California ISO

California Independent
System Operator

2022
LOCAL CAPACITY TECHNICAL ANALYSIS

DRAFT REPORT
AND STUDY RESULTS

April 10, 2017

Local Capacity Technical Analysis
Overview and Study Results

I. Executive Summary

This report documents the results of the 2022 Long-Term Local Capacity Technical (LCT) Study. The LCT Study objectives, inputs, methodologies and assumptions are the same as those discussed in the 2018 LCT Study to be adopted by the CAISO and submitted to the CPUC for adoption in their 2018 Local Resource Adequacy process.

Overall, the LCR trend compared with 2021, is up by about 800 MW mainly due to most limiting contingency in Fresno area for S-N flow on Path 15 compared with the under-reported value in the 2021 study. It is worth mentioning the following areas: (1) Humboldt, North Coast/North Bay and LA Basin where LCR has decreased mostly due to load forecast; (2) Sierra where LCR has increased mostly due to corrected LCR needs in the South of Table Mountain sub-area compared with the under-reported 2017 values; (3) Stockton where LCR has increased mostly due to delay in transmission project implementation; (4) Greater Bay Area, Kern, Big Creek/Ventura and San Diego where LCR has increased due to load forecast increase; (5) Fresno, where the LCR has increased significantly due to the new limiting contingency found for Path 15 S-N flow.

The load forecast used in this study is based on the final adopted California Energy Demand Updated Forecast, 2017-2027 developed by the CEC; namely the mid-demand baseline with low-mid additional achievable energy efficiency (AAEE), re-posted on 2/27/2017: http://www.energy.ca.gov/2016_energypolicy/documents/2016-12-08_workshop/LSE-BA_Forecasts.php.

For comparison below you will find the 2018 and 2022 total LCR needs.

2018 Local Capacity Needs

	Qualifying Capacity			2018 LCR Need Based on Category B			2018 LCR Need Based on Category C with operating procedure		
Local Area Name	**QF/ Muni (MW)**	**Market (MW)**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**Existing Capacity Needed****	**Deficiency**	**Total (MW)**
Humboldt	14	196	210	121	0	**121**	169	0	**169**
North Coast/ North Bay	118	751	869	634	0	**634**	634	0	**634**
Sierra	1176	949	2125	1215	0	**1215**	1826	287*	**2113**
Stockton	139	466	605	358	0	**358**	398	321*	**719**
Greater Bay	1008	6095	7103	3910	0	**3910**	5160	0	**5160**
Greater Fresno	364	3215	3579	1949	0	**1949**	2081	0	**2081**
Kern	15	551	566	0	0	**0**	453	0	**453**
LA Basin	1556	9179	10735	6873	0	**6873**	7525	0	**7525**
Big Creek/Ventura	430	5227	5657	2023	0	**2023**	2321	0	**2321**
San Diego/ Imperial Valley	202	4751	4953	4032	0	**4032**	4032	0	**4032**
Total	5052	31350	36402	21115	0	**21115**	24599	608	**25207**

2022 Local Capacity Needs

	Qualifying Capacity			2022 LCR Need Based on Category B			2022 LCR Need Based on Category C with operating procedure		
Local Area Name	**QF/ Muni (MW)**	**Market (MW)**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**Existing Capacity Needed****	**Deficiency**	**Total (MW)**
Humboldt	14	196	210	121	0	**121**	169	0	**169**
North Coast/ North Bay	118	751	869	209	0	**209**	440	0	**440**
Sierra	1176	890	2066	836	0	**836**	1905	62*	**1967**
Stockton	139	466	605	355	0	**355**	406	296*	**702**
Greater Bay	1008	5871	6879	4257	0	**4257**	5153	162*	**5315**
Greater Fresno	231	3295	3526	1479	0	**1479**	1860	0	**1860**
Kern	15	551	566	0	0	**0**	123	0	**123**
LA Basin	1556	6582	8138	5957	0	**5957**	6022	0	**6022**
Big Creek/Ventura	430	3430	3859	2208	0	**2208**	2597	0	**2597**
San Diego/ Imperial Valley	217	4393	4610	4610	33	**4643**	4610	33	**4643**
Total	4904	26425	31328	20032	33	**20065**	23285	553	**23838**

* No local area is “overall deficient”. Resource deficiency values result from a few deficient sub-areas; and since there are no resources that can mitigate this deficiency the numbers are carried forward into the total area needs. Resource deficient sub-area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.
** Since “deficiency” cannot be mitigated by any available resource, the “Existing Capacity Needed” will be split among LSEs on a load share ratio during the assignment of local area resource responsibility.

The write-up for each Local Capacity Area lists important new projects included in the base cases as well as a description of reason for changes between the 2021 Long-Term LCR study and this 2022 Long-Term LCR study.

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II. Overview of the Study: Inputs, Outputs and Options

A. Objectives

As was the objective of all previous LCT Studies, the intent of the 2022 Long-Term LCT Study is to identify specific areas within the CAISO Balancing Authority Area that have limited import capability and determine the minimum generation capacity (MW) necessary to mitigate the local reliability problems in those areas.

B. Key Study Assumptions

Inputs and Methodology

The CAISO used the same Inputs and Methodology as does agreed upon by interested parties previously incorporated into the 2018 LCR Study. The following table sets forth a summary of the approved inputs and methodology that have been used in the previous 2018 LCR Study as well as this 2022 LCR Study:

Summary Table of Inputs and Methodology Used in this LCR Study:

Issue:	How Incorporated into THIS LCR Study:
Input Assumptions:	
• Transmission System Configuration	The existing transmission system has been modeled, including all projects operational on or before June 1, of the study year and all other feasible operational solutions brought forth by the PTOs and as agreed to by the CAISO.
• Generation Modeled	The existing generation resources has been modeled and also includes all projects that will be on-line and commercial on or before June 1, of the study year
• Load Forecast	Uses a 1-in-10 year summer peak load forecast
Methodology:	
• Maximize Import Capability	Import capability into the load pocket has been maximized, thus minimizing the generation required in the load pocket to meet applicable reliability requirements.
• QF/Nuclear/State/Federal Units	Regulatory Must-take and similarly situated units like QF/Nuclear/State/Federal resources have been modeled on-line at qualifying capacity output values for purposes of this LCR Study.
• Maintaining Path Flows	Path flows have been maintained below all established path ratings into the load pockets, including the 500 kV. For clarification, given the existing transmission system configuration, the only 500 kV path that flows directly into a load pocket and will, therefore, be considered in this LCR Study is the South of Lugo transfer path flowing into the LA Basin.
Performance Criteria:	
• Performance Level B & C, including incorporation of PTO operational solutions	This LCR Study is being published based on Performance Level B and Performance Level C criterion, yielding the low and high range LCR scenarios. In addition, the CAISO will incorporate all new projects and other feasible and CAISO-approved operational solutions brought forth by the PTOs that can be operational on or before June 1, of the study year. Any such solutions that can reduce the need for procurement to meet the Performance Level C criteria will be incorporated into the LCR Study.
Load Pocket:	
• Fixed Boundary, including limited reference to published effectiveness factors	This LCR Study has been produced based on load pockets defined by a fixed boundary. The CAISO only publishes effectiveness factors where they are useful in facilitating procurement where excess capacity exists within a load pocket.

Further details regarding the 2018 as well as 2022 LCR Study methodology and assumptions are provided in Section III, below.

C. Grid Reliability

Service reliability builds from grid reliability because grid reliability is reflected in the Reliability Standards of the North American Electric Reliability Council (NERC) and the Western Electricity Coordinating Council ("WECC") Regional Criteria (collectively "Reliability Standards"). The Reliability Standards apply to the interconnected electric system in the United States and are intended to address the reality that within an integrated network, whatever one Balancing Authority Area does can affect the reliability of other Balancing Authority Areas. Consistent with the mandatory nature of the Reliability Standards, the CAISO is under a statutory obligation to ensure efficient use and reliable operation of the transmission grid consistent with achievement of the Reliability Standards.[1] The CAISO is further under an obligation, pursuant to its FERC-approved Transmission Control Agreement, to secure compliance with all "Applicable Reliability Criteria." Applicable Reliability Criteria consists of the Reliability Standards as well as reliability criteria adopted by the CAISO (Grid Planning Standards).

The Reliability Standards define reliability on interconnected electric systems using the terms "adequacy" and "security." "Adequacy" is the ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account physical characteristics of the transmission system such as transmission ratings and scheduled and reasonably expected unscheduled outages of system elements. "Security" is the ability of the electric systems to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements. The Reliability Standards are organized by Performance Categories. Certain categories require that the grid operator not only ensure that grid integrity is maintained under certain adverse system conditions (e.g., security), but also that all customers continue to receive electric supply to meet demand (e.g., adequacy). In that case, grid reliability and service reliability would overlap. But there are other levels of performance where security can be maintained without ensuring adequacy.

[1] Pub. Utilities Code § 345

D. Application of N-1, N-1-1, and N-2 Criteria

The CAISO will maintain the system in a safe operating mode at all times. This obligation translates into respecting the Reliability Criteria at all times, for example during normal operating conditions (N-0) the CAISO must protect for all single contingencies (N-1) and common mode (N-2) double line outages. Also, after a single contingency, the CAISO must re-adjust the system to support the loss of the next most stringent contingency. This is referred to as the N-1-1 condition.

The N-1-1 vs N-2 terminology was introduced only as a temporal differentiation between two existing NERC Category C events. N-1-1 represents NERC Category C3 ("category B contingency, manual system adjustment, followed by another category B contingency"). The N-2 represents NERC Category C5 ("any two circuits of a multiple circuit tower line") as well as WECC-S2 (for 500 kV only) ("any two circuits in the same right-of-way") with no manual system adjustment between the two contingencies.

E. Performance Criteria

As set forth on the Summary Table of Inputs and Methodology, this LCR Report is based on NERC Performance Level B and Performance Level C criterion. The NERC Standards refer mainly to thermal overloads. However, the CAISO also tests the electric system in regards to the dynamic and reactive margin compliance with the existing WECC standards for the same NERC performance levels. These Performance Levels can be described as follows:

a. <u>Performance Criteria- Category B</u>

Category B describes the system performance that is expected immediately following the loss of a single transmission element, such as a transmission circuit, a generator, or a transformer.

Category B system performance requires that all thermal and voltage limits must be within their "Applicable Rating," which, in this case, are the emergency ratings as generally determined by the PTO or facility owner. Applicable Rating includes a temporal element such that emergency ratings can only be maintained for certain duration. Under this category, load cannot be shed in order to assure the Applicable Ratings are met however there is no guarantee that facilities are returned to within normal ratings or to a state where it is safe to continue to operate the system in a reliable manner such that the next element out will not cause a violation of the Applicable Ratings.

b. <u>Performance Criteria- Category C</u>

The NERC Planning Standards require system operators to "look forward" to make sure they safely prepare for the "next" N-1 following the loss of the "first" N-1 (stay within Applicable Ratings after the "next" N-1). This is commonly referred to as N-1-1. Because it is assumed that some time exists between the "first" and "next" element losses, operating personnel may make any reasonable and feasible adjustments to the system to prepare for the loss of the second element, including, operating procedures, dispatching generation, moving load from one substation to another to reduce equipment loading, dispatching operating personnel to specific station locations to manually adjust load from the substation site, or installing a "Special Protection Scheme" that would remove pre-identified load from service upon the loss of the "next " element.[2] All Category C requirements in this report refer to situations when in real time (N-0) or after the first contingency (N-1) the system requires additional readjustment in

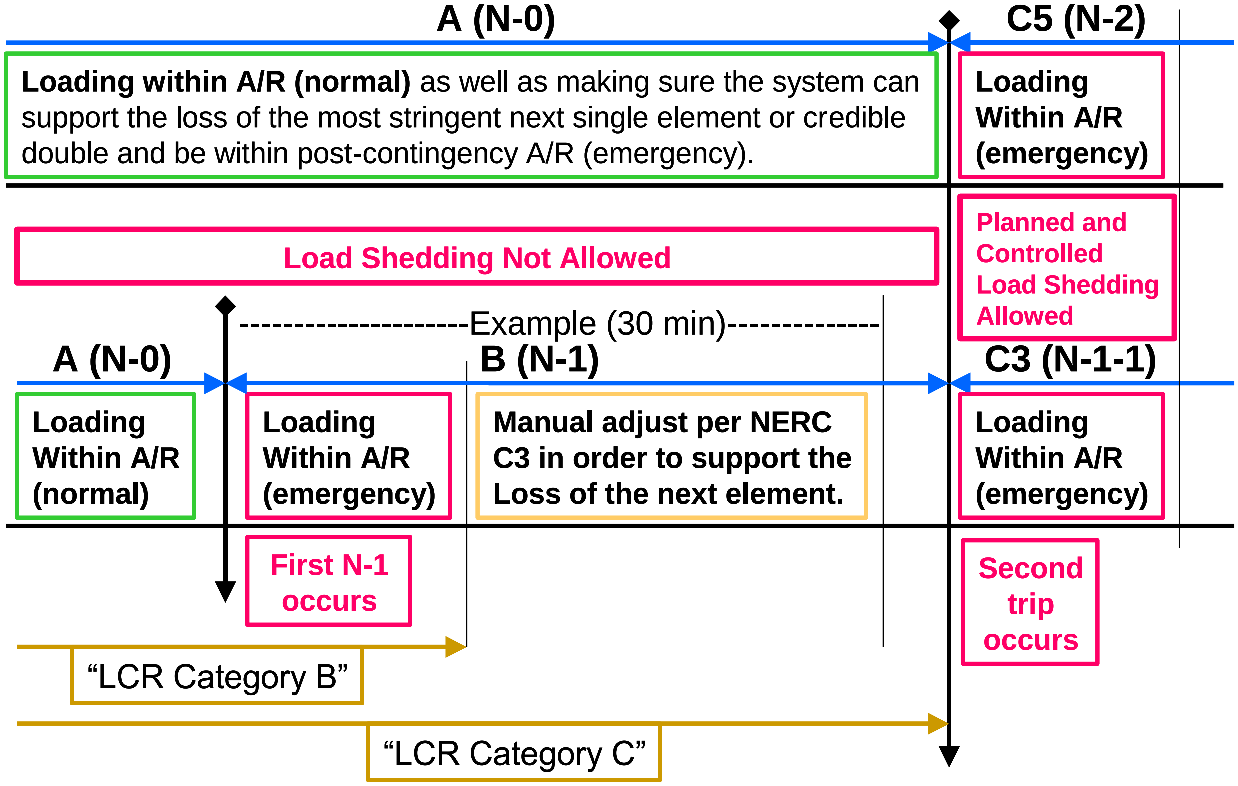
[2] A Special Protection Scheme is typically proposed as an operational solution that does not require additional generation and permits operators to effectively prepare for the next event as well as ensure security should the next event occur. However, these systems have their own risks, which limit the extent to which they could be deployed as a solution for grid reliability augmentation. While they provide the value of protecting against the next event without the need for pre-contingency load shedding, they add points of potential failure to the transmission network. This increases the potential for load interruptions because sometimes these systems will operate when not required and other times they will not operate when needed.

order to prepare for the next worst contingency. In this time frame, load drop is not allowed per existing planning criteria.

Generally, Category C describes system performance that is expected following the loss of two or more system elements. This loss of two elements is generally expected to happen simultaneously, referred to as N-2. It should be noted that once the "next" element is lost after the first contingency, as discussed above under the Performance Criteria B, N-1-1 scenario, the event is effectively a Category C. As noted above, depending on system design and expected system impacts, the **planned and controlled** interruption of supply to customers (load shedding), the removal from service of certain generators and curtailment of exports may be utilized to maintain grid "security."

c. CAISO Statutory Obligation Regarding Safe Operation

The CAISO will maintain the system in a safe operating mode at all times. This obligation translates into respecting the Reliability Criteria at all times, for example during normal operating conditions **A (N-0)** the CAISO must protect for all single contingencies **B (N-1)** and common mode **C5 (N-2)** double line outages. As a further example, after a single contingency the CAISO must readjust the system in order to be able to support the loss of the next most stringent contingency **C3 (N-1-1)**.



The following definitions guide the CAISO’s interpretation of the Reliability Criteria governing safe mode operation and are used in this LCT Study:

<u>Applicable Rating:</u>

This represents the equipment rating that will be used under certain contingency conditions.

<u>Normal rating</u> is to be used under normal conditions.

<u>Long-term emergency ratings</u>, if available, will be used in all emergency conditions as long as “system readjustment” is provided in the amount of time given (specific to each element) to reduce the flow to within the normal ratings. If not available normal rating is to be used.

<u>Short-term emergency ratings</u>, if available, can be used as long as “system readjustment” is provided in the “short-time” available in order to reduce the flow to within the long-term emergency ratings where the element can be kept for another

length of time (specific to each element) before the flow needs to be reduced the below the normal ratings. If not available long-term emergency rating should be used.
Temperature-adjusted ratings shall not be used because this is a year-ahead study not a real-time tool, as such the worst-case scenario must be covered. In case temperature-adjusted ratings are the only ratings available then the minimum rating (highest temperature) given the study conditions shall be used.
CAISO Transmission Register is the only official keeper of all existing ratings mentioned above.
Ratings for future projects provided by PTO and agree upon by the CAISO shall be used.
Other short-term ratings not included in the CAISO Transmission Register may be used as long as they are engineered, studied and enforced through clear operating procedures that can be followed by real-time operators.
Path Ratings need to be maintained within their limits in order to assure that proper capacity is available in order to operate the system in real-time in a safe operating zone.

Controlled load drop:

This is achieved with the use of a Special Protection Scheme.

Planned load drop:

This is achieved when the most limiting equipment has short-term emergency ratings AND the operators have an operating procedure that clearly describes the actions that need to be taken in order to shed load.

Special Protection Scheme:

All known SPS shall be assumed. New SPS must be verified and approved by the CAISO and must comply with the new SPS guideline described in the CAISO Planning Standards.

System Readjustment:

This represents the actions taken by operators in order to bring the system within a safe operating zone after any given contingency in the system.

Actions that can be taken as system readjustment after a single contingency (Category B):

1. System configuration change – based on validated and approved operating procedures
2. Generation re-dispatch
   a. Decrease generation (up to 1150 MW) – limit given by single contingency SPS as part of the CAISO Grid Planning standards (ISO G4)
   b. Increase generation – this generation will become part of the LCR need

Actions, which shall not be taken as system readjustment after a single contingency (Category B):

1. Load drop – based on the intent of the CAISO/WECC and NERC criteria for category B contingencies.

The NERC Transmission Planning Standards footnote mentions that load shedding can be done after a category B event in certain local areas in order to maintain compliance with performance criteria. However, the main body of the criteria spells out that no dropping of load should be done following a single contingency. All stakeholders and the CAISO agree that no involuntary interruption of load should be done immediately after a single contingency. Further, the CAISO and stakeholders now agree on the viability of dropping load as part of the system readjustment period – in order to protect for the next most limiting contingency. After a single contingency, it is understood that the system is in a Category B condition and the system should be planned based on the body of the criteria with no shedding of load regardless of whether it is done immediately or in 15-30 minute after the original contingency. Category C conditions only arrive after the second contingency has happened; at that point in time, shedding load is allowed in a planned and controlled manner.

A robust California transmission system should be, and under the LCT Study is being, planned based on the main body of the criteria, not the footnote regarding Category B contingencies. Therefore, if there are available resources in the area, they are looked to meet reliability needs (and included in the LCR requirement) before resorting to involuntary load curtailment. The footnote may be applied for criteria compliance issues only where there are no resources available in the area.

<u>Time allowed for manual readjustment:</u>

Tariff Section 40.3.1.1, requires the CAISO, in performing the Local Capacity Technical Study, to apply the following reliability criterion:

Time Allowed for Manual Adjustment: This is the amount of time required for the Operator to take all actions necessary to prepare the system for the next Contingency. The time should not be more than thirty (30) minutes.

The CAISO Planning Standards also impose this manual readjustment requirement. As a parameter of the Local Capacity Technical Study, the CAISO must assume that as the system operator the CAISO will have sufficient time to:

(1) make an informed assessment of system conditions after a contingency has occurred;

(2) identify available resources and make prudent decisions about the most effective system redispatch;

(3) manually readjust the system within safe operating limits after a first contingency to be prepared for the next contingency; and

(4) allow sufficient time for resources to ramp and respond according to the operator's redispatch instructions. This all must be accomplished within 30 minutes.

Local capacity resources can meet this requirement by either (1) responding with sufficient speed, allowing the operator the necessary time to assess and redispatch resources to effectively reposition the system within 30 minutes after the first contingency, or (2) have sufficient energy available for frequent dispatch on a pre-contingency basis to ensure the operator can meet minimum online commitment constraints or reposition the system within 30 minutes after the first contingency occurs.

Accordingly, when evaluating resources that satisfy the requirements of the CAISO Local Capacity Technical Study, the CAISO assumes that local capacity resources need to be available in no longer than 20 minutes so the CAISO and demand response providers have a reasonable opportunity to perform their respective and necessary tasks and enable the CAISO to reposition the system within the 30 minutes in accordance with applicable reliability criteria.

F. The Two Options Presented In This LCT Report

This LCT Study sets forth different solution “options” with varying ranges of potential service reliability consistent with CAISO’s Reliability Criteria. The CAISO applies Option 2 for its purposes of identifying necessary local capacity needs and the corresponding potential scope of its backstop authority. Nevertheless, the CAISO continues to provide Option 1 as a point of reference for the CPUC and Local Regulatory Authorities in considering procurement targets for their jurisdictional LSEs.

1. Option 1- Meet Performance Criteria Category B

Option 1 is a service reliability level that reflects generation capacity that must be available to comply with reliability standards immediately after a NERC Category B given that load cannot be removed to meet this performance standard under Reliability Criteria. However, this capacity amount implicitly relies on load interruption as the **only means** of meeting any Reliability Criteria that is beyond the loss of a single transmission element (N-1). These situations will likely require substantial load interruptions in order to maintain system continuity and alleviate equipment overloads prior to the actual occurrence of the second contingency.[3]

[3] This potential for pre-contingency load shedding also occurs because real time operators must prepare for the loss of a common mode N-2 at all times.

2. Option 2- Meet Performance Criteria Category C and Incorporate Suitable Operational Solutions

Option 2 is a service reliability level that reflects generation capacity that is needed to readjust the system to prepare for the loss of a second transmission element (N-1-1) using generation capacity *after* considering all reasonable and feasible operating solutions (including those involving customer load interruption) developed and approved by the CAISO, in consultation with the PTOs. Under this option, there is no expected load interruption to end-use customers under normal or single contingency conditions as the CAISO operators prepare for the second contingency. However, the customer load may be interrupted in the event the second contingency occurs.

As noted, Option 2 is the local capacity level that the CAISO requires to reliably operate the grid per NERC, WECC and CAISO standards. As such, the CAISO recommends adoption of this Option to guide resource adequacy procurement.

III. Assumption Details: How the Study was Conducted

A. System Planning Criteria

The following table provides a comparison of system planning criteria, based on the NERC performance standards, used in the study:

Table 4: Criteria Comparison

Contingency Component(s)	ISO Grid Planning Criteria	Old RMR Criteria	Local Capacity Criteria
<u>A – No Contingencies</u>	X	X	X
<u>B – Loss of a single element</u>			
1. Generator (G-1)	X	X	X[1]
2. Transmission Circuit (L-1)	X	X	X[1]
3. Transformer (T-1)	X	X[2]	X[1,2]
4. Single Pole (dc) Line	X	X	X[1]
5. G-1 system readjusted L-1	X	X	X
<u>C – Loss of two or more elements</u>			
1. Bus Section	X		
2. Breaker (failure or internal fault)	X		
3. L-1 system readjusted G-1	X		X
3. G-1 system readjusted T-1 or T-1 system readjusted G-1	X		X
3. L-1 system readjusted T-1 or T-1 system readjusted L-1	X		X
3. G-1 system readjusted G-1	X		X
3. L-1 system readjusted L-1	X		X
3. T-1 system readjusted T-1	X		
4. Bipolar (dc) Line	X		X
5. Two circuits (Common Mode) L-2	X		X
6. SLG fault (stuck breaker or protection failure) for G-1	X		
7. SLG fault (stuck breaker or protection failure) for L-1	X		
8. SLG fault (stuck breaker or protection failure) for T-1	X		
9. SLG fault (stuck breaker or protection failure) for Bus section	X		
WECC-S3. Two generators (Common Mode) G-2	X[3]		X
<u>D – Extreme event – loss of two or more elements</u>			
Any B1-4 system readjusted (Common Mode) L-2	X[4]		X[3]
All other extreme combinations D1-14.	X[4]		

[1] System must be able to readjust to a safe operating zone in order to be able to support the loss of the next contingency.

[2] A thermal or voltage criterion violation resulting from a transformer outage may not be cause for a local area reliability requirement if the violation is considered marginal (e.g. acceptable loss of facility life or low voltage), otherwise, such a violation will necessitate creation of a requirement.

[3] Evaluate for risks and consequence, per NERC standards. No voltage collapse or dynamic instability allowed.

[4] Evaluate for risks and consequence, per NERC standards.

A significant number of simulations were run to determine the most critical contingencies within each Local Capacity Area. Using power flow, post-transient load flow, and stability assessment tools, the system performance results of all the contingencies that were studied were measured against the system performance requirements defined by the criteria shown in Table 4. Where the specific system performance requirements were not met, generation was adjusted such that the minimum amount of generation required to meet the criteria was determined in the Local Capacity Area. The following describes how the criteria were tested for the specific type of analysis performed.

1. Power Flow Assessment:

Contingencies	Thermal Criteria[3]	Voltage Criteria[4]
Generating unit [1, 6]	Applicable Rating	Applicable Rating
Transmission line [1, 6]	Applicable Rating	Applicable Rating
Transformer [1, 6]	Applicable Rating[5]	Applicable Rating[5]
(G-1)(L-1) [2, 6]	Applicable Rating	Applicable Rating
Overlapping [6, 7]	Applicable Rating	Applicable Rating

[1] All single contingency outages (i.e. generating unit, transmission line or transformer) will be simulated on Participating Transmission Owners' local area systems.

[2] Key generating unit out, system readjusted, followed by a line outage. This overlapping outage is considered a single contingency within the ISO Grid Planning Criteria. Therefore, load dropping for an overlapping G-1, L-1 scenario is not permitted.

[3] Applicable Rating – Based on CAISO Transmission Register or facility upgrade plans including established Path ratings.

[4] Applicable Rating – CAISO Grid Planning Criteria or facility owner criteria as appropriate including established Path ratings.

[5] A thermal or voltage criterion violation resulting from a transformer outage may not be cause for a local area reliability requirement if the violation is considered marginal (e.g. acceptable loss of facility life or low voltage), otherwise, such a violation will necessitate creation of a requirement.

[6] Following the first contingency (N-1), the generation must be sufficient to allow the operators to bring the system back to within acceptable (normal) operating range (voltage and loading) and/or appropriate OTC following the studied outage conditions.

[7] During normal operation or following the first contingency (N-1), the generation must be sufficient to allow the operators to prepare for the next worst N-1 or

common mode N-2 without pre-contingency interruptible or firm load shedding. SPS/RAS/Safety Nets may be utilized to satisfy the criteria after the second N-1 or common mode N-2 except if the problem is of a thermal nature such that short-term ratings could be utilized to provide the operators time to shed either interruptible or firm load. T-2s (two transformer bank outages) would be excluded from the criteria.

2. Post Transient Load Flow Assessment:

Contingencies	Reactive Margin Criteria [2]
Selected [1]	**Applicable Rating**

[1] If power flow results indicate significant low voltages for a given power flow contingency, simulate that outage using the post transient load flow program. The post-transient assessment will develop appropriate Q/V and/or P/V curves.
[2] Applicable Rating – positive margin based on the higher of imports or load increase by 5% for N-1 contingencies, and 2.5% for N-2 contingencies.

3. Stability Assessment:

Contingencies	Stability Criteria [2]
Selected [1]	**Applicable Rating**

[1] Base on historical information, engineering judgment and/or if power flow or post transient study results indicate significant low voltages or marginal reactive margin for a given contingency.
[2] Applicable Rating – CAISO Grid Planning Criteria or facility owner criteria as appropriate.

B. Load Forecast

1. System Forecast

The California Energy Commission (CEC) derives the load forecast at the system and Participating Transmission Owner (PTO) levels. This relevant CEC forecast is then distributed across the entire system, down to the local area, division and substation level. The PTOs use an econometric equation to forecast the system load. The predominant parameters affecting the system load are (1) number of households, (2) economic activity (gross metropolitan products, GMP), (3) temperature and (4) increased energy efficiency and distributed generation programs.

2. Base Case Load Development Method

The method used to develop the load in the base case is a melding process that extracts, adjusts and modifies the information from the system, distribution and municipal utility forecasts. The melding process consists of two parts: Part 1 deals with the PTO load and Part 2 deals with the municipal utility load. There may be small differences between the methodologies used by each PTO to disaggregate the CEC load forecast to their level of local area as well as bar-bus model.

a. PTO Loads in Base Case

The methods used to determine the PTO loads are, for the most part, similar. One part of the method deals with the determination of the division[4] loads that would meet the requirements of 1-in-5 or 1-in-10 system or area base cases and the other part deals with the allocation of the division load to the transmission buses.

i. Determination of division loads

The annual division load is determined by summing the previous year division load and the current division load growth. Thus, the key steps are the determination of the initial year division load and the annual load growth. The initial year for the base case development method is based heavily on recorded data. The division load growth in the system base case is determined in two steps. First, the total PTO load growth for the year is determined, as the product of the PTO load and the load growth rate from the system load forecast. Then this total PTO load growth is allocated to the division, based on the relative magnitude of the load growth projected for the divisions by the distribution planners. For example, for the 1-in-10 area base case, the division load growth determined for the system base case is adjusted to the 1-in-10 temperature using the load temperature relation determined from the latest peak load and temperature data of the division.

[4] Each PTO divides its territory in a number of smaller area named divisions. These are usually smaller and compact areas that have the same temperature profile.

ii. Allocation of division load to transmission bus level

Since the loads in the base case are modeled at the various transmission buses, the division loads developed must be allocated to those buses. The allocation process is different depending on the load types. For the most part, each PTO classifies its loads into four types: conforming, non-conforming, self-generation and generation-plant loads. Since the non-conforming and self-generation loads are assumed to not vary with temperature, their magnitude would be the same in the system or area base cases of the same year. The remaining load (the total division load developed above, less the quantity of non-conforming and self-generation load) is the conforming load. The remaining load is allocated to the transmission buses based on the relative magnitude of the distribution forecast. The summation of all base case loads is generally higher than the load forecast because some load, i.e., self-generation and generation-plant, are behind the meter and must be modeled in the base cases. However, for the most part, metered or aggregated data with telemetry is used to come up with the load forecast.

b. Municipal Loads in Base Case

The municipal utility forecasts that have been provided to the CEC and PTOs for the purposes of their base cases were also used for this study.

C. Power Flow Program Used in the LCR analysis

The technical studies were conducted using General Electric's Power System Load Flow (GE PSLF) program version 19.0 and PowerGem's Transmission Adequacy and Reliability Assessment (TARA) program version 870. This GE PSLF program is available directly from GE or through the Western System Electricity Council (WECC) to any member and TARA program is commercially available.

To evaluate Local Capacity Areas, the starting base case was adjusted to reflect the latest generation and transmission projects as well as the one-in-ten-year peak load forecast for each Local Capacity Area as provided to the CAISO by the PTOs.

Electronic contingency files provided by the PTOs were utilized to perform the numerous contingencies required to identify the LCR. These contingency files include remedial action and special protection schemes that are expected to be in operation during the year of study. A CAISO created EPCL (a GE programming language contained within the GE PSLF package) routine and/or TARA software were used to run the combination of contingencies; however, other routines are available from WECC with the GE PSFL package or can be developed by third parties to identify the most limiting combination of contingencies requiring the highest amount of generation within the local area to maintain power flows within applicable ratings.

IV. Locational Capacity Requirement Study Results

A. Summary of Study Results

LCR is defined as the amount of resource capacity that is needed within a Local Capacity Area to reliably serve the load located within this area. The results of the CAISO's analysis are summarized in the Executive Summary Tables.

Table 5: 2018 Local Capacity Needs vs. Peak Load and Local Area Resources

	2018 Total LCR (MW)	Peak Load (1 in10) (MW)	2018 LCR as % of Peak Load	Total Dependable Local Area Resources (MW)	2018 LCR as % of Total Area Resources
Humboldt	169	187	90%	210	80%
North Coast/North Bay	634	1333	48%	869	73%
Sierra	2113	1818	116%	2125	99%**
Stockton	719	1169	62%	605	119%**
Greater Bay	5160	10247	50%	7103	73%
Greater Fresno	2081	3290	63%	3579	58%
Kern	453	867	52%	566	80%
LA Basin	7525	18466	41%	10735	70%
Big Creek/Ventura	2321	4802	48%	5657	41%
San Diego/Imperial Valley	4032	4924	82%	4953	81%
Total	**25207**	**47103***	**54%***	**36402**	**69%**

Table 6: 2022 Local Capacity Needs vs. Peak Load and Local Area Resources

	2022 Total LCR (MW)	Peak Load (1 in10) (MW)	2022 LCR as % of Peak Load	Total Dependable Local Area Resources (MW)	2022 LCR as % of Total Area Resources
Humboldt	169	190	89%	210	80%
North Coast/North Bay	440	1249	35%	869	51%
Sierra	1967	1814	108%	2066	95%**
Stockton	702	1035	68%	605	116%**
Greater Bay	5315	10180	52%	6879	77%**
Greater Fresno	1860	3352	55%	3526	53%
Kern	123	885	14%	566	22%
LA Basin	6022	19020	32%	8138	74%
Big Creek/Ventura	2597	5020	52%	3859	67%
San Diego/Imperial Valley	4643	5053	92%	4610	101%
Total	**23838**	**47798***	**50%***	**31328**	**76%**

* Value shown only illustrative, since each local area peaks at a different time.

** Resource deficient LCA (or with sub-area that are deficient) – deficiency included in LCR. Resource deficient area implies that in order to comply with the criteria, at summer peak, load must be shed immediately after the first contingency.

Tables 5 and 6 shows how much of the Local Capacity Area load is dependent on local resources and how many local resources must be available in order to serve the load in those Local Capacity Areas in a manner consistent with the Reliability Criteria. These tables also indicate where new transmission projects, new resource additions or demand side management programs would be most useful in order to reduce the dependency on existing, generally older and less efficient local area resources.

The term “Qualifying Capacity” used in this report is the “Net Qualifying Capacity” (“NQC”) posted on the CAISO web site at:

http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx

The NQC list includes the area (if applicable) where each resource is located for units already operational. Neither the NQC list nor this report incorporates Demand Side Management programs and their related NQC. Units scheduled to become operational before June 1 of 2022 have been included in this 2022 Long-Term LCR Report and added to the total NQC values for those respective areas (see detail write-up for each area).

Regarding the main tables up front (page 2), the first column, “Qualifying Capacity,” reflects two sets of resources. The first set is comprised of resources that would normally be expected to be on-line such as Municipal and Regulatory Must-take resources (state, federal, QFs, wind and nuclear units). The second set is “market” resources. The second column, “YEAR LCR Requirement Based on Category B” identifies the local capacity requirements, and deficiencies that must be addressed, in order to achieve a service reliability level based on Performance Criteria- Category B. The third column, “YEAR LCR Requirement Based on Category C with Operating Procedure”, sets forth the local capacity requirements, and deficiencies that must be addressed, necessary to attain a service reliability level based on Performance Criteria-Category C with operational solutions.

B. Summary of Results by Local Area

Each Local Capacity Area’s overall requirement is determined by also achieving each sub-area requirement. Because these areas are a part of the interconnected electric system, the total for each Local Capacity Area is not simply a summation of the sub-area needs. For example, some sub-areas may overlap and therefore the same units may count for meeting the needs in both sub-areas.

1. Humboldt Area

Area Definition:

The transmission tie lines into the area include:

1) Bridgeville-Cottonwood 115 kV line #1
2) Humboldt-Trinity 115 kV line #1

3) Willits-Garberville 60 kV line #1
4) Trinity-Maple Creek 60 kV line #1

The substations that delineate the Humboldt Area are:

1) Bridgeville and Low Gap are in, Cottonwood is out
2) Humboldt is in Trinity is out
3) Willits is out, Kekawaka and Garberville are in
4) Trinity is out, Ridge Cabin and Maple Creek are in

Load:

Total 2022 busload within the defined area: 196 MW with -17 MW of AAEE and 11 MW of losses resulting in total load + losses of 190 MW.

List of physical units: See Appendix A.

Major new projects modeled:

1. Maple Creek Reactive Support
2. Garberville Reactive Support
3. Bridgeville 115/60 kV #1 transformer replacement

Critical Contingency Analysis Summary:

Humboldt Overall:

The most critical contingency for the Humboldt area is the outage of the Cottonwood-Bridgeville 115 kV line overlapping with an outage of the gen-tie from Humboldt Bay Power Plant to units 1-4. The local area limitation is potential overload on the Humboldt -Trinity 115 kV Line. This contingency establishes a local capacity need of 169 MW in 2022 as the minimum capacity necessary for reliable load serving capability within this area.

The single most critical contingency for the Humboldt area is the outage of the Cottonwood-Bridgeville 115 kV line with one of the Humboldt Bay Power Plant units already out of service, which could potentially overload the Humboldt -Trinity 115 kV line. This contingency establishes a local capacity need of 121 MW in 2022.

Effectiveness factors:

The following table has units at least 5% effective to the above-mentioned constraint:

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31156	BLUELKPP	1	65
31180	HUMB_G1	4	64
31180	HUMB_G1	3	64
31180	HUMB_G1	2	64
31180	HUMB_G1	1	64
31150	FAIRHAVN	1	61
31158	LP SAMOA	1	61
31182	HUMB_G3	10	61
31182	HUMB_G3	9	61
31182	HUMB_G3	8	61
31181	HUMB_G2	7	61
31181	HUMB_G2	6	61
31181	HUMB_G2	5	61
31152	PAC.LUMB	1	57
31152	PAC.LUMB	2	57
31153	PAC.LUMB	3	57

Changes compared to last year's results:

The load and losses have decreased by 5 MW from 2021 to 2022 and the total LCR has remained the same.

Humboldt Overall Requirements:

2022	QF/Selfgen (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	14	196	210

2022	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[5]	121	0	121
Category C (Multiple)[6]	169	0	169

[5] LCR requirement for a single contingency means that there wouldn't be any criteria violations following the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[6] LCR requirement for multiple contingencies means that not only there wouldn't be any criteria violations following the loss of a single element, but also the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

2. North Coast / North Bay Area

<u>Area Definition:</u>

The transmission tie facilities coming into the North Coast/North Bay area are:

1) Cortina-Mendocino 115 kV Line
2) Cortina-Eagle Rock 115 kV Line
3) Willits-Garberville 60 kV line #1
4) Vaca Dixon-Lakeville 230 kV line #1
5) Tulucay-Vaca Dixon 230 kV line #1
6) Lakeville-Sobrante 230 kV line #1
7) Ignacio-Sobrante 230 kV line #1

The substations that delineate the North Coast/North Bay area are:

1) Cortina is out, Mendocino and Indian Valley are in
2) Cortina is out, Eagle Rock, Highlands and Homestake are in
3) Willits and Lytonville are in, Kekawaka and Garberville are out
4) Vaca Dixon is out, Lakeville is in
5) Tulucay is in, Vaca Dixon is out
6) Lakeville is in, Sobrante is out
7) Ignacio is in, Sobrante and Crocket are out

<u>Load:</u>

Total 2022 busload within the defined area: 1371 MW with -50 MW of AAEE, -103 MW BTM-PV, and 31 MW of losses resulting in total load + losses of 1249 MW.

<u>List of physical units:</u> See Appendix A.

<u>Major new projects modeled:</u>

1. Napa – Tulucay 60 kV line upgrade
2. Vaca Dixon-Lakeville 230 kV reconductoring

<u>Critical Contingency Analysis Summary:</u>

Eagle Rock Sub-area

The most critical overlapping contingency is an outage of the Geysers #3 - Geyser #5 115 kV line and the Cortina-Mendocino 115 kV line. The sub-area area limitation is thermal overloading of the Eagle Rock-Cortina 115 kV line. This limiting contingency establishes a local capacity need of 233 MW in 2022 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is an outage of the Cortina-Mendocino 115 kV transmission line with Geysers 11 unit out of service. The sub-area limitation is thermal overloading of the parallel Eagle Rock-Cortina 115 kV line. This limiting contingency establishes a local capacity need of 209 MW in 2022.

Effectiveness factors:

The following units have at least 5% effectiveness to the above-mentioned constraint:

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31406	GEYSR5-6	1	36
31406	GEYSR5-6	2	36
31408	GEYSER78	1	36
31408	GEYSER78	2	36
31412	GEYSER11	1	37
31435	GEO.ENGY	1	35
31435	GEO.ENGY	2	35
31433	POTTRVLY	1	34
31433	POTTRVLY	3	34
31433	POTTRVLY	4	34
38020	CITY UKH	1	32
38020	CITY UKH	2	32

Fulton Sub-area

The most critical overlapping contingency is the outage of the Fulton-Ignacio 230 kV line #1 and the Fulton-Lakeville 230 kV line #1. The sub-area area limitation is thermal overloading of Lakeville # 2 60 kV line (Lakeville-Petaluma A – Cotati 60 kV). This limiting contingency establishes a local capacity need of 411 MW in 2022 as the minimum capacity necessary for reliable load serving capability within this sub-area. All of the units required to meet the Eagle Rock pocket count towards the Fulton total requirement.

Effectiveness factors:

The following table has units within the Fulton pocket as well as units outside the pocket that are at least 5% effective to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31466	SONMA LF	**1**	52
31422	GEYSER17	1	12
31404	WEST FOR	1	12
31404	WEST FOR	2	12
31414	GEYSER12	1	12
31418	GEYSER14	1	12
31420	GEYSER16	1	12
31402	BEAR CAN	1	12
31402	BEAR CAN	2	12
38110	NCPA2GY1	1	12
38112	NCPA2GY2	1	12
32700	MONTICLO	1	10
32700	MONTICLO	2	10
32700	MONTICLO	3	10
31435	GEO.ENGY	1	6
31435	GEO.ENGY	2	6
31408	GEYSER78	1	6
31408	GEYSER78	2	6
31412	GEYSER11	1	6
31406	GEYSR5-6	1	6
31406	GEYSR5-6	2	6

Lakeville Sub-area (North Coast/North Bay Overall)

The most limiting contingency for the North Coast/North Bay Area is a common mode outage of the Vaca Dixon-Lakeville and Vaca Dixon-Tulucay 230 kV lines. The area limitation is thermal overloading of the Eagle Rock-Cortina 115 kV line, the Bridgeville-Garberville 60 kV line and the Sobrante-Moraga 115 kV line. This limiting contingency establishes a local capacity need of 440 MW in 2022 as the minimum capacity necessary for reliable load serving capability within this area.

Local capacity requirement in the North Coast/North Bay area substantially depend on the generation in the Bay Area, especially Pittsburg sub-area.

The study assumed that the Vaca Dixon- Lakeville 230 kV line is reconductored. If it is not reconductored, than the limiting contingency will be single outage of the Vaca Dixon-Tulucay 230 kV line. This contingency may overload the Vaca Dixon- Lakeville 230 kV line. In this case, local capacity requirement will be 628 MW. If this line is not re-conductored, but re-rated, local capacity requirement will be 440 MW as described above.

Changes compared to last year's results:

Overall the load and losses forecast went down by 69 MW compared to 2021. The overall LCR requirement went down by 40 MW as a combination of load decrease and need to use North Coast/North Bay resources to mitigate potential overload of Sobrante-Moraga 115 kV due to resource retirements in the Pittsburg sub-area.

North Coast/North Bay Overall Requirements:

2022	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	5	113	751	869

2022	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category P1 (Single)[7]	209	0	209
Category P7 (Multiple)[8]	440	0	440

[7] LCR requirement for a single contingency means that there wouldn't be any criteria violations following the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.
[8] LCR requirement for multiple contingencies means that not only there wouldn't be any criteria violations following the loss of a single element, but also the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

3. Sierra Area

Area Definition:

The transmission tie lines into the Sierra Area are:

1) Table Mountain-Rio Oso 230 kV line
2) Table Mountain-Palermo 230 kV line
3) Table Mt-Pease 60 kV line
4) Caribou-Palermo 115 kV line
5) Drum-Summit 115 kV line #1
6) Drum-Summit 115 kV line #2
7) Spaulding-Summit 60 kV line
8) Brighton-Bellota 230 kV line
9) Rio Oso-Lockeford 230 kV line
10) Gold Hill-Eight Mile Road 230 kV line
11) Lodi-Eight Mile Road 230 kV line
12) Gold Hill-Lake 230 kV line
13) Vaca Dixon–Davis #1 115kV line
14) Vaca Dixon–Davis #2 115kV line

The substations that delineate the Sierra Area are:

1) Table Mountain is out Rio Oso is in
2) Table Mountain is out Palermo is in
3) Table Mt is out Pease is in
4) Caribou is out Palermo is in
5) Drum is in Summit is out
6) Drum is in Summit is out
7) Spaulding is in Summit is out
8) Brighton is in Bellota is out
9) Rio Oso is in Lockeford is out
10) Gold Hill is in Eight Mile is out
11) Lodi is in Eight Mile is out
12) Gold Hill is in Lake is out
13) Vaca Dixon is out Vaca Dixon Junction 1 is in
14) Vaca Dixon is out Vaca Dixon Junction 2 is in

Load:

Total 2022 busload within the defined area: 1940 MW with -63 MW of AAEE, -144 MW of BTM-PV, and 81 MW of losses resulting in total load + losses of 1814 MW.

List of physical units: See Appendix A.

Major new projects modeled:

1. Gold Hill-Missouri Flat #1 and #2 115 kV line reconductoring
2. Rio Oso #1 and #2 230/115 kV transformer replacement
3. Pease 115/60 kV transformer addition
4. South of Palermo 115 kV Reinforcement

Critical Contingency Analysis Summary:

Placerville Sub-area

No requirements due to the Missouri Flat-Gold Hill 115 kV lines reconductoring project.

Placer Sub-area

The most critical contingency is the loss of the Gold Hill-Placer #1 115 kV line with Chicago Park unit out of service. The area limitation is thermal overloading of the Drum-Higgins 115 kV line. This limiting contingency establishes a local capacity need of 77 MW in 2022 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area (Chicago Park, Dutch Flat #1, Wise units 1&2, Newcastle, and Halsey) have the same effectiveness factor.

Pease Sub-area

The most critical contingency is the loss of the Palermo-Pease 115 kV line followed by Pease-Rio Oso 115 kV line. The area limitation is thermal overloading of the Table Mountain-Pease 60 kV line. This limiting contingency establishes a LCR of 86 MW in 2022 as the minimum capacity necessary for reliable load serving capability within this sub-area.

There is no single contingency requirement.

Effectiveness factors:

All units within this sub-area have the same effectiveness factor.

Drum-Rio Oso Sub-area

No requirement due to the Rio Oso 230/115 kV Transformer Upgrade project.

South of Rio Oso Sub-area

The most critical contingency is the loss of the Rio Oso-Gold Hill 230 kV line followed by loss of the Rio Oso-Atlantic #1 230 kV line. The sub-area limitation is thermal overloading of the Rio Oso-Lincoln 115 kV line. This limiting contingency establishes a LCR of 770 MW (includes 30 MW of deficiency) in 2022 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency is the loss of the Rio Oso-Gold Hill 230 kV line with Ralston unit out of service. The area limitation is thermal overloading of the Rio Oso-Atlantic 230 kV line. This limiting contingency establishes a LCR of 389 MW in 2022.

Effectiveness factors:

The following table has all units in South of Rio Oso sub-area and their effectiveness factor to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	Eff Fctr. (%)
32456	MIDLFORK	1	30
32456	MIDLFORK	2	30
32458	RALSTON	1	30
32486	HELLHOLE	1	30
32508	FRNCH MD	1	30
32510	CHILIBAR	1	30
32513	ELDRADO1	1	30
32514	ELDRADO2	1	30
32460	NEWCSTLE	1	29
32478	HALSEY F	1	28
32512	WISE	1	28
32500	ULTR RCK	1	26
38114	STIG CC	1	13
38123	LODI CT1	1	13
38124	LODI ST1	1	13
32462	CHI.PARK	1	13
32498	SPILINCF	1	10
32464	DTCHFLT1	1	9

South of Palermo Sub-area

Due to the assumption of having South of Palermo project implemented before 2022, there is no additional requirement for the South of Palermo sub-area as units needed for Pease and South of Rio Oso sub-areas, satisfy Category B and C requirements for this area as well.

Effectiveness factors:

The following table has all units in South of Palermo sub-area and their effectiveness factor to the above-mentioned constraint

Gen Bus #	Gen Name	Gen ID	Eff Fctr (%)
31784	BELDEN	1	15
31786	ROCK CK1	1	15
31788	ROCK CK2	1	15
31790	POE 1	1	15
31792	POE 2	1	15
31812	CRESTA	1	15
31812	CRESTA	2	15
31820	BCKS CRK	1	15
31820	BCKS CRK	2	15
32498	SPILINCF	1	12
32500	ULTR RCK	1	12
32502	DTCHFLT2	1	12
32156	WOODLAND	1	12
32454	DRUM 5	1	12
32472	SPAULDG	1	12
32472	SPAULDG	2	12
32472	SPAULDG	3	12
32474	DEER CRK	1	12
32476	ROLLINSF	1	12
32480	BOWMAN	1	12
32484	OXBOW F	1	12
32488	HAYPRES+	1	12
32488	HAYPRES+	2	12
32504	DRUM 1-2	1	12
32504	DRUM 1-2	2	12
32506	DRUM 3-4	1	12
32506	DRUM 3-4	2	12
32464	DTCHFLT1	1	12
32462	CHI.PARK	1	12
32166	UC DAVIS	1	12
32478	HALSEY F	1	11
32512	WISE	1	11
32460	NEWCSTLE	1	11
32162	RIV.DLTA	1	11
32510	CHILIBAR	1	11
32513	ELDRADO1	1	11
32514	ELDRADO2	1	11

32456	MIDLFORK	1	10
32456	MIDLFORK	2	10
32458	RALSTON	1	10
32486	HELLHOLE	1	10
32508	FRNCH MD	1	10
38114	STIG CC	1	5
38123	LODI CT1	1	5
38124	LODI ST1	1	5

South of Table Mountain Sub-area

The most critical contingency is the loss of the Table Mountain-Rio Oso and Table Mountain-Palermo 230 kV double circuit tower line. The area limitation is thermal overloading of the Caribou-Palermo 115 kV line. This limitation establishes a local capacity need of 1905 MW in 2022 as the minimum capacity necessary for reliable load serving capability within this area.

The most critical single contingency is the loss of the Table Mountain-Palermo 230 kV line with Belden unit out of service. The area limitation is thermal overloading of the Table Mountain-Rio Oso 230 kV line. This limiting contingency establishes a local capacity need of 836 MW in 2022.

Effectiveness factors:

The following table has effectiveness factor to the most critical contingency.

Gen Bus #	Gen Name	Gen ID	Eff Fctr (%)
31814	FORBSTWN	1	7
31794	WOODLEAF	1	7
31832	SLY.CR.	1	7
31862	DEADWOOD	1	7
31890	PO POWER	1	6
31890	PO POWER	2	6
31888	OROVLLE	1	6
31834	KELLYRDG	1	6
32450	COLGATE1	1	4
32466	NARROWS1	1	4
32468	NARROWS2	1	4
32452	COLGATE2	1	4
32470	CMP.FARW	1	4
32451	FREC	1	4
32490	GRNLEAF1	1	4
32490	GRNLEAF1	2	4
32496	YCEC	1	4
32494	YUBA CTY	1	4
32492	GRNLEAF2	1	4
32498	SPILINCF	1	2

31788	ROCK CK2	1	2
31812	CRESTA	1	2
31812	CRESTA	2	2
31820	BCKS CRK	1	2
31820	BCKS CRK	2	2
31786	ROCK CK1	1	2
31790	POE 1	1	2
31792	POE 2	1	2
31784	BELDEN	1	2
32500	ULTR RCK	1	2
32156	WOODLAND	1	2
32510	CHILIBAR	1	2
32513	ELDRADO1	1	2
32514	ELDRADO2	1	2
32478	HALSEY F	1	2
32460	NEWCSTLE	1	1
32458	RALSTON	1	1
32512	WISE	1	1
32456	MIDLFORK	1	1
32456	MIDLFORK	2	1
32486	HELLHOLE	1	1
32508	FRNCH MD	1	1
32162	RIV.DLTA	1	1
32502	DTCHFLT2	1	1
32462	CHI.PARK	1	1
32464	DTCHFLT1	1	1
32454	DRUM 5	1	1
32476	ROLLINSF	1	1
32484	OXBOW F	1	1
32474	DEER CRK	1	1
32504	DRUM 1-2	1	1
32504	DRUM 1-2	2	1
32506	DRUM 3-4	1	1
32506	DRUM 3-4	2	1
32166	UC DAVIS	1	1
32472	SPAULDG	1	1
32472	SPAULDG	2	1
32472	SPAULDG	3	1
32480	BOWMAN	1	1
32488	HAYPRES+	1	1
32488	HAYPRES+	2	1
38124	LODI ST1	1	1
38123	LODI CT1	1	1
38114	STIG CC	1	1

***Changes compared to last year's results*:**

The load forecast went down by 8 MW as compared to 2021. Overall the total LCR for the Sierra area has increased by 281 MW due to corrected LCR needs for the South of Table sub-area vs. the under-reported 2021 values.

Sierra Overall Requirements:

2022	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	66	1110	890	2066

2022	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[9]	836	0	836
Category C (Multiple)[10]	1905	62	1967

4. Stockton Area

The LCR requirement for the Stockton Area is driven by the sum of the requirements for the Tesla-Bellota, Lockeford and Weber sub-areas.

Area Definition:

Tesla-Bellota Sub-Area Definition

The transmission facilities that establish the boundary of the Tesla-Bellota sub-area are:

1) Bellota 230/115 kV Transformer #1
2) Bellota 230/115 kV Transformer #2
3) Tesla-Tracy 115 kV Line
4) Tesla-Salado 115 kV Line
5) Tesla-Salado-Manteca 115 kV line
6) Tesla-Schulte #1 115 kV Line
7) Tesla-Schulte #2 115kV line
8) Tesla-Vierra 115 kV Line

The substations that delineate the Tesla-Bellota Sub-area are:

1) Bellota 230 kV is out Bellota 115 kV is in
2) Bellota 230 kV is out Bellota 115 kV is in

[9] LCR requirement for a single contingency means that there wouldn't be any criteria violations following the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[10] LCR requirement for multiple contingencies means that not only there wouldn't be any criteria violations following the loss of a single element, but also the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

3) Tesla is out Tracy is in
4) Tesla is out Salado is in
5) Tesla is out Salado and Manteca are in
6) Tesla is out Schulte is in
7) Tesla is out Schulte is in
8) Tesla is out Thermal Energy is in

Lockeford Sub-Area Definition

The transmission facilities that establish the boundary of the Lockeford sub-area are:

1) Lockeford-Industrial 60 kV line
2) Lockeford-Lodi #1 60 kV line
3) Lockeford-Lodi #2 60 kV line
4) Lockeford-Lodi #3 60 kV line

The substations that delineate the Lockeford Sub-area are:

1) Lockeford is out Industrial is in
2) Lockeford is out Lodi is in
3) Lockeford is out Lodi is in
4) Lockeford is out Lodi is in

Weber Sub-Area Definition

The transmission facilities that establish the boundary of the Weber Sub-area are:

1) Weber 230/60 kV Transformer #1
2) Weber 230/60 kV Transformer #2

The substations that delineate the Weber Sub-area are:

1) Weber 230 kV is out Weber 60 kV is in
2) Weber 230 kV is out Weber 60 kV is in

Load:

Total 2022 busload within the defined area: 1124 MW with -56 MW of AAEE, -51 MW of BTM-PV, and 18 MW of losses resulting in total load + losses of 1035 MW.

List of physical units: See Appendix A.

Major new projects modeled:

1. Weber-Stockton “A” #1 and #2 60 kV Reconductoring
2. Ripon 115 kV line

Critical Contingency Analysis Summary:

Stanislaus Sub-area

The critical contingency for the Stanislaus sub-area is the loss of Bellota-Riverbank-Melones 115 kV circuit with Stanislaus PH out of service. The area limitation is thermal overloading of the River Bank Jct.-Manteca 115 kV line. This limiting contingency establishes a local capacity need of 144 MW in 2022 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area have the same effectiveness factor.

Tesla-Bellota Sub-area

The two most critical contingencies listed below together establish a local capacity need of 643 MW (includes 288 MW of deficiency) in 2022 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical contingency for the Tesla-Bellota pocket is the loss of Schulte-Kasson-Manteca 115 kV and Schulte-Lammers 115 kV. The area limitation is thermal overload of the Tesla-Tracy 115 kV line above its emergency rating. This limiting contingency establishes a local capacity need of 526 MW (includes 288 MW of deficiency) in 2022.

The single most critical contingency for the Tesla-Bellota pocket is the loss of Tesla-Schulte #1 115 kV line and the loss of the GWF Tracy unit #3. The area limitation is thermal overload of the Tesla-Schulte #2 115 kV line. This single contingency establishes a local capacity need of 355 MW in 2022.

All of the resources needed to meet the Stanislaus sub-area count towards the Tesla-Bellota sub-area LCR need.

Effectiveness factors:

The effectiveness factors for the most critical contingency are listed below:

Gen Bus#	Gen Name	Gen ID	Eff Fctr (%)
33805	GWFTRCY1	1	71
33807	GWFTRCY2	1	71
33811	Q268ST1	1	71
33808	SJ COGEN	1	35
33810	SP CMPNY	1	31
34062	STANISLS	1	28
34050	CH.STN.	1	23
33917	FBERBORD	1	22
34078	SPRNG GP	1	20
34060	SANDBAR	1	20
34074	BEARDSLY	1	20
34058	DONNELLS	1	20
34076	TULLOCH	1	18
34076	TULLOCH	2	18
33806	TH.E.DV.	1	9
34056	STNSLSRP	1	8
33814	CPC STCN	1	3
33850	CAMANCHE	1	3
33850	CAMANCHE	2	3
33850	CAMANCHE	3	3

Lockeford Sub-area

The critical contingency for the Lockeford area is the loss of Lockeford-Industrial 60 kV circuit and Lockeford-Lodi #2 60 kV circuit. The area limitation is thermal overloading of the Lockeford-Lodi Jct. section of the Lockeford-Lodi #3 60 kV circuit. This limiting contingency establishes a local capacity need of 31 MW (including 8 MW of deficiency) in 2022 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area are needed therefore no effectiveness factor is required.

Weber Sub-area

The critical contingency for the Weber area is the loss of Stockton A-Weber #1 & #2 60 kV lines. The area limitation is thermal overloading of the Stockton A-Weber #3 60 kV line. This limiting contingency establishes a local capacity need of 28 MW in 2022 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area have the same effectiveness factor.

Stockton Overall

The requirement for this area is driven by the sum of requirements for the Tesla-Bellota, Lockeford and Weber sub-areas.

Changes compared to last year's results:

The 2022 load forecast went down by 151 MW and the overall LCR has increased, mostly in deficiency, by 298 MW compared to the 2021 due to delay in Vierra 115 kV loop-in transmission project implementation.

Stockton Overall Requirements:

2022	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	16	123	466	605

2022	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[11]	355	0	355
Category C (Multiple)[12]	406	296	702

[11] LCR requirement for a single contingency means that there wouldn't be any criteria violations following the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[12] LCR requirement for multiple contingencies means that not only there wouldn't be any criteria violations following the loss of a single element, but also the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

5. Greater Bay Area

Area Definition:

The transmission tie lines into the Greater Bay Area are:

1) Lakeville-Sobrante 230 kV
2) Ignacio-Sobrante 230 kV
3) Parkway-Moraga 230 kV
4) Bahia-Moraga 230 kV
5) Lambie SW Sta-Vaca Dixon 230 kV
6) Peabody-Contra Costa P.P. 230 kV
7) Tesla-Kelso 230 kV
8) Tesla-Delta Switching Yard 230 kV
9) Tesla-Pittsburg #1 230 kV
10) Tesla-Pittsburg #2 230 kV
11) Tesla-Newark #1 230 kV
12) Tesla-Newark #2 230 kV
13) Tesla-Ravenswood 230 kV
14) Tesla-Metcalf 500 kV
15) Moss Landing-Metcalf 500 kV
16) Moss Landing-Metcalf #1 230 kV
17) Moss Landing-Metcalf #2 230 kV
18) Oakdale TID-Newark #1 115 kV
19) Oakdale TID-Newark #2 115 kV

The substations that delineate the Greater Bay Area are:

1) Lakeville is out Sobrante is in
2) Ignacio is out Sobrante is in
3) Parkway is out Moraga is in
4) Bahia is out Moraga is in
5) Lambie SW Sta is in Vaca Dixon is out
6) Peabody is out Contra Costa P.P. is in
7) Tesla is out Kelso is in
8) Tesla is out Delta Switching Yard is in
9) Tesla is out Pittsburg is in
10) Tesla is out Pittsburg is in
11) Tesla is out Newark is in
12) Tesla is out Newark is in
13) Tesla is out Ravenswood is in
14) Tesla is out Metcalf is in
15) Moss Landing is out Metcalf is in
16) Moss Landing is out Metcalf is in
17) Moss Landing is out Metcalf is in
18) Oakdale TID is out Newark is in
19) Oakdale TID is out Newark is in

Load:

Total 2022 busload within the defined area: 10,629 MW with -424 MW of AAEE, -483 MW of Behind the meter DG, 194 MW of losses and 264 MW of pumps resulting in total load + losses + pumps of 10,180 MW.

List of physical units: See Appendix A.

Major new projects modeled:

1. Tesla-Newark 230 kV Path upgrade
2. Morgan Hill Area Reinforcement (New 420MVA Spring 230/115kV Bank#1)
3. Metcalf-Evergreen 115 kV Line Reconductoring
4. Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade
5. East Shore-Oakland J 115 kV Reconductoring Project
6. Vaca Dixon-Lakeville 230 kV Reconductoring
7. A few small renewable resources
8. Pittsburg Power Plant retirement
9. Moss Landing Units 6 & 7 retirement

Critical Contingency Analysis Summary:

Oakland Sub-area

The critical contingency for the Oakland pocket is the loss of both C-X #2 and C-X #3 115 kV Cables. The area limitation is thermal overloading of the remaining Moraga-Claremont 115 kV lines above their emergency rating. This limiting contingency establishes a local capacity need of 50 MW in 2022 as minimum capacity necessary for reliable load serving capability within this sub-area.

The Oakland resources are required in order to meet local reliability requirements in the Oakland sub-area based on actual real-time data that shows a need of at least 98 MW for a 1 in 3 heat wave (2015/16). Further, the real-time data also showed that at times all three Oakland generators are on-line simultaneously in order to maintain local reliability. The local capacity technical study was intended to model a 1 in 10 heat wave resulting in an increased local capacity need beyond that observed in real-time. The discrepancy is due to load forecast distribution among substations in the area. ISO will work with PG&E and CEC to correct this discrepancy in future base cases.

Effectiveness factors:

All units within this sub-area have the same effectiveness factor.

Llagas Sub-area

The most critical contingency is an outage of Metcalf D-Morgan Hill 115 kV line with the Spring 230/115 kV transformer bank #1. The area limitation is the thermal overloading of the Morgan Hill-Llagas 115 kV line above its emergency rating. This limiting contingency establishes a local capacity need of 24 MW in 2022 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area have the same effectiveness factor.

San Jose Sub-area

The most critical contingency is the Metcalf-El Patio #1 115 kV line overlapped with Metcalf-Evergreen #2 115 kV line. The limiting element is the Metcalf-El Patio #2 115 kV line and establishes a local capacity 111 MW in 2022 as minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area have the same effectiveness factor.

South Bay-Moss Landing Sub-area

The most critical contingency is an outage of the Tesla-Metcalf 500 kV and Moss Landing-Los Banos 500 kV. The area limitation is thermal overloading of the Las Aguillas-Moss Landing 230 kV. This limiting contingency establishes a LCR of 2346 MW in 2022 (includes 162 MW of deficiency) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Resources in San Jose and Llagas sub-areas are also included in this sub-area.

Effectiveness factors:

For thermal overloads, resources in the Moss Landing area are more effective than the resources in the South Bay. For voltage support, resources in the South Bay are more effective than the resources in the Moss Landing area. Minimum requirement assumes at least two blocks of Combined Cycle at Moss Landing.

Ames and Pittsburg Sub-areas Combined

The need for OTC generation in this sub-area is eliminated after the following projects are operational: Tesla-Pittsburg 230 kV Reconductoring, Moraga 230/115 kV Banks Replacement, Contra Costa-Moraga 230 kV Reconductoring and the Vaca Dixon-Lakeville 230 kV Reconductoring.

<u>Scenario 1 - Vaca Dixon-Lakeville 230 kV Not Reconductored</u>

The two most critical contingencies listed below together establish a local capacity need of 2386 MW in 2022 as follows: 628 MW in NCNB and 1758 MW in the Bay Area – 596 MW in Ames and 1162 MW in Pittsburg as the minimum capacity necessary for reliable load serving capability within these sub-areas.

<u>Scenario 2 - Vaca Dixon-Lakeville 230 kV Reconductored</u>

The two most critical contingencies listed below together establish a local capacity need of 2268 MW in 2022 as follows: 440 MW in NCNB and 1828 MW in the Bay Area – 596 MW in Ames and 1232 MW in Pittsburg as the minimum capacity necessary for reliable load serving capability within these sub-areas.

In both scenarios, the most critical contingency in the Bay Area is an outage of DCTL Newark-Ravenswood & Tesla-Ravenswood 230 kV. The area limitation is thermal overloading of Newark-Ames #1, #2, #3 and Newark- Ames Distribution 115 kV lines.

The most critical contingency in North Coast/North Bay area is an outage of Vaca Dixon-Tulucay 230 kV line with Delta Energy Center power plant out of service. The limiting element is the thermal overload on the Vaca Dixon-Lakeville 230 kV line.

Effectiveness factors:

Resources must satisfy both constraints simultaneously, therefore no effectiveness factor is provided.

Contra Costa Sub-area

The most critical contingency is an outage of Kelso-Tesla 230 kV with Gateway out of service. The area limitation is thermal overloading of the Delta Switching Yard-Tesla 230 kV line. This limiting contingency establishes a LCR of 1043 MW in 2022 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The following table has units within the Bay Area that are at least 10% effective.

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
33175	ALTAMONT	1	83
38760	DELTA E	10	71
38760	DELTA E	11	71
38765	DELTA D	8	71
38765	DELTA D	9	71
38770	DELTA C	6	71
38770	DELTA C	7	71
38815	DELTA B	4	71
38815	DELTA B	5	71
38820	DELTA A	3	71
33170	WINDMSTR	1	68
33118	GATEWAY1	1	23
33119	GATEWAY2	1	23
33120	GATEWAY3	1	23
33116	C.COS 6	1	23
33117	C.COS 7	1	23
33133	GWF #3	1	23
33134	GWF #4	1	23
33178	RVEC_GEN	1	23
33131	GWF #1	1	22
32179	T222	1	18
32188	P0611G	1	18

32190	Q039	1	18
32186	P0609	1	18
32171	HIGHWND3	1	18
32177	Q0024	1	18
32168	ENXCO	2	18
32169	SOLANOWP	1	18
32172	HIGHWNDS	1	18
32176	SHILOH	1	18
33838	USWP_#3	1	18
32173	LAMBGT1	1	14
32174	GOOSEHGT	2	14
32175	CREEDGT1	3	14
35312	SEAWESTF	1	11
35316	ZOND SYS	1	11
35320	USW FRIC	1	11

Bay Area overall

The most critical need is the aggregate of sub-area requirements. This establishes a LCR of 5315 MW in 2022 (including 162 MW of deficiency) as the minimum capacity necessary for reliable load serving capability within this area.

The most critical single contingency is the loss of the Tesla-Metcalf 500 kV with Delta Energy Center out of service. The area limitation is reactive margin. This limiting contingency establishes a local capacity need of 4257 MW in 2022 .

Effectiveness factors:

For most helpful procurement information please read procedure M-2210Z effectiveness factors at: http://www.caiso.com/Documents/2210Z.pdf

Changes compared to last year's results:

From 2021 the load forecast increases by 536 MW compared with the physically defined Bay Area. The LCR has increased by 121 MW due to the higher load forecast.

Bay Area Overall Requirements:

2022	Wind (MW)	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	320	277	411	5871	6879

2022	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[13]	4257	0	4257
Category C (Multiple)[14]	5153	162	5315

6. Greater Fresno Area

Area Definition:

The transmission facilities coming into the Greater Fresno area are:

1) Gates-Mustang #1 230 kV
2) Gates-Mustang #2 230 kV
3) Gates #5 230/70 kV Transformer Bank
4) Mercy Spring 230 /70 Bank # 1
5) Los Banos #3 230/70 Transformer Bank
6) Los Banos #4 230/70 Transformer Bank
7) Warnerville-Wilson 230kV
8) Melones-North Merced 230 kV line
9) Panoche-Tranquility #1 230 kV
10) Panoche-Tranquility #2 230 kV
11) Panoche #1 230/115 kV Transformer Bank
12) Panoche #2 230/115 kV Transformer Bank
13) Corcoran-Smyrna 115kV
14) Coalinga #1-San Miguel 70 kV

The substations that delineate the Greater Fresno area are:

1) Gates is out Henrietta is in
2) Gates is out Henrietta is in

[13] LCR requirement for a single contingency means that there wouldn't be any criteria violations following the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[14] LCR requirement for multiple contingencies means that not only there wouldn't be any criteria violations following the loss of a single element, but also the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

3) Gates 230 is out Gates 70 is in
4) Mercy Springs 230 is out Mercy Springs 70 is in
5) Los Banos 230 is out Los Banos 70 is in
6) Los Banos 230 is out Los Banos 70 is in
7) Warnerville is out Wilson is in
8) Melones is out North Merced is in
9) Panoche is out Tranquility #1 is in
10) Panoche is out Tranquility #2 is in
11) Panoche 230 is out Panoche 115 is in
12) Panoche 230 is out Panoche 115 is in
13) Corcoran is in Smyrna is out
14) Coalinga is in San Miguel is out

Load:

Total 2022 load within the defined area: 3247 MW with -99 MW of AAEE, 105 MW of losses and -198MW of DG resulting in total load + losses of 3352 MW.

List of physical units: See Appendix A.

Major new projects modeled:

1. Kerchhoff PH #2 - Oakhurst 115 kV Line
2. Warnerville-Wilson 230 kV reactor
3. Oro Loma 70 kV Area Reinforcement
4. New E2 substation
5. New North Merced 230/115 kV substation
6. New Mercy Spring 230/70 kV substation
7. Le Grand-Chowchilla 115 kV reconductoring
8. Panoche-Oro Loma 115 kV Reconductoring Project
9. Gates 500/230kV Transformer Bank #12

Critical Contingency Analysis Summary:

Hanford Sub-area

The most critical contingency for the Hanford sub-area is the loss of the Gates-Mustang #1 and #2 230 kV lines, which would thermally overload the McCall-Kingsburg #1 115 kV line . This limiting contingency establishes a local capacity need of 148 MW in 2022 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

There is no single critical contingency in this sub-area.

Effectiveness factors:
All units within this sub-area have the same effectiveness factor.

Coalinga Sub-area
The most critical contingency for the Coalinga sub-area is the loss of the Gates #5 230/70 kV transformer followed by the Panoche-Schindler #1 and #2 common tower contingency, which could cause voltage instability in the pocket. This limiting contingency establishes a local capacity need of 32 MW in 2022 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

There is no single critical contingency in this sub-area.

Effectiveness factors:
All units within this sub-area have the same effectiveness factor.

Borden Sub-area
The most critical contingency for the Borden sub-area is the loss of the Borden #4 230/70 kV transformer followed by the Friant-Coppermine 70 kV line, which could cause overload on the Borden #1 230/70 kV transformer. This limiting contingency establishes a local capacity need of 19 MW in 2022 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

There is no single critical contingency in this sub-area.

Effectiveness factors:
All units within this sub-area have the same effectiveness factor.

Reedley Sub-area

This sub-area has been eliminated due to New McCall-Reedley #2 115 kV line project.

Herndon Sub-area

The most critical contingency is the loss of Herndon-Woodward 115kV line and Herndon-Manchester 115kV line. This contingency could thermally overload the Herndon-Barton 115 kV line. This limiting contingency established an LCR of 852 MW in 2022 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The second most critical contingency is the loss of Herndon-Barton 115 kV line with Balch 1 generating unit out of service. This contingency would thermally overload the Herndon-Manchester 115 kV line and establishes an LCR of 327 MW.

Effectiveness factors:

The following table has units within Fresno area that are relatively effective to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	Eff Factor %
34624	BALCH 1	1	18.198
34616	KINGSRIV	1	16.901
34671	KRCDPCT1	1	16.258
34672	KRCDPCT2	1	16.258
34648	DINUBA E	1	15.628
34603	JGBSWLT	ST	12.418
34677	Q558	1	12.418
34690	CORCORAN_3	FW	12.418
34692	CORCORAN_4	FW	12.418
34696	CORCORANPV_S	1	12.418
34699	Q529	1	12.418
34610	HAAS	1	11.344
34610	HAAS	2	11.344
34612	BLCH 2-2	1	11.344
34614	BLCH 2-3	1	11.344
34308	KERCKHOF	1	8.609
34343	KERCK1-2	2	8.609

34344	KERCK1-1	1	8.609
34345	KERCK1-3	3	8.609
34431	GWF_HEP1	1	7.258
34433	GWF_HEP2	1	7.258
34617	Q581	1	4.142
34649	Q965	1	4.142
34680	KANSAS	1	4.142

Overall (Wilson) Sub-area

The most critical contingency for the Fresno area is the loss of the Gates-Midway 230kV line and Los Banos #1 500/230kV transformer, which could thermally overload the Gates #11 500/230 kV transformer. This limiting contingency establishes a local capacity need of 1860 MW in 2022 as the generation capacity necessary for reliable load serving capability within this area.

The most critical single contingency for the Fresno area is the loss of the Los Banos #1 500/230 kV transformer, which could thermally overload the Gates #11 500/230 kV transformer. This limiting contingency establishes a local capacity need of 1479 MW in 2022 as the generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

For most helpful procurement information please read procedure M-2210Z effectiveness factors at: http://www.caiso.com/Documents/2210Z.pdf

Changes compared to last year's results:

Overall the load forecast increased by 112 MW. The LCR need has increased by 700 MW (vs. the under-reported 2021 need) due to: load increase, Path 15 being studied from S-N resulting in new Limiting Contingency and Limiting element, as well as the delay in the Northern Fresno 115 kV Reinforcement project.

Fresno Area Overall Requirements:

2022	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	64	167	3295	3526

2022	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single) [15]	1479	0	1479
Category C (Multiple) [16]	1860	0	1860

7. Kern Area

Area Definition:

The transmission facilities coming into the Kern PP sub-area are:

1) Midway-Kern PP #1 230 kV Line
2) Midway-Kern PP #3 230 kV Line
3) Midway-Kern PP #4 230 kV Line
4) Famoso-Charca 115 kV Line (Normal Open)
5) Wasco-Famoso 70 kV Line (Normal Open)
6) Maricopa-Copus 70 kV Line (Normal Open)
7) Copus-Old River 70 kV Line (Normal Open)
8) Kern Canyo-Magunden-Weedpatch 70 kV Line (Normal Open)
9) Wheeler Ridge-Lamont 115 kV Line (Normal Open)

The substations that delineate the Kern-PP sub-area are:

1) Midway 230 kV is out Bakersfield and Stockdale 230 kV are in
2) Midway 230 kV is out Kern and Stockdale 230 kV are in
3) Midway 230 kV is out Kern PP 230 kV is in

[15] LCR requirement for a single contingency means that there wouldn't be any criteria violations following the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.
[16] LCR requirement for multiple contingencies means that not only there wouldn't be any criteria violations following the loss of a single element, but also the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

4) Charca 115kV is out Famoso 115 kV is in
5) Wasco 70 kV is out Mc Farland 70 kV is in
6) Basic School Junction 70 kV is out, Copus 70 kV is in
7) Lakeview 70 kV is out, San Emidio Junction 70 kV is in
8) Magunden Junction 70 kV is out, Magunden 70 kV is in
9) Wheeler Ridge 115 kV is out, Adobe Solar 115 kV is in

Load:

2022 total busload within the defined area is 950 MW with -27 MW of AAEE, 6 MW of losses and -44 MW DG resulting in a total (load plus losses) of 885 MW.

List of physical units: See Appendix A.

Major new projects modeled:

1. Kern PP 230 kV area reinforcement project
2. Kern PP 115 kV area reinforcement project
3. New Wheeler Ridge Junction substation
4. Midway-Kern PP 1, 3 &4 230 kV line capacity increase project

Critical Contingency Analysis Summary

West Park Sub-area

The West Park Sub area has been eliminated due to the normally open CB122 at Magunden and Kern PP 115 kV are reinforcement project.

Kern Oil Sub-area

The most critical contingency is the Kern PP-Magunden-Witco 115 kV line followed by Kern PP-7th Standard 115 kV line or vice versa resulting in the thermal overload of the Kern PP-Live Oak 115 kV line. This limiting contingency establishes a LCR of 123 MW in 2022 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area have the same effectiveness factor.

South Kern PP Sub-area

South Kern PP Sub-area has been eliminated due to Kern PP 230 kV area reinforcement and the Midway-Kern 1, 3 & 4 230 kV line capacity increase project.

Changes compared to last year's results:

The load may not be directly compared with 2021 due to change in area definition. LCR requirement have gone up by 18 MW.

Kern Area Overall Requirements:

2022	QF/Selfgen (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	15	551	566

2022	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single) [17]	0	0	0
Category C (Multiple) [18]	123	0	123

8. LA Basin Area

<u>Area Definition:</u>

The transmission tie lines into the LA Basin Area are:

1) San Onofre - San Luis Rey #1, #2, and #3 230 kV Lines
2) San Onofre - Talega #2 230 kV Lines

[17] LCR requirement for a single contingency means that there wouldn't be any criteria violations following the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[18] LCR requirement for multiple contingencies means that not only there wouldn't be any criteria violations following the loss of a single element, but also the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

3) San Onofre - Capistrano #1 230 kV Lines
4) Lugo - Mira Loma #2 & #3 500 kV Lines
5) Lugo - Rancho Vista #1 500 kV Line
6) Vincent – Mesacal 500 kV Line
7) Sylmar - Eagle Rock 230 kV Line
8) Sylmar - Gould 230 kV Line
9) Vincent - Mesa Cal #1 & #2 230 kV Lines
10) Vincent - Rio Hondo #1 & #2 230 kV Lines
11) Devers - Red Bluff 500 kV #1 and #2 Lines
12) Mirage – Coachela Valley # 1 230 kV Line
13) Mirage - Ramon # 1 230 kV Line
14) Mirage - Julian Hinds 230 kV Line

The substations that delineate the LA Basin Area are:

1) San Onofre is in San Luis Rey is out
2) San Onofre is in Talega is out
3) San Onofre is in Capistrano is out
4) Mira Loma is in Lugo is out
5) Rancho Vista is in Lugo is out
6) Eagle Rock is in Sylmar is out
7) Gould is in Sylmar is out
8) Mira Loma is in Vincent is out
9) Mesa Cal is in Vincent is out
10) Rio Hondo is in Vincent is out
11) Devers is in Red Bluff is out
12) Mirage is in Coachela Valley is out
13) Mirage is in Ramon is out
14) Mirage is in Julian Hinds is out

Load:

The CEC-adopted demand forecast for 2022 from the 2017-2027 Mid Baseline, Low AAEE savings for 1-in-10 heat wave forecast is 18,567 MW[19] (this includes loads & losses and 831 MW AAEE). The total adjusted demand after including 458 MW peak shift adjustment[20] is 19,025 MW. A total of 19,020 MW of adjusted peak demand with 450 MW of peak shift adjustment was modeled for the study.

[19] CEC-adopted 2016 IEPR demand forecast for 2017-2027, January 2017, for Mid Demand Baseline Case with Low AAEE Savings.

[20] The CEC provided a total of 708 MW of peak shift for all of SCE area. It is estimated that about 458 MW is for the LA Basin based on the ratio of the behind-the-meter PV modeled in the LA Basin vs. entire SCE area (i.e., 640 MW / 989 MW).

List of physical units: See Appendix A.

Major new projects modeled:

1. Vincent-Mira Loma 500 kV (part of Tehachapi Upgrade)
2. East County 500kV Substation (ECO)
3. Mesa Loop-In Project and South of Mesa 230 kV line upgrades
4. Imperial Valley Phase Shifting Transformers (2x400 MVA)
5. Delaney – Colorado River 500 kV Line
6. Hassayampa – North Gila #2 500 kV Line (APS)
7. Bay Blvd. Substation Project
8. Sycamore – Penasquitos 230 kV Line
9. Talega Synchronous Condensers (2x225 MVAR)
10. San Luis Rey Synchronous Condensers (2x225 MVAR)
11. San Onofre Synchronous Condensers (225 MVAR)
12. Santiago Synchronous Condenser (3x81 MVAR)
13. West of Devers 230 kV line upgrades
14. Carlsbad Energy Center (500 MW)
15. Pio Pico peakers (300 MW)
16. Battery energy storage system projects in the LA Basin and San Diego area (CPUC-approved projects related to the Aliso Canyon gas storage constraint)
17. South Orange County Reliability Enhancement

Critical Contingency Analysis Summary

El Nido Sub-area:

There are no local capacity requirements due to lower demand forecast.

Western LA Basin Sub-area:

The most limiting contingency is the loss of Mesa – Redondo 230 kV line, system re-adjusted, followed by the loss of Mesa – Lighthipe 230 kV line. This N-1-1 (P6) contingency causes an overloading concern on the Mesa – Laguna Bell No. 1 230kV line. This limiting contingency requires a local capacity need of 3,803 MW as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The following table has units that have at least 5% effectiveness factors.

Resource Locations	Effectiveness Factor (%)
REFUSE 13.8 #D1	-34.52
MALBRG1G 13.8 #C1	-34.42
ELSEG6ST 13.8 #6	-26.66
ELSEG5GT 16.5 #5	-26.64
VENICE 13.8 #1	-26.22
MOBGEN1 13.8 #1	-26.18
PALOGEN 13.8 #D1	-26.18
ARCO 1G 13.8 #1	-23.13
HARBOR G 13.8 #1	-23.03
THUMSGEN 13.8 #1	-23.03
CARBGEN1 13.8 #1	-23.02
SERRFGEN 13.8 #D1	-23.02
ICEGEN 13.8 #D1	-22.33
ALMITOSW 66.0 #l3	-18.01
ALAMTX1 18.0 #X1	-17.93
CTRPKGEN 13.8 #1	-17.51
SIGGEN 13.8 #D1	-17.51
BARRE 66.0 #m3	-12.76
BARPKGEN 13.8 #1	-12.71
RIOHONDO 66.0 #l8	-12.5
WALNUT 66.0 #l3	-12.29
OLINDA 66.0 #1	-12.07
EME WCG1 13.8 #1	-12
BREAPWR2 13.8 #C4	-11.98
ELLIS 66.0 #l7	-11.98
JOHANNA 66.0 #l5	-11.42
SANTIAGO 66.0 #l8	-10.63
DowlingCTG 13.8 #1	-9.62
CanyonGT 1 13.8 #1	-9.58
VILLA PK 66.0 #l2	-9.29

There are numerous other combinations of contingencies in the area that could overload a significant number of 230 kV lines in this sub-area/area and have slightly less LCR need. As such, anyone of them (combination of contingencies) could become binding for any given set of procured resources. As a result, these effectiveness factors may not facilitate more informed procurement.

West of Devers Sub-area:

There are no local capacity requirements due to implementation of the Mesa Loop-in as well as West of Devers reconductoring projects.

Valley-Devers Sub-area:

There are no local capacity requirements due to implementation of the Colorado River-Delaney 500 kV line project.

Valley Sub-area:

There are no local capacity requirements due to implementation of the Colorado River-Delaney 500 kV line project.

Eastern LA Basin Sub-area:

The most critical contingency is the loss of the Alberhill - Serrano 500 kV line, followed by an N-2 of Red Bluff-Devers #1 and #2 500 kV lines, which could result in voltage instability. This limiting contingency establishes a local capacity need of about 2,107 MW as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area have the same effectiveness factor.

Overall LA Basin Area and San Diego-Imperial Valley Area Combined:

The LCR needs of the LA Basin area and San Diego-Imperial Valley area have been considered through a coordinated study process to ensure that the resource needs for each LCR area not only satisfy its own area reliability need but also provide support to the other area if needed. With the retirement of the San Onofre Nuclear Generating Station, and the impending retirement of other once-through cooled generation in the LA

Basin and San Diego areas, the two areas are electrically interdependent on each other. Resource needs in one area are dependent on the amount of resources that are dispatched for the adjacent area and vice versa. The SDG&E system, being the southernmost electrical area in the ISO's southern system and smaller of the overall LA Basin-San Diego-Imperial Valley area, is evaluated first for its LCR needs. The LCR needs for the LA Basin and its subareas are then evaluated after the initial determination of the LCR needs for the overall San Diego-Imperial Valley area. The LCR needs in the overall San Diego-Imperial Valley area are then re-checked to ensure that the initial determination is still adequate. This iterative process is needed due to the interaction of resources on the LCR needs in the LA Basin-San Diego-Imperial Valley area. With this process, the LCR needs for the respective areas are coordinated within the overall LA Basin-San Diego-Imperial Valley area. *It is important to note that the San Diego subarea is a part or subset of the overall San Diego-Imperial Valley area.*

An additional consideration is whether the Aliso Canyon gas storage constraint needs to be evaluated to determine the LCR needs for the LA Basin and the San Diego-Imperial Valley for 2022. At this time, the ISO is not performing analyses that would involve balancing resources between the LA Basin and San Diego areas similar to the 2017 LCR due to the benefits of the enhanced balancing rules as the CPUC has recognized the effectiveness of tighter non-core balancing rules. Based on the recent CPUC Public Utilities Code Section 715 report[21], dated January 17, 2017, on page 15, the CPUC indicated that the 150 mmcf potential imbalance has been offset by the new balancing rules and directly reduces the amount of the original curtailment identified in the four summer technical scenarios involving various levels of gas facility outages. However, as Southern California Gas Company has informed the CPUC in its February 17, 2017 Storage Safety Enhancement Plan, it is important to note that there are potential deliverability impacts due to tubing flow only operation of the remaining gas storage

21 http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/AlisoGas1-9-715.pdf

fields at Goleta, Playa Del Rey and Honor Rancho. More study is necessary to understand the meaning and the extent of the tubing only production limitation.

As mentioned above, the overall LA Basin-San Diego-Imperial Valley LCR needs were determined by evaluating the LCR needs in the San Diego-Imperial Valley LCR area first, and then determining the LCR needs for the LA Basin. The total LCR needs for the combined LA Basin-San Diego-Imperial Valley area are the sum of the LCR needs for the LA Basin and the San Diego-Imperial Valley area.

The following is the discussion of the LCR needs for each of these respective areas:

1. *Overall San Diego-Imperial Valley Area:*

The most critical contingency resulting in thermal loading concerns for the overall San Diego-Imperial Valley area is the G-1/N-1 (Category B) overlapping outage that involves the loss of the TDM combined cycled power plant (593 MW), system readjustment, followed by the loss of the Imperial Valley – North Gila 500 kV line or vice versa (Category C). This overlapping contingency could thermally overload the Imperial Valley – El Centro 230 kV line (i.e., the "S" line)[22]. This contingency establishes a total local capacity need of 4,643 MW (includes 33 MW of deficiency) in 2022 as the resource capacity necessary for reliable load serving capability within the overall San Diego – Imperial Valley area. Imperial Valley renewables, with future planned in-service dates prior to summer 2022 are also modeled in the study. The reason that the LCR need for the San Diego-Imperial Valley area is higher than 2018 LCR need is due to higher total managed peak load with peak shift for San Diego subarea, as well as higher assumed maximum import capability (702 MW) from the IID-SCE and IID-SDG&E branch groups.[23]

[22] The "S" line is owned and operated by the Imperial Irrigation District (IID) that connects the IID electrical grid with the ISO BAA's SDG&E-owned electrical grid.
[23] The assumption for 2022 import capability from IID-SCE and IID-SDG&E is based on "Advisory Estimates of Future Resource Adequacy Import Capability for Years 2017 – 2026 (http://www.caiso.com/Documents/AdvisoryestimatesoffutureResourceAdequacyImportCapabilityforyears2017-2026.pdf)

The corresponding overall LA Basin LCR need associated with this level of LCR need for the San Diego – Imperial Valley area is 5,957 MW. The reasons that the LA Basin LCR need is lower than the previous LCR assessments due to the following:

- Implementation of major transmission projects, such as the Mesa Loop-In and the new Delaney-Colorado River 500 kV line;
- Having lower demand forecast from the CEC;
- LA Basin generating resources are much less effective than generating resources in the Imperial Valley and the San Diego sub-area in mitigating the "S" line overloading concern.

2. *Overall LA Basin Area:*

As discussed earlier, to determine whether the aforementioned LCR need in the LA Basin is adequate for the LA Basin LCR area, the ISO performed contingency analyses in the LA Basin after the evaluation of the LCR need for the San Diego-Imperial Valley LCR.

The most critical contingency resulting in thermal loading concerns for the overall LA Basin is the loss of the Mesa – Redondo 230 kV line, system readjustment, followed by the loss of Mesa – Lighthipe 230 kV line or vice versa. This overlapping contingency could thermally overload the Mesa – Laguna Bell #1 230 kV line. This establishes a total local capacity need for overall LA Basin area of 6,022 MW in 2018 as the minimum resource capacity necessary for reliable load serving capability within this area.

The overall combined LA Basin-San Diego-Imperial Valley area has a total of 10,665 MW in 2022 time frame as follows: 6,022 MW in the LA Basin and 4,643 MW in the San Diego-Imperial Valley area as the minimum capacity necessary for reliable load serving capability within these areas. The most limiting constraint is the thermal loading concern on the Mesa – Laguna Bell #1 230 kV line under an overlapping P6 contingency, followed closely the limiting constraint on the "S" line between IID and SDG&E under an overlapping G-1/N-1 contingency or vice versa (i.e., an N-1, followed by a G-1).

Effectiveness factors:

The following table summarizes effectiveness factors of the resources in mitigating identified reliability concern for the most limiting constraint in the LA Basin (i.e., the Mesa – Laguna Bell #1 230 kV line under an overlapping N-1-1 contingency).

Resource Locations	Effectiveness Factor (%)
REFUSE 13.8 #D1	-34.52
MALBRG1G 13.8 #C1	-34.42
ELSEG6ST 13.8 #6	-26.66
ELSEG5GT 16.5 #5	-26.64
VENICE 13.8 #1	-26.22
MOBGEN1 13.8 #1	-26.18
PALOGEN 13.8 #D1	-26.18
ARCO 1G 13.8 #1	-23.13
HARBOR G 13.8 #1	-23.03
THUMSGEN 13.8 #1	-23.03
CARBGEN1 13.8 #1	-23.02
SERRFGEN 13.8 #D1	-23.02
ICEGEN 13.8 #D1	-22.33
ALMITOSW 66.0 #l3	-18.01
ALAMTX1 18.0 #X1	-17.93
CTRPKGEN 13.8 #1	-17.51
SIGGEN 13.8 #D1	-17.51
BARRE 66.0 #m3	-12.76
BARPKGEN 13.8 #1	-12.71
RIOHONDO 66.0 #l8	-12.50
WALNUT 66.0 #l3	-12.29
OLINDA 66.0 #1	-12.07
EME WCG1 13.8 #1	-12.00
BREAPWR2 13.8 #C4	-11.98
ELLIS 66.0 #l7	-11.98
JOHANNA 66.0 #l5	-11.42
SANTIAGO 66.0 #l8	-10.63
DowlingCTG 13.8 #1	-9.62
CanyonGT 1 13.8 #1	-9.58
VILLA PK 66.0 #l2	-9.29

Sensitivity assessment with Imperial Valley solar generation unavailable at 6 p.m. for a peak load day

The purpose of performing this sensitivity study is to evaluate the potential impact to the LCR requirements for the LA Basin-San Diego-Imperial Valley area for the scenario in which the Imperial Valley solar generation is unavailable to provide resource needs to mitigate loading concern on the Imperial Valley – El Centro 230 kV line under an overlapping G-1/N-1 contingency of the combined cycled TDM generation, system adjustment, followed by an outage on the Imperial Valley – North Gila 500 kV line. Since the solar generation in the Imperial Valley area are effective in mitigating this line overloading concern, its unavailability at the time of the area peak load at 6 p.m. could affect the LCR requirements in the overall LA Basin, San Diego subarea, and the overall San Diego – Imperial Valley area. This analysis is for risk assessment purposes. The existing practice is to establishing local capacity requirements for use in the resource adequacy (RA) process based on individual resource net qualifying capacity (NQC) as dictated by accounting rules of Local Regulatory Agencies (LRA).

For this sensitivity assessment, the ISO reviewed the availability of the solar central plants in the Imperial Valley area at 6 p.m. on September 26, 2016, using archived data from the ISO Energy Management System (EMS). This date had high loads for SDG&E in 2016. The Imperial Valley solar generation had either 0 MW output or was negligible (i.e., less than 1% of its maximum output which is within 2% tolerance of the archived real-time data). The study case was modified from having NQC values for Imperial Valley solar generation to no output. The limiting contingency is the overlapping G-1/N-1 of TDM combined cycled generation, system readjustment, followed by the loss of the Imperial Valley – North Gila 500 kV line. This contingency could cause an overloading concern on the Imperial Valley – El Centro 230 kV line. The LCR requirements for the combined LA Basin-San Diego-Imperial Valley area, based on this scenario are: LA Basin LCR needs at 7,404 MW (all effective resources) and San Diego-Imperial Valley area LCR needs at 4,739 MW (all available non-solar resources as well as over 900 MW of deficiency at most effective location).

The following are key observations when comparing the LCR needs of the sensitivity study to the LCR needs based on the currently established NQC values:

- With less solar generating resources being available in the Imperial Valley at 6 p.m., the next effective generating resources are located in the San Diego sub-area. This increases the San Diego sub-area LCR needs to 2,800 MW, which at this time, is the maximum potential available non-solar resources in this sub-area estimated for summer 2022.
- When available resources in the San Diego sub-area are fully utilized, the resources in the western LA Basin are used to help relieve the loading concerns. The estimated 7,404 MW is the potential maximum available in the LA Basin in the 2022 timeframe, after massive retirement of the once-through-cool generation resources at the end of 2020.
- After non-solar resources in both the LA Basin and San Diego sub-area are fully utilized to mitigate the potential overloading concern on the “S” line, the estimated deficiency, if mitigated by load drop, would be in the 1,300 MW range in the San Diego area (less effective than Imperial Valley resources. This potential overloading concern is a reliability concern and requires mitigation, either with additional resource procurement, or transmission upgrades, or a combination of these.

<u>Changes compared to last year’s results:</u>

Compared with the 2021 LCR study results, the latest CEC-adopted adjusted peak demand forecast for 2022, with peak shift adjustment, is lower by 478 MW for the geographic LA Basin area. The 2022 LCR need for the overall LA Basin is lower by about 876 MW when compared with the recently completed 2021 LCR study report.[24] This is primarily due to lower demand forecast from the CEC, as well as dispatch of the

[24] http://www.caiso.com/Documents/Final2021Long-TermLocalCapacityTechnicalReport.pdf

more effective available local resources in the LA Basin and the San Diego-Imperial Valley area to mitigate their respective reliability concerns.

LA Basin Overall Requirements:

2022	QF (MW)	Wind (MW)	Muni (MW)	Market (MW)	Preferred Res. (MW)	20 Min. DR (MW)	Mothball (MW)	Max. Qualifying Capacity (MW)
Available generation	321	59	1176	5394	432	321	435	8138

2022	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[25]	5957	0	5957
Category C (Multiple)[26]	6022	0	6022

9. Big Creek/Ventura Area

Area Definition:

The transmission tie lines into the Big Creek/Ventura Area are:

1) Antelope #1 500/230 kV Transformer
2) Antelope #2 500/230 kV Transformer
3) Sylmar - Pardee 230 kV #1 and #2 Lines
4) Vincent - Pardee 230 kV #2 Line
5) Vincent - Santa Clara 230 kV Line

The substations that delineate the Big Creek/Ventura Area are:

1) Antelope 500 kV is out Antelope 230 kV is in
2) Antelope 500 kV is out Antelope 230 kV is in
3) Sylmar is out Pardee is in
4) Vincent is out Pardee is in
5) Vincent is out Santa Clara is in

[25] LCR requirement for a single contingency means that there wouldn't be any criteria violations following the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.
[26] LCR requirement for multiple contingencies means that not only there wouldn't be any criteria violations following the loss of a single element, but also the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

Load:

Total 2022 busload within the defined area[27] is 4,968 MW with (232) MW of AAEE, (131) MW of BTM PV impact[28], 46 MW of losses and 369 MW of pumps resulting in a total managed load + losses + pumps of 5,020 MW.

List of physical units: See Appendix A.

Major new projects modeled: None.

Critical Contingency Analysis Summary:

Rector Sub-area:

The most critical contingency is the loss of the Rector - Vestal 230 kV line with the Eastwood unit out of service, which could thermally overload the remaining Rector - Vestal 230 kV line. This limiting contingency establishes a local capacity need of 507 MW as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The following table has units that have at least 5% effectiveness to the above-mentioned constraint within Rector sub-area:

Gen Bus	Gen Name	Gen ID	MW Eff Fctr (%)
24370	KAWGEN	1	51
24306	B CRK1-1	1	46
24306	B CRK1-1	2	46
24307	B CRK1-2	3	46
24307	B CRK1-2	4	46
24319	EASTWOOD	1	46
24323	PORTAL	1	46
24308	B CRK2-1	1	45
24308	B CRK2-1	2	45
24309	B CRK2-2	3	45

[27] The Big Creek Ventura LCA includes the Saugus Substation.
[28] The BTM PV impact value includes a downward adjustment of 194 MW due to peak shift.

24309	B CRK2-2	4	45
24310	B CRK2-3	5	45
24310	B CRK2-3	6	45
24315	B CRK 8	81	45
24315	B CRK 8	82	45
24311	B CRK3-1	1	45
24311	B CRK3-1	2	45
24312	B CRK3-2	3	45
24312	B CRK3-2	4	45
24313	B CRK3-3	5	45
24317	MAMOTH1G	1	45
24318	MAMOTH2G	2	45
24314	B CRK 4	41	43
24314	B CRK 4	42	43

Vestal Sub-area:

The most critical contingency is the loss of the Magunden - Vestal 230 kV line with the Eastwood unit out of service, which could thermally overload the remaining Magunden - Vestal 230 kV line. This limiting contingency establishes a local capacity need of 848 MW as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The following table has units that have at least 5% effectiveness to the above-mentioned constraint within Vestal sub-area:

Gen Bus	Gen Name	Gen ID	MW Eff Fctr (%)
24113	PANDOL	1	65
24113	PANDOL	2	65
24116	WELLGEN	1	65
24150	ULTRAGEN	1	65
24372	KR 3-1	1	65
24373	KR 3-2	2	65
28019	WDT190G	1	65
29008	LAKEGEN	1	65
24370	KAWGEN	1	50
24306	B CRK1-1	1	44
24306	B CRK1-1	2	44
24307	B CRK1-2	3	44
24307	B CRK1-2	4	44
24319	EASTWOOD	1	44

24323	PORTAL	1	44
24308	B CRK2-1	1	44
24308	B CRK2-1	2	44
24309	B CRK2-2	3	44
24309	B CRK2-2	4	44
24310	B CRK2-3	5	44
24310	B CRK2-3	6	44
24315	B CRK 8	81	44
24315	B CRK 8	82	44
24311	B CRK3-1	1	44
24311	B CRK3-1	2	44
24312	B CRK3-2	3	44
24312	B CRK3-2	4	44
24313	B CRK3-3	5	44
24317	MAMOTH1G	1	44
24318	MAMOTH2G	2	44
24314	B CRK 4	41	42
24314	B CRK 4	42	42

Santa Clara Sub-area:

The most critical contingency is the loss of the Pardee - Santa Clara 230 kV line followed by the loss of Moorpark - Santa Clara 230 kV #1 and #2 lines, which would cause voltage collapse. This limiting contingency establishes a local capacity need of 289 MW as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area have the same effectiveness factor.

Moorpark Sub-area:

The most critical contingency is the loss of the Moorpark - Pardee 230 kV #3 line followed by the loss of the Moorpark - Pardee 230 kV #1 and #2 lines, which will cause voltage collapse. This limiting contingency establishes a local capacity need of 554 MW as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area have the same effectiveness factor.

Big Creek/Ventura overall:

The most critical contingency is the loss of the Lugo - Victorville 500 kV line followed by loss of one of the Sylmar - Pardee 230 kV line, which would thermally overload the remaining Sylmar - Pardee 230 kV line. This limiting contingency establishes a local capacity need of 2597 MW as the minimum capacity necessary for reliable load serving capability within this area.

The single most critical contingency is the loss of Sylmar - Pardee #1 (or # 2) line with Pastoria power plant (CCGT) out of service, which could thermally overload the remaining Sylmar - Pardee #2 or #1 230 kV line. This limiting contingency establishes a local capacity need of 2208 MW.

Effectiveness factors:

The following table has effectiveness factors to the most critical contingency.

Gen Bus	Gen Name	Gen ID	MW Eff Fctr (%)
24009	APPGEN1G	1	31
24010	APPGEN2G	2	31
24118	PITCHGEN	D1	31
24148	TENNGEN1	D1	31
24149	TENNGEN2	D2	31
24361	APPGEN3G	3	31
29954	WDT273	EQ	31
24107	ORMOND1G	1	30
24108	ORMOND2G	2	30
25651	WARNE1	1	28
25652	WARNE2	1	28
24089	MANDLY1G	1	26
24090	MANDLY2G	2	26
24110	OXGEN	D1	26
24119	PROCGEN	D1	26
24127	S.CLARA	1	26
24159	WILLAMET	D1	26
24222	MANDLY3G	3	26
24326	EXGEN1	S1	26

24340	CHARMIN	1	26
24362	EXGEN2	G1	26
29004	ELLWOOD	1	26
29306	MCGPKGEN	1	26
29952	CAMGEN	D1	26
25653	ALAMO SC	1	26
29051	PSTRIAG1	G1	25
29052	PSTRIAG2	G2	25
29053	PSTRIAS1	S1	25
29054	PSTRIAG3	G3	25
29055	PSTRIAS2	S2	25
24102	OMAR 1G	1	21
24103	OMAR 2G	2	21
24104	OMAR 3G	3	21
24105	OMAR 4G	4	21
24113	PANDOL	1	21
24113	PANDOL	2	21
24116	WELLGEN	1	21
24143	SYCCYN1G	1	21
24144	SYCCYN2G	2	21
24145	SYCCYN3G	3	21
24146	SYCCYN4G	4	21
24150	ULTRAGEN	1	21
24306	B CRK1-1	1	21
24306	B CRK1-1	2	21
24307	B CRK1-2	3	21
24307	B CRK1-2	4	21
24308	B CRK2-1	1	21
24308	B CRK2-1	2	21
24309	B CRK2-2	3	21
24309	B CRK2-2	4	21
24310	B CRK2-3	5	21
24310	B CRK2-3	6	21
24311	B CRK3-1	1	21
24311	B CRK3-1	2	21
24312	B CRK3-2	3	21
24312	B CRK3-2	4	21
24313	B CRK3-3	5	21
24314	B CRK 4	41	21
24314	B CRK 4	42	21
24315	B CRK 8	81	21
24315	B CRK 8	82	21
24317	MAMOTH1G	1	21
24318	MAMOTH2G	2	21
24319	EASTWOOD	1	21

24323	PORTAL	1	21
24370	KAWGEN	1	21
24372	KR 3-1	1	21
24373	KR 3-2	2	21
28019	WDT190G	1	21
29008	LAKEGEN	1	21
29900	ALPINE_G	EQ	17
24422	PALMDALE	1	8
29884	DAWNGEN	EQ	8
29888	TWILGHTG	EQ	8
29896	APPINV	EQ	8
29918	VLYFLR_G	EQ	8

Changes compared to last year's results:

Compared with 2021 the load forecast is up by 343 MW and the LCR need has increased by 199 MW.

Big Creek/Ventura Overall Requirements:

2022	QF (MW)	Muni (MW)	Battery St. (MW)	Preferred Res. (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	58	372	5	12	3413	3859

2022	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[29]	2208	0	2208
Category C (Multiple)[30]	2597	0	2597

[29] LCR requirement for a single contingency means that there wouldn't be any criteria violations following the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[30] LCR requirement for multiple contingencies means that not only there wouldn't be any criteria violations following the loss of a single element, but also the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

10. San Diego-Imperial Valley Area

<u>Area Definition:</u>

The transmission tie lines forming a boundary around the Greater San Diego-Imperial Valley area include:

1) Imperial Valley – North Gila 500 kV Line
2) Otay Mesa – Tijuana 230 kV Line
3) San Onofre - San Luis Rey #1 230 kV Line
4) San Onofre - San Luis Rey #2 230 kV Line
5) San Onofre - San Luis Rey #3 230 kV Line
6) San Onofre – Talega 230 kV Line
7) San Onofre – Capistrano 230 kV Line
8) Imperial Valley – El Centro 230 kV Line
9) Imperial Valley – La Rosita 230 kV Line

The substations that delineate the Greater San Diego-Imperial Valley area are:

1) Imperial Valley is in North Gila is out
2) Otay Mesa is in Tijuana is out
3) San Onofre is out San Luis Rey is in
4) San Onofre is out San Luis Rey is in
5) San Onofre is out San Luis Rey is in
6) San Onofre is out Talega is in
7) San Onofre is out Talega is in
8) Imperial Valley is in El Centro is out
9) Imperial Valley is in La Rosita is out

<u>Load:</u>

The CEC-adopted demand forecast for 2022 from the 2017-2027 Mid Baseline, Low AAEE savings for 1-in-10 heat wave forecast is 4,704 MW[31] (this is the net value that includes loads, 133 MW of losses and 217 MW AAEE). The total adjusted demand after including 415 MW peak shift adjustment to be modeled for the study is 5,119 MW. A final total of 5,053 MW of adjusted peak demand with the CEC-forecasted peak shift adjustment was modeled in this study. The reason for the discrepancy with the targeted 5,119 MW value is because the final study case had lower losses due to higher dispatch of internal generating resources.

[31] CEC-adopted 2016 IEPR demand forecast for 2017-2027, January 2017, for Mid Demand Baseline Case with Low AAEE Savings.

List of physical units: See Appendix A.

Major new projects modeled:

1. Second Encina 230/138 bank #61
2. Reconductor of Mission-Mesa Heights and Mesa Heights loop-in 69 kV project
3. Reconductor of Kearny-Mission 69 kV line
4. T600 Loo-in to Mesa Hights 69 kV
5. TL6906 Mesa Rim reconfiguration
6. Salt Creek 69 kV substation
7. Vine 69 kV substation
8. Ocean Ranch 69 kV substation
9. Second Poway to Pomerado line
10. TL632 Granite loop-in and TL6914 reconfiguration
11. Reconductor of Stuart Tap-Las Pulgas 69 kV line (TL690E)
12. Reconductor of Japanes Mesa–Basilone–Talega Tap 69 kV lines
13. Second San Marcos – Escondido 69kV line
14. Upgrade Bernardo - Rancho Carmel 69kV line
15. Second Poway-Pomerado 69 kV line
16. Bay Boulevard 230 kV substation
17. Imperial Valley phase shifting transformers
18. Sycamore - Penasquitos 230kV Line
19. Artesian 230 kV expansion with 69kV upgrade
20. Second Miguel – Bay Boulevard 230 kV line
21. South Orange County Reliability Enhancement
22. Miguel synchronous condensers (2x225 Mvar)
23. San Luis Rey synchronous condensers (2x225 Mvar)
24. San Onofre synchronous condenser (1x240 Mvar)
25. Suncrest SVC project
26. New capacitors at Pendlenton and Basilone 69 kV substations
27. Storage projects at Escondido(3x10 MW) and El Cajon (7.5 MW)
28. Carlsbad Energy Center (500 MW)

Critical Contingency Analysis Summary:

El Cajon Sub-area

The most critical contingency for the El Cajon sub-area is the loss of the Granite - Los Coches 69 kV lines #1 and #2, which could thermally overload the El Cajon-Los Coches 69 kV line (TL631). This limiting contingency establishes a LCR of 40 MW in 2022 as the minimum generation capacity necessary for reliable load serving capability within this sub-area after the TL632 Granite Loop-In and TL6914 reconfiguration project are completed.

Effectiveness factors:

All units within this sub-area have the same effectiveness factor.

Mission Sub-area

The LCR need for the Mission sub-area will be eliminated by implementing the T600 Loo-in to Mesa Hights 69 kV and TL676 Mission – Mesa Heights 69 kV reconductor projects before 2022.

Effectiveness factors:

All Kearny Peakers have the same effectiveness factor.

Esco Sub-area

The most critical contingency for the Esco sub-area is the loss of anyone of the two Sycamore-Pomerado 69 kV lines (TL6915 or TL6924) followed by the loss of Artisian 230/69 kV transformer bank, which could thermally overload the remaining Sycamore-Pomerado 69 kV line. This limiting contingency establishes a LCR of 30 MW in 2022 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Pala Sub-area

The most critical contingency for the Pala sub-area is the loss of Pendleton – San Luis Rey 69kV line (TL6912) followed by the loss of Lilac - Pala 69kV line (TL6932), which could thermally overload the Monserate – Morro Hill Tap 69 kV line (TL694). This limiting contingency establishes a local capacity need of 28 MW in 2022 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area (Pala) have the same effectiveness factor.

Border Sub-area

The most critical contingency for the Border sub-area is the loss of Bay Boulevard – Otay 69kV line #1 (TL645) followed by Bay Boulevard Otay – 69 kV line #2 (TL646), which could thermally overload the Imperial Beach – Bay Boulevard 69 kV line (TL647). This limiting contingency establishes a local capacity need of 62 MW in 2022 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area have the same effectiveness factor.

Miramar Sub-area

After the implementation of the Sycamore - Penasquitos 230 kV line and second Miguel – Bay Boulevard 230 kV line projects, this sub-area is eliminated.

It is recommended to retain 42 MW of Miramar Energy Center in this sub-area, until these projects are in service before 2022.

Overall LA Basin Area and San Diego-Imperial Valley Area Combined:

The LCR needs of the LA Basin area and San Diego-Imperial Valley area have been considered through a coordinated study process to ensure that the resource needs for each LCR area not only satisfy its own area reliability need but also provide support to the other area if needed. With the retirement of the San Onofre Nuclear Generating Station, and the impending retirement of other once-through cooled generation in the LA Basin and San Diego areas, the two areas are electrically interdependent on each other. Resource needs in one area are dependent on the amount of resources that are dispatched for the adjacent area and vice versa. The SDG&E system, being the southernmost electrical area in the ISO's southern system and smaller of the overall LA Basin-San Diego-Imperial Valley area, is evaluated first for its LCR needs. The LCR needs for the LA Basin and its subareas are then evaluated after the initial determination of the LCR needs for the overall San Diego-Imperial Valley area. The LCR needs in the overall San Diego-Imperial Valley area are then re-checked to ensure that the initial determination is still adequate. This iterative process is needed due to the interaction of resources on the LCR needs in the LA Basin-San Diego-Imperial Valley area. With this process, the LCR needs for the respective areas are coordinated within the overall LA Basin-San Diego-Imperial Valley area. *It is important to note that the San Diego subarea is a part or subset of the overall San Diego-Imperial Valley area.*

An additional consideration is whether the Aliso Canyon gas storage constraint needs to be evaluated to determine the LCR needs for the LA Basin and the San Diego-Imperial Valley for 2022. At this time, the ISO is not performing analyses that would involve balancing resources between the LA Basin and San Diego areas similar to the 2017 LCR due to the benefits of the enhanced balancing rules as the CPUC has recognized the effectiveness of tighter non-core balancing rules. Based on the recent CPUC Public Utilities Code Section 715 report[32], dated January 17, 2017, on page 15, the CPUC indicated that the 150 mmcf potential imbalance has been offset by the new balancing rules and directly reduces the amount of the original curtailment identified in the four summer technical scenarios involving various levels of gas facility outages. However, as Southern California Gas Company has informed the CPUC in its February 17, 2017 Storage Safety Enhancement Plan, it is important to note that there are potential deliverability impacts due to tubing flow only operation of the remaining gas storage fields at Goleta, Playa Del Rey and Honor Rancho. More study is necessary to understand the meaning and the extent of the tubing only production limitation.

32 http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/AlisoGas1-9-715.pdf

As mentioned above, the overall LA Basin-San Diego-Imperial Valley LCR needs were determined by evaluating the LCR needs in the San Diego-Imperial Valley LCR area first, and then determining the LCR needs for the LA Basin. The total LCR needs for the combined LA Basin-San Diego-Imperial Valley area are the sum of the LCR needs for the LA Basin and the San Diego-Imperial Valley area.

The following is the discussion of the LCR needs for each of these respective areas:

1. Overall San Diego-Imperial Valley Area:

The most critical contingency resulting in thermal loading concerns for the overall San Diego-Imperial Valley area is the G-1/N-1 (Category B) overlapping outage that involves the loss of the TDM combined cycled power plant (593 MW), system readjustment, followed by the loss of the Imperial Valley – North Gila 500 kV line or vice versa (Category C). This overlapping contingency could thermally overload the Imperial Valley – El Centro 230 kV line (i.e., the "S" line)[33]. This contingency establishes a total local capacity need of 4,643 MW (includes 33 MW of deficiency) in 2022 as the resource capacity necessary for reliable load serving capability within the overall San Diego – Imperial Valley area. Imperial Valley renewables, with future planned in-service dates prior to summer 2022 are also modeled in the study. The reason that the LCR need for the San Diego-Imperial Valley area is higher than 2018 LCR need is due to higher total managed peak load with peak shift for San Diego subarea, as well as higher assumed maximum import capability (702 MW) from the IID-SCE and IID-SDG&E branch groups.[34]

The corresponding overall LA Basin LCR need associated with this level of LCR need for the San Diego – Imperial Valley area is 5,957 MW. The reasons that the LA Basin LCR need is lower than the previous LCR assessments due to the following:

[33] The "S" line is owned and operated by the Imperial Irrigation District (IID) that connects the IID electrical grid with the ISO BAA's SDG&E-owned electrical grid.
[34] The assumption for 2022 import capability from IID-SCE and IID-SDG&E is based on "Advisory Estimates of Future Resource Adequacy Import Capability for Years 2017 – 2026 (http://www.caiso.com/Documents/AdvisoryestimatesoffutureResourceAdequacyImportCapabilityforyears2017-2026.pdf)

- Implementation of major transmission projects, such as the Mesa Loop-In and the new Delaney-Colorado River 500 kV line;
- Having lower demand forecast from the CEC;
- LA Basin generating resources are much less effective than generating resources in the Imperial Valley and the San Diego sub-area in mitigating the “S” line overloading concern.

Effectiveness factors:

The following lists the effectiveness factors for resources in the San Diego sub-area in response to thermal loading constraint associated with the overlapping G-1/N-1 contingency.

Resource Locations	Effectiveness Factor (%)
INTBCT 16.0 #1	25.42
INTBST 18.0 #1	25.42
DW GEN2 G1 0.4 #1	25.18
DW GEN1 G1 0.3 #G1	25.15
DU GEN1 G2 0.2 #G2	25.14
DW GEN1 G2 0.3 #G2	25.14
DU GEN1 G1 0.2 #G1	25.08
DW GEN3&4 0.3 #1	25.08
OCO GEN G1 0.7 #G1	22.71
OCO GEN G2 0.7 #G2	22.71
ECO GEN1 G 0.7 #G1	21.85
Q644G 0.3 #1	21.11
OTAYMGT1 18.0 #1	17.82
OTAYMGT2 18.0 #1	17.82
OTAYMST1 16.0 #1	17.82
PIO PICO 1 13.8 #1	17.52
PIO PICO 1 13.8 #1	17.52
PIO PICO 1 13.8 #1	17.52
KUMEYAAY 0.7 #1	17.05
EC GEN2 13.8 #1	16.91
EC GEN1 13.8 #1	16.89
OY GEN 13.8 #1	16.82
OTAY 69.0 #1	16.81
OTAY 69.0 #3	16.81
DIVISION 69.0 #1	16.78
NOISLMTR 69.0 #1	16.75
SAMPSON 12.5 #1	16.69
CABRILLO 69.0 #1	16.62
LRKSPBD1 13.8 #1	16.56
LRKSPBD2 13.8 #1	16.56
POINTLMA 69.0 #2	16.56
CALPK_BD 13.8 #1	16.55
MESAHGTS 69.0 #1	16.48
CARLTNHS 138.0 #1	16.46

CARLTNHS 138.0 #2	16.46
MISSION 69.0 #1	16.39
EASTGATE 69.0 #1	16.25
MEF MR1 13.8 #1	16.23
CHCARITA 138.0 #1	16.21
MEF MR2 13.8 #1	16.08
LkHodG1 13.8 #1	15.60
LkHodG2 13.8 #1	15.60
GOALLINE 69.0 #1	15.23
PEN_CT1 18.0 #1	14.98
CALPK_ES 13.8 #1	14.97
ENCINA 2 14.4 #1	14.96
ES GEN 13.8 #1	14.96
PEN_CT2 18.0 #1	14.93
PEN_ST 18.0 #1	14.92
SANMRCOS 69.0 #1	14.84
PA GEN1 13.8 #1	14.40
PA GEN2 13.8 #1	14.40
BR GEN1 0.2 #1	13.67
CAPSTRNO 138.0 #1	11.88

2. San Diego Sub-area:

San Diego sub-area is part of the overall San Diego-Imperial Valley LCR area. The LCR need for the San Diego sub-area can either be caused by the larger need for the San Diego-Imperial Valley area (as discussed in item #1 above), or be caused by other outages that exclusively affect the San Diego sub-area only. The ultimate San Diego sub-area LCR need will be determined by the larger requirement of these analyses.

For the outages that exclusively affect the San Diego sub-area only, it is the overlapping N-1-1 of the ECO-Miguel 500 kV line, system readjustment, followed by the outage of the Ocotillo-Suncrest 500 kV line. The limiting constraint is the post-transient voltage instability, causing an LCR need of 2,502 MW for the San Diego sub-area. The LCR need for the San Diego sub-area based on this 500 kV line N-1-1 contingency is smaller than the need determined in item #1 above. The additions of the synchronous condenser projects in Orange County and San Diego areas help mitigating the voltage instability issue and keep this from becoming a predominant concern for this sub-area in this study.

3. *Overall LA Basin Area:*

As discussed earlier, to determine whether the aforementioned LCR need in the LA Basin is adequate for the LA Basin LCR area, the ISO performed contingency analyses in the LA Basin after the evaluation of the LCR need for the San Diego-Imperial Valley LCR.

The most critical contingency resulting in thermal loading concerns for the overall LA Basin is the loss of the Mesa – Redondo 230 kV line, system readjustment, followed by the loss of Mesa – Lighthipe 230 kV line or vice versa. This overlapping contingency could thermally overload the Mesa – Laguna Bell #1 230 kV line. This establishes a total local capacity need for overall LA Basin area of 6,022 MW in 2018 as the minimum resource capacity necessary for reliable load serving capability within this area.

The overall combined LA Basin-San Diego-Imperial Valley area has a total of 10,665 MW in 2022 time frame as follows: 6,022 MW in the LA Basin and 4,643 MW in the San Diego-Imperial Valley area as the minimum capacity necessary for reliable load serving capability within these areas. The most limiting constraint is the thermal loading concern on the Mesa – Laguna Bell #1 230 kV line under an overlapping P6 contingency, followed closely the limiting constraint on the "S" line between IID and SDG&E under an overlapping G-1/N-1 contingency or vice versa (i.e., an N-1, followed by a G-1).

Sensitivity assessment with Imperial Valley solar generation unavailable at 6 p.m. for a peak load day

The purpose of performing this sensitivity study is to evaluate the potential impact to the LCR requirements for the LA Basin-San Diego-Imperial Valley area for the scenario in which the Imperial Valley solar generation is unavailable to provide resource needs to mitigate loading concern on the Imperial Valley – El Centro 230 kV line under an overlapping G-1/N-1 contingency of the combined cycled TDM generation, system adjustment, followed by an outage on the Imperial Valley – North Gila 500 kV line. Since the solar generation in the Imperial Valley area are effective in mitigating this line overloading concern, its unavailability at the time of the area peak load at 6 p.m. could affect the LCR requirements in the overall LA Basin, San Diego subarea, and the overall San Diego – Imperial Valley area. This analysis is for risk assessment purposes. The existing practice is to establishing local capacity requirements for use in the resource adequacy (RA) process based on individual resource net qualifying capacity (NQC) as dictated by accounting rules of Local Regulatory Agencies (LRA).

For this sensitivity assessment, the ISO reviewed the availability of the solar central plants in the Imperial Valley area at 6 p.m. on September 26, 2016, using archived data from the ISO Energy Management System (EMS). This date had high loads for SDG&E in 2016. The Imperial Valley solar generation had either 0 MW output or was negligible (i.e., less than 1% of its maximum output which is within 2% tolerance of the archived real-time data). The study case was modified from having NQC values for Imperial Valley solar generation to no output. The limiting contingency is the overlapping G-1/N-1 of TDM combined cycled generation, system readjustment, followed by the loss of the Imperial Valley – North Gila 500 kV line. This contingency could cause an overloading concern on the Imperial Valley – El Centro 230 kV line. The LCR requirements for the combined LA Basin-San Diego-Imperial Valley area, based on this scenario are: LA Basin LCR needs at 7,404 MW (all effective resources) and San Diego-Imperial Valley area LCR needs at 4,739 MW (all available non-solar resources as well as over 900 MW of deficiency at most effective location).

The following are key observations when comparing the LCR needs of the sensitivity study to the LCR needs based on the currently established NQC values:

- With less solar generating resources being available in the Imperial Valley at 6 p.m., the next effective generating resources are located in the San Diego sub-area. This increases the San Diego sub-area LCR needs to 2,800 MW, which at this time, is the maximum potential available non-solar resources in this sub-area estimated for summer 2022.

- When available resources in the San Diego sub-area are fully utilized, the resources in the western LA Basin are used to help relieve the loading concerns.

The estimated 7,404 MW is the potential maximum available in the LA Basin in the 2022 timeframe, after massive retirement of the once-through-cool generation resources at the end of 2020.

- After non-solar resources in both the LA Basin and San Diego sub-area are fully utilized to mitigate the potential overloading concern on the "S" line, the estimated deficiency, if mitigated by load drop, would be in the 1,300 MW range in the San Diego area (less effective than Imperial Valley resources. This potential overloading concern is a reliability concern and requires mitigation, either with additional resource procurement, or transmission upgrades, or a combination of these.

<u>Changes compared to last year's results:</u>

Compared with the 2021 LCR study results, the latest CEC-adopted adjusted peak demand forecast for 2022, with peak shift adjustment, is higher by 139 MW for the San Diego area. The 2022 LCR need for the overall San Diego – Imperial Valley area is higher by about 286 MW when compared with the recently completed 2021 LCR study report.[35] This is primarily due to higher adjusted peak demand forecast with peak shift.

<u>San Diego-Imperial Valley Area Overall Requirements:</u>

2022	QF (MW)	Wind (MW)	Market (MW)	Battery St. (MW)	20 minute DR (MW)	Max. Qualifying Capacity (MW)
Available generation	104	113	4336	38	19	4610

2022	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[36]	4610	33	4643
Category C (Multiple)[37]	4610	33	4643

[35] http://www.caiso.com/Documents/Final2021Long-TermLocalCapacityTechnicalReport.pdf
[36] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.
[37] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system

11. Valley Electric Area

Valley Electric Association LCR area has been eliminated on the basis of the following:

- No generation exists in this area
- No category B issues were observed in this area
- Category C and beyond –
    - No common-mode N-2 issues were observed
    - No issues were observed for category B outage followed by a common-mode N-2 outage
    - All the N-1-1 issues that were observed can either be mitigated by the existing UVLS or by an operating procedure

within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

V. Appendix A – List of physical resources by PTO, local area and market ID

PTO	MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR AREA NAME	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
PG&E	ALMEGT_1_UNIT 1	38118	ALMDACT1	13.8	23.80	1	Bay Area	Oakland		MUNI
PG&E	ALMEGT_1_UNIT 2	38119	ALMDACT2	13.8	24.40	1	Bay Area	Oakland		MUNI
PG&E	BANKPP_2_NSPIN	38820	DELTA A	13.2	11.55	1	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38820	DELTA A	13.2	11.55	2	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38820	DELTA A	13.2	11.55	3	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38815	DELTA B	13.2	11.55	4	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38815	DELTA B	13.2	11.55	5	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38770	DELTA C	13.2	11.55	6	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38770	DELTA C	13.2	11.55	7	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38765	DELTA D	13.2	11.55	8	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38765	DELTA D	13.2	11.55	9	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38760	DELTA E	13.2	11.55	10	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BANKPP_2_NSPIN	38760	DELTA E	13.2	11.55	11	Bay Area	Contra Costa	Pumps	MUNI
PG&E	BRDSLD_2_HIWIND	32172	HIGHWINDS	34.5	37.71	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_MTZUM2	32179	MNTZUMA2	0.69	23.38	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_MTZUMA	32188	HIGHWND3	0.69	8.86	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_SHILO1	32176	SHILOH	34.5	48.20	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_SHILO2	32177	SHILOH 2	34.5	40.62	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_SHLO3A	32191	SHILOH3	0.58	23.03	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_SHLO3B	32194	SHILOH4	0.58	35.20	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	CALPIN_1_AGNEW	35860	OLS-AGNE	9.11	28.00	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	CAYTNO_2_VASCO	30531	0162-WD	230	4.30	FW	Bay Area	Contra Costa	Aug NQC	Market
PG&E	CLRMTK_1_QF				0.00		Bay Area	Oakland	Not modeled	QF/Selfgen
PG&E	COCOPP_2_CTG1	33188	MARSHCT1	16.4	200.80	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	COCOPP_2_CTG2	33188	MARSHCT2	16.4	199.90	2	Bay Area	Contra Costa	Aug NQC	Market
PG&E	COCOPP_2_CTG3	33189	MARSHCT3	16.4	199.50	3	Bay Area	Contra Costa	Aug NQC	Market
PG&E	COCOPP_2_CTG4	33189	MARSHCT4	16.4	201.40	4	Bay Area	Contra Costa	Aug NQC	Market

PG&E	COCOSB_6_SOLAR				0.00		Bay Area	Contra Costa	Not modeled Energy Only	Market
PG&E	CONTAN_1_UNIT	36856	CCA100	13.8	27.70	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	MUNI
PG&E	CROKET_7_UNIT	32900	CRCKTCOG	18	232.78	1	Bay Area	Pittsburg	Aug NQC	QF/Selfgen
PG&E	CSCCOG_1_UNIT 1	36859	Laf300	12	3.00	1	Bay Area	San Jose, South Bay-Moss Landing		MUNI
PG&E	CSCCOG_1_UNIT 1	36859	Laf300	12	3.00	2	Bay Area	San Jose, South Bay-Moss Landing		MUNI
PG&E	CSCGNR_1_UNIT 1	36858	Gia100	13.8	24.00	1	Bay Area	San Jose, South Bay-Moss Landing		MUNI
PG&E	CSCGNR_1_UNIT 2	36895	Gia200	13.8	24.00	2	Bay Area	San Jose, South Bay-Moss Landing		MUNI
PG&E	CUMBIA_1_SOLAR	33102	COLUMBIA	0.38	15.27	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	DELTA_2_PL1X4	33108	DEC CTG1	18	181.13	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	DELTA_2_PL1X4	33109	DEC CTG2	18	181.13	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	DELTA_2_PL1X4	33110	DEC CTG3	18	181.13	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	DELTA_2_PL1X4	33107	DEC STG1	24	269.60	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	DIXNLD_1_LNDFL				1.30		Bay Area		Not modeled Aug NQC	Market
PG&E	DUANE_1_PL1X3	36863	DVRaGT1	13.8	49.72	1	Bay Area	San Jose, South Bay-Moss Landing		MUNI
PG&E	DUANE_1_PL1X3	36865	DVRaST3	13.8	48.36	1	Bay Area	San Jose, South Bay-Moss Landing		MUNI
PG&E	DUANE_1_PL1X3	36864	DVRbGT2	13.8	49.72	1	Bay Area	San Jose, South Bay-Moss Landing		MUNI
PG&E	GATWAY_2_PL1X3	33118	GATEWAY1	18	192.11	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	GATWAY_2_PL1X3	33119	GATEWAY2	18	181.90	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	GATWAY_2_PL1X3	33120	GATEWAY3	18	181.90	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	GILROY_1_UNIT	35850	GLRY COG	13.8	69.00	1	Bay Area	Llagas, South Bay-Moss Landing	Aug NQC	Market
PG&E	GILROY_1_UNIT	35850	GLRY COG	13.8	36.00	2	Bay Area	Llagas, South Bay-Moss Landing	Aug NQC	Market
PG&E	GILRPP_1_PL1X2	35851	GROYPKR1	13.8	47.70	1	Bay Area	Llagas, South Bay-Moss Landing	Aug NQC	Market

PG&E	GILRPP_1_PL1X2	35852	GROYPKR2	13.8	47.70	1	Bay Area	Llagas, South Bay-Moss Landing	Aug NQC	Market
PG&E	GILRPP_1_PL3X4	35853	GROYPKR3	13.8	46.20	1	Bay Area	Llagas, South Bay-Moss Landing	Aug NQC	Market
PG&E	GRZZLY_1_BERKLY	32741	HILLSIDE_12	12.5	23.40	1	Bay Area	None	Aug NQC	QF/Selfgen
PG&E	KELSO_2_UNITS	33813	MARIPCT1	13.8	47.45	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	KELSO_2_UNITS	33815	MARIPCT2	13.8	47.45	2	Bay Area	Contra Costa	Aug NQC	Market
PG&E	KELSO_2_UNITS	33817	MARIPCT3	13.8	47.45	3	Bay Area	Contra Costa	Aug NQC	Market
PG&E	KELSO_2_UNITS	33819	MARIPCT4	13.8	47.45	4	Bay Area	Contra Costa	Aug NQC	Market
PG&E	KIRKER_7_KELCYN				3.21		Bay Area	Pittsburg	Not modeled	Market
PG&E	LAWRNC_7_SUNYVL				0.16		Bay Area	None	Not modeled Aug NQC	Market
PG&E	LECEF_1_UNITS	35854	LECEFGT1	13.8	47.44	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	LECEF_1_UNITS	35855	LECEFGT2	13.8	47.44	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	LECEF_1_UNITS	35856	LECEFGT3	13.8	47.44	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	LECEF_1_UNITS	35857	LECEFGT4	13.8	47.44	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	LECEF_1_UNITS	35858	LECEFST1	13.8	113.85	1	Bay Area	San Jose, South Bay-Moss Landing		Market
PG&E	LMBEPK_2_UNITA1	32173	LAMBGT1	13.8	48.00	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	LMBEPK_2_UNITA2	32174	GOOSEHGT	13.8	48.00	2	Bay Area	Contra Costa	Aug NQC	Market
PG&E	LMBEPK_2_UNITA3	32175	CREEDGT1	13.8	48.00	3	Bay Area	Contra Costa	Aug NQC	Market
PG&E	LMEC_1_PL1X3	33112	LMECCT1	18	160.07	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	LMEC_1_PL1X3	33111	LMECCT2	18	160.07	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	LMEC_1_PL1X3	33113	LMECST1	18	235.85	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	MARTIN_1_SUNSET				1.94		Bay Area	None	Not modeled Aug NQC	QF/Selfgen
PG&E	METCLF_1_QF				0.00		Bay Area	None	Not modeled Aug NQC	QF/Selfgen
PG&E	METEC_2_PL1X3	35881	MEC CTG1	18	178.43	1	Bay Area	South Bay-Moss Landing	Aug NQC	Market
PG&E	METEC_2_PL1X3	35882	MEC CTG2	18	178.43	1	Bay Area	South Bay-Moss Landing	Aug NQC	Market
PG&E	METEC_2_PL1X3	35883	MEC STG1	18	213.13	1	Bay Area	South Bay-Moss Landing	Aug NQC	Market

PG&E	MISSIX_1_QF				0.01		Bay Area	None	Not modeled Aug NQC	QF/Selfgen
PG&E	MLPTAS_7_QFUNTS				0.01		Bay Area	San Jose, South Bay-Moss Landing	Not modeled Aug NQC	QF/Selfgen
PG&E	MOSSLD_1_QF				0.00		Bay Area		Not modeled Aug NQC	Market
PG&E	MOSSLD_2_PSP1	36221	DUKMOSS1	18	127.30	1	Bay Area	South Bay-Moss Landing	78% starting 2021	Market
PG&E	MOSSLD_2_PSP1	36222	DUKMOSS2	18	127.30	1	Bay Area	South Bay-Moss Landing	78% starting 2021	Market
PG&E	MOSSLD_2_PSP1	36223	DUKMOSS3	18	143.21	1	Bay Area	South Bay-Moss Landing	78% starting 2021	Market
PG&E	MOSSLD_2_PSP2	36224	DUKMOSS4	18	127.30	1	Bay Area	South Bay-Moss Landing	78% starting 2021	Market
PG&E	MOSSLD_2_PSP2	36225	DUKMOSS5	18	127.30	1	Bay Area	South Bay-Moss Landing	78% starting 2021	Market
PG&E	MOSSLD_2_PSP2	36226	DUKMOSS6	18	143.21	1	Bay Area	South Bay-Moss Landing	78% starting 2021	Market
PG&E	NEWARK_1_QF				0.02		Bay Area	None	Not modeled Aug NQC	QF/Selfgen
PG&E	OAK C_1_EBMUD				1.51		Bay Area	Oakland	Not modeled Aug NQC	MUNI
PG&E	OAK C_7_UNIT 1	32901	OAKLND 1	13.8	55.00	1	Bay Area	Oakland		Market
PG&E	OAK C_7_UNIT 2	32902	OAKLND 2	13.8	55.00	1	Bay Area	Oakland		Market
PG&E	OAK C_7_UNIT 3	32903	OAKLND 3	13.8	55.00	1	Bay Area	Oakland		Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	1	Bay Area	Ames		Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	2	Bay Area	Ames		Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	3	Bay Area	Ames		Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	4	Bay Area	Ames		Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	5	Bay Area	Ames		Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	6	Bay Area	Ames		Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	7	Bay Area	Ames		Market
PG&E	PALALT_7_COBUG				4.50		Bay Area	None	Not modeled	MUNI
PG&E	RICHMN_7_BAYENV				2.00		Bay Area	None	Not modeled Aug NQC	Market
PG&E	RUSCTY_2_UNITS	35304	RUSELCT1	15	180.15	1	Bay Area	Ames	No NQC - Pmax	Market
PG&E	RUSCTY_2_UNITS	35305	RUSELCT2	15	180.15	2	Bay Area	Ames	No NQC - Pmax	Market

PG&E	RUSCTY_2_UNITS	35306	RUSELST1	15	237.09	3	Bay Area	Ames	No NQC - Pmax	Market
PG&E	RVRVEW_1_UNITA1	33178	RVEC_GEN	13.8	48.70	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	SRINTL_6_UNIT	33468	SRI INTL	9.11	0.52	1	Bay Area	None	Aug NQC	QF/Selfgen
PG&E	STAUFF_1_UNIT	33139	STAUFER	9.11	0.07	1	Bay Area	None	Aug NQC	QF/Selfgen
PG&E	STOILS_1_UNITS	32921	CHEVGEN1	13.8	0.00	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	STOILS_1_UNITS	32922	CHEVGEN2	13.8	0.00	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	STOILS_1_UNITS	32923	CHEVGEN3	13.8	0.00	3	Bay Area	Pittsburg	Aug NQC	Market
PG&E	TIDWTR_2_UNITS	33151	FOSTER W	12.5	4.95	1	Bay Area	Pittsburg	Aug NQC	Net Seller
PG&E	TIDWTR_2_UNITS	33151	FOSTER W	12.5	4.95	2	Bay Area	Pittsburg	Aug NQC	Net Seller
PG&E	TIDWTR_2_UNITS	33151	FOSTER W	12.5	3.77	3	Bay Area	Pittsburg	Aug NQC	Net Seller
PG&E	UNCHEM_1_UNIT	32920	UNION CH	9.11	10.95	1	Bay Area	Pittsburg	Aug NQC	QF/Selfgen
PG&E	UNOCAL_1_UNITS	32910	UNOCAL	12	0.27	1	Bay Area	Pittsburg	Aug NQC	QF/Selfgen
PG&E	UNOCAL_1_UNITS	32910	UNOCAL	12	0.27	2	Bay Area	Pittsburg	Aug NQC	QF/Selfgen
PG&E	UNOCAL_1_UNITS	32910	UNOCAL	12	0.27	3	Bay Area	Pittsburg	Aug NQC	QF/Selfgen
PG&E	USWNDR_2_SMUD	32169	SOLANOWP	21	22.43	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	USWNDR_2_SMUD2	32186	SOLANO	34.5	43.15	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	USWNDR_2_UNITS	32168	EXNCO	9.11	4.00	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	USWPJR_2_UNITS	39233	GRNRDG	0.69	17.35	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	WNDMAS_2_UNIT 1	33170	WINDMSTR	9.11	3.52	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	ZOND_6_UNIT	35316	ZOND SYS	9.11	1.52	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	ZZ_IBMCTL_1_UNIT 1	35637	IBM-CTLE	115	0.00	1	Bay Area	San Jose, South Bay-Moss Landing	No NQC - hist. data	Market
PG&E	ZZ_IMHOFF_1_UNIT 1	33136	CCCSD	12.5	0.00	1	Bay Area	Pittsburg	No NQC - hist. data	QF/Selfgen
PG&E	ZZ_LFC 51_2_UNIT 1	35310	PPASSWND	21	7.20	1	Bay Area	None	No NQC - est. data	Wind
PG&E	ZZ_MARKHM_1_CATLST	35863	CATALYST	9.11	0.00	1	Bay Area	San Jose, South Bay-Moss Landing		QF/Selfgen
PG&E	ZZ_NA	35861	SJ-SCL W	4.3	6.50	1	Bay Area	San Jose, South Bay-Moss Landing	No NQC - hist. data	QF/Selfgen

PG&E	ZZ_NA	36209	SLD ENRG	12.5	0.00	1	Bay Area	South Bay-Moss Landing		QF/Selfgen
PG&E	ZZ_SEAWST_6_LAPOS	35312	FOREBAYW	22	4.30	1	Bay Area	Contra Costa	No NQC - est. data	Wind
PG&E	ZZ_SHELRF_1_UNITS	33141	SHELL 1	12.5	0.00	1	Bay Area	Pittsburg	No NQC - hist. data	Net Seller
PG&E	ZZ_SHELRF_1_UNITS	33142	SHELL 2	12.5	0.00	1	Bay Area	Pittsburg	No NQC - hist. data	Net Seller
PG&E	ZZ_SHELRF_1_UNITS	33143	SHELL 3	12.5	0.00	1	Bay Area	Pittsburg	No NQC - hist. data	Net Seller
PG&E	ZZ_ZANKER_1_UNIT 1	35861	SJ-SCL W	4.3	0.00	RN	Bay Area	San Jose, South Bay-Moss Landing	No NQC - hist. data	QF/Selfgen
PG&E	ZZZ_New Unit	30524	0354-WD	230	1.83	EW	Bay Area	Contra Costa	No NQC - Pmax	Market
PG&E	ZZZ_New Unit	35859	HGST-LV	12.4	0.00	RN	Bay Area		Energy Only	Market
PG&E	ZZZ_New Unit	35302	NUMMI-LV	12.6	0.00	RN	Bay Area		Energy Only	Market
PG&E	ZZZ_New Unit	35622	SWIFT	115	4.00	BT	Bay Area	South Bay-Moss Landing	No NQC - Pmax	Market
PG&E	ZZZZ_New Unit	35307	A100US-L	12.6	0.00	RN	Bay Area		Energy Only	Market
PG&E	ZZZZZZ_COCOPP_7_UNIT 6	33116	C.COS 6	18	0.00	RT	Bay Area	Contra Costa	Retired	Market
PG&E	ZZZZZZ_COCOPP_7_UNIT 7	33117	C.COS 7	18	0.00	RT	Bay Area	Contra Costa	Retired	Market
PG&E	ZZZZZZ_GWFPW1_6_UNIT	33131	GWF #1	9.11	0.00	1	Bay Area	Pittsburg, Contra Costa	Retired	QF/Selfgen
PG&E	ZZZZZZ_GWFPW2_1_UNIT 1	33132	GWF #2	13.8	0.00	1	Bay Area	Pittsburg	Retired	QF/Selfgen
PG&E	ZZZZZZ_GWFPW3_1_UNIT 1	33133	GWF #3	13.8	0.00	1	Bay Area	Pittsburg, Contra Costa	Retired	QF/Selfgen
PG&E	ZZZZZZ_GWFPW4_6_UNIT 1	33134	GWF #4	13.8	0.00	1	Bay Area	Pittsburg, Contra Costa	Retired	QF/Selfgen
PG&E	ZZZZZZ_GWFPW5_6_UNIT 1	33135	GWF #5	13.8	0.00	1	Bay Area	Pittsburg	Retired	QF/Selfgen
PG&E	ZZZZZZ_MOSSLD_7_UNIT 6	36405	MOSSLND6	22	0.00	1	Bay Area	South Bay-Moss Landing	Retired	Market
PG&E	ZZZZZZ_MOSSLD_7_UNIT 7	36406	MOSSLND7	22	0.00	1	Bay Area	South Bay-Moss Landing	Retired	Market
PG&E	ZZZZZZ_PITTSP_7_UNIT 5	33105	PTSB 5	18	0.00	1	Bay Area	Pittsburg	Retired	Market

PG&E	ZZZZZZ_PITTSP_7_UNIT 6	33106	PTSB 6	18	0.00	1	Bay Area	Pittsburg	Retired	Market
PG&E	ZZZZZZ_PITTSP_7_UNIT 7	30000	PTSB 7	20	0.00	1	Bay Area	Pittsburg	Retired	Market
PG&E	ZZZZZZ_UNTDQF_7_UNITS	33466	UNTED CO	9.11	0.00	1	Bay Area	None	Retired	QF/Selfgen
PG&E	ADERA_1_SOLAR1	34319	Q644	0.48	0.00	1	Fresno	Wilson, Herndon	Aug NQC	Market
PG&E	ADMEST_6_SOLAR	34315	ADAMS_E	12.5	0.00	1	Fresno	Wilson, Herndon	Energy Only	Market
PG&E	AGRICO_6_PL3N5	34608	AGRICO	13.8	20.00	3	Fresno	Wilson, Herndon		Market
PG&E	AGRICO_7_UNIT	34608	AGRICO	13.8	7.45	2	Fresno	Wilson, Herndon		Market
PG&E	AGRICO_7_UNIT	34608	AGRICO	13.8	43.05	4	Fresno	Wilson, Herndon		Market
PG&E	AVENAL_6_AVPARK	34265	AVENAL P	12	0.00	1	Fresno	Wilson, Coalinga	Energy Only	Market
PG&E	AVENAL_6_SANDDG	34263	SANDDRAG	12	0.00	1	Fresno	Wilson, Coalinga	Energy Only	Market
PG&E	AVENAL_6_SUNCTY	34257	SUNCTY D	12	0.00	1	Fresno	Wilson, Coalinga	Energy Only	Market
PG&E	BALCHS_7_UNIT 1	34624	BALCH	13.2	33.00	1	Fresno	Wilson, Herndon	Aug NQC	Market
PG&E	BALCHS_7_UNIT 2	34612	BLCH	13.8	52.50	1	Fresno	Wilson, Herndon	Aug NQC	Market
PG&E	BALCHS_7_UNIT 3	34614	BLCH	13.8	52.50	1	Fresno	Wilson, Herndon	Aug NQC	Market
PG&E	CANTUA_1_SOLAR	34349	CANTUA_D	12.5	6.76	1	Fresno	Wilson	Aug NQC	Market
PG&E	CANTUA_1_SOLAR	34349	CANTUA_D	12.5	6.76	2	Fresno	Wilson	Aug NQC	Market
PG&E	CAPMAD_1_UNIT 1	34179	MADERA_G	13.8	4.29	1	Fresno	Wilson		Market
PG&E	CHEVCO_6_UNIT 1	34652	CHV.COAL	9.11	1.00	1	Fresno	Wilson, Coalinga	Aug NQC	QF/Selfgen
PG&E	CHEVCO_6_UNIT 2	34652	CHV.COAL	9.11	0.75	2	Fresno	Wilson, Coalinga	Aug NQC	QF/Selfgen
PG&E	CHWCHL_1_BIOMAS	34305	CHWCHLA2	13.8	7.60	1	Fresno	Wilson, Herndon	Aug NQC	Market
PG&E	CHWCHL_1_UNIT	34301	CHOWCOGN	13.8	48.00	1	Fresno	Wilson, Herndon		Market
PG&E	COLGA1_6_SHELLW	34654	COLNGAGN	9.11	34.70	1	Fresno	Wilson, Coalinga	Aug NQC	Net Seller
PG&E	CORCAN_1_SOLAR1				0.35		Fresno	Wilson, Herndon, Hanford	Not Modeled Aug NQC	Market
PG&E	CORCAN_1_SOLAR2				0.19		Fresno	Wilson, Herndon, Hanford	Not Modeled Aug NQC	Market
PG&E	CRESSY_1_PARKER	34140	CRESSEY	115	0.67		Fresno	Wilson	Not modeled Aug NQC	MUNI
PG&E	CRNEVL_6_CRNVA	34634	CRANEVLY	12	0.90	1	Fresno	Wilson, Borden	Aug NQC	Market
PG&E	CRNEVL_6_SJQN 2	34631	SJ2GEN	9.11	3.20	1	Fresno	Wilson, Borden	Aug NQC	Market
PG&E	CRNEVL_6_SJQN 3	34633	SJ3GEN	9.11	4.20	1	Fresno	Wilson, Borden	Aug NQC	Market

PG&E	DINUBA_6_UNIT	34648	DINUBA E	13.8	7.59	1	Fresno	Wilson, Herndon, Reedley		Market
PG&E	EEKTMN_6_SOLAR1	34627	KETTLEMN	0.34	0.00	1	Fresno	Wilson	Energy Only	Market
PG&E	ELCAP_1_SOLAR				1.27		Fresno	Wilson	Not Modeled Aug NQC	Market
PG&E	ELNIDP_6_BIOMAS	34330	ELNIDO	13.8	7.22	1	Fresno	Wilson	Aug NQC	Market
PG&E	EXCHEC_7_UNIT 1	34306	EXCHQUER	13.8	94.50	1	Fresno	Wilson	Aug NQC	MUNI
PG&E	EXCLSG_1_SOLAR	34623	Q678	0.5	41.54	1	Fresno	Wilson	Aug NQC	Market
PG&E	FRESHW_1_SOLAR1	34669	Q529A	4.16	0.00	1	Fresno	Wilson, Herndon	Energy Only	Market
PG&E	FRESHW_1_SOLAR1	34669	Q529A	0.48	0.00	2	Fresno	Wilson, Herndon	Energy Only	Market
PG&E	FRIANT_6_UNITS	34636	FRIANTDM	6.6	6.74	2	Fresno	Wilson, Borden	Aug NQC	Net Seller
PG&E	FRIANT_6_UNITS	34636	FRIANTDM	6.6	3.60	3	Fresno	Wilson, Borden	Aug NQC	Net Seller
PG&E	FRIANT_6_UNITS	34636	FRIANTDM	6.6	0.95	4	Fresno	Wilson, Borden	Aug NQC	Net Seller
PG&E	GUERNS_6_SOLAR	34461	GUERNSEY	12.5	3.24	1	Fresno	Wilson	Aug NQC	Market
PG&E	GUERNS_6_SOLAR	34461	GUERNSEY	12.5	3.24	2	Fresno	Wilson	Aug NQC	Market
PG&E	GWFPWR_1_UNITS	34431	GWF_HEP1	13.8	42.20	1	Fresno	Wilson, Herndon, Hanford		Market
PG&E	GWFPWR_1_UNITS	34433	GWF_HEP2	13.8	42.20	1	Fresno	Wilson, Herndon, Hanford		Market
PG&E	HAASPH_7_PL1X2	34610	HAAS	13.8	72.00	1	Fresno	Wilson, Herndon	Aug NQC	Market
PG&E	HAASPH_7_PL1X2	34610	HAAS	13.8	72.00	2	Fresno	Wilson, Herndon	Aug NQC	Market
PG&E	HELMPG_7_UNIT 1	34600	HELMS	18	407.00	1	Fresno	Wilson	Aug NQC	Market
PG&E	HELMPG_7_UNIT 2	34602	HELMS	18	407.00	2	Fresno	Wilson	Aug NQC	Market
PG&E	HELMPG_7_UNIT 3	34604	HELMS	18	404.00	3	Fresno	Wilson	Aug NQC	Market
PG&E	HENRTA_6_SOLAR1				0.00		Fresno	Wilson	Not modeled Energy Only	Market
PG&E	HENRTA_6_SOLAR2				0.00		Fresno	Wilson	Not modeled Energy Only	Market
PG&E	HENRTA_6_UNITA1	34539	GWF_GT1	13.8	45.33	1	Fresno	Wilson		Market
PG&E	HENRTA_6_UNITA2	34541	GWF_GT2	13.8	45.23	1	Fresno	Wilson		Market
PG&E	HENRTS_1_SOLAR	34617	Q581	0.38	80.34	1	Fresno	Wilson	Aug NQC	Market
PG&E	HURON_6_SOLAR	34557	HURON_DI	12.5	6.79	1	Fresno	Wilson, Coalinga	Aug NQC	Market
PG&E	HURON_6_SOLAR	34557	HURON_DI	12.5	6.79	2	Fresno	Wilson, Coalinga	Aug NQC	Market
PG&E	INTTRB_6_UNIT	34342	INT.TURB	9.11	2.76	1	Fresno	Wilson	Aug NQC	QF/Selfgen
PG&E	JAYNE_6_WLSLR	34639	WESTLNDS	0.48	0.00	1	Fresno	Wilson, Coalinga	Energy Only	Market

PG&E	KANSAS_6_SOLAR	34666	KANSASS_S	12.5	0.00	F	Fresno	Wilson	Energy Only	Market
PG&E	KERKH1_7_UNIT 1	34344	KERCK1-1	6.6	13.00	1	Fresno	Wilson, Herndon	Aug NQC	Market
PG&E	KERKH1_7_UNIT 3	34345	KERCK1-3	6.6	12.80	3	Fresno	Wilson, Herndon	Aug NQC	Market
PG&E	KERKH2_7_UNIT 1	34308	KERCKHOF	13.8	153.90	1	Fresno	Wilson, Herndon	Aug NQC	Market
PG&E	KERMAN_6_SOLAR1				0.00		Fresno	Wilson	Not modeled Energy Only	Market
PG&E	KERMAN_6_SOLAR2				0.00		Fresno	Wilson	Not modeled Energy Only	Market
PG&E	KINGCO_1_KINGBR	34642	KINGSBUR	9.11	23.71	1	Fresno	Wilson, Herndon, Hanford	Aug NQC	Net Seller
PG&E	KINGRV_7_UNIT 1	34616	KINGSRIV	13.8	51.20	1	Fresno	Wilson, Herndon	Aug NQC	Market
PG&E	KNGBRG_1_KBSLR1				0.00		Fresno	Wilson	Not modeled Energy Only	Market
PG&E	KNGBRG_1_KBSLR2				0.00		Fresno	Wilson	Not modeled Energy Only	Market
PG&E	KNTSTH_6_SOLAR	34694	KENT_S	0.8	0.00	1	Fresno	Wilson	Energy Only	Market
PG&E	LEPRFD_1_KANSAS	34680	Q636	12.5	4.50	1	Fresno	Wilson, Hanford	Aug NQC	Market
PG&E	MALAGA_1_PL1X2	34671	KRCDPCT1	13.8	48.00	1	Fresno	Wilson, Herndon		Market
PG&E	MALAGA_1_PL1X2	34672	KRCDPCT2	13.8	48.00	1	Fresno	Wilson, Herndon		Market
PG&E	MCCALL_1_QF	34219	MCCALL 4	12.5	0.44	QF	Fresno	Wilson, Herndon	Aug NQC	QF/Selfgen
PG&E	MCSWAN_6_UNITS	34320	MCSWAIN	9.11	10.00	1	Fresno	Wilson	Aug NQC	MUNI
PG&E	MENBIO_6_RENEW1	34339	CALRENEW	12.5	4.02	1	Fresno	Wilson, Herndon	Aug NQC	Net Seller
PG&E	MENBIO_6_UNIT	34334	BIO PWR	9.11	19.24	1	Fresno	Wilson	Aug NQC	QF/Selfgen
PG&E	MERCED_1_SOLAR1				0.00		Fresno	Wilson	Not modeled Energy Only	Market
PG&E	MERCED_1_SOLAR2				0.00		Fresno	Wilson	Not modeled Energy Only	Market
PG&E	MERCFL_6_UNIT	34322	MERCEDFL	9.11	3.50	1	Fresno	Wilson	Aug NQC	Market
PG&E	MNDOTA_1_SOLAR1	34311	NORTHSTAR	0.2	50.90	1	Fresno	Wilson	Aug NQC	Market
PG&E	MNDOTA_1_SOLAR2				0.00		Fresno	Wilson	Not modeled Energy Only	Market
PG&E	MSTANG_2_SOLAR	34683	Q643W	0.8	24.10	1	Fresno	Wilson	Aug NQC	Market
PG&E	MSTANG_2_SOLAR3	34683	Q643W	0.8	32.14	1	Fresno	Wilson	Aug NQC	Market
PG&E	MSTANG_2_SOLAR4	34683	Q643W	0.8	24.10	1	Fresno	Wilson	Aug NQC	Market

PG&E	ONLLPP_6_UNITS	34316	ONEILPMP	9.11	0.37	1	Fresno	Wilson	Aug NQC	MUNI
PG&E	PINFLT_7_UNITS	38720	PINEFLAT	13.8	70.00	1	Fresno	Wilson, Herndon	Aug NQC	MUNI
PG&E	PINFLT_7_UNITS	38720	PINEFLAT	13.8	70.00	2	Fresno	Wilson, Herndon	Aug NQC	MUNI
PG&E	PINFLT_7_UNITS	38720	PINEFLAT	13.8	70.00	3	Fresno	Wilson, Herndon	Aug NQC	MUNI
PG&E	PNCHPP_1_PL1X2	34328	STARGT1	13.8	55.58	1	Fresno	Wilson		Market
PG&E	PNCHPP_1_PL1X2	34329	STARGT2	13.8	55.58	2	Fresno	Wilson		Market
PG&E	PNOCHE_1_PL1X2	34142	WHD_PAN2	13.8	49.97	1	Fresno	Wilson, Herndon		Market
PG&E	PNOCHE_1_UNITA1	34186	DG_PAN1	13.8	48.00	1	Fresno	Wilson		Market
PG&E	REEDLY_6_SOLAR				0.00		Fresno	Wilson, Herndon, Reedley	Not modeled Energy Only	Market
PG&E	S_RITA_6_SOLAR1				0.00		Fresno	Wilson	Not modeled Energy Only	Market
PG&E	SCHNDR_1_FIVPTS	34353	SCHINDLER_D	12.5	4.25	1	Fresno	Wilson, Coalinga	Aug NQC	Market
PG&E	SCHNDR_1_FIVPTS	34353	SCHINDLER_D	12.5	2.12	2	Fresno	Wilson, Coalinga	Aug NQC	Market
PG&E	SCHNDR_1_WSTSDE	34353	SCHINDLER_D	12.5	6.17	3	Fresno	Wilson, Coalinga	Aug NQC	Market
PG&E	SCHNDR_1_WSTSDE	34353	SCHINDLER_D	12.5	3.09	4	Fresno	Wilson, Coalinga	Aug NQC	Market
PG&E	SGREGY_6_SANGER	34646	SANGERCO	13.8	19.41	1	Fresno	Wilson	Aug NQC	Market
PG&E	SGREGY_6_SANGER	34646	SANGERCO	13.8	4.66	2	Fresno	Wilson	Aug NQC	Market
PG&E	STOREY_2_MDRCH2				0.25		Fresno	Wilson	Not modeled Aug NQC	Market
PG&E	STOREY_2_MDRCH3				0.19		Fresno	Wilson	Not modeled Aug NQC	Market
PG&E	STOREY_7_MDRCHW	34209	STOREY D	12.5	0.00	1	Fresno	Wilson	Aug NQC	Net Seller
PG&E	STROUD_6_SOLAR	34563	STROUD_D	12.5	2.56	1	Fresno	Wilson, Herndon	Aug NQC	Market
PG&E	STROUD_6_SOLAR	34563	STROUD_D	12.5	2.56	2	Fresno	Wilson, Herndon	Aug NQC	Market
PG&E	TRNQLT_2_SOLAR	34340	Q643X	0.8	160.69	1	Fresno	Wilson	Aug NQC	Market
PG&E	ULTPFR_1_UNIT 1	34640	ULTR.PWR	9.11	23.92	1	Fresno	Wilson, Herndon	Aug NQC	QF/Selfgen
PG&E	VEGA_6_SOLAR1	34314	Q548	34.5	0.00	1	Fresno	Wilson	Energy Only	Market
PG&E	WAUKNA_1_SOLAR	34696	CORCORANPV_S	21	0.40	1	Fresno	Wilson, Herndon, Hanford	Aug NQC	Market
PG&E	WAUKNA_1_SOLAR2	34677	Q558	21	17.43	1	Fresno	Wilson, Herndon, Hanford	No NQC - Pmax	Market

PG&E	WFRESN_1_SOLAR				0.00		Fresno	Wilson	Not modeled Energy Only	Market
PG&E	WISHON_6_UNITS	34658	WISHON	2.3	4.51	1	Fresno	Wilson, Borden	Aug NQC	Market
PG&E	WISHON_6_UNITS	34658	WISHON	2.3	4.51	2	Fresno	Wilson, Borden	Aug NQC	Market
PG&E	WISHON_6_UNITS	34658	WISHON	2.3	4.51	3	Fresno	Wilson, Borden	Aug NQC	Market
PG&E	WISHON_6_UNITS	34658	WISHON	2.3	4.51	4	Fresno	Wilson, Borden	Aug NQC	Market
PG&E	WISHON_6_UNITS	34658	WISHON	2.3	0.36	SJ	Fresno	Wilson, Borden	Aug NQC	Market
PG&E	WRGHTP_7_AMENGY	34207	WRIGHT D	12.5	0.14	QF	Fresno	Wilson	Aug NQC	QF/Selfgen
PG&E	ZZ_BULLRD_7_SAGNES	34213	BULLD 12	12.5	0.00	1	Fresno	Wilson	Aug NQC	QF/Selfgen
PG&E	ZZ_GATES_6_PL1X2	34553	WHD_GAT2	13.8	0.00	1	Fresno	Wilson, Coalinga		Market
PG&E	ZZ_JRWOOD_1_UNIT 1	34332	JRWCOGEN	9.11	0.00	1	Fresno	Wilson		QF/Selfgen
PG&E	ZZ_NA	34485	FRESNOWW	12.5	0.00	1	Fresno	Wilson	No NQC - hist. data	QF/Selfgen
PG&E	ZZ_NA	34485	FRESNOWW	12.5	0.00	2	Fresno	Wilson	No NQC - hist. data	QF/Selfgen
PG&E	ZZ_NA	34485	FRESNOWW	12.5	0.00	3	Fresno	Wilson	No NQC - hist. data	QF/Selfgen
PG&E	ZZZ_New Unit	34420	CORCORAN	115	19.00	WD	Fresno	Wilson, Herndon, Hanford	No NQC - Pmax	Market
PG&E	ZZZ_New Unit	34467	GIFFEN_DIST	12.5	10.00	1	Fresno	Wilson, Herndon	No NQC - Pmax	Market
PG&E	ZZZ_New Unit	34603	JGBSWLT	12.5	0.00	ST	Fresno	Wilson, Herndon	Energy Only	Market
PG&E	ZZZ_New Unit	39601	PATRIOTA	0.32	0.00	1	Fresno	Wilson	Energy Only	Market
PG&E	ZZZ_New Unit	39604	PATRIOTB	0.32	0.00	1	Fresno	Wilson	Energy Only	Market
PG&E	ZZZ_New Unit	34688	Q272	0.55	125.00	1	Fresno	Wilson	No NQC - Pmax	Market
PG&E	ZZZ_New Unit	34653	Q526	33	0.00	1	Fresno	Wilson, Coalinga	Energy Only	Market
PG&E	ZZZ_New Unit	34673	Q532	13.8	0.00	1	Fresno	Wilson, Coalinga	Energy Only	Market
PG&E	ZZZ_New Unit	34300	Q550	34.5	0.00	1	Fresno	Wilson	Energy Only	Market
PG&E	ZZZ_New Unit	34303	Q612	13.8	0.00	1	Fresno	Wilson, Coalinga	Energy Only	Market
PG&E	ZZZ_New Unit	36205	Q648	34.5	0.00	1	Fresno	Wilson	Energy Only	Market
PG&E	ZZZ_New Unit	34644	Q679	0.48	20.00	1	Fresno	Wilson	No NQC - Pmax	Market
PG&E	ZZZ_New Unit	34335	Q723	0.32	50.00	1	Fresno	Wilson, Borden	No NQC - Pmax	Market
PG&E	ZZZ_New Unit	34649	Q965	0.36	14.00	1	Fresno	Wilson, Herndon	No NQC - Pmax	Market

PG&E	BRDGVL_7_BAKER				0.00		Humboldt	None	Not modeled Aug NQC	Net Seller
PG&E	FAIRHV_6_UNIT	31150	FAIRHAVN	13.8	13.58	1	Humboldt	None	Aug NQC	Net Seller
PG&E	FTSWRD_6_TRFORK				0.10		Humboldt	None	Not modeled Aug NQC	Market
PG&E	FTSWRD_7_QFUNTS				0.00		Humboldt	None	Not modeled Aug NQC	QF/Selfgen
PG&E	GRSCRK_6_BGCKWW				0.00		Humboldt	None	Not modeled Energy Only	QF/Selfgen
PG&E	HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.30	1	Humboldt	None		Market
PG&E	HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	15.83	2	Humboldt	None		Market
PG&E	HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.67	3	Humboldt	None		Market
PG&E	HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.20	4	Humboldt	None		Market
PG&E	HUMBPP_6_UNITS	31181	HUMB_G2	13.8	16.14	5	Humboldt	None		Market
PG&E	HUMBPP_6_UNITS	31181	HUMB_G2	13.8	16.33	6	Humboldt	None		Market
PG&E	HUMBPP_6_UNITS	31181	HUMB_G2	13.8	16.24	7	Humboldt	None		Market
PG&E	HUMBPP_6_UNITS	31182	HUMB_G3	13.8	16.62	8	Humboldt	None		Market
PG&E	HUMBPP_6_UNITS	31182	HUMB_G3	13.8	16.33	9	Humboldt	None		Market
PG&E	HUMBPP_6_UNITS	31182	HUMB_G3	13.8	15.95	10	Humboldt	None		Market
PG&E	HUMBSB_1_QF				0.00		Humboldt	None	Not modeled Aug NQC	QF/Selfgen
PG&E	KEKAWK_6_UNIT	31166	KEKAWAK	9.1	0.00	1	Humboldt	None	Aug NQC	Net Seller
PG&E	LAPAC_6_UNIT	31158	LP SAMOA	12.5	20.00	1	Humboldt	None		Market
PG&E	LOWGAP_1_SUPHR				0.00		Humboldt	None	Not modeled Aug NQC	Market
PG&E	PACLUM_6_UNIT	31152	PAC.LUMB	13.8	5.25	1	Humboldt	None	Aug NQC	QF/Selfgen
PG&E	PACLUM_6_UNIT	31152	PAC.LUMB	13.8	5.25	2	Humboldt	None	Aug NQC	QF/Selfgen
PG&E	PACLUM_6_UNIT	31153	PAC.LUMB	2.4	3.15	3	Humboldt	None	Aug NQC	QF/Selfgen
PG&E	ZZZZZ_BLULKE_6_BLUELK	31156	BLUELKPP	12.5	0.00	1	Humboldt	None	Retired	Market
PG&E	7STDRD_1_SOLAR1	35065	7STNDRD_1	21	17.56	FW	Kern	South Kern PP, Kern Oil	Aug NQC	Market
PG&E	ADOBEE_1_SOLAR	35021	Q622B	34.5	18.42	1	Kern	South Kern PP	Aug NQC	Market
PG&E	BDGRCK_1_UNITS	35029	BADGERCK	13.8	44.00	1	Kern	South Kern PP	Aug NQC	Net Seller

PG&E	BEARMT_1_UNIT	35066	PSE-BEAR	13.8	47.00	1	Kern	South Kern PP, West Park	Aug NQC	Net Seller
PG&E	BKRFLD_2_SOLAR1				1.20		Kern	South Kern PP	Not modeled Aug NQC	Market
PG&E	DEXZEL_1_UNIT	35024	DEXEL +	13.8	13.52	1	Kern	South Kern PP, Kern Oil	Aug NQC	Net Seller
PG&E	DISCOV_1_CHEVRN	35062	DISCOVRY	13.8	2.05	1	Kern	South Kern PP, Kern Oil	Aug NQC	QF/Selfgen
PG&E	DOUBLC_1_UNITS	35023	DOUBLE C	13.8	51.60	1	Kern	South Kern PP	Aug NQC	Net Seller
PG&E	KERNFT_1_UNITS	35026	KERNFRNT	9.11	52.10	1	Kern	South Kern PP	Aug NQC	Net Seller
PG&E	KRNCNY_6_UNIT	35018	KERNCNYN	11	11.50	1	Kern	South Kern PP	Aug NQC	Market
PG&E	LAMONT_1_SOLAR1	35019	REGULUS	0.4	52.75	1	Kern	South Kern PP	Aug NQC	Market
PG&E	LAMONT_1_SOLAR3	35087	Q744G3	0.4	12.04	3	Kern	South Kern PP	Aug NQC	Market
PG&E	LAMONT_1_SOLAR4	35059	Q744G2	0.4	21.42	2	Kern	South Kern PP	Aug NQC	Market
PG&E	LAMONT_1_SOLAR5	35054	Q744G1	0.4	13.39	1	Kern	South Kern PP	Aug NQC	Market
PG&E	LIVOAK_1_UNIT 1	35058	PSE-LVOK	9.1	44.80	1	Kern	South Kern PP, Kern Oil	Aug NQC	Net Seller
PG&E	MTNPOS_1_UNIT	35036	MT POSO	13.8	31.12	1	Kern	South Kern PP, Kern Oil	Aug NQC	Net Seller
PG&E	OLDRIV_6_BIOGAS				1.38		Kern	South Kern PP	Not modeled Aug NQC	Market
PG&E	OLDRV1_6_SOLAR	35091	OLD_RVR1	12.5	16.67	1	Kern	South Kern PP	Aug NQC	Market
PG&E	RIOBRV_6_UNIT 1 3	35020	RIOBRAVO	9.1	0.20	1	Kern	South Kern PP	Aug NQC	Market
PG&E	SIERRA_1_UNITS	35027	HISIERRA	9.11	52.20	1	Kern	South Kern PP	Aug NQC	Market
PG&E	SKERN_6_SOLAR1	35089	S_KERN	0.48	14.73	1	Kern	South Kern PP	Aug NQC	Market
PG&E	SKERN_6_SOLAR2	35069	Q885	0.36	8.03	1	Kern	South Kern PP	Aug NQC	Market
PG&E	VEDDER_1_SEKERN	35046	SEKR	9.11	12.47	1	Kern	South Kern PP, Kern Oil	Aug NQC	QF/Selfgen
PG&E	ZZZ_New Unit	35092	Q744G4	0.38	25.46	1	Kern	South Kern PP	No NQC - est. data	Market
PG&E	ZZZZZZ_OILDAL_1_UNIT 1	35028	OILDALE	9.11	0.00	1	Kern	South Kern PP, Kern Oil	Retired	Net Seller
PG&E	ZZZZZZ_ULTOGL_1_POSO	35035	ULTR PWR	9.11	0.00	1	Kern	South Kern PP, Kern Oil	Retired	QF/Selfgen
PG&E	ADLIN_1_UNITS	31435	GEO.ENGY	9.1	8.00	1	NCNB	Eagle Rock, Fulton, Lakeville		Market
PG&E	ADLIN_1_UNITS	31435	GEO.ENGY	9.1	8.00	2	NCNB	Eagle Rock, Fulton, Lakeville		Market

PG&E	CLOVDL_1_SOLAR				1.07		NCNB	Eagle Rock, Fulton, Lakeville	Not modeled Aug NQC	Market
PG&E	CSTOGA_6_LNDFIL				0.00		NCNB	Fulton, Lakeville	Not modeled Energy Only	Market
PG&E	FULTON_1_QF				0.01		NCNB	Fulton, Lakeville	Not modeled Aug NQC	QF/Selfgen
PG&E	GEYS11_7_UNIT11	31412	GEYSER11	13.8	68.00	1	NCNB	Eagle Rock, Fulton, Lakeville		Market
PG&E	GEYS12_7_UNIT12	31414	GEYSER12	13.8	50.00	1	NCNB	Fulton, Lakeville		Market
PG&E	GEYS13_7_UNIT13	31416	GEYSER13	13.8	56.00	1	NCNB	Lakeville		Market
PG&E	GEYS14_7_UNIT14	31418	GEYSER14	13.8	50.00	1	NCNB	Fulton, Lakeville		Market
PG&E	GEYS16_7_UNIT16	31420	GEYSER16	13.8	49.00	1	NCNB	Fulton, Lakeville		Market
PG&E	GEYS17_7_UNIT17	31422	GEYSER17	13.8	56.00	1	NCNB	Fulton, Lakeville		Market
PG&E	GEYS18_7_UNIT18	31424	GEYSER18	13.8	45.00	1	NCNB	Lakeville		Market
PG&E	GEYS20_7_UNIT20	31426	GEYSER20	13.8	40.00	1	NCNB	Lakeville		Market
PG&E	GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	42.50	1	NCNB	Eagle Rock, Fulton, Lakeville		Market
PG&E	GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	42.50	2	NCNB	Eagle Rock, Fulton, Lakeville		Market
PG&E	GYS7X8_7_UNITS	31408	GEYSER78	13.8	38.00	1	NCNB	Eagle Rock, Fulton, Lakeville		Market
PG&E	GYS7X8_7_UNITS	31408	GEYSER78	13.8	38.00	2	NCNB	Eagle Rock, Fulton, Lakeville		Market
PG&E	GYSRVL_7_WSPRNG				1.45		NCNB	Fulton, Lakeville	Not modeled Aug NQC	QF/Selfgen
PG&E	HILAND_7_YOLOWD				0.00		NCNB	Eagle Rock, Fulton, Lakeville	Not Modeled. Energy Only	Market
PG&E	IGNACO_1_QF				0.00		NCNB	Lakeville	Not modeled Aug NQC	QF/Selfgen
PG&E	INDVLY_1_UNITS	31436	INDIAN V	9.1	1.11	1	NCNB	Eagle Rock, Fulton, Lakeville	Aug NQC	Net Seller
PG&E	MONTPH_7_UNITS	32700	MONTICLO	9.1	5.43	1	NCNB	Fulton, Lakeville	Aug NQC	Market
PG&E	MONTPH_7_UNITS	32700	MONTICLO	9.1	5.43	2	NCNB	Fulton, Lakeville	Aug NQC	Market
PG&E	MONTPH_7_UNITS	32700	MONTICLO	9.1	1.63	3	NCNB	Fulton, Lakeville	Aug NQC	Market
PG&E	NCPA_7_GP1UN1	38106	NCPA1GY1	13.8	31.00	1	NCNB	Lakeville	Aug NQC	MUNI
PG&E	NCPA_7_GP1UN2	38108	NCPA1GY2	13.8	28.00	1	NCNB	Lakeville	Aug NQC	MUNI
PG&E	NCPA_7_GP2UN3	38110	NCPA2GY1	13.8	0.00	1	NCNB	Fulton, Lakeville	Aug NQC	MUNI

PG&E	NCPA_7_GP2UN4	38112	NCPA2GY2	13.8	52.73	1	NCNB	Fulton, Lakeville	Aug NQC	MUNI
PG&E	POTTER_6_UNITS	31433	POTTRVLY	2.4	5.29	1	NCNB	Eagle Rock, Fulton, Lakeville	Aug NQC	Market
PG&E	POTTER_6_UNITS	31433	POTTRVLY	2.4	2.40	3	NCNB	Eagle Rock, Fulton, Lakeville	Aug NQC	Market
PG&E	POTTER_6_UNITS	31433	POTTRVLY	2.4	2.40	4	NCNB	Eagle Rock, Fulton, Lakeville	Aug NQC	Market
PG&E	POTTER_7_VECINO				0.00		NCNB	Eagle Rock, Fulton, Lakeville	Not modeled Aug NQC	QF/Selfgen
PG&E	SANTFG_7_UNITS	31400	SANTA FE	13.8	31.50	1	NCNB	Lakeville		Market
PG&E	SANTFG_7_UNITS	31400	SANTA FE	13.8	31.50	2	NCNB	Lakeville		Market
PG&E	SMUDGO_7_UNIT 1	31430	SMUDGEO1	13.8	47.00	1	NCNB	Lakeville		Market
PG&E	SNMALF_6_UNITS	31446	SONMA LF	9.1	3.29	1	NCNB	Fulton, Lakeville	Aug NQC	QF/Selfgen
PG&E	UKIAH_7_LAKEMN	38020	CITY UKH	115	0.49	1	NCNB	Eagle Rock, Fulton, Lakeville	Aug NQC	MUNI
PG&E	UKIAH_7_LAKEMN	38020	CITY UKH	115	1.21	2	NCNB	Eagle Rock, Fulton, Lakeville	Aug NQC	MUNI
PG&E	WDFRDF_2_UNITS	31404	WEST FOR	13.8	12.50	1	NCNB	Fulton, Lakeville		Market
PG&E	WDFRDF_2_UNITS	31404	WEST FOR	13.8	12.50	2	NCNB	Fulton, Lakeville		Market
PG&E	ZZZZZ_BEARCN_2_UNITS	31402	BEAR CAN	13.8	0.00	1	NCNB	Fulton, Lakeville	Retired	Market
PG&E	ZZZZZ_BEARCN_2_UNITS	31402	BEAR CAN	13.8	0.00	2	NCNB	Fulton, Lakeville	Retired	Market
PG&E	ZZZZZZ_GEYS17_2_BOTRCK	31421	BOTTLERK	13.8	0.00	1	NCNB	Fulton, Lakeville	Retired	Market
PG&E	ALLGNY_6_HYDRO1				0.15		Sierra	South of Table Mountain	Not modeled Aug NQC	Market
PG&E	APLHIL_1_SLABCK				0.00	1	Sierra	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Energy Only	Market
PG&E	BANGOR_6_HYDRO				0.54		Sierra	South of Table Mountain	Not modeled Aug NQC	Market
PG&E	BELDEN_7_UNIT 1	31784	BELDEN	13.8	119.00	1	Sierra	South of Palermo, South of Table Mountain	Aug NQC	Market

PG&E	BIOMAS_1_UNIT 1	32156	WOODLAND	9.11	24.31	1	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Net Seller
PG&E	BNNIEN_7_ALTAPH	32376	BONNIE N	60	1.00		Sierra	Weimer, Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
PG&E	BOGUE_1_UNITA1	32451	FREC	13.8	45.00	1	Sierra	Bogue, Drum-Rio Oso, South of Table Mountain	Aug NQC	Market
PG&E	BOWMN_6_HYDRO	32480	BOWMAN	9.11	1.98	1	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
PG&E	BUCKCK_2_HYDRO				0.45		Sierra	South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
PG&E	BUCKCK_7_OAKFLT				1.30		Sierra	South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
PG&E	BUCKCK_7_PL1X2	31820	BCKS CRK	11	31.03	1	Sierra	South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	BUCKCK_7_PL1X2	31820	BCKS CRK	11	26.97	2	Sierra	South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	CAMPFW_7_FARWST	32470	CMP.FARW	9.11	2.90	1	Sierra	South of Table Mountain	Aug NQC	MUNI
PG&E	CHICPK_7_UNIT 1	32462	CHI.PARK	11.5	42.00	1	Sierra	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
PG&E	COLGAT_7_UNIT 1	32450	COLGATE1	13.8	161.65	1	Sierra	South of Table Mountain	Aug NQC	MUNI
PG&E	COLGAT_7_UNIT 2	32452	COLGATE2	13.8	161.68	1	Sierra	South of Table Mountain	Aug NQC	MUNI
PG&E	CRESTA_7_PL1X2	31812	CRESTA	11.5	34.66	1	Sierra	South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	CRESTA_7_PL1X2	31812	CRESTA	11.5	35.34	2	Sierra	South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	DAVIS_1_SOLAR1				0.90		Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
PG&E	DAVIS_1_SOLAR2				0.95		Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market

PG&E	DAVIS_7_MNMETH				1.96		Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
PG&E	DEADCK_1_UNIT	31862	DEADWOOD	9.11	0.00	1	Sierra	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
PG&E	DEERCR_6_UNIT 1	32474	DEER CRK	9.11	7.00	1	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	DRUM_7_PL1X2	32504	DRUM 1-2	6.6	13.00	1	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	DRUM_7_PL1X2	32504	DRUM 1-2	6.6	13.00	2	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	DRUM_7_PL3X4	32506	DRUM 3-4	6.6	13.26	1	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	DRUM_7_PL3X4	32506	DRUM 3-4	6.6	15.64	2	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	DRUM_7_UNIT 5	32454	DRUM 5	13.8	50.00	1	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	DUTCH1_7_UNIT 1	32464	DTCHFLT1	11	22.00	1	Sierra	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	DUTCH2_7_UNIT 1	32502	DTCHFLT2	6.9	26.00	1	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
PG&E	ELDORO_7_UNIT 1	32513	ELDRADO1	21.6	11.00	1	Sierra	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain		Market
PG&E	ELDORO_7_UNIT 2	32514	ELDRADO2	21.6	11.00	1	Sierra	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain		Market

PG&E	FMEADO_6_HELLHL	32486	HELLHOLE	9.11	0.30	1	Sierra	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
PG&E	FMEADO_7_UNIT	32508	FRNCH MD	4.2	18.00	1	Sierra	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
PG&E	FORBST_7_UNIT 1	31814	FORBSTWN	11.5	37.50	1	Sierra	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
PG&E	GOLDHL_1_QF				0.00		Sierra	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled	QF/Selfgen
PG&E	GRIDLY_6_SOLAR	38054	GRIDLEY	60	0.00	1	Sierra	Pease, South of Table Mountain	Energy Only	Market
PG&E	GRNLF1_1_UNITS	32490	GRNLEAF1	13.8	31.84	1	Sierra	Bogue, Drum-Rio Oso, South of Table Mountain	Aug NQC	Market
PG&E	GRNLF1_1_UNITS	32491	GRNLEAF1	13.8	15.12	2	Sierra	Bogue, Drum-Rio Oso, South of Table Mountain	Aug NQC	Market
PG&E	GRNLF2_1_UNIT	32492	GRNLEAF2	13.8	33.87	1	Sierra	Pease, Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
PG&E	HALSEY_6_UNIT	32478	HALSEY F	9.11	13.50	1	Sierra	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	HAYPRS_6_QFUNTS	32488	HAYPRES+	9.11	0.00	1	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
PG&E	HAYPRS_6_QFUNTS	32488	HAYPRES+	9.11	0.00	2	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
PG&E	HIGGNS_1_COMBIE				0.00		Sierra	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Energy Only	Market
PG&E	HIGGNS_7_QFUNTS				0.23		Sierra	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	QF/Selfgen

PG&E	KANAKA_1_UNIT				0.00		Sierra	Drum-Rio Oso, South of Table Mountain	Not modeled Aug NQC	MUNI
PG&E	KELYRG_6_UNIT	31834	KELLYRDG	9.11	11.00	1	Sierra	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
PG&E	LIVEOK_6_SOLAR				0.87		Sierra	Pease, South of Table Mountain	Not modeled Aug NQC	Market
PG&E	LODIEC_2_PL1X2	38123	LODI CT1	18	184.18	1	Sierra	South of Rio Oso, South of Palermo, South of Table Mountain		MUNI
PG&E	LODIEC_2_PL1X2	38124	LODI ST1	18	95.82	1	Sierra	South of Rio Oso, South of Palermo, South of Table Mountain		MUNI
PG&E	MDFKRL_2_PROJCT	32456	MIDLFORK	13.8	66.49	1	Sierra	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
PG&E	MDFKRL_2_PROJCT	32456	MIDLFORK	13.8	66.49	2	Sierra	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
PG&E	MDFKRL_2_PROJCT	32458	RALSTON	13.8	85.41	1	Sierra	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
PG&E	NAROW1_2_UNIT	32466	NARROWS1	9.1	12.00	1	Sierra	South of Table Mountain	Aug NQC	Market
PG&E	NAROW2_2_UNIT	32468	NARROWS2	9.1	28.51	1	Sierra	South of Table Mountain	Aug NQC	MUNI
PG&E	NWCSTL_7_UNIT 1	32460	NEWCSTLE	13.2	12.00	1	Sierra	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	OROVIL_6_UNIT	31888	OROVLLE	9.11	7.50	1	Sierra	Drum-Rio Oso, South of Table Mountain	Aug NQC	Market
PG&E	OXBOW_6_DRUM	32484	OXBOW F	9.11	6.00	1	Sierra	Weimer, Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
PG&E	PLACVL_1_CHILIB	32510	CHILIBAR	4.2	8.40	1	Sierra	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	PLACVL_1_RCKCRE				0.00		Sierra	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market

PG&E	PLSNTG_7_LNCLND	32408	PLSNT GR	60	3.20		Sierra	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
PG&E	POEPH_7_UNIT 1	31790	POE 1	13.8	60.00	1	Sierra	South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	POEPH_7_UNIT 2	31792	POE 2	13.8	60.00	1	Sierra	South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	RCKCRK_7_UNIT 1	31786	ROCK CK1	13.8	57.00	1	Sierra	South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	RCKCRK_7_UNIT 2	31788	ROCK CK2	13.8	56.90	1	Sierra	South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	RIOOSO_1_QF				0.92		Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	QF/Selfgen
PG&E	ROLLIN_6_UNIT	32476	ROLLINSF	9.11	13.50	1	Sierra	Weimer, Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
PG&E	SLYCRK_1_UNIT 1	31832	SLY.CR.	9.11	13.00	1	Sierra	Drum-Rio Oso, South of Table Mountain	Aug NQC	Market
PG&E	SPAULD_6_UNIT 3	32472	SPAULDG	9.11	6.50	3	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	SPAULD_6_UNIT12	32472	SPAULDG	9.11	7.00	1	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	SPAULD_6_UNIT12	32472	SPAULDG	9.11	4.40	2	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	SPI LI_2_UNIT 1	32498	SPILINCF	12.5	9.79	1	Sierra	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Net Seller
PG&E	STIGCT_2_LODI	38114	Stig CC	13.8	49.50	1	Sierra	South of Rio Oso, South of Palermo, South of Table Mountain		MUNI

PG&E	ULTRCK_2_UNIT	32500	ULTR RCK	9.11	21.81	1	Sierra	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
PG&E	WDLEAF_7_UNIT 1	31794	WOODLEAF	13.8	60.00	1	Sierra	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
PG&E	WHEATL_6_LNDFIL	32350	WHEATLND	60	3.20		Sierra	South of Table Mountain	Not modeled Aug NQC	Market
PG&E	WISE_1_UNIT 1	32512	WISE	12	14.50	1	Sierra	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	WISE_1_UNIT 2	32512	WISE	12	3.20	1	Sierra	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PG&E	YUBACT_1_SUNSWT	32494	YUBA CTY	9.11	23.98	1	Sierra	Pease, Drum-Rio Oso, South of Table Mountain	Aug NQC	Net Seller
PG&E	YUBACT_6_UNITA1	32496	YCEC	13.8	46.00	1	Sierra	Pease, Drum-Rio Oso, South of Table Mountain		Market
PG&E	ZZ_NA	32162	RIV.DLTA	9.11	0.00	1	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	No NQC - hist. data	QF/Selfgen
PG&E	ZZ_UCDAVS_1_UNIT	32166	UC DAVIS	9.11	0.00	RN	Sierra	Drum-Rio Oso, South of Palermo, South of Table Mountain	No NQC - hist. data	QF/Selfgen
PG&E	BEARDS_7_UNIT 1	34074	BEARDSLY	6.9	8.36	1	Stockton	Tesla-Bellota, Stanislaus	Aug NQC	MUNI
PG&E	CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	0.19	1	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	0.19	2	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	0.19	3	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	COGNAT_1_UNIT	33818	COG.NTNL	12	41.58	1	Stockton	Weber	Aug NQC	Net Seller
PG&E	CRWCKS_1_SOLAR1	34051	Q539	34.5	0.00	1	Stockton	Tesla-Bellota	Energy Only	Market
PG&E	DONNLS_7_UNIT	34058	DONNELLS	13.8	72.00	1	Stockton	Tesla-Bellota, Stanislaus	Aug NQC	MUNI
PG&E	FROGTN_7_UTICA				0.00		Stockton	Tesla-Bellota, Stanislaus	Not modeled Energy Only	Market
PG&E	LOCKFD_1_BEARCK				0.00		Stockton	Tesla-Bellota	Not modeled Energy Only	Market

PG&E	LOCKFD_1_KSOLAR				0.00		Stockton	Tesla-Bellota	Not modeled Energy Only	Market
PG&E	LODI25_2_UNIT 1	38120	LODI25CT	9.11	22.70	1	Stockton	Lockeford		MUNI
PG&E	PEORIA_1_SOLAR				1.35		Stockton	Tesla-Bellota, Stanislaus	Not modeled Aug NQC	Market
PG&E	PHOENX_1_UNIT				2.00		Stockton	Tesla-Bellota, Stanislaus	Not modeled Aug NQC	Market
PG&E	SCHLTE_1_PL1X3	33805	GWFTRCY1	13.8	82.90	1	Stockton	Tesla-Bellota		Market
PG&E	SCHLTE_1_PL1X3	33807	GWFTRCY2	13.8	82.90	1	Stockton	Tesla-Bellota		Market
PG&E	SCHLTE_1_PL1X3	33811	GWFTRCY3	13.8	133.59	1	Stockton	Tesla-Bellota		Market
PG&E	SNDBAR_7_UNIT 1	34060	SANDBAR	13.8	4.19	1	Stockton	Tesla-Bellota, Stanislaus	Aug NQC	MUNI
PG&E	SPIFBD_1_PL1X2	33917	FBERBORD	115	1.53	1	Stockton	Tesla-Bellota, Stanislaus	Aug NQC	Market
PG&E	SPRGAP_1_UNIT 1	34078	SPRNG GP	6	7.00	1	Stockton	Tesla-Bellota, Stanislaus	Aug NQC	Market
PG&E	STANIS_7_UNIT 1	34062	STANISLS	13.8	91.00	1	Stockton	Tesla-Bellota, Stanislaus	Aug NQC	Market
PG&E	STNRES_1_UNIT	34056	STNSLSRP	13.8	18.23	1	Stockton	Tesla-Bellota	Aug NQC	Net Seller
PG&E	TULLCK_7_UNITS	34076	TULLOCH	6.9	5.08	1	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	TULLCK_7_UNITS	34076	TULLOCH	6.9	5.72	2	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	TULLCK_7_UNITS	34076	TULLOCH	6.9	3.75	3	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	ULTPCH_1_UNIT 1	34050	CH.STN.	13.8	16.19	1	Stockton	Tesla-Bellota, Stanislaus	Aug NQC	QF/Selfgen
PG&E	VLYHOM_7_SSJID				0.74		Stockton	Tesla-Bellota, Stanislaus	Not modeled Aug NQC	MUNI
PG&E	WEBER_6_FORWRD				4.20		Stockton	Weber	Not modeled Aug NQC	Market
PG&E	ZZ_NA	33830	GEN.MILL	9.11	0.00	1	Stockton	Lockeford	No NQC - hist. data	QF/Selfgen
PG&E	ZZ_NA	33687	STKTN WW	60	0.00	1	Stockton	Weber	No NQC - hist. data	QF/Selfgen
SCE	ACACIA_6_SOLAR	29878	ACACIA_G	0.48	0.00	EQ	BC/Ventura	Big Creek	Energy Only	Market
SCE	ALAMO_6_UNIT	25653	ALAMO SC	13.8	15.07	1	BC/Ventura	Big Creek	Aug NQC	MUNI
SCE	BIGCRK_2_EXESWD	24314	B CRK 4	11.5	49.60	41	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24314	B CRK 4	11.5	49.80	42	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24315	B CRK 8	13.8	24.01	81	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24315	B CRK 8	13.8	43.30	82	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24306	B CRK1-1	7.2	19.58	1	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24306	B CRK1-1	7.2	21.26	2	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market

SCE	BIGCRK_2_EXESWD	24307	B CRK1-2	13.8	21.26	3	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24307	B CRK1-2	13.8	30.71	4	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24308	B CRK2-1	13.8	49.99	1	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24308	B CRK2-1	13.8	51.18	2	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24309	B CRK2-2	7.2	18.40	3	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24309	B CRK2-2	7.2	19.39	4	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24310	B CRK2-3	7.2	16.73	5	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24310	B CRK2-3	7.2	18.21	6	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24311	B CRK3-1	13.8	34.44	1	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24311	B CRK3-1	13.8	33.46	2	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24312	B CRK3-2	13.8	34.44	3	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24312	B CRK3-2	13.8	35.43	4	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24313	B CRK3-3	13.8	35.92	5	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24317	MAMOTH1G	13.8	92.02	1	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24318	MAMOTH2G	13.8	92.02	2	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24323	PORTAL	4.8	9.45	1	BC/Ventura	Big Creek, Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_7_DAM7				0.00		BC/Ventura	Big Creek, Rector, Vestal	Not modeled Energy Only	Market
SCE	BIGCRK_7_MAMRES				0.00		BC/Ventura	Big Creek, Rector, Vestal	Not modeled Energy Only	Market
SCE	BIGSKY_2_SOLAR1	29703	SP_ANTG1	0.8	16.07	1	BC/Ventura	Big Creek	Aug NQC	Market
SCE	BIGSKY_2_SOLAR2	29703	SP_ANTG1	0.8	32.13	1	BC/Ventura	Big Creek	Aug NQC	Market
SCE	BIGSKY_2_SOLAR3	29704	SP_ANTG2	0.8	16.07	1	BC/Ventura	Big Creek	Aug NQC	Market
SCE	BIGSKY_2_SOLAR4	29704	SP_ANTG2	0.8	16.06	1	BC/Ventura	Big Creek	Aug NQC	Market
SCE	BIGSKY_2_SOLAR5	29704	SP_ANTG2	0.8	4.02	1	BC/Ventura	Big Creek	Aug NQC	Market
SCE	BIGSKY_2_SOLAR6	29704	SP_ANTG2	0.8	68.29	1	BC/Ventura	Big Creek	Aug NQC	Market
SCE	BIGSKY_2_SOLAR7	29704	SP_ANTG2	0.8	40.17	1	BC/Ventura	Big Creek	Aug NQC	Market
SCE	CEDUCR_2_SOLAR1	25054	WDT394_a	0.48	0.00	EQ	BC/Ventura	Big Creek, Vestal	Energy Only	Market
SCE	CEDUCR_2_SOLAR2	25052	WDT390_a	0.48	0.00	EQ	BC/Ventura	Big Creek, Vestal	Energy Only	Market
SCE	CEDUCR_2_SOLAR3	25058	WDT603L	0.48	0.00	EQ	BC/Ventura	Big Creek, Vestal	Energy Only	Market
SCE	CEDUCR_2_SOLAR4	25056	WDT439L	0.48	0.00	EQ	BC/Ventura	Big Creek, Vestal	Energy Only	Market
SCE	DELSUR_6_CREST				0.00		BC/Ventura	Big Creek	Energy Only	Market
SCE	DELSUR_6_DRYFRB				4.37		BC/Ventura	Big Creek	Not modeled Aug NQC	Market

SCE	DELSUR_6_SOLAR1				5.39		BC/Ventura	Big Creek	Not modeled Aug NQC	Market
SCE	EASTWD_7_UNIT	24319	EASTWOOD	13.8	199.00	1	BC/Ventura	Big Creek, Rector, Vestal		Market
SCE	EDMONS_2_NSPIN	25605	EDMON1AP	14.4	16.86	1	BC/Ventura	Big Creek	Pumps	MUNI
SCE	EDMONS_2_NSPIN	25606	EDMON2AP	14.4	16.86	2	BC/Ventura	Big Creek	Pumps	MUNI
SCE	EDMONS_2_NSPIN	25607	EDMON3AP	14.4	16.86	3	BC/Ventura	Big Creek	Pumps	MUNI
SCE	EDMONS_2_NSPIN	25607	EDMON3AP	14.4	16.86	4	BC/Ventura	Big Creek	Pumps	MUNI
SCE	EDMONS_2_NSPIN	25608	EDMON4AP	14.4	16.86	5	BC/Ventura	Big Creek	Pumps	MUNI
SCE	EDMONS_2_NSPIN	25608	EDMON4AP	14.4	16.86	6	BC/Ventura	Big Creek	Pumps	MUNI
SCE	EDMONS_2_NSPIN	25609	EDMON5AP	14.4	16.86	7	BC/Ventura	Big Creek	Pumps	MUNI
SCE	EDMONS_2_NSPIN	25609	EDMON5AP	14.4	16.86	8	BC/Ventura	Big Creek	Pumps	MUNI
SCE	EDMONS_2_NSPIN	25610	EDMON6AP	14.4	16.86	9	BC/Ventura	Big Creek	Pumps	MUNI
SCE	EDMONS_2_NSPIN	25610	EDMON6AP	14.4	16.86	10	BC/Ventura	Big Creek	Pumps	MUNI
SCE	EDMONS_2_NSPIN	25611	EDMON7AP	14.4	16.85	11	BC/Ventura	Big Creek	Pumps	MUNI
SCE	EDMONS_2_NSPIN	25611	EDMON7AP	14.4	16.85	12	BC/Ventura	Big Creek	Pumps	MUNI
SCE	EDMONS_2_NSPIN	25612	EDMON8AP	14.4	16.85	13	BC/Ventura	Big Creek	Pumps	MUNI
SCE	EDMONS_2_NSPIN	25612	EDMON8AP	14.4	16.85	14	BC/Ventura	Big Creek	Pumps	MUNI
SCE	GLOW_6_SOLAR	29896	APPINV	0.42	0.00	EQ	BC/Ventura	Big Creek	Energy Only	Market
SCE	GOLETA_2_QF	24057	GOLETA	66	0.05		BC/Ventura	Ventura, S.Clara, Moorpark	Not modeled Aug NQC	QF/Selfgen
SCE	GOLETA_6_ELLWOD	29004	ELLWOOD	13.8	54.00	1	BC/Ventura	Ventura, S.Clara, Moorpark		Market
SCE	GOLETA_6_EXGEN	24326	EXGEN1	13.8	1.49	S1	BC/Ventura	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SCE	GOLETA_6_EXGEN	24362	EXGEN2	13.8	2.17	G1	BC/Ventura	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SCE	GOLETA_6_GAVOTA	24057	GOLETA	66	0.51		BC/Ventura	Ventura, S.Clara, Moorpark	Not modeled Aug NQC	Market
SCE	GOLETA_6_TAJIGS	24057	GOLETA	66	2.93		BC/Ventura	Ventura, S.Clara, Moorpark	Not modeled Aug NQC	Market
SCE	LEBECS_2_UNITS	29051	PSTRIAG1	18	165.58	G1	BC/Ventura	Big Creek	Aug NQC	Market
SCE	LEBECS_2_UNITS	29052	PSTRIAG2	18	165.58	G2	BC/Ventura	Big Creek	Aug NQC	Market
SCE	LEBECS_2_UNITS	29054	PSTRIAG3	18	165.58	G3	BC/Ventura	Big Creek	Aug NQC	Market
SCE	LEBECS_2_UNITS	29053	PSTRIAS1	18	170.45	S1	BC/Ventura	Big Creek	Aug NQC	Market
SCE	LEBECS_2_UNITS	29055	PSTRIAS2	18	82.79	S2	BC/Ventura	Big Creek	Aug NQC	Market

SCE	LITLRK_6_SEPV01				0.00		BC/Ventura	Big Creek	Not modeled Energy Only	Market
SCE	LITLRK_6_SOLAR1				4.12		BC/Ventura	Big Creek	Not modeled Aug NQC	Market
SCE	LITLRK_6_SOLAR2				1.61		BC/Ventura	Big Creek	Not modeled Aug NQC	Market
SCE	LITLRK_6_SOLAR4				2.41		BC/Ventura	Big Creek	Not modeled Aug NQC	Market
SCE	LNCSTR_6_CREST				0.00		BC/Ventura	Big Creek	Not modeled Energy Only	Market
SCE	MNDALY_6_MCGRTH	29306	MCGPKGEN	13.8	47.20	1	BC/Ventura	Ventura, S.Clara, Moorpark		Market
SCE	MNDALY_7_UNIT 1	24089	MANDLY1G	13.8	0.00	1	BC/Ventura	Ventura, S.Clara, Moorpark	Retired by 2021	Market
SCE	MNDALY_7_UNIT 2	24090	MANDLY2G	13.8	0.00	2	BC/Ventura	Ventura, S.Clara, Moorpark	Retired by 2021	Market
SCE	MNDALY_7_UNIT 3	24222	MANDLY3G	16	0.00	3	BC/Ventura	Ventura, S.Clara, Moorpark	Retired by 2021	Market
SCE	MOORPK_2_CALABS	25081	WDT251	13.8	4.90	EQ	BC/Ventura	Ventura, Moorpark	Aug NQC	Market
SCE	MOORPK_6_QF	29952	CAMGEN	13.8	26.07	D1	BC/Ventura	Ventura, S.Clara, Moorpark	Aug NQC	Market
SCE	MOORPK_7_UNITA1	24098	MOORPARK	66	2.12		BC/Ventura	Ventura, Moorpark	Not modeled Aug NQC	Market
SCE	NEENCH_6_SOLAR	29900	ALPINE_G	0.48	51.71	EQ	BC/Ventura	Big Creek	Aug NQC	Market
SCE	OASIS_6_CREST				0.00		BC/Ventura	Big Creek	Not modeled Energy Only	Market
SCE	OASIS_6_SOLAR1				0.00		BC/Ventura	Big Creek	Not modeled Energy Only	Market
SCE	OASIS_6_SOLAR2	25075	SOLARISG	0.2	16.07	EQ	BC/Ventura	Big Creek	Aug NQC	Market
SCE	OMAR_2_UNIT 1	24102	OMAR 1G	13.8	74.30	1	BC/Ventura	Big Creek		Net Seller
SCE	OMAR_2_UNIT 2	24103	OMAR 2G	13.8	75.90	2	BC/Ventura	Big Creek		Net Seller
SCE	OMAR_2_UNIT 3	24104	OMAR 3G	13.8	78.40	3	BC/Ventura	Big Creek		Net Seller
SCE	OMAR_2_UNIT 4	24105	OMAR 4G	13.8	77.25	4	BC/Ventura	Big Creek		Net Seller
SCE	ORMOND_7_UNIT 1	24107	ORMOND1G	26	0.00	1	BC/Ventura	Ventura, Moorpark	Retired by 2021	Market
SCE	ORMOND_7_UNIT 2	24108	ORMOND2G	26	0.00	2	BC/Ventura	Ventura, Moorpark	Retired by 2021	Market
SCE	OSO_6_NSPIN	25614	OSO A P	13.2	2.25	1	BC/Ventura	Big Creek	Pumps	MUNI
SCE	OSO_6_NSPIN	25614	OSO A P	13.2	2.25	2	BC/Ventura	Big Creek	Pumps	MUNI

SCE	OSO_6_NSPIN	25614	OSO A P	13.2	2.25	3	BC/Ventura	Big Creek	Pumps	MUNI
SCE	OSO_6_NSPIN	25614	OSO A P	13.2	2.25	4	BC/Ventura	Big Creek	Pumps	MUNI
SCE	OSO_6_NSPIN	25615	OSO B P	13.2	2.25	5	BC/Ventura	Big Creek	Pumps	MUNI
SCE	OSO_6_NSPIN	25615	OSO B P	13.2	2.25	6	BC/Ventura	Big Creek	Pumps	MUNI
SCE	OSO_6_NSPIN	25615	OSO B P	13.2	2.25	7	BC/Ventura	Big Creek	Pumps	MUNI
SCE	OSO_6_NSPIN	25615	OSO B P	13.2	2.25	8	BC/Ventura	Big Creek	Pumps	MUNI
SCE	PANDOL_6_UNIT	24113	PANDOL	13.8	23.32	1	BC/Ventura	Big Creek, Vestal	Aug NQC	Market
SCE	PANDOL_6_UNIT	24113	PANDOL	13.8	23.32	2	BC/Ventura	Big Creek, Vestal	Aug NQC	Market
SCE	PLAINV_6_BSOLAR	29918	VLYFLR_G	0.2	0.00	EQ	BC/Ventura	Big Creek	Energy Only	Market
SCE	PLAINV_6_DSOLAR	29914	DRYRCH G	0.8	8.03	EQ	BC/Ventura	Big Creek	Aug NQC	Market
SCE	PLAINV_6_NLRSR1				16.07		BC/Ventura	Big Creek	Not modeled Aug NQC	Market
SCE	PLAINV_6_SOLAR3	25089	TOT524_PV	0.42	0.00	EQ	BC/Ventura	Big Creek	Energy Only	Market
SCE	PLAINV_6_SOLARC	25086	TOT521_a	0.2	0.00	EQ	BC/Ventura	Big Creek	Energy Only	Market
SCE	PMDLET_6_SOLAR1				8.20		BC/Ventura	Big Creek	Not modeled Aug NQC	Market
SCE	RECTOR_2_KAWEAH	24212	RECTOR	66	0.01		BC/Ventura	Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
SCE	RECTOR_2_KAWH 1	24212	RECTOR	66	0.13		BC/Ventura	Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
SCE	RECTOR_2_QF	24212	RECTOR	66	0.00		BC/Ventura	Big Creek, Rector, Vestal	Not modeled Aug NQC	QF/Selfgen
SCE	RECTOR_7_TULARE	24212	RECTOR	66	0.00		BC/Ventura	Big Creek, Rector, Vestal	Not modeled	Market
SCE	RSMSLR_6_SOLAR1	29984	DAWNGEN	0.8	20.00	EQ	BC/Ventura	Big Creek	Aug NQC	Market
SCE	RSMSLR_6_SOLAR2	29888	TWILGHTG	0.8	17.54	EQ	BC/Ventura	Big Creek	Aug NQC	Market
SCE	SAUGUS_2_TOLAND	24135	SAUGUS	66	0.00		BC/Ventura	Big Creek	Not modeled Energy Only	Market
SCE	SAUGUS_6_MWDFTH	24135	SAUGUS	66	7.40		BC/Ventura	Big Creek	Not modeled Aug NQC	MUNI
SCE	SAUGUS_6_PTCHGN	24118	PITCHGEN	13.8	19.30	D1	BC/Ventura	Big Creek	Aug NQC	MUNI
SCE	SAUGUS_6_QF	24135	SAUGUS	66	0.63		BC/Ventura	Big Creek	Not modeled Aug NQC	QF/Selfgen
SCE	SAUGUS_7_CHIQCN	24135	SAUGUS	66	4.71		BC/Ventura	Big Creek	Not modeled Aug NQC	Market
SCE	SAUGUS_7_LOPEZ	24135	SAUGUS	66	5.34		BC/Ventura	Big Creek	Not modeled Aug NQC	QF/Selfgen

SCE	SHUTLE_6_CREST				0.00		BC/Ventura	Big Creek	Not modeled Energy Only	Market
SCE	SNCLRA_2_HOWLNG	25080	GFID8045	13.8	7.63	EQ	BC/Ventura	Ventura, S.Clara, Moorpark	Aug NQC	Market
SCE	SNCLRA_2_SPRHYD				0.45		BC/Ventura	Ventura, S.Clara, Moorpark	Not modeled Aug NQC	Market
SCE	SNCLRA_2_UNIT1				16.31		BC/Ventura	Ventura, S.Clara, Moorpark	Not modeled Aug NQC	Market
SCE	SNCLRA_6_OXGEN	24110	OXGEN	13.8	33.50	D1	BC/Ventura	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SCE	SNCLRA_6_PROCGN	24119	PROCGEN	13.8	44.52	D1	BC/Ventura	Ventura, S.Clara, Moorpark	Aug NQC	Market
SCE	SNCLRA_6_QF				0.00		BC/Ventura	Ventura, S.Clara, Moorpark	Not modeled Aug NQC	QF/Selfgen
SCE	SNCLRA_6_WILLMT	24159	WILLAMET	13.8	13.61	D1	BC/Ventura	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SCE	SPRGVL_2_QF	24215	SPRINGVL	66	0.12		BC/Ventura	Big Creek, Rector, Vestal	Not modeled Aug NQC	QF/Selfgen
SCE	SPRGVL_2_TULE	24215	SPRINGVL	66	6.40		BC/Ventura	Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
SCE	SPRGVL_2_TULESC	24215	SPRINGVL	66	0.00		BC/Ventura	Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
SCE	SUNSHN_2_LNDFL	29954	WDT273	13.7	3.31	1	BC/Ventura	Big Creek	Aug NQC	Market
SCE	SUNSHN_2_LNDFL	29954	WDT273	13.7	3.31	2	BC/Ventura	Big Creek	Aug NQC	Market
SCE	SUNSHN_2_LNDFL	29954	WDT273	13.7	3.31	3	BC/Ventura	Big Creek	Aug NQC	Market
SCE	SUNSHN_2_LNDFL	29954	WDT273	13.7	3.31	4	BC/Ventura	Big Creek	Aug NQC	Market
SCE	SUNSHN_2_LNDFL	29954	WDT273	13.7	3.31	5	BC/Ventura	Big Creek	Aug NQC	Market
SCE	SYCAMR_2_UNIT 1	24143	SYCCYN1G	13.8	66.33	1	BC/Ventura	Big Creek	Aug NQC	Net Seller
SCE	SYCAMR_2_UNIT 2	24144	SYCCYN2G	13.8	85.00	2	BC/Ventura	Big Creek	Aug NQC	Net Seller
SCE	SYCAMR_2_UNIT 3	24145	SYCCYN3G	13.8	67.26	3	BC/Ventura	Big Creek	Aug NQC	Net Seller
SCE	SYCAMR_2_UNIT 4	24146	SYCCYN4G	13.8	85.00	4	BC/Ventura	Big Creek	Aug NQC	Net Seller
SCE	TENGEN_2_PL1X2	24148	TENNGEN1	13.8	18.40	D1	BC/Ventura	Big Creek	Aug NQC	Net Seller
SCE	TENGEN_2_PL1X2	24149	TENNGEN2	13.8	18.40	D2	BC/Ventura	Big Creek	Aug NQC	Net Seller
SCE	VESTAL_2_KERN	24372	KR 3-1	11	0.20	1	BC/Ventura	Big Creek, Vestal	Aug NQC	QF/Selfgen
SCE	VESTAL_2_KERN	24373	KR 3-2	11	0.19	2	BC/Ventura	Big Creek, Vestal	Aug NQC	QF/Selfgen

SCE	VESTAL_2_RTS042				0.00		BC/Ventura	Big Creek, Vestal	Not modeled Energy Only	Market
SCE	VESTAL_2_SOLAR1	25069	WDT43331	0.36	13.85	EQ	BC/Ventura	Big Creek, Vestal	Aug NQC	Market
SCE	VESTAL_2_SOLAR2	25070	WDT43332	0.36	6.69	EQ	BC/Ventura	Big Creek, Vestal	Aug NQC	Market
SCE	VESTAL_2_SOLAR2	25071	WDT43333	0.36	3.00	EQ	BC/Ventura	Big Creek, Vestal	Aug NQC	Market
SCE	VESTAL_2_UNIT1				2.93		BC/Ventura	Big Creek, Vestal	Not modeled Aug NQC	Market
SCE	VESTAL_2_WELLHD	24116	WELLGEN	13.8	49.00	1	BC/Ventura	Big Creek, Vestal		Market
SCE	VESTAL_6_QF	29008	LAKEGEN	13.8	0.26	1	BC/Ventura	Big Creek, Vestal	Aug NQC	QF/Selfgen
SCE	WARNE_2_UNIT	25651	WARNE1	13.8	38.00	1	BC/Ventura	Big Creek	Aug NQC	MUNI
SCE	WARNE_2_UNIT	25652	WARNE2	13.8	38.00	2	BC/Ventura	Big Creek	Aug NQC	MUNI
SCE	ZZ_APPGEN_6_UNIT 1	24009	APPGEN1G	13.8	0.00	1	BC/Ventura	Big Creek	No NQC - hist. data	Market
SCE	ZZ_APPGEN_6_UNIT 1	24010	APPGEN2G	13.8	0.00	2	BC/Ventura	Big Creek	No NQC - hist. data	Market
SCE	ZZ_APPGEN_6_UNIT 1	24361	APPGEN3G	13.8	0.00	3	BC/Ventura	Big Creek	No NQC - hist. data	Market
SCE	ZZ_NA	24340	CHARMIN	13.8	0.00	1	BC/Ventura	Ventura, S.Clara, Moorpark	No NQC - hist. data	QF/Selfgen
SCE	ZZ_NA	24370	KAWGEN	13.8	0.00	1	BC/Ventura	Big Creek, Rector, Vestal	No NQC - hist. data	Market
SCE	ZZ_NA	24422	PALMDALE	66	0.00	1	BC/Ventura	Big Creek	No NQC - hist. data	Market
SCE	ZZZ_New Unit	25076	WDT1098	0.4	50.00	EQ	BC/Ventura	Big Creek	No NQC - Pmax	Market
SCE	ZZZ_New Unit	97676	WDT1200AG1	0.48	0.00	1	BC/Ventura	Ventura, S.Clara, Moorpark	Energy Only	Market
SCE	ZZZZ_New Unit	24089	MANDLY1G	13.8	131.00	X1	BC/Ventura	Ventura, S.Clara, Moorpark	No NQC - Pmax	Market
SCE	ZZZZ_New Unit	24090	MANDLY2G	13.8	131.00	X2	BC/Ventura	Ventura, S.Clara, Moorpark	No NQC - Pmax	Market
SCE	ALAMIT_7_UNIT 1	24001	ALAMT1 G	18	0.00	1	LA Basin	Western	Retired by 2021	Market
SCE	ALAMIT_7_UNIT 2	24002	ALAMT2 G	18	0.00	2	LA Basin	Western	Retired by 2021	Market
SCE	ALAMIT_7_UNIT 3	24003	ALAMT3 G	18	0.00	3	LA Basin	Western	Retired by 2021	Market
SCE	ALAMIT_7_UNIT 4	24004	ALAMT4 G	18	0.00	4	LA Basin	Western	Retired by 2021	Market
SCE	ALAMIT_7_UNIT 5	24005	ALAMT5 G	20	0.00	5	LA Basin	Western	Retired by 2021	Market

SCE	ALAMIT_7_UNIT 6	24161	ALAMT6 G	20	0.00	6	LA Basin	Western	Retired by 2021	Market
SCE	ALTWD_1_QF	25635	ALTWIND	115	4.15	Q1	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	ALTWD_1_QF	25635	ALTWIND	115	4.14	Q2	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	ANAHM_2_CANYN1	25211	CanyonGT 1	13.8	49.40	1	LA Basin	Western		MUNI
SCE	ANAHM_2_CANYN2	25212	CanyonGT 2	13.8	48.00	2	LA Basin	Western		MUNI
SCE	ANAHM_2_CANYN3	25213	CanyonGT 3	13.8	48.00	3	LA Basin	Western		MUNI
SCE	ANAHM_2_CANYN4	25214	CanyonGT 4	13.8	49.40	4	LA Basin	Western		MUNI
SCE	ANAHM_7_CT	25208	DowlingCTG	13.8	40.64	1	LA Basin	Western	Aug NQC	MUNI
SCE	ARCOGN_2_UNITS	24011	ARCO 1G	13.8	52.84	1	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24012	ARCO 2G	13.8	52.84	2	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24013	ARCO 3G	13.8	52.84	3	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24014	ARCO 4G	13.8	52.84	4	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24163	ARCO 5G	13.8	26.42	5	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24164	ARCO 6G	13.8	26.42	6	LA Basin	Western	Aug NQC	Net Seller
SCE	BARRE_2_QF	24016	BARRE	230	0.00		LA Basin	Western	Not modeled	QF/Selfgen
SCE	BARRE_6_PEAKER	29309	BARPKGEN	13.8	47.00	1	LA Basin	Western		Market
SCE	BLAST_1_WIND	24839	BLAST	115	3.49	1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	BRDWAY_7_UNIT 3	29007	BRODWYSC	13.8	0.00		LA Basin	Western	Not modeled	MUNI
SCE	BUCKWD_1_NPALM1	25634	BUCKWIND	115	1.36		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind
SCE	BUCKWD_1_QF	25634	BUCKWIND	115	2.64	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	BUCKWD_7_WINTCV	25634	BUCKWIND	115	0.16	W5	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	CABZON_1_WINDA1	29290	CABAZON	33	8.90	1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	CAPWD_1_QF	25633	CAPWIND	115	3.45	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	CENTER_2_QF	29953	SIGGEN	13.8	17.40	D1	LA Basin	Western	Aug NQC	QF/Selfgen
SCE	CENTER_2_RHONDO	24203	CENTER S	66	1.91		LA Basin	Western	Not modeled	QF/Selfgen
SCE	CENTER_2_SOLAR1				0.00		LA Basin	Western	Not modeled Energy Only	Market
SCE	CENTER_6_PEAKER	29308	CTRPKGEN	13.8	47.00	1	LA Basin	Western		Market

SCE	CENTRY_6_PL1X4	25302	CLTNCTRY	13.8	36.00	1	LA Basin	Eastern, Eastern Metro	Aug NQC	MUNI
SCE	CHEVMN_2_UNITS	24022	CHEVGEN1	13.8	5.90	1	LA Basin	Western, El Nido	Aug NQC	Net Seller
SCE	CHEVMN_2_UNITS	24023	CHEVGEN2	13.8	5.90	2	LA Basin	Western, El Nido	Aug NQC	Net Seller
SCE	CHINO_2_APEBT1				20.00		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	CHINO_2_JURUPA				0.00		LA Basin	Eastern, Eastern Metro	Not modeled Energy Only	Market
SCE	CHINO_2_QF				5.09		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
SCE	CHINO_2_SASOLR				0.00		LA Basin	Eastern, Eastern Metro	Not modeled Energy Only	Market
SCE	CHINO_2_SOLAR				0.34		LA Basin	Eastern, Eastern Metro	Not modeled	Market
SCE	CHINO_2_SOLAR2				0.00		LA Basin	Eastern, Eastern Metro	Not modeled Energy Only	Market
SCE	CHINO_6_CIMGEN	24026	CIMGEN	13.8	25.18	D1	LA Basin	Eastern, Eastern Metro	Aug NQC	QF/Selfgen
SCE	CHINO_6_SMPPAP	24140	SIMPSON	13.8	22.78	D1	LA Basin	Eastern, Eastern Metro	Aug NQC	QF/Selfgen
SCE	CHINO_7_MILIKN	24024	CHINO	66	1.19		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	COLTON_6_AGUAM1	25303	CLTNAGUA	13.8	43.00	1	LA Basin	Eastern, Eastern Metro	Aug NQC	MUNI
SCE	CORONS_2_SOLAR				0.00		LA Basin	Eastern, Eastern Metro	Not modeled Energy Only	Market
SCE	CORONS_6_CLRWTR	29338	CLRWTRCT	13.8	20.72	G1	LA Basin	Eastern, Eastern Metro		MUNI
SCE	CORONS_6_CLRWTR	29340	CLRWTRST	13.8	7.28	S1	LA Basin	Eastern, Eastern Metro		MUNI
SCE	DELAMO_2_SOLAR1				0.75		LA Basin	Western	Not modeled Aug NQC	Market
SCE	DELAMO_2_SOLAR2				1.11		LA Basin	Western	Not modeled Aug NQC	Market
SCE	DELAMO_2_SOLAR6				0.00		LA Basin		Not modeled Energy Only	
SCE	DELAMO_2_SOLRC1				0.00		LA Basin	Western	Not modeled Energy Only	Market
SCE	DELAMO_2_SOLRD				0.00		LA Basin	Western	Not modeled Energy Only	Market

SCE	DEVERS_1_QF	25639	SEAWIND	115	10.18	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	DEVERS_1_QF	25632	TERAWND	115	8.49	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	DEVERS_1_SEPV05				0.00		LA Basin	Eastern, Valley-Devers	Not modeled Energy Only	Market
SCE	DEVERS_1_SOLAR				0.00		LA Basin	Eastern, Valley-Devers	Not modeled Energy Only	Market
SCE	DEVERS_1_SOLAR1				0.00		LA Basin	Eastern, Valley-Devers	Not modeled Energy Only	Market
SCE	DEVERS_1_SOLAR2				0.00		LA Basin	Eastern, Valley-Devers	Not modeled Energy Only	Market
SCE	DMDVLY_1_UNITS	25425	ESRP P2	6.9	0.00	8	LA Basin	Eastern, Eastern Metro	Aug NQC	QF/Selfgen
SCE	DREWS_6_PL1X4	25301	CLTNDREW	13.8	36.00	1	LA Basin	Eastern, Eastern Metro	Aug NQC	MUNI
SCE	DVLCYN_1_UNITS	25648	DVLCYN1G	13.8	50.35	1	LA Basin	Eastern, Eastern Metro	Aug NQC	MUNI
SCE	DVLCYN_1_UNITS	25649	DVLCYN2G	13.8	50.35	2	LA Basin	Eastern, Eastern Metro	Aug NQC	MUNI
SCE	DVLCYN_1_UNITS	25603	DVLCYN3G	13.8	67.13	3	LA Basin	Eastern, Eastern Metro	Aug NQC	MUNI
SCE	DVLCYN_1_UNITS	25604	DVLCYN4G	13.8	67.13	4	LA Basin	Eastern, Eastern Metro	Aug NQC	MUNI
SCE	ELLIS_2_QF	24325	ORCOGEN	13.8	0.01	1	LA Basin	Western	Aug NQC	QF/Selfgen
SCE	ELSEGN_2_UN1011	29904	ELSEG5GT	16.5	131.50	5	LA Basin	Western, El Nido	Aug NQC	Market
SCE	ELSEGN_2_UN1011	29903	ELSEG6ST	13.8	131.50	6	LA Basin	Western, El Nido	Aug NQC	Market
SCE	ELSEGN_2_UN2021	29902	ELSEG7GT	16.5	131.84	7	LA Basin	Western, El Nido	Aug NQC	Market
SCE	ELSEGN_2_UN2021	29901	ELSEG8ST	13.8	131.84	8	LA Basin	Western, El Nido	Aug NQC	Market
SCE	ETIWND_2_CHMPNE				0.00		LA Basin	Eastern, Eastern Metro	Not modeled Energy Only	Market
SCE	ETIWND_2_FONTNA	24055	ETIWANDA	66	0.21		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
SCE	ETIWND_2_RTS010	24055	ETIWANDA	66	0.86		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS015	24055	ETIWANDA	66	1.03		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS017	24055	ETIWANDA	66	1.41		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS018	24055	ETIWANDA	66	0.58		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market

SCE	ETIWND_2_RTS023	24055	ETIWANDA	66	1.43		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS026	24055	ETIWANDA	66	4.82		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS027	24055	ETIWANDA	66	1.57		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	ETIWND_2_SOLAR1				0.00		LA Basin		Not modeled Energy Only	
SCE	ETIWND_2_SOLAR5				0.00		LA Basin		Not modeled Energy Only	
SCE	ETIWND_2_UNIT1	24071	INLAND	13.8	19.71	1	LA Basin	Eastern, Eastern Metro	Aug NQC	QF/Selfgen
SCE	ETIWND_6_GRPLND	29305	ETWPKGEN	13.8	46.00	1	LA Basin	Eastern, Eastern Metro		Market
SCE	ETIWND_6_MWDETI	25422	ETI MWDG	13.8	0.89	1	LA Basin	Eastern, Eastern Metro	Aug NQC	Market
SCE	ETIWND_7_MIDVLY	24055	ETIWANDA	66	1.67		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
SCE	ETIWND_7_UNIT 3	24052	MTNVIST3	18	0.00	3	LA Basin	Eastern, Eastern Metro	Assumed Retired by age	Market
SCE	ETIWND_7_UNIT 4	24053	MTNVIST4	18	0.00	4	LA Basin	Eastern, Eastern Metro	Assumed Retired by age	Market
SCE	GARNET_1_SOLAR	24815	GARNET	115	0.00		LA Basin	Eastern, Valley-Devers	Not modeled Energy Only	Market
SCE	GARNET_1_SOLAR2	24815	GARNET	115	3.20		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Market
SCE	GARNET_1_UNITS	24815	GARNET	115	0.79	G1	LA Basin	Eastern, Valley-Devers	Aug NQC	Market
SCE	GARNET_1_UNITS	24815	GARNET	115	0.27	G2	LA Basin	Eastern, Valley-Devers	Aug NQC	Market
SCE	GARNET_1_UNITS	24815	GARNET	115	0.62	G3	LA Basin	Eastern, Valley-Devers	Aug NQC	Market
SCE	GARNET_1_WIND	24815	GARNET	115	0.40	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	GARNET_1_WINDS	24815	GARNET	115	3.48	W2	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	GARNET_1_WT3WND	24815	GARNET	115	0.00	W3	LA Basin	Eastern, Valley-Devers	Aug NQC	Market
SCE	GARNET_2_HYDRO	24815	GARNET	115	0.45		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Market
SCE	GARNET_2_WIND1	24815	GARNET	115	1.83	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	GARNET_2_WIND2	24815	GARNET	115	1.76	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	GARNET_2_WIND3	24815	GARNET	115	2.22	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	GARNET_2_WIND4	24815	GARNET	115	1.73	QF	LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind

Appendix A – List of physical resources by PTO, local area and marker ID

SCE	GARNET_2_WIND5	24815	GARNET	115	0.53	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	GLNARM_2_UNIT 5	29013	GLENARM5_CT	13.8	50.00	CT	LA Basin	Western		MUNI
SCE	GLNARM_2_UNIT 5	29014	GLENARM5_ST	13.8	15.00	ST	LA Basin	Western		MUNI
SCE	GLNARM_7_UNIT 1	29005	PASADNA1	13.8	22.07	1	LA Basin	Western		MUNI
SCE	GLNARM_7_UNIT 2	29006	PASADNA2	13.8	22.30	1	LA Basin	Western		MUNI
SCE	GLNARM_7_UNIT 3	25042	PASADNA3	13.8	44.83	1	LA Basin	Western		MUNI
SCE	GLNARM_7_UNIT 4	25043	PASADNA4	13.8	42.42	1	LA Basin	Western		MUNI
SCE	HARBGN_7_UNITS	24062	HARBOR G	13.8	76.27	1	LA Basin	Western	Mothballed	Market
SCE	HARBGN_7_UNITS	24062	HARBOR G	13.8	11.86	HP	LA Basin	Western	Mothballed	Market
SCE	HARBGN_7_UNITS	25510	HARBORG4	4.16	11.86	LP	LA Basin	Western	Mothballed	Market
SCE	HINSON_6_CARBGN	24020	CARBGEN1	13.8	14.65	1	LA Basin	Western	Aug NQC	Market
SCE	HINSON_6_CARBGN	24328	CARBGEN2	13.8	14.65	1	LA Basin	Western	Aug NQC	Market
SCE	HINSON_6_LBECH1	24170	LBEACH12	13.8	65.00	1	LA Basin	Western		Market
SCE	HINSON_6_LBECH2	24170	LBEACH12	13.8	65.00	2	LA Basin	Western		Market
SCE	HINSON_6_LBECH3	24171	LBEACH34	13.8	65.00	3	LA Basin	Western		Market
SCE	HINSON_6_LBECH4	24171	LBEACH34	13.8	65.00	4	LA Basin	Western		Market
SCE	HINSON_6_SERRGN	24139	SERRFGEN	13.8	26.93	D1	LA Basin	Western	Aug NQC	QF/Selfgen
SCE	HNTGBH_7_UNIT 1	24066	HUNT1 G	13.8	0.00	1	LA Basin	Western	Retired by 2021	Market
SCE	HNTGBH_7_UNIT 2	24067	HUNT2 G	13.8	0.00	2	LA Basin	Western	Retired by 2021	Market
SCE	INDIGO_1_UNIT 1	29190	WINTECX2	13.8	42.00	1	LA Basin	Eastern, Valley-Devers		Market
SCE	INDIGO_1_UNIT 2	29191	WINTECX1	13.8	42.00	1	LA Basin	Eastern, Valley-Devers		Market
SCE	INDIGO_1_UNIT 3	29180	WINTEC8	13.8	42.00	1	LA Basin	Eastern, Valley-Devers		Market
SCE	INLDEM_5_UNIT 1	29041	IEEC-G1	19.5	335.00	1	LA Basin	Eastern, Valley, Valley-Devers	Aug NQC	Market
SCE	INLDEM_5_UNIT 2	29042	IEEC-G2	19.5	335.00	1	LA Basin	Eastern, Valley, Valley-Devers	Mothballed	Market
SCE	LACIEN_2_VENICE	24337	VENICE	13.8	0.00	1	LA Basin	Western, El Nido	Aug NQC	MUNI
SCE	LAGBEL_2_STG1				9.60		LA Basin		Not modeled Aug NQC	Market
SCE	LAGBEL_6_QF	29951	REFUSE	13.8	9.77	D1	LA Basin	Western	Aug NQC	QF/Selfgen
SCE	LGHTHP_6_ICEGEN	24070	ICEGEN	13.8	48.00	1	LA Basin	Western	Aug NQC	QF/Selfgen
SCE	MESAS_2_QF	24209	MESA CAL	66	0.00		LA Basin	Western	Not modeled Aug NQC	QF/Selfgen

SCE	MIRLOM_2_CORONA				2.30		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
SCE	MIRLOM_2_ONTARO				2.25		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	MIRLOM_2_RTS032				0.30		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	MIRLOM_2_RTS033				0.46		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	MIRLOM_2_TEMESC				2.60		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
SCE	MIRLOM_6_DELGEN	29339	DELGEN	13.8	25.93	1	LA Basin	Eastern, Eastern Metro	Aug NQC	QF/Selfgen
SCE	MIRLOM_6_PEAKER	29307	MRLPKGEN	13.8	46.00	1	LA Basin	Eastern, Eastern Metro		Market
SCE	MIRLOM_7_MWDLKM	24210	MIRALOMA	66	4.80		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	MUNI
SCE	MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	4.19	1	LA Basin	Eastern, Eastern Metro	Aug NQC	Market
SCE	MOJAVE_1_SIPHON	25658	MJVSPHN1	13.8	4.19	2	LA Basin	Eastern, Eastern Metro	Aug NQC	Market
SCE	MOJAVE_1_SIPHON	25659	MJVSPHN1	13.8	4.19	3	LA Basin	Eastern, Eastern Metro	Aug NQC	Market
SCE	MTWIND_1_UNIT 1	29060	MOUNTWND	115	6.49	S1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	MTWIND_1_UNIT 2	29060	MOUNTWND	115	2.95	S2	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	MTWIND_1_UNIT 3	29060	MOUNTWND	115	2.41	S3	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	OLINDA_2_COYCRK	24211	OLINDA	66	3.13		LA Basin	Western	Not modeled	QF/Selfgen
SCE	OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	3.56	C1	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	3.56	C2	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	3.56	C3	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	3.56	C4	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	6.37	S1	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_QF	24211	OLINDA	66	0.06		LA Basin	Western	Not modeled Aug NQC	QF/Selfgen
SCE	OLINDA_7_LNDFIL	24211	OLINDA	66	0.05		LA Basin	Western	Not modeled Aug NQC	QF/Selfgen
SCE	PADUA_2_ONTARO	24111	PADUA	66	0.12		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
SCE	PADUA_2_SOLAR1	24111	PADUA	66	0.00		LA Basin	Eastern, Eastern Metro	Not modeled Energy Only	Market

SCE	PADUA_6_MWDSDM	24111	PADUA	66	5.00		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	MUNI
SCE	PADUA_6_QF	24111	PADUA	66	0.31		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
SCE	PADUA_7_SDIMAS	24111	PADUA	66	1.05		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	PANSEA_1_PANARO	25640	PANAERO	115	0.18	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	PWEST_1_UNIT	24815	GARNET	115	0.20	PC	LA Basin	Western	Aug NQC	Market
SCE	REDOND_7_UNIT 5	24121	REDON5 G	18	0.00	5	LA Basin	Western	Retired by 2021	Market
SCE	REDOND_7_UNIT 6	24122	REDON6 G	18	0.00	6	LA Basin	Western	Retired by 2021	Market
SCE	REDOND_7_UNIT 7	24123	REDON7 G	20	0.00	7	LA Basin	Western	Retired by 2021	Market
SCE	REDOND_7_UNIT 8	24124	REDON8 G	20	0.00	8	LA Basin	Western	Retired by 2021	Market
SCE	RENWD_1_QF	25636	RENWIND	115	1.73	Q1	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	RENWD_1_QF	25636	RENWIND	115	1.72	Q2	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	RHONDO_2_QF	24213	RIOHONDO	66	0.21		LA Basin	Western	Not modeled Aug NQC	QF/Selfgen
SCE	RHONDO_6_PUENTE	24213	RIOHONDO	66	0.00		LA Basin	Western	Not modeled Aug NQC	Net Seller
SCE	RVSIDE_2_RERCU3	24299	RERC2G3	13.8	48.50	1	LA Basin	Eastern, Eastern Metro		MUNI
SCE	RVSIDE_2_RERCU4	24300	RERC2G4	13.8	48.50	1	LA Basin	Eastern, Eastern Metro		MUNI
SCE	RVSIDE_6_RERCU1	24242	RERC1G	13.8	48.35	1	LA Basin	Eastern, Eastern Metro		MUNI
SCE	RVSIDE_6_RERCU2	24243	RERC2G	13.8	48.50	1	LA Basin	Eastern, Eastern Metro		MUNI
SCE	RVSIDE_6_SOLAR1	24244	SPRINGEN	13.8	6.03		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	RVSIDE_6_SPRING	24244	SPRINGEN	13.8	36.00	1	LA Basin	Eastern, Eastern Metro		Market
SCE	SANITR_6_UNITS	24324	SANIGEN	13.8	1.20	D1	LA Basin	Eastern, Eastern Metro	Aug NQC	QF/Selfgen
SCE	SANTGO_2_LNDFL1				15.88		LA Basin		Not modeled Aug NQC	Market
SCE	SANWD_1_QF	25646	SANWIND	115	1.70	Q1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	SANWD_1_QF	25646	SANWIND	115	1.70	Q2	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	SBERDO_2_PSP3	24921	MNTV-CT1	18	129.71	1	LA Basin	Eastern, West of Devers, Eastern Metro		Market
SCE	SBERDO_2_PSP3	24922	MNTV-CT2	18	129.71	1	LA Basin	Eastern, West of Devers, Eastern Metro		Market

SCE	SBERDO_2_PSP3	24923	MNTV-ST1	18	225.07	1	LA Basin	Eastern, West of Devers, Eastern Metro		Market
SCE	SBERDO_2_PSP4	24924	MNTV-CT3	18	129.71	1	LA Basin	Eastern, West of Devers, Eastern Metro		Market
SCE	SBERDO_2_PSP4	24925	MNTV-CT4	18	129.71	1	LA Basin	Eastern, West of Devers, Eastern Metro		Market
SCE	SBERDO_2_PSP4	24926	MNTV-ST2	18	225.07	1	LA Basin	Eastern, West of Devers, Eastern Metro		Market
SCE	SBERDO_2_QF	24214	SANBRDNO	66	0.12		LA Basin	Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
SCE	SBERDO_2_REDLND	24214	SANBRDNO	66	0.64		LA Basin	Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS005	24214	SANBRDNO	66	1.15		LA Basin	Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS007	24214	SANBRDNO	66	1.03		LA Basin	Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS011	24214	SANBRDNO	66	0.91		LA Basin	Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS013	24214	SANBRDNO	66	0.87		LA Basin	Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS016	24214	SANBRDNO	66	0.46		LA Basin	Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS048	24214	SANBRDNO	66	0.00		LA Basin	Eastern, West of Devers, Eastern Metro	Not modeled Energy Only	Market
SCE	SBERDO_2_SNTANA	24214	SANBRDNO	66	0.00		LA Basin	Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
SCE	SBERDO_6_MILLCK	24214	SANBRDNO	66	0.73		LA Basin	Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
SCE	SENTNL_2_CTG1	29101	SENTINEL_G1	13.8	92.09	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG2	29102	SENTINEL_G2	13.8	92.40	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG3	29103	SENTINEL_G3	13.8	92.36	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG4	29104	SENTINEL_G4	13.8	91.98	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG5	29105	SENTINEL_G5	13.8	91.83	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG6	29106	SENTINEL_G6	13.8	92.16	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG7	29107	SENTINEL_G7	13.8	91.84	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG8	29108	SENTINEL_G8	13.8	91.56	1	LA Basin	Eastern, Valley-Devers		Market
SCE	TIFFNY_1_DILLON	29021	WINTEC6	115	4.96	1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind

SCE	TRNSWD_1_QF	25637	TRANWIND	115	7.42	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	VALLEY_5_PERRIS	24160	VALLEYSC	115	7.94		LA Basin	Eastern, Valley, Valley-Devers	Not modeled Aug NQC	QF/Selfgen
SCE	VALLEY_5_REDMTN	24160	VALLEYSC	115	3.70		LA Basin	Eastern, Valley, Valley-Devers	Not modeled Aug NQC	QF/Selfgen
SCE	VALLEY_5_RTS044	24160	VALLEYSC	115	3.37		LA Basin	Eastern, Valley, Valley-Devers	Not modeled Aug NQC	Market
SCE	VALLEY_5_SOLAR1	24160	VALLEYSC	115	0.00		LA Basin	Eastern, Valley, Valley-Devers	Not modeled Energy Only	Market
SCE	VALLEY_5_SOLAR2	25082	WDT786	34.5	16.65	EQ	LA Basin	Eastern, Valley, Valley-Devers	Aug NQC	Market
SCE	VALLEY_7_BADLND	24160	VALLEYSC	115	0.44		LA Basin	Eastern, Valley, Valley-Devers	Not modeled Aug NQC	Market
SCE	VALLEY_7_UNITA1	24160	VALLEYSC	115	2.56		LA Basin	Eastern, Valley, Valley-Devers	Not modeled Aug NQC	Market
SCE	VENWD_1_WIND1	25645	VENWIND	115	1.66	Q1	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	VENWD_1_WIND2	25645	VENWIND	115	2.83	Q2	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	VENWD_1_WIND3	25645	VENWIND	115	3.36	EU	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	VERNON_6_GONZL1	24342	FEDGEN	13.8	5.75	1	LA Basin	Western		MUNI
SCE	VERNON_6_GONZL2	24342	FEDGEN	13.8	5.75	1	LA Basin	Western		MUNI
SCE	VERNON_6_MALBRG	24239	MALBRG1G	13.8	42.37	C1	LA Basin	Western		MUNI
SCE	VERNON_6_MALBRG	24240	MALBRG2G	13.8	42.37	C2	LA Basin	Western		MUNI
SCE	VERNON_6_MALBRG	24241	MALBRG3G	13.8	49.26	S3	LA Basin	Western		MUNI
SCE	VILLPK_2_VALLYV	24216	VILLA PK	66	4.10		LA Basin	Western	Not modeled Aug NQC	QF/Selfgen
SCE	VILLPK_6_MWDYOR	24216	VILLA PK	66	4.20		LA Basin	Western	Not modeled Aug NQC	MUNI
SCE	VISTA_2_RIALTO	24901	VSTA	230	0.25		LA Basin	Eastern, Eastern Metro	Energy Only	Market
SCE	VISTA_2_RTS028	24901	VSTA	230	2.29		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	Market
SCE	VISTA_6_QF	24902	VSTA	66	0.06		LA Basin	Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
SCE	WALCRK_2_CTG1	29201	WALCRKG1	13.8	96.00	1	LA Basin	Western		Market
SCE	WALCRK_2_CTG2	29202	WALCRKG2	13.8	96.00	1	LA Basin	Western		Market

SCE	WALCRK_2_CTG3	29203	WALCRKG3	13.8	96.00	1	LA Basin	Western		Market
SCE	WALCRK_2_CTG4	29204	WALCRKG4	13.8	96.00	1	LA Basin	Western		Market
SCE	WALCRK_2_CTG5	29205	WALCRKG5	13.8	96.65	1	LA Basin	Western		Market
SCE	WALNUT_2_SOLAR				0.00		LA Basin	Western	Not modeled Energy Only	Market
SCE	WALNUT_6_HILLGEN	24063	HILLGEN	13.8	45.28	D1	LA Basin	Western	Aug NQC	QF/Selfgen
SCE	WALNUT_7_WCOVCT	24157	WALNUT	66	3.45		LA Basin	Western	Not modeled Aug NQC	Market
SCE	WALNUT_7_WCOVST	24157	WALNUT	66	5.12		LA Basin	Western	Not modeled Aug NQC	Market
SCE	WHTWTR_1_WINDA1	29061	WHITEWTR	33	5.22	1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	ZZ_ARCOGN_2_UNITS	24018	BRIGEN	13.8	0.00	1	LA Basin	Western	No NQC - hist. data	Net Seller
SCE	ZZ_HINSON_6_QF	24064	HINSON	66	0.00	1	LA Basin	Western	No NQC - hist. data	QF/Selfgen
SCE	ZZ_LAFRES_6_QF	24332	PALOGEN	13.8	0.00	D1	LA Basin	Western, El Nido	No NQC - hist. data	QF/Selfgen
SCE	ZZ_MOBGEN_6_UNIT 1	24094	MOBGEN	13.8	0.00	1	LA Basin	Western, El Nido	No NQC - hist. data	QF/Selfgen
SCE	ZZ_NA	29260	ALTAMSA4	115	0.00	1	LA Basin	Eastern, Valley-Devers	No NQC - hist. data	Wind
SCE	ZZ_NA	24329	MOBGEN2	13.8	0.00	1	LA Basin	Western, El Nido	No NQC - hist. data	QF/Selfgen
SCE	ZZ_NA	24330	OUTFALL1	13.8	0.00	1	LA Basin	Western, El Nido	No NQC - hist. data	QF/Selfgen
SCE	ZZ_NA	24331	OUTFALL2	13.8	0.00	1	LA Basin	Western, El Nido	No NQC - hist. data	QF/Selfgen
SCE	ZZ_NA	24327	THUMSGEN	13.8	0.00	1	LA Basin	Western	No NQC - hist. data	QF/Selfgen
SCE	ZZ_SANTGO_6_COYOTE	24341	COYGEN	13.8	0.00	1	LA Basin	Western	No NQC - hist. data	QF/Selfgen
SCE	ZZZZ_New	90000	ALMT-GT1	18	200.00	X1	LA Basin	Western	No NQC - Pmax	Market
SCE	ZZZZ_New	90001	ALMT-GT2	18	200.00	X2	LA Basin	Western	No NQC - Pmax	Market
SCE	ZZZZ_New	90002	ALMT-ST1	18	240.00	X3	LA Basin	Western	No NQC - Pmax	Market
SCE	ZZZZ_New	90003	HUNT-GT1	18	202.00	X1	LA Basin	Western	No NQC - Pmax	Market
SCE	ZZZZ_New	90004	HUNT-GT2	18	202.00	X2	LA Basin	Western	No NQC - Pmax	Market

SCE	ZZZZ_New	90005	HUNT-ST1	18	240.00	X3	LA Basin	Western	No NQC - Pmax	Market
SCE	ZZZZZZ_ELSEGN_7_UNIT 4	24048	ELSEG4 G	18	0.00	4	LA Basin	Western, El Nido	Retired	Market
SDG&E	BORDER_6_UNITA1	22149	CALPK_BD	13.8	48.00	1	SD-IV	San Diego, Border		Market
SDG&E	BREGGO_6_DEGRSL				5.16		SD-IV	San Diego	Not modeled Aug NQC	Market
SDG&E	BREGGO_6_SOLAR	22082	BR GEN1	0.21	22.44	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CBRLLO_6_PLSTP1	22092	CABRILLO	69	2.53	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CCRITA_7_RPPCHF	22124	CHCARITA	138	2.17	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CHILLS_1_SYCENG	22120	CARLTNHS	138	0.67	1	SD-IV	San Diego	Aug NQC	QF/Selfgen
SDG&E	CHILLS_7_UNITA1	22120	CARLTNHS	138	1.52	2	SD-IV	San Diego	Aug NQC	QF/Selfgen
SDG&E	CNTNLA_2_SOLAR1	23463	DW GEN3&4	0.33	113.75	1	SD-IV	None	Aug NQC	Market
SDG&E	CNTNLA_2_SOLAR2	23463	DW GEN3&4	0.33	0.00	2	SD-IV	None	Energy Only	Market
SDG&E	CPSTNO_7_PRMADS	22112	CAPSTRNO	138	5.38	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CPVERD_2_SOLAR	23309	IV GEN3 G1	0.31	57.15	G1	SD-IV	None	Aug NQC	Market
SDG&E	CPVERD_2_SOLAR	23301	IV GEN3 G2	0.31	45.74	G2	SD-IV	None	Aug NQC	Market
SDG&E	CRELMN_6_RAMON1				1.74		SD-IV	San Diego	Not modeled Aug NQC	Market
SDG&E	CRELMN_6_RAMON2				4.33		SD-IV	San Diego	Not modeled Aug NQC	Market
SDG&E	CRSTWD_6_KUMYAY	22915	KUMEYAAY	0.69	7.63	1	SD-IV	San Diego	Aug NQC	Wind
SDG&E	CSLR4S_2_SOLAR	23298	DW GEN1 G1	0.32	43.70	G1	SD-IV	None	Aug NQC	Market
SDG&E	CSLR4S_2_SOLAR	23299	DW GEN1 G2	0.32	43.70	G2	SD-IV	None	Aug NQC	Market
SDG&E	DIVSON_6_NSQF	22172	DIVISION	69	43.07	1	SD-IV	San Diego	Aug NQC	QF/Selfgen
SDG&E	ELCAJN_6_EB1BT1				7.50		SD-IV	San Diego, El Cajon	Not modeled.	Market
SDG&E	ELCAJN_6_LM6K	23320	EC GEN2	13.8	48.10	1	SD-IV	San Diego, El Cajon		Market
SDG&E	ELCAJN_6_UNITA1	22150	EC GEN1	13.8	45.42	1	SD-IV	San Diego, El Cajon		Market
SDG&E	ENCINA_7_EA2	22234	ENCINA 2	14.4	0.00	1	SD-IV	San Diego, Encina	Retired by 2021	Market
SDG&E	ENCINA_7_EA3	22236	ENCINA 3	14.4	0.00	1	SD-IV	San Diego, Encina	Retired by 2021	Market
SDG&E	ENCINA_7_EA4	22240	ENCINA 4	22	0.00	1	SD-IV	San Diego, Encina	Retired by 2021	Market
SDG&E	ENCINA_7_EA5	22244	ENCINA 5	24	0.00	1	SD-IV	San Diego, Encina	Retired by 2021	Market
SDG&E	ENCINA_7_GT1	22248	ENCINAGT	12.5	0.00	1	SD-IV	San Diego, Encina	Retired by 2021	Market

SDG&E	ENERSJ_2_WIND				23.33		SD-IV	None	Not modeled Aug NQC	Wind
SDG&E	ESCNDO_6_EB1BT1				10.00	1	SD-IV	San Diego, Esco	Not modeled.	Market
SDG&E	ESCNDO_6_EB2BT2				10.00	1	SD-IV	San Diego, Esco	Not modeled.	Market
SDG&E	ESCNDO_6_EB3BT3				10.00	1	SD-IV	San Diego, Esco	Not modeled.	Market
SDG&E	ESCNDO_6_PL1X2	22257	ESGEN	13.8	48.71	1	SD-IV	San Diego, Esco		Market
SDG&E	ESCNDO_6_UNITB1	22153	CALPK_ES	13.8	48.00	1	SD-IV	San Diego, Esco		Market
SDG&E	ESCO_6_GLMQF	22332	GOALLINE	69	36.41	1	SD-IV	San Diego, Esco	Aug NQC	Net Seller
SDG&E	IVSLRP_2_SOLAR1	23440	DW GEN2 G1	0.36	57.32	1	SD-IV	None	Aug NQC	Market
SDG&E	IVSLRP_2_SOLAR1	23441	DW GEN2 G2	0.36	57.32	1	SD-IV	None	Aug NQC	Market
SDG&E	IVSLRP_2_SOLAR1	23442	DW GEN2 G3	0.36	57.32	1	SD-IV	None	Aug NQC	Market
SDG&E	IVWEST_2_SOLAR1	23155	DU GEN1 G1	0.2	65.20	G1	SD-IV	None	Aug NQC	Market
SDG&E	IVWEST_2_SOLAR1	23156	DU GEN1 G2	0.2	55.32	G2	SD-IV	None	Aug NQC	Market
SDG&E	LAKHDG_6_UNIT 1	22625	LKHODG1	13.8	20.00	1	SD-IV	San Diego		Market
SDG&E	LAKHDG_6_UNIT 2	22626	LKHODG2	13.8	20.00	2	SD-IV	San Diego		Market
SDG&E	LARKSP_6_UNIT 1	22074	LRKSPBD1	13.8	46.00	1	SD-IV	San Diego, Border		Market
SDG&E	LARKSP_6_UNIT 2	22075	LRKSPBD2	13.8	46.00	1	SD-IV	San Diego, Border		Market
SDG&E	LAROA1_2_UNITA1	20187	LRP-U1	16	0.00	1	SD-IV	None	Connect to CENACE/CFE grid for the summer – not available for ISO BAA RA purpose	Market
SDG&E	LAROA2_2_UNITA1	22997	INTBCT	16	176.81	1	SD-IV	None		Market
SDG&E	LAROA2_2_UNITA1	22996	INTBST	18	145.19	1	SD-IV	None		Market
SDG&E	LILIAC_6_SOLAR				2.41		SD-IV	San Diego	Not modeled.	Market
SDG&E	MRGT_6_MEF2	22487	MEF_MR2	13.8	47.90	1	SD-IV	San Diego, Miramar		Market
SDG&E	MRGT_6_MMAREF	22486	MEF_MR1	13.8	48.00	1	SD-IV	San Diego, Miramar		Market
SDG&E	MSHGTS_6_MMARLF	22448	MESAHGTS	69	3.70	1	SD-IV	San Diego, Mission	Aug NQC	Market
SDG&E	MSSION_2_QF	22496	MISSION	69	0.65	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	NIMTG_6_NIQF	22576	NOISLMTR	69	34.98	1	SD-IV	San Diego	Aug NQC	QF/Selfgen
SDG&E	OCTILO_5_WIND	23314	OCO GEN G1	0.69	8.17	G1	SD-IV	None	Aug NQC	Wind
SDG&E	OCTILO_5_WIND	23318	OCO GEN G2	0.69	8.17	G2	SD-IV	None	Aug NQC	Wind
SDG&E	OGROVE_6_PL1X2	22628	PA GEN1	13.8	48.00	1	SD-IV	San Diego, Pala		Market
SDG&E	OGROVE_6_PL1X2	22629	PA GEN2	13.8	48.00	1	SD-IV	San Diego, Pala		Market

SDG&E	OTAY_6_LNDFL5	22604	OTAY	69	0.00		SD-IV	San Diego, Border	Not modeled Energy Only	Market
SDG&E	OTAY_6_LNDFL6	22604	OTAY	69	0.00		SD-IV	San Diego, Border	Not modeled Energy Only	Market
SDG&E	OTAY_6_PL1X2	22617	OYGEN	13.8	35.50	1	SD-IV	San Diego, Border		Market
SDG&E	OTAY_6_UNITB1	22604	OTAY	69	2.38	1	SD-IV	San Diego, Border	Aug NQC	Market
SDG&E	OTAY_7_UNITC1	22604	OTAY	69	1.78	3	SD-IV	San Diego, Border	Aug NQC	QF/Selfgen
SDG&E	OTMESA_2_PL1X3	22605	OTAYMGT1	18	165.16	1	SD-IV	San Diego		Market
SDG&E	OTMESA_2_PL1X3	22606	OTAYMGT2	18	166.17	1	SD-IV	San Diego		Market
SDG&E	OTMESA_2_PL1X3	22607	OTAYMST1	16	272.27	1	SD-IV	San Diego		Market
SDG&E	PALOMR_2_PL1X3	22262	PEN_CT1	18	170.18	1	SD-IV	San Diego		Market
SDG&E	PALOMR_2_PL1X3	22263	PEN_CT2	18	170.18	1	SD-IV	San Diego		Market
SDG&E	PALOMR_2_PL1X3	22265	PEN_ST	18	225.24	1	SD-IV	San Diego		Market
SDG&E	PIOPIC_2_CTG1	23162	PIO PICO CT1	13.8	106.00	1	SD-IV	San Diego	No NQC - Pmax	Market
SDG&E	PIOPIC_2_CTG2	23163	PIO PICO CT2	13.8	106.00	1	SD-IV	San Diego	No NQC - Pmax	Market
SDG&E	PIOPIC_2_CTG3	23164	PIO PICO CT3	13.8	106.00	1	SD-IV	San Diego	No NQC - Pmax	Market
SDG&E	PTLOMA_6_NTCCGN	22660	POINTLMA	69	2.07	2	SD-IV	San Diego	Aug NQC	QF/Selfgen
SDG&E	PTLOMA_6_NTCQF	22660	POINTLMA	69	19.74	1	SD-IV	San Diego	Aug NQC	QF/Selfgen
SDG&E	SAMPSN_6_KELCO1	22704	SAMPSON	12.5	6.39	1	SD-IV	San Diego	Aug NQC	Net Seller
SDG&E	SMRCOS_6_LNDFIL	22724	SANMRCOS	69	1.28	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	TERMEX_2_PL1X3	22982	TDM CTG2	18	156.44	1	SD-IV	None		Market
SDG&E	TERMEX_2_PL1X3	22983	TDM CTG3	18	156.44	1	SD-IV	None		Market
SDG&E	TERMEX_2_PL1X3	22981	TDM STG	21	280.13	1	SD-IV	None		Market
SDG&E	VLCNTR_6_VCSLR				1.87		SD-IV	San Diego, Pala	Not modeled Aug NQC	Market
SDG&E	VLCNTR_6_VCSLR1				2.17		SD-IV	San Diego, Pala	Not modeled Aug NQC	Market
SDG&E	VLCNTR_6_VCSLR2				4.78		SD-IV	San Diego, Pala	Not modeled Aug NQC	Market
SDG&E	ZZ_NA	22916	PFC-AVC	0.6	0.00	1	SD-IV	San Diego	No NQC - hist. data	QF/Selfgen
SDG&E	ZZZ_New Unit	22942	BUE GEN 1 G1	0.69	23.12	G1	SD-IV	None	No NQC - est. data	Wind

SDG&E	ZZZ_New Unit	23100	ECO GEN1 G1	0.69	27.38	G1	SD-IV	None	No NQC - est. data	Wind
SDG&E	ZZZ_New Unit	23287	Q429 G1	0.31	80.00	1	SD-IV	None	No NQC - est. data	Market
SDG&E	ZZZ_New Unit	23352	Q644G	0.31	16.00	1	SD-IV	None	No NQC - est. data	Market
SDG&E	ZZZZ_New Unit	22945	BUE GEN 1 G2	0.69	15.40	G2	SD-IV	None	No NQC - est. data	Wind
SDG&E	ZZZZ_New unit	22783	EA5 REPOWER1	13.8	100.00	1	SD-IV	San Diego	No NQC - Pmax	Market
SDG&E	ZZZZ_New unit	22784	EA5 REPOWER2	13.8	100.00	1	SD-IV	San Diego	No NQC - Pmax	Market
SDG&E	ZZZZ_New unit	22788	EA5 REPOWER3	13.8	100.00	1	SD-IV	San Diego	No NQC - Pmax	Market
SDG&E	ZZZZ_New unit	22786	EA5 REPOWER4	13.8	100.00	1	SD-IV	San Diego	No NQC - Pmax	Market
SDG&E	ZZZZ_New unit	22787	EA5 REPOWER5	13.8	100.00	1	SD-IV	San Diego	No NQC - Pmax	Market
SDG&E	ZZZZ_New Unit	23131	Q183_G1	0.69	0.00	G1	SD-IV	None	Energy Only	Market
SDG&E	ZZZZ_New Unit	23134	Q183_G2	0.69	0.00	G2	SD-IV	None	Energy Only	Market
SDG&E	ZZZZZ_ELCAJN_7_GT1	22212	ELCAJNGT	12.5	0.00	1	SD-IV	San Diego, El Cajon	Retired	Market
SDG&E	ZZZZZ_ENCINA_7_EA1	22233	ENCINA 1	14.4	0.00	1	SD-IV	San Diego, Encina	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY2	22373	KEARN2AB	12.5	0.00	1	SD-IV	San Diego, Mission	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY2	22373	KEARN2AB	12.5	0.00	2	SD-IV	San Diego, Mission	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY2	22374	KEARN2CD	12.5	0.00	1	SD-IV	San Diego, Mission	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY2	22374	KEARN2CD	12.5	0.00	2	SD-IV	San Diego, Mission	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY3	22375	KEARN3AB	12.5	0.00	1	SD-IV	San Diego, Mission	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY3	22375	KEARN3AB	12.5	0.00	2	SD-IV	San Diego, Mission	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY3	22376	KEARN3CD	12.5	0.00	1	SD-IV	San Diego, Mission	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY3	22376	KEARN3CD	12.5	0.00	2	SD-IV	San Diego, Mission	Retired	Market

SDG&E	ZZZZZ_MRGT_7_UNITS	22488	MIRAMRGT	12.5	0.00	1	SD-IV	San Diego, Miramar	Retired	Market
SDG&E	ZZZZZ_MRGT_7_UNITS	22488	MIRAMRGT	12.5	0.00	2	SD-IV	San Diego, Miramar	Retired	Market