent of normal facility rating with all facilities in-service (base case), except where otherwise indicated, such as A-Bank loading for charging cases. Mitigation will be required to address any identified normal overload triggered by the inclusion of these 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 these 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 2014 – 2023 load forecast. The 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 2014-2023. Figure 3.1 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 3.1
Santiago 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 3.1 and were used as the basis for evaluating the subtransmission system performance.

Table 3.1
Subtransmission System Load Assumptions

Santiago System Load Serving Substations	2020	
	Normal	Criteria
[redacted]		

To model year hourly forecast load performance, historical A-Bank data were 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 each load forecast. Shown below, Figure 3.2., is the normalized local subtransmission system A-Bank hourly load performance.

Figure 3.2
Normalized Local Subtransmission System
A-bank Hourly Load Performance

The assessment evaluating maximum generation output considered various load demand for this study. Utilizing the normalized hourly load performance shown above in Figure 3.2, 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). In addition, the study considered a scenario representing maximum load demand (L5) with maximum generation.

For energy storage, the assessment evaluating maximum charging considered four scenarios with the maximum load. The first charging scenario would use the maximum per-unit load during the 2:00 AM – 6:00 AM time period (shown as L3). The second charging scenario would use the maximum per-unit load during the 8:00 AM – 12:00 PM time period (shown as L4). The third charging scenario would use the maximum per-unit load during the 2:00 PM – 6:00 PM time period (shown as L5). Lastly, the fourth charging scenario would use the maximum per-unit load during the 8:00 PM – 12:00 AM time period (shown as L6).

These per-unit values were used to define the specific load distribution assumptions at each load serving substation for each year evaluated. 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 through L6, with the "Normal" load distribution except for L5, which used the "Criteria" load distribution. The resulting information for year 2014 and 2020 are provided below in Table 3.2 and Table 3.3 respectively.

Table 3.2
Year 2014 B-Bank Load Distribution

Santiago System Load Serving Substations	Minimum Load		Maximum Load			
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 3.3
Year 2020 B-Bank Load Distribution

Santiago System Load Serving Substations	Minimum Load		Maximum Load			
[redacted]						

3.3 Generation Assumptions

Generation dispatch of local subtransmission system generation (existing and queued) was done in a manner that would provide for a stressed export of generation in the system. In order to assess the subtransmission system and stress it to its maximum capacity, all local generation resources were dispatched. The existing and queued ahead local generation that was turned on for the Santiago 66 kV Subtransmission System assessment is listed in the table below.

Table 3.3
Existing and Queued Ahead Local Generation

Generation	Status	Resource	Size (MW)
Coygen	Existing Generation	Gas	20.0
WDT292	In service 1/2016	Synchronous	19.6
WDT1294	Study Phase	BESS	10
WDT1372	Study Phase	BESS	2
		TOTAL MW	51.6

3.4 Subtransmission System Assumptions

As part of the operational studies performed for WDT1382, the study modeled the existing Santiago 66 kV Subtransmission System without any additional upgrades to determine if interconnection of the Project is dependent on the completion of planned subtransmission

upgrades. The study also considered existing system operating bulletins/procedures, if applicable.

In addition, the Study included an evaluation with the inclusion of all planned subtransmission upgrades including those identified to be needed to support queued ahead generation projects. Below is a summary of these subtransmission upgrades:

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 represent load conditions reflected in Table 3.2. A pre-case without the inclusion of WDT1382 and a post-case with the inclusion of WDT1382 were modeled for the applicable load conditions reflected in Table 3.2. Mitigation measures will be recommended for any power flow criteria violation

identified to be triggered with the inclusion of WDT1382. The critical outage conditions evaluated are provided below in Table 3.5.1.

Table 3.5.1
List of Contingencies Evaluated

No.	Description
[redacted]	[redacted]

Notes:

a) Though other relevant contingencies were also evaluated, only those listed above were the most critical and seen to create overloads that could be attributed to the addition of the Project.

b) There is an operational risk associated with non-common corridor N-2 outages. Loss of such two lines is considered an N-1-1 contingency event which allows for manual system adjustments between contingencies if an overload is anticipated for the next contingency that follows the first contingency (N-1). Consequently, it is important to note that under such potential conditions, curtailment of generation output will be implemented, if required, in advance of the second outage to ensure potential overload is properly mitigated.

c) Due to short-circuit duty operational limitation, the loss of an A-bank on Santiago A 220/66 kV assumption is that the bus-tie breaker will remain open (normal split bus configuration) to prevent operating three A-banks in parallel. The figures below in Section 4.2 represent loading under this assumption.

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 contingency outages on the subtransmission system. Mitigation measures will be

recommended for any criteria violation identified to be triggered with the inclusion of the Project.

3.5.3. Short-Circuit Duty Study

To determine the impact on short-circuit duty within the subtransmission system after inclusion of the Project, 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 customer were utilized. Bus locations where short-circuit duty is increased with the inclusion of the Project 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, mitigation will be identified for circuit breakers exposed to fault currents in excess of 100 percent of their interrupting capacities. Mitigation measures can involve circuit breaker upgrade, circuit breaker replacement, system reconfiguration to lower short-circuit duty, or the use of operating procedures. Cost for short-circuit duty mitigation will be allocated to the appropriate Project if the study identifies that the upgrades are triggered by the inclusion of the Project for which this study is performed. It is important to note that costs for mitigation measures triggered by queued ahead projects may ultimately be reallocated if the triggering entities ultimately withdraw and the need for the upgrades is still required and triggered by the inclusion of later queued projects following any such withdrawals.

3.5.4. Ground Grid Analysis

The short-circuit studies are used to determine substations within the subtransmission where the Project can potentially cause the need for upgrade to the existing station ground grid. The assessment will flag substations where single-phase-to-ground short-circuit duty is increased by 0.25 kA or more and seek further engineering review.

4. Power Flow Results

Given that the Project is seeking interconnection under ISP, no power flow impacts are identified on the CAISO controlled system since all ISP requests are treated as Energy Only Interconnection. Any overloads identified are subject to mitigation via the use of congestion management protocols and no network upgrades are required to address power flow impacts corresponding to Energy Only Interconnections.

4.1 Maximum Generation Coupled with Maximum Load Conditions

Under maximum generation coupled with maximum load conditions, the inclusion of the Project did not result in any identified power flow system impacts under base case or outage conditions.

4.2 Maximum Generation Coupled with Minimum Daytime Load Conditions

Under maximum generation coupled with minimum daytime load conditions, the inclusion of Project did not result in any identified power flow system impacts under base case or outage conditions.

4.3 Maximum Generation Coupled with Minimum Anytime Load Conditions

Under maximum generation coupled with minimum anytime load conditions, the inclusion of the Project did not result in any identified power flow system impacts under base case or outage conditions.

4.4 Maximum Energy Storage Coupled with Minimum Generation Dispatch

The storage facility charging study was performed using the load assumptions discussed above in Table 3.3. Study results for each applicable time-block are provided below.

4.4.1 Contingency: Time Block L3 (2 AM – 6 AM)

The study did not identify any issues under this time block period.

4.4.2 Contingency: Time Block L4 (8 AM – 12 PM)

With the inclusion of the Project, the study identified overloads on the Santiago A-Banks, a portion of the Santiago-Estrella-Las Lomas 66 kV line, and Santiago-Irvine No. 2 66 kV line during this time block as summarized in Table 4.4.2 below.

Table 4.4.2
Overloads for L4

[redacted]

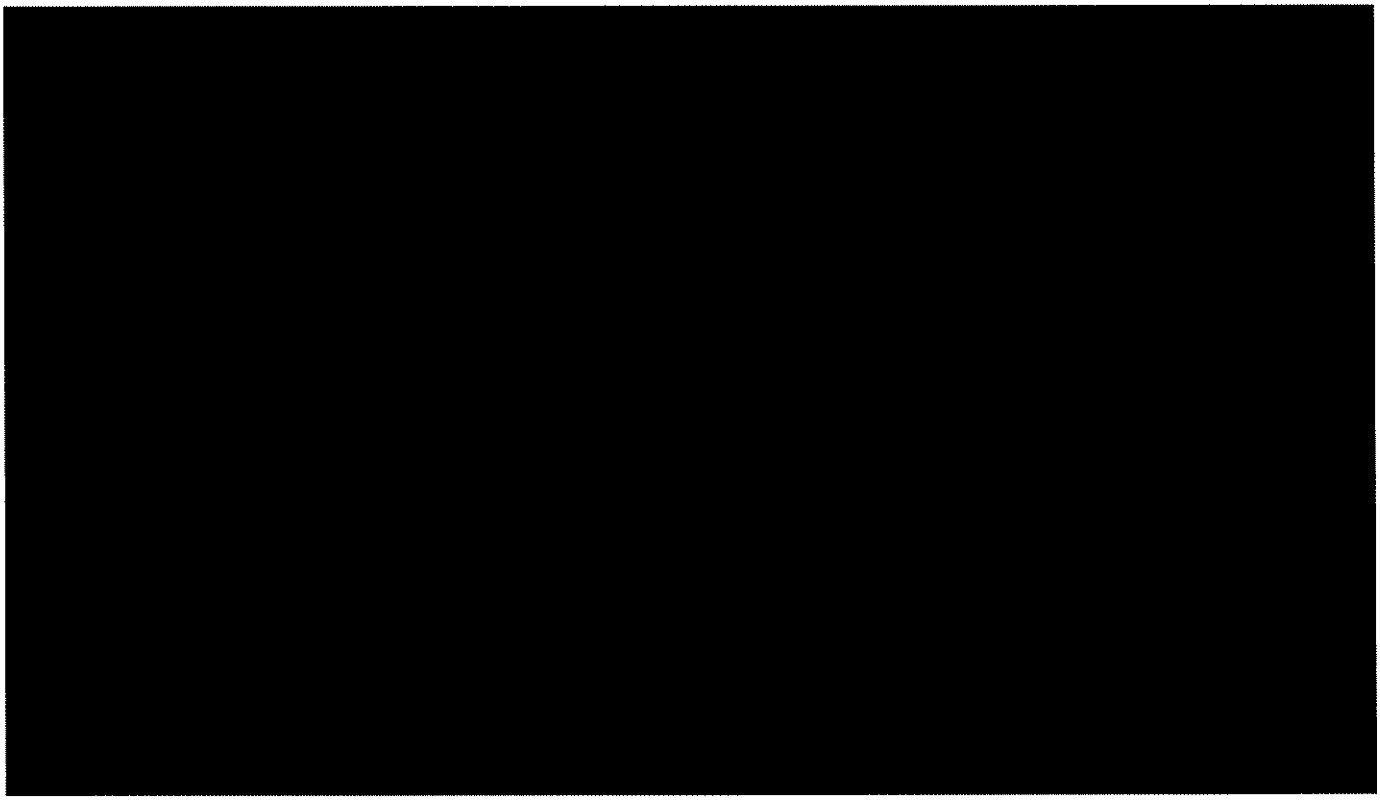
Note 1: Please note that an SCE mitigation project has been identified to replace CBs at Irvine 66 kV and Santiago 66 kV to increase emergency rating to [redacted] Planned for an in-service date of 2021, which will eliminate this N-1 overload.

Note 2: An SCE mitigation project has been identified to replace CBs at Irvine 66 kV, Las Lomas 66 kV and Santiago 66 kV to increase the emergency rating to [redacted] Planned for an in-service date of 2017 for Las Lomas 66 kV, and Irvine 66 kV and Santiago 66 kV for 2021, which will lessen the severity of the N-2 overloads.

4.4.3 Contingency: Time Block L5 (2 PM – 6 PM)

With the inclusion of the Project, the study identify overloads on the Santiago A A-Banks, a portion of the Santiago-Estrella-Las Lomas 66 kV line, and Santiago-Irvine No. 2 66 kV line during this time block as summarized in Table 4.4.3 below.

Table 4.4.3
Overloads for L5



Note 1: Please note that an SCE mitigation project has been identified to replace CBs at Irvine 66 kV and Santiago 66 kV to increase emergency rating to [redacted] Planned for an in-service date of 2021, which will eliminate this N-1 overload.

Note 2: An SCE mitigation project has been identified to replace CBs at Irvine 66 kV, Las Lomas 66 kV and Santiago 66 kV to increase the emergency rating to [redacted] Planned for an in-service date of 2017 for Las Lomas 66 kV, and Irvine 66 kV and Santiago 66 kV for 2021, which will lessen the severity of the N-2 overloads.

4.4.4 Contingency: Time Block L6 (8 PM – 12 AM)

With the inclusion of the Project, the study identify overloads on the Santiago A A-Banks, a portion of the Santiago-Estrella-Las Lomas 66 kV line, and Santiago-Irvine No. 2 66 kV line during this time block as summarized in Table 4.4.4 below.

Table 4.4.4
Overloads for L6

[redacted]

Note 1: Please note that an SCE mitigation project has been identified to replace CBs at Irvine 66 kV and Santiago 66 kV to increase emergency rating to [redacted] Planned for an in-service date of 2021, which will eliminate this N-1 overload.

4.5 Subtransmission Assessment Power Flow Mitigations

4.5.1. Maximum Generation

Based on the study results obtained under maximum generation dispatch conditions, no mitigation is required to accommodate the Project under discharge operation.

4.5.2. Maximum Energy Storage Coupled with Minimum Generation Dispatch

Based on the study results obtained under maximum energy storage "charging" coupled with minimum generation dispatch internal to the subtransmission system, the Santiago 66 kV Subtransmission System is inadequate to accommodate the Project without mitigation. The recommended mitigation involves the use of a storage management system which would limit or restrict charging based on loadings on the Santiago 220/66 kV transformer banks as well as loading on the Santiago-Estrella-Las Lomas 66 kV and Santiago-Irvine No. 2 66 kV lines. The details pertaining to cost allocation is provided in the Distribution Assessment.

4.6 Subtransmission System Energy Storage Restrictions

Based on the load forecast used in this study, current system configuration, and the amount of Energy Storage (MW) seeking interconnection as part of the ISP, the estimated restrictions and arming of the storage management system is illustrated below in Figure 4.6.1

Figure 4.6.1
Charging Restrictions and Arming of Storage Control System
Limitation: Santiago A-Banks

A summary of the hourly performance for each month assuming future load performance mimics historical load performance (same load shape pattern) is shown below in Figure 4.6.2. The performance takes into account the use of the storage management system and therefore summarizes the time periods where charging is expected to be restricted (cells highlighted in red with the number of hours where restriction is expected shown in the cell).

Figure 4.6.2
Monthly Time of Day Performance Expectations
Charging Restrictions and Arming of Storage Control System

These values are specific to restrictions associated with loadings on the Santiago A-Banks. Additional restrictions not identified in this study may exist for projects which are seeking interconnection to low-voltage distribution (12 kV) served out of the Santiago 66 kV Subtransmission System. Capacity issues on the 12 kV distribution feeders and/or the 66/12 kV transformer bank (B-Bank) may further restrict these projects. Results of the low-voltage distribution performance for projects seeking interconnection to low-voltage distribution are provided in the FE Report.

It is important to note that incremental or new charging restrictions beyond those identified in the study may occur in the future under the following conditions, but not limited to:

- Incremental load growth beyond forecasts
- Decrease in amount of internal generation in the area assumed to be available
- Additional energy storage interconnection requests beyond this ISP
- Limitations on CAISO network corresponding to operating conditions that involve loss of multiple elements
- Maintenance and/or unplanned outage conditions

Should incremental or new charging restrictions arise in the future, a storage management system will be implemented at such time that the need arises to ensure system reliability is maintained. Consequently, the Project may be required to participate in future restrictions.

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.

6. Short-Circuit Duty Assessment Results

Meaningful contributions to short-circuit duty were identified to be limited to the Subtransmission System. Consequently, the Projects did not impact the Bulk Electric System.

6.1 Application Queue

6.1.1. Subtransmission Level (66 kV)

Short Circuit Duty assessment have been performed as part of End of Queue Generation study. No impacts were identified to the Santiago 66 kV Subtransmission system that would necessitate mitigation.

6.1.2. Distribution Level (less than 66 kV)

Short-circuit duty results for distribution level less than 66 kV are provided in the FE Report.

6.2 Ground Grid Evaluation

The study did not identify any substation in the Santiago 66 kV Subtransmission System where the single line to ground short-circuit duty contribution from the Project increased duty in excess of 0.25 kA. Therefore, no further ground grid evaluation for substations served out of the Santiago 66 kV Subtransmission System is required.

7. Conclusion

Based on the study results, the inclusion of the Project did not trigger new impacts requiring mitigation beyond those that are already existing as mentioned in Section 4.5.2. Consequently, the Project can proceed to interconnection without any new subtransmission level upgrades.

ATTACHMENT C

Distribution Charging Assessment

ATTACHMENT C

Southern California Edison Company

[redacted]

WDT1382

Distribution Charging Assessment

Table of Contents

1. Purpose

The Project encompasses energy storage equipment that required additional analysis to be performed in order to evaluate the impacts of the charging facility within SCE's Distribution System. These analyses focused on the charging[1] aspects of the charging facilities and consider varying levels of system demand with minimal generation dispatch within the local Distribution System.

Consequently, the report also discloses the adequacy of SCE's Distribution System to support the charging aspects of the charging facilities, identifies system limitations that may restrict the charging facility's ability to charge during certain demand conditions, and provides a high-level explanation of potential exposure to charging restrictions on the Distribution System in addition to identifying Distribution System improvements, which would mitigate such restrictions to charging.

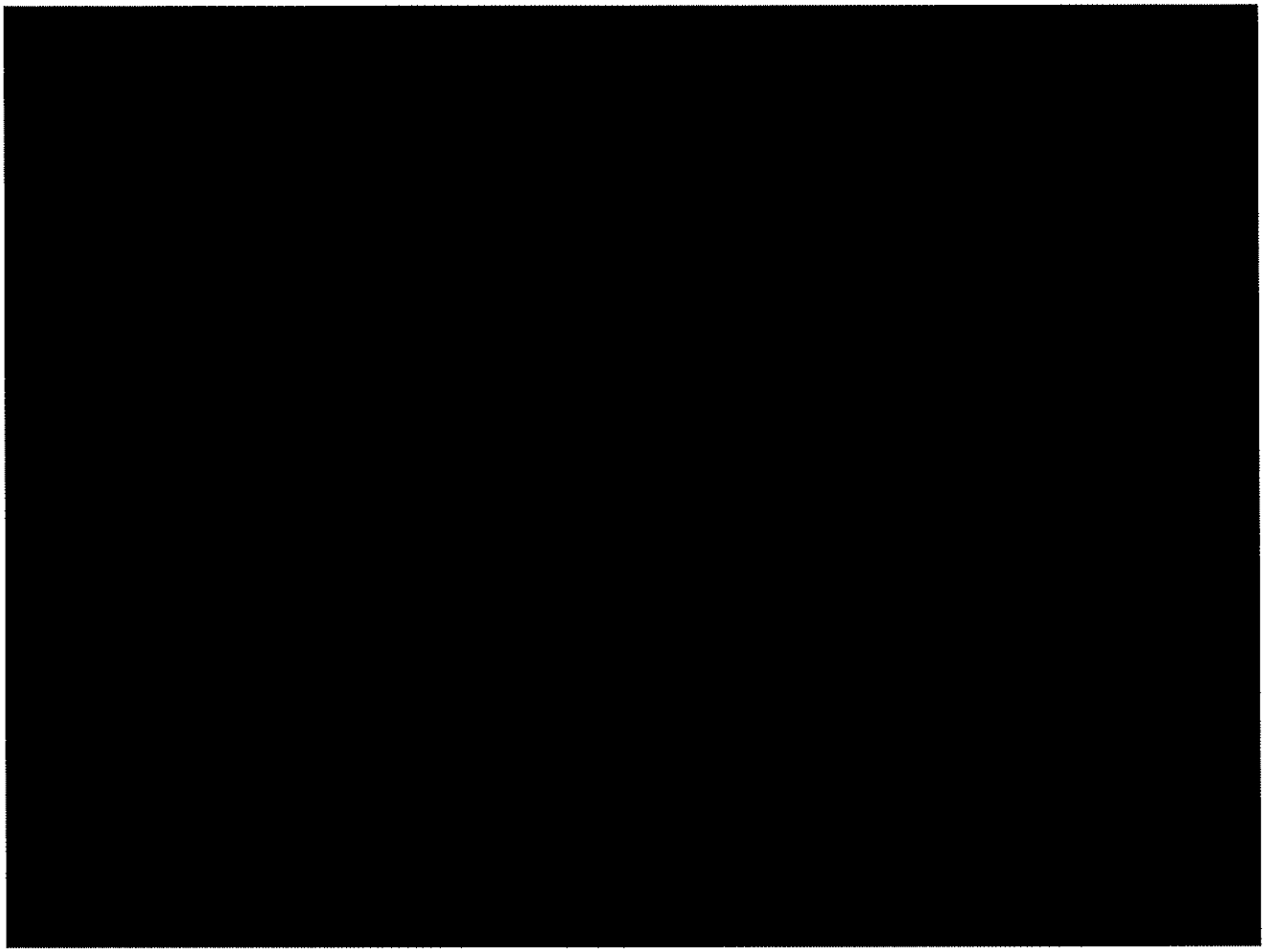
Please note that operational flexibility to charge at any time may not be attainable even with substation and Distribution System Upgrades due to limitations that may exist further upstream on SCE's Subtransmission and/or Transmission systems[2]. Furthermore, the results included as part of this attachment utilize historical data to make a projection of possible charging profiles. As is typically the case with utilizing historical data to make projections, past performance is not guaranteed to be an indicator of future performance. For example, this can be the case due to changes in system topology on the Distribution System, which can occur more frequently than on the Transmission System or due to load increase in the Distribution System.

Note: details related to the generation aspect for the Project are provided in the Interconnection System Impact Study Report.

---

[1] Charging is defined as when the Project draws energy from the grid to "charge" the Project-associated charging facilities.

[2] Please see Figure 2-1 explaining the varying levels of electrical topology of the electric system that can result in restrictions



2. Study Assumptions

2.1 Planning Criteria

For detailed assumptions regarding the subtransmission level, please refer to the applicable Subtransmission Assessment Report (Attachment B). Below are the assumptions specific to the Project.

2.1.1 The Plan of Service (POS) is defined as the facilities needed to interconnect the Project to SCE's Distribution System. The following is the POS assumed for the Project in the Interconnection System Impact Study:

The Project was modeled as interconnecting 3.0 MW of Energy storage through the [redacted] out of Estrella 66/12 kV Substation bus.

NOTES:

- ❖ The metering potential and current transformers installed for the ISO metering will also be used for SCE owned retail and wholesale load meters if requested by the Interconnection Customer.

2.1.2 The following facilities will be installed by the Interconnection Customer and are not included in this Interconnection System Impact Study report:

- Ducts as required
- Structures as required
- 12 kV primary switchgear
- Isolating circuit breaker
- Protection System requirements to comply with SCE's Interconnection Handbook
- Transformation as required
- Metering Equipment compliant with SCE's Electrical Service Requirements
- The required ISO metering equipment (potential and current transformers and ISO meters) and metering cabinet for SCE retail and wholesale load meters.

2.1.3 SCE's System Topology

The typological structure of SCE's transmission lines, substations, and subtransmission lines is depicted below to provide an overview of SCE's Transmission and Distribution Systems pursuant to this study.

3. System Assumptions

3.1 Charging Analysis Planning Criteria

This study was conducted by applying SCE's Distribution Planning Criteria. More specifically, the key criteria applicable to this Interconnection System Impact Study are as follows:

- The thermal rating of any conductor, connector, or apparatus shall not exceed 100% of its normal rated capacity[3] with all facilities in service (N-0 or base case).

[3] Normal rated capacity or Planned Loading Limit (PLL) capacity is determined by the lesser of the limiting component on the Distribution System or 75% of minimum trip of the upstream protection device.

- The thermal rating of any conductor, connector, or apparatus shall not exceed 100% of its emergency rated capacity under loss of one element (N-1) conditions.

- The thermal rating of any B-Bank shall not exceed 100% of its nameplate rated capacity with all facilities in service (N-0 or base case).

- The thermal rating of any B-Bank shall not exceed 100% of its nameplate rating capacity under loss of one element (N-1) or emergency conditions.

- Operational flexibility, safety, and reliability of the Distribution System shall be maintained at all times.

- Circuit voltage profiles shall be maintained to comply with SCE's CPUC Jurisdictional Rule 2 tariff requirements. The Interconnection Customer will be responsible for maintaining designated voltage levels under all conditions, including but not limited to the conditions identified above.

- The power factor for the energy storage system facility is assumed to be within WDAT Tariff requirements of 0.95 lagging or leading.

- Expected loading on the Distribution System as projected by SCE's internal 2016-2026 Distribution System forecast is utilized for the purposes of this charging analysis.

- Charging facilities connected to the Distribution System are analyzed offline (pre-Project) and online (post-Project) during peak demand conditions, as well as during absolute minimum demand conditions, as to determine the worst case scenario between these two "book-ends" of demand.

The following SCE Distribution System Planning Criteria and Conditions were included in the Interconnection System Impact Study:

- Distributed generation resources connected to the Distribution System are analyzed offline and online during peak load conditions as well as during minimum daytime load conditions as to determine the worst case scenario.

- The short circuit duty contribution from the inverter systems was determined using inverter manufacturer documents.

- The Interconnection System Impact Study assumes the upgrades triggered by queued ahead projects, including Rule 21 projects under CPUC jurisdiction as In-Service, are included in the base case for the Interconnection System Impact Study projects. If any queued ahead projects were to withdraw, then the Interconnection

System Impact Study projects may be subjected to the cost identified for those queued ahead projects.

- Current distribution design standards are being updated to address generation interconnection systems. The proposed POS in this report may change according to detailed design in order to comply with the updated Distribution design standards.

The use of "charging" restrictions (or curtailment of energy storage facilities), in lieu of physical upgrades, are considered as a viable alternative for this charging study. Any restrictions identified here are purely projections, and the storage management system mentioned above will need to be installed as an upgrade to determine the Resource Dispatch Limit (RDLs) for the facility.

3.2 Load Assumptions

The load assumptions used for SCE's Distribution System considers SCE's 2016-2026 Distribution Load Forecast and the previous two (2) years of historical data.

To model the hourly forecast demand performance of SCE's Distribution System, historical year 2015-2016 B-Bank and circuit data were obtained and adjusted to reflect the worst case year within SCE's Distribution Load forecast. The use of historical data established a baseline upon which to build a comparable hourly demand performance for the worst case year in SCE's Distribution Load Forecast.

Note: The Interconnection Customer should note that due to the dynamic nature of SCE's Distribution System, the operational limitations yielded by the charging analysis results disclosed in this report are for informational purposes only. Furthermore, the charging analysis used historical system performance information, which can only speak to past system performance. Hence, the charging analysis results cannot establish hard conditions for future real time operational conditions in which the Project's charging are restricted.

Figure 3-1
Estrella 66/12 kV Substation
B-Bank Hourly Demand Performance

Figure 3-2
Horoscope 12 kV Circuit
Hourly Demand Performance

3.3 Generation Dispatch Assumptions

Generation dispatch of resources (existing and queued) connected to SCE's Distribution System is done in a manner that provides for stressed conditions on the system. This effectively results in not dispatching Distribution System resources in a manner that would inject power into the local Distribution System, but rather dispatching resources in a manner that would extract power out of the system (i.e. charging of storage facilities).

4. Charging Study Results

The storage facility charging study was performed using the assumptions discussed above. Study results are provided below:

4.1 Thermal Overloads

The distribution level study indicated that the Project contributes to the following facility overloads or non-convergence problems. The details of the analysis and overload levels are provided in the area study.

- Category "P0" (All facilities in service, N-0)
  - Estrella 66/12 kV Substation
    - The addition of the Project resulted in a no thermal overload of the duct banks inside the substation.
  - [redacted]
    - The addition of the Project resulted in a no thermal overload of the duct bank on the [redacted]
- Category "P1"" (loss of a single element, N-1)
  - Estrella 66/12 kV
    - None
  - [redacted]
    - None
- Note: Under emergency N-1 conditions (loss of a B-Bank, or loss of the [redacted], no thermal overloads were triggered by the Project. However, due to the dynamic Distribution System conditions and configurations, SCE may deem it necessary to open the source Remote Control Switch Generation (RCSG) to remove the Project from SCE's Distribution System, in order to reduce bank loading or line loading to its normal ratings. Once SCE's system is restored to

normal, SCE would then close the RCSG and the generation system can resume normal operation.

4.2 Power Flow Non-Convergence

There were no non-convergence issues identified with the inclusion of the Project due to the limited system capacity.

4.3 Voltage Performance

- The [redacted] out of Estrella 66/12 kV Substation is not expected to experience a voltage rise that exceeds Rule 2 requirements with the Project in service.
- Individual Project Power Factor Requirements

  The results of the study analyzed the effects of the Project running at unity power factor. The Project will need to be designed to maintain a composite power delivery at continuous rated power at the Point of Change of Ownership (POCO) at a power factor within the range of 0.95 leading and 0.95 lagging. 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 system.

4.4 Protection

- Estrella 66/12 kV Substation:
  - No additional protection requirements are triggered by the charging aspect of the Project.
- [redacted]
  - No additional protection requirements are triggered by the charging aspect of the Project.

5. Mitigations

5.1 Distribution Upgrades

A Storage management system (SMS) will be required to restrict the project from charging, as described in the tables shown below.

5.1.1 Storage Management System[4]

[4] The Storage Management System is purely conceptual at this time. At minimum, the Storage Management System may require participation in SCE's Netcom System, and the following equipment, RFIs, packet radio, and a remote telemetry unit, which will be used to transmit the various data points to each participating Interconnection Customer. The preliminary cost estimate for the Storage Management System is approximately $600,000, excluding ITCC.

The Storage Management System (SMS) provides monitoring of system loading conditions from both monitored data of SCE's facilities and Interconnection Customer's facilities. The SMS will calculate the available charging capacity limits and will transmit the limits to the Interconnection Customer. It will be required that the customer's control system follows the provided limits. If the Interconnection Customer's control system does not comply with this requirement, SCE will mitigate this condition at its discretion including, but not limited to disconnecting the Interconnection Customer's storage system from the grid.

Refer to Sections IV and V of the Interconnection System Impact Study Report for scope description and associated Project cost responsibility of these Distribution Upgrade(s).

Please note that operational flexibility to charge at any time may not be attainable even with substation and Distribution System Upgrades due to limitations that may exist further upstream on SCE's Transmission Systems. Furthermore, the results included utilize historical data to make a projection of possible charging profiles. As is typically the case with utilizing historical data to make projections, past performance is not guaranteed to be an indicator of future performance. For example, this can be the case due to changes in system topology on the Distribution System, which can occur more frequently than on the Transmission System.

In the event of an N-1 condition (loss of a B-Bank), SCE would send a signal through the Storage management system that will require the charging facility either stop charging or limit their amount of charging depending on system configurations.

A. Estrella 66/12 kV Substation

- Service and test storage management system.

B. Power Systems Control

- Create Storage management system program in Energy Management System (EMS) to support charging aspect of energy storage project.

C. Telecommunications

Install packet radio.

D. Corporate Environmental Health and Safety

Obtain licensing, permits, land rights and perform all required environmental activities for the installation of the telecommunication requirements.

5.2 Required Charging Restrictions

The study results have identified no base case thermal overload problems on the Estrella 66/12 kV B-Banks. Specifically, the studies have identified no base case and emergency (N-1) overload problems during energy storage system charging.

5.2.1 Charging Restriction Categories

- Category "P0" (All facilities in service, N-0)

  Based on the assessment results, there were charging restrictions identified for the Project. Adjustments to the charging restrictions may also become necessary for the Project in the future. Assuming adjusted 2015-2016 historical demand patterns adequately represent worst case year within SCE's Distribution Load forecast performance, the evaluation identified the need to restrict charging during portions of the day, month, and year. The need to restrict charging will increase over time as normal system demand continues to grow. See tables below for projected charging forecast.

- Category "P1"" (loss of a single element, N-1)

  - Estrella 66/12 kV Substation:

    At this time, the available capacity at the substation allows the Project to charge with restrictions.

  - [redacted]

    At this time, the available capacity at the circuit requires the Project to charge with restrictions.

Note: Under emergency conditions, [redacted] will be de-energized resulting in disconnection of the Project. Additionally, due to the dynamic Distribution System conditions and configurations, SCE may deem it necessary to disconnect the Project under N-1 conditions on other distribution circuits (if abnormal) until the Distribution System returns to normal conditions.

5.2.2 Restrictions to Charging Operations

It is important to note that the increased risk of restrictions is not only based on load forecast, load growth, and demand performance assumptions but are also based on the feasibility of implementing real-time system information and ability to use the Storage management system as means of maximizing the loading limit that can be accommodated. The Storage management system would limit amount of charging to stay within the limits of SCE's equipment ratings.

The assessment includes an hourly evaluation. Utilizing the adjusted hourly demand performance shown above in Figure 3-1, the estimated number of hours the charging facility is restricted to charge at a given demand value in a given month are shown below. This is subject to change as loading on the system changes. Note that charging restrictions illustrated in the tables below are for the respective areas within the Distribution System (i.e. distribution substation or distribution circuit). However, it should not be misinterpreted that the Project is not restricted for a specific time or for a certain number of hours only based on these tables alone. The Project's charging restrictions will be based on the most restrictive conditions and real time information from the distribution circuit to the transmission system.

Table 5-1
Estrella 66/12 kV Substation
#Number of Charging Hours Restricted for Energy Storage System

Table 5-2
Estrella 66/12 kV Substation
Charging Hour Restrictions of Day for Energy Storage System

Table 5-3
Horoscope 12 kV Circuit

#Number of Charging Hours Restricted for Energy Storage System

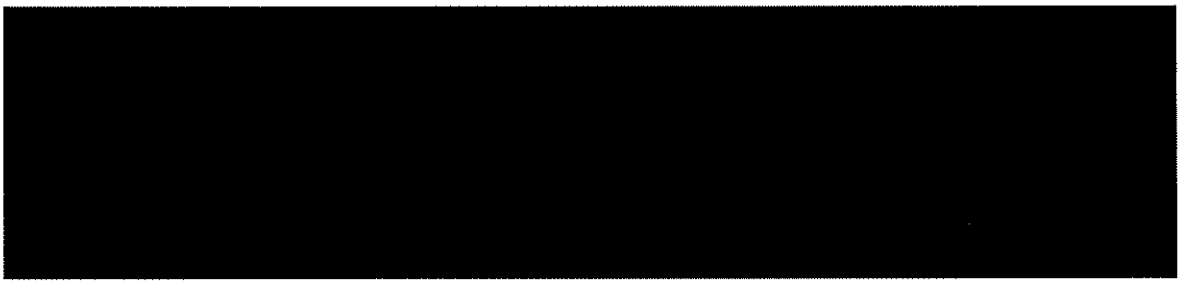


Chart reflects MW evaluation as follow: (0) 0MW-1MW; (1) 1MW-2MW; (2) 2MW-3MW, (3) 3MW-4MW

Table 5-4
Horoscope 12 kV Circuit
Charging Hour Restrictions of Day for Energy Storage System

5.3 Outage Conditions

5.3.1 Restrictions to Charging Operations

Without any physical upgrades implemented to address outage related overloads, charging restrictions in anticipation of an outage may be necessary. As discussed in Section 5.1.1, the inclusion of the Project seeking interconnection into the Distribution System may result in charging restrictions that are forecast in the future.

5.3.2 Distribution Upgrades

A. Loss of One Estrella B-Bank without the Installation of Additional B-Bank(s)

As discussed above, the use of a Storage management system would enable greater loading of the existing B-Banks thereby maximizing the use of available capacity under base case conditions. The Storage management system would also address future potential outage related problems that may be identified under the loss of a single B-Bank when such outage actually happens. A description of the facilities needed to implement the storage management system is provided in section 5.1 of this report.

6. Caveats

1. Adding charging restrictions may occur in the future under future base case overloads.
2. Additional limitations may be driven by the ISO market and Distribution System operations.
3. Please note that SCE has made its best efforts to convey as much information possible based on information provided by the Interconnection Customer about its proposed Project. The information contained herein may indicate to Interconnection Customers 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 Point of Interconnection or downsize is purely at the Interconnection Customer's discretion and would be subject to a SCE material modification review pursuant to the tariff.