2023 LOCAL CAPACITY TECHNICAL STUDY

DRAFT REPORT

AND STUDY RESULTS

Intentionally left blank

Executive Summary

This Report documents the results and recommendations of the 2023 Local Capacity Technical (LCT) Study. The LCT Study assumptions, processes, and criteria were discussed and recommended through the 2023 Local Capacity Technical Study Criteria, Methodology and Assumptions Stakeholder Meeting held on October 27, 2021. On balance, the assumptions, and processes used for the 2023 LCT Study mirror those used in the 2007-2022 LCT Studies.

Overall, the capacity needed for LCR has increased by about 336 MW or about 1.3% from 2022 to 2023.

The LCR needs have decreased in the following areas: North Coast/North Bay and Fresno due to load forecast decrease, Sierra due to change in resources NQC values, Stockton due to new transmission line rating and San Diego due to new transmission projects.

The LCR needs have increased in the following areas: Humboldt, Bay Area and Big Creek/Ventura due to load forecast increase, LA Basin due to load forecast increase and new constraint, Kern due to new limiting contingency and element.

The 2023 LCT study results are provided to the CPUC for consideration in its 2023 resource adequacy requirements program. These results will also be used by the CAISO as "Local Capacity Requirements" or "LCR" (minimum quantity of local capacity necessary to meet the LCR criteria) and for assisting in the allocation of costs of any CAISO procurement of capacity needed to achieve the Reliability Standards notwithstanding the resource adequacy procurement of Load Serving Entities (LSEs).[1]

The load forecast used in this study is based on the final adopted California Energy Demand Forecast 2021-2035, developed by the CEC; namely the load-serving entity (LSE) and balancing authority (BA) mid baseline demand with low additional achievable energy efficiency (AAEE) and high additional achievable fuel substitution (AAFS): https://efiling.energy.ca.gov/GetDocument.aspx?tn=241384.

To aide procurement, this LCT study provides load profiles and transmission capacity information that shows the effectiveness of local resources in meeting temporal local reliability needs.

[1] For information regarding the conditions under which the CAISO may engage in procurement of local capacity and the allocation of the costs of such procurement, please see Sections 41 and 43 of the current CAISO Tariff, at: http://www.caiso.com/238a/238acd24167f0.html.

The studied results for 2023 are provided below and 2027 LCR needs are provided for comparison:

2023 Local Capacity Needs

	August Qualifying Capacity				Capacity Available at Peak	2023 LCR Need
Local Area Name	**QF/ Muni (MW)**	**Non-Solar (MW)**	**Solar (MW)**	**Total (MW)**	**Total (MW)**	**Capacity Needed**
Humboldt	0	178	0	**178**	**178**	**141**
North Coast/ North Bay	138	773	0	**911**	**911**	**857**
Sierra	1206	698	5	**1909**	**1904**	**1150***
Stockton	136	431	12	**579**	**567**	**579***
Greater Bay	611	7151	8	**7770**	**7770**	**7312***
Greater Fresno	216	2759	436	**3411**	**2979**	**1870***
Kern	6	360	73	**439**	**366**	**439***
Big Creek/ Ventura	407	4593	475	**5475**	**5475**	**2240**
LA Basin	1080	8570	11	**9661**	**9656**	**7529**
San Diego/ Imperial Valley	2	4960	396	**5358**	**4962**	**3332**
Total	**3802**	**30473**	**1416**	**35691**	**34768**	**25449**

2027 Local Capacity Needs

	August Qualifying Capacity				Capacity Available at Peak	2027 LCR Need
Local Area Name	**QF/ Muni (MW)**	**Non-Solar (MW)**	**Solar (MW)**	**Total (MW)**	**Total (MW)**	**Capacity Needed**
Humboldt	0	178	0	**178**	**178**	**147**
North Coast/ North Bay	138	773	0	**911**	**911**	**911***
Sierra	1206	698	5	**1909**	**1904**	**1345***
Stockton	112	431	12	**555**	**543**	**555***
Greater Bay	611	7151	8	**7770**	**7770**	**7540***
Greater Fresno	216	2759	436	**3411**	**2979**	**2179***
Kern	6	360	73	**439**	**366**	**320**
Big Creek/ Ventura	407	3321	475	**4203**	**4203**	**1126**
LA Basin	1080	6368	11	**7459**	**7454**	**6131**
San Diego/ Imperial Valley	2	5390	396	**5788**	**5392**	**3369***
Total	**3778**	**27429**	**1416**	**32623**	**31700**	**23623**

* Details about magnitude of deficiencies can be found in the applicable section below. Resource deficient areas and sub-area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.

The estimated results for years 2024 and 2025 LCR needs are provided below:

2024 Estimated Local Capacity Needs (No technical studies conducted)

	August Qualifying Capacity				Capacity Available at Peak	2024 LCR Need
Local Area Name	QF/ Muni (MW)	Non-Solar (MW)	Solar (MW)	Total (MW)	Total (MW)	Capacity Needed
Humboldt	0	178	0	**178**	**178**	**143**
North Coast/ North Bay	138	773	0	**911**	**911**	**899**
Sierra	1206	698	5	**1909**	**1904**	**1199***
Stockton	136	431	12	**579**	**567**	**579***
Greater Bay	611	7151	8	**7770**	**7770**	**7369***
Greater Fresno	216	2759	436	**3411**	**2979**	**1947***
Kern	6	360	73	**439**	**366**	**316***
Big Creek/ Ventura	407	3321	475	**4203**	**4203**	**2258**
LA Basin	1080	6368	11	**7459**	**7454**	**5851**
San Diego/ Imperial Valley	2	5390	396	**5788**	**5392**	**3341**
Total	**3802**	**27429**	**1416**	**32647**	**31724**	**23902**

2025 Estimated Local Capacity Needs (No technical studies conducted)

	August Qualifying Capacity				Capacity Available at Peak	2025 LCR Need
Local Area Name	QF/ Muni (MW)	Non-Solar (MW)	Solar (MW)	Total (MW)	Total (MW)	Capacity Needed
Humboldt	0	178	0	**178**	**178**	**144**
North Coast/ North Bay	138	773	0	**911**	**911**	**911***
Sierra	1206	698	5	**1909**	**1904**	**1248***
Stockton	136	431	12	**579**	**567**	**579***
Greater Bay	611	7151	8	**7770**	**7770**	**7426***
Greater Fresno	216	2759	436	**3411**	**2979**	**2025***
Kern	6	360	73	**439**	**366**	**318***
Big Creek/ Ventura	407	3321	475	**4203**	**4203**	**2275**
LA Basin	1080	6368	11	**7459**	**7454**	**5944**
San Diego/ Imperial Valley	2	5390	396	**5788**	**5392**	**3351**
Total	**3802**	**27429**	**1416**	**32647**	**31724**	**24221**

* Details about magnitude of deficiencies can be found in the applicable section below. Resource deficient areas and sub-area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.

The studied results for year 2022 LCR needs are provided below for comparison:

2022 Local Capacity Needs

	August Qualifying Capacity				Capacity Available at Peak	2022 LCR Need
Local Area Name	QF/ Muni (MW)	Non-Solar (MW)	Solar (MW)	Total (MW)	Total (MW)	Capacity Needed
Humboldt	0	181	0	**181**	**181**	**111**
North Coast/ North Bay	119	715	0	**834**	**834**	**834***
Sierra	1193	894	5	**2092**	**2087**	**1220***
Stockton	129	445	12	**586**	**574**	**562***
Greater Bay	611	7129	8	**7748**	**7748**	**7231***
Greater Fresno	194	2819	357	**3370**	**3172**	**1987***
Kern	4	333	81	**418**	**337**	**356***
Big Creek/ Ventura	424	4816	369	**5609**	**5609**	**2173**
LA Basin	1160	7603	11	**8774**	**8774**	**6646**
San Diego/ Imperial Valley	8	3985	369	**4362**	**3993**	**3993**
Total	3842	28920	1212	**33974**	**33309**	**25113**

* Details about magnitude of deficiencies can be found in the applicable section below. Resource deficient areas and sub-area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.

The narrative for each Local Capacity Area lists important new projects included in the base cases as well as a description of the reason for changes between the 2022 and 2023 LCT study results.

Intentionally left blank

Table of Contents

Intentionally left blank

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

1.1 Objectives

The intent of the 2023 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, as was the objective of all previous Local Capacity Technical Studies.

To aid procurement, this LCT study provides load profiles and transmission capacity information that shows the effectiveness of local resources in meeting temporal local reliability needs.

1.2 Key Study Assumptions

1.2.1 Inputs, Assumptions and Methodology

The inputs, assumptions and methodology were discussed and agreed to by stakeholders at the 2023 LCT Study Criteria, Methodology and Assumptions Stakeholder Meeting held on October 27, 2021. Except for Study Criteria all other Methodology and Assumptions are similar to those used and incorporated in previous LCT studies. The following table sets forth a summary of the approved inputs and methodology that have been used in this 2023 LCT Study:

Table 1.2-1 Summary Table of Inputs and Methodology Used in this LCT Study:

Issue	How Incorporated into this LCT 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 LCT 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 LCT Study is the South of Lugo transfer path flowing into the LA Basin.
Performance Criteria:	
All Performance Levels, including incorporation of PTO operational solutions	This LCT Study is being published based on the most stringent of all mandatory reliability standards. 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 mandatory standards will be incorporated into the LCT Study.
Load Pocket:	
Fixed Boundary, including limited reference to published effectiveness factors	This LCT 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 2023 LCT Study methodology and assumptions are provided in Section III, below.

1.3 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.[2] 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.

1.4 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 P6 and P7 events. N-1-1 represents NERC Category C6 ("category P1 contingency, manual system adjustment, followed by another category P1 contingency"). The N-2 represents NERC Category P7 ("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.

[2] Pub. Utilities Code § 345

1.5 Performance Criteria

As set forth on the Summary Table of Inputs and Methodology, this LCR Report is based on the most stringent mandatory standard (NERC, WECC or CAISO). The CAISO tests the electric system in regards to thermal overloads as well as dynamic and reactive margin compliance with the existing standards.

1.5.1 Performance Criteria

Category P0, P1 & P3 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.

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.[3] All Category P2, P4, P5, P6, P7 and extreme event 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 order to prepare for the next worst contingency. In this time frame, load drop is not allowed per existing planning criteria.

Generally, Category P2, P4, P5, P6, P7 and extreme event 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 P1, the event is effectively a Category P6 or N-1-1 scenario. As noted above, depending on system design and expected system impacts, the **planned and controlled** interruption of

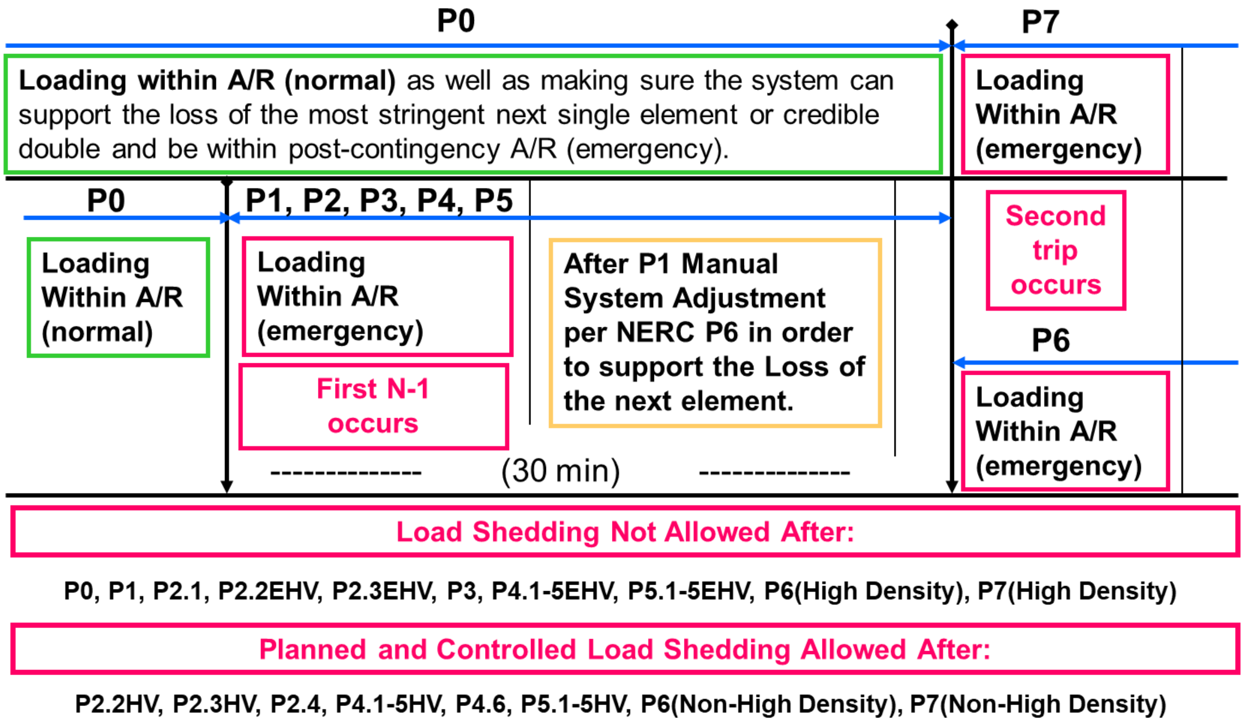
[3] A Special Protection Scheme is typically proposed as an operational solution that does not require additional generation and permits operators to effectively prepare for the next event as well as ensure security should the next event occur. However, these systems have their own risks, which limit 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.

supply to customers (load shedding), the removal from service of certain generators and curtailment of exports may be utilized to maintain grid "security."

1.5.2 CAISO Statutory Obligation Regarding Safe Operation

The ISO must 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 (8760 hours per year), the ISO must protect for all single contingencies (P1, P2) and multiple contingencies (P4, P5) as well as common mode double line outages (P7). As a further example, after a single contingency, the ISO must readjust the system in order to be able to support the loss of the next most stringent contingency (P3 , P6 and P1+P7 resulting in potential voltage collapse or dynamic instability).

Figure 1.5-1 Temporal graph of LCR Category P0-P7



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

Applicable Rating:

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

Normal rating is to be used under normal conditions.

Long-term emergency ratings, 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, the normal rating is to be used.

Short-term emergency ratings, 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, and 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 agreed 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 Category P1, P2.1, P2.2(EHV), P2.3(EHV), P3, P4.1-5(EHV), P5.1-5(EHV), P6(high density area)&P7(high density area) contingency:

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 ISO Grid Planning standards (ISO SPS3)

b. Increase generation – this generation will become part of the LCR need

Actions, which shall not be taken as system readjustment after a Category P1, P2.1, P2.2(EHV), P2.3(EHV), P3, P4.1-5(EHV), P5.1-5(EHV), P6(high density area)&P7(high density area) contingency:

1. Load drop – based on the intent of the ISO/WECC and NERC criteria for category P1 contingencies.

An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. NERC and ISO Planning standards mandate that no load shedding should be done immediately after a Category P1, P2.1, P2.2(EHV), P2.3(EHV), P3, P4.1-5(EHV), P5.1-5(EHV), P6(high density area)&P7(high density area) contingency. The system should be planned with no load shedding regardless of when it may occur (immediately or within 15-30 minutes after the first contingency). It follows that load shedding may not be utilized as part of the system readjustment period – in order to protect for the next most limiting contingency. Therefore, if there are available resources in the local area, such resources should be used during the manual adjustment period (and included in the LCR need) before resorting to shedding firm load.

Firm load shedding is allowed in a planned and controlled manner after the first contingency in P2.2(HV), P2.3(HV), P2.4, P4.1-5(HV), P4.6, P5.1-5(HV) and after the second contingency in P6(non-high density area), P7(non-high density area) & P1 system adjusted followed by P7 category events.

This interpretation tends to guarantee that firm load shedding is used to address Category P1, P2.1, P2.2(EHV), P2.3(EHV), P3, P4.1-5(EHV), P5.1-5(EHV), P6(high density area)&P7(high density area) conditions only under the limited circumstances where no other resource or validated operational measure is available. A contrary interpretation would constitute a departure from existing practice and degrade current service expectations by increasing load's exposure to service interruptions.

Time allowed for manual readjustment:

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) having 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.

2. Assumption Details: How the Study was Conducted

2.1 System Planning Criteria

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

Table 2.1-1: Criteria Comparison for Bulk Electric System contingencies

Contingency Component(s)	Mandatory Reliability Standards	Old Local Capacity Criteria	Local Capacity Criteria
P0 – No Contingencies	X	X	X
P1 – Single Contingency			
1. Generator (G-1)	X	X[1]	X[1]
2. Transmission Circuit (L-1)	X	X[1]	X[1]
3. Transformer (T-1)	X	X[1,2]	X[1]
4. Shunt Device	X		X[1]
5. Single Pole (dc) Line	X	X[1]	X[1]
P2 – Single contingency			
1. Opening a line section w/o a fault	X		X
2. Bus Section fault	X		X
3. Internal Breaker fault (non-Bus-tie Breaker)	X		X
4. Internal Breaker fault (Bus-tie Breaker)	X		X
P3 – Multiple Contingency – G-1 + system adjustment and:			
1. Generator (G-1)	X	X	X
2. Transmission Circuit (L-1)	X	X	X
3. Transformer (T-1)	X	X[2]	X
4. Shunt Device	X		X
5. Single Pole (dc) Line	X	X	X
P4 – Multiple Contingency - Fault plus stuck breaker			
1. Generator (G-1)	X		X
2. Transmission Circuit (L-1)	X		X
3. Transformer (T-1)	X		X
4. Shunt Device	X		X
5. Bus section	X		X
6. Bus-tie breaker	X		X
P5 – Multiple Contingency – Relay failure (delayed clearing)			
1. Generator (G-1)	X		X
2. Transmission Circuit (L-1)	X		X
3. Transformer (T-1)	X		X
4. Shunt Device	X		X
5. Bus section	X		X

P6 – Multiple Contingency – P1.2-P1.5 system adjustment and:			
1. Transmission Circuit (L-1)	X	x	X
2. Transformer (T-1)	X	x	X
3. Shunt Device	X		X
4. Bus section	X		X
P7 – Multiple Contingency - Fault plus stuck breaker			
1. Two circuits on common structure (L-2)	X	X	X
2. Bipolar DC line	X	X	X
Extreme event – loss of two or more elements			
Two generators (Common Mode) G-2	X[4]	X	X[4]
Any P1.1-P1.3 & P1.5 system readjusted (Common Mode) L-2	X[4]	X[3]	X[5]
All other extreme combinations.	X[4]		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.
5 Expanded to include any P1 system readjustment followed by any P7 without stuck breaker. For voltage collapse or dynamic instability situations mitigation is required "if there is a risk of cascading" beyond a relatively small predetermined area – less than 250 MW - directly affected by the outage.

Table 2.1-2: Criteria Comparison for non-Bulk Electric System contingencies

Contingency Component(s)	Mandatory Reliability Standards	Old Local Capacity Criteria	Local Capacity Criteria
P0 – No Contingencies	X	X	X
P1 – Single Contingency			
1. Generator (G-1)	X	X[1]	X
2. Transmission Circuit (L-1)	X	X[1]	X
3. Transformer (T-1)	X	X[1,2]	X
4. Shunt Device	X		X
5. Single Pole (dc) Line	X	X[1]	X
P2 – Single contingency			
1. Opening a line section w/o a fault			
2. Bus Section fault			
3. Internal Breaker fault (non-Bus-tie Breaker)			
4. Internal Breaker fault (Bus-tie Breaker)			

P3 – Multiple Contingency – G-1 + system adjustment and:			
1. Generator (G-1)	X	X	X
2. Transmission Circuit (L-1)	X	X	X
3. Transformer (T-1)	X	X[2]	X
4. Shunt Device	X		X
5. Single Pole (dc) Line	X	X	X
P4 – Multiple Contingency - Fault plus stuck breaker			
1. Generator (G-1)			
2. Transmission Circuit (L-1)			
3. Transformer (T-1)			
4. Shunt Device			
5. Bus section			
6. Bus-tie breaker			
P5 – Multiple Contingency – Relay failure (delayed clearing)			
1. Generator (G-1)			
2. Transmission Circuit (L-1)			
3. Transformer (T-1)			
4. Shunt Device			
5. Bus section			
P6 – Multiple Contingency – P1.2-P1.5 system adjustment and:			
1. Transmission Circuit (L-1)		x	
2. Transformer (T-1)		x	
3. Shunt Device			
4. Bus section			
P7 – Multiple Contingency - Fault plus stuck breaker			
1. Two circuits on common structure (L-2)		X	
2. Bipolar DC line		X	
Extreme event – loss of two or more elements			
Two generators (Common Mode) G-2		X	
Any P1.1-P1.3 & P1.5 system readjusted (Common Mode) L-2		X[3]	
All other extreme combinations.			

[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.

A significant number of simulations were run to determine the most critical contingencies within each local area. Using power flow, post-transient load flow, and stability assessment tools, the system performance results of all tested contingencies were measured against the system performance requirements defined by the criteria shown in Tables 1 and 2. Where the specific system performance requirements were not met, generation was adjusted until performance requirements were met for the local area. The adjusted generation constitutes the minimum generation needed in the local area. The following describes how the criteria were tested for the specific type of analysis performed.

2.1.19 Power Flow Assessment:

Table 2.1-3 Power flow criteria

Contingencies	Thermal Criteria[1]	Voltage Criteria[2]
P0	Applicable Rating	Applicable Rating
P1 [3]	Applicable Rating	Applicable Rating
P2	Applicable Rating	Applicable Rating
P3	Applicable Rating	Applicable Rating
P4	Applicable Rating	Applicable Rating
P5	Applicable Rating	Applicable Rating
P6 [4]	Applicable Rating	Applicable Rating
P7	Applicable Rating	Applicable Rating
P1 + P7 [4]	-	No Voltage Collapse

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

2 Applicable Rating – CAISO Grid Planning Criteria or facility owner criteria as appropriate.

3 Following the first contingency (N-1), the generation must be sufficient to allow the operators to bring the system back to within acceptable operating range (voltage and loading) and/or appropriate OTC following the studied outage conditions and be able to safely prepare for the loss of the next most stringent element and be within Applicable Rating after the loss of the second element.

4 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.

2.1.20 Post Transient Load Flow Assessment:

Table 2.1-4 Post transient load flow criteria

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.

2.1.21 Stability Assessment:

Table 2.1-5 Stability criteria

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.

2.1.22 Engineering Estimate for Intermediate Years:

Due to combined CEC/CPUC/CAISO timelines required by the RA process, the ISO must estimate LCR requirement for intermediate years, between the technical studies run for years one and five.

ISO will be using an engineering estimate for intermediate years. Elements of the engineering judgement estimates are described below:

2.1.22.1 *Net Peak Load Growth driven estimate*

Assuming nothing else changes, no transmission or resource mix changes, including no changes to long-term contractual arrangements, the increase (or decrease) in LCR, assuming a linear function, will be estimated based on ratio of load growth to ratio of LCR needs to be multiplied by the number of years using the following formula:

LCR for Year of Need = Year 1 LCR + [(Year 5 LCR-Year 1 LCR)/4] X (Year of Need-Year 1)

For non-linear functions, like voltage collapse or dynamic instability, ISO will use engineering judgment in order to provide estimated LCR requirement.

2.1.22.2 *Single New Transmission driven estimate*

Assuming nothing else changes, no load growth, no other new transmission projects or resource mix changes, including no changes to long-term contractual arrangements, the increase (or decrease in LCR) will be estimated based on a step function (usually decreasing the LCR needs) in the year when the transmission project is supposed to be first operational (if in-service before June 1-st of estimated year for summer peaking areas).

2.1.22.3 *Single New Resource driven estimate*

Assuming nothing else changes, no load growth, no new transmission projects or any other resource mix changes, including no changes to long-term contractual arrangements, the increase (or decrease in LCR) will be estimated based on a step function if:

a) The new resource is catalogued with a higher dispatch priority or the same priority as the marginal resource used for establishment of LCR need AND

b) The new resource has a significantly different (10% or more) effectiveness factor difference vs. the marginal resource used for the establishment of the LCR need.

Priority dispatch order (from LCR study manual):

1. QF/MUNI/State/Federal
2. RA resources under long-term contracts
3. Unknown contractual status

2.1.22.4 *Single Change in Resource contractual status driven estimate*

Assuming nothing else changes, no load growth, no new transmission projects or resource mix changes, including no changes to other long-term contractual arrangements, the increase (or decrease in LCR) will be estimated based on a step function if:

a) The resource is moving to a higher dispatch priority or the same priority as the marginal resource used for establishment of LCR need AND

b) The resource has a significantly different (10% or more) effectiveness factor difference vs. the marginal resource used for the establishment of the LCR need.

2.1.22.5 *Single Known Resource Retirement driven estimate*

Assuming nothing else changes, no load growth, no new transmission projects or other resource mix changes, including no changes to long-term contractual arrangements, the increase (or decrease in LCR) will be estimated based on a step function if:

a) The retired resource was included in a higher dispatch priority or the same priority as the marginal resource used for establishment of LCR need AND

b) The resource has a significantly different (10% or more) effectiveness factor difference vs. the marginal resource used for the establishment of the LCR need.

2.1.22.6 *Multi Reason Change driven estimate*

From multi-year available LCR studies the ISO will use engineering judgement, guided by the above explain single change principles, in order to estimate intermediate year LCR needs any time more than one factor is influencing the LCR results:

a) Net peak load growth

b) New transmission project(s)

c) New resource(s)

d) Change in resource contractual status

e) Known resource retirement(s)

2.2 Load Forecast

2.2.1 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.

2.2.2 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.

2.2.2.1 *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.

a. 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

[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.

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.

b. 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.

2.2.2.2 *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.

2.3 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 21.0.10.1 and PowerGem's Transmission Adequacy and Reliability Assessment (TARA) program version 2102_1. 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 PSLF 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.

2.4 Estimate of Battery Storage Needs due to Charging Constraints

Local areas and sub-areas have limited transmission capability and therefore rely on internal resources to be available in order to reliably serve internal load. Battery storage will help serve local load during the discharge cycle, however it will also increase local load during the charging cycle.

Due to recent procurement activities geared toward the acquisition of this type of technology, the CAISO is herein estimating the characteristics (MW, MWh, discharge duration) required from battery storage technology in order to seamlessly integrate in each local area and sub-area.

The CAISO expects that for batteries that displace other local resource adequacy resources, the transmission capability under the most limiting contingency and the other local capacity resources must be sufficient to recharge the batteries in anticipation of the outage continuing through the night and into the next day's peak load period.

For each local area and sub-area, the CAISO has estimated the battery storage characteristics, given their unique load shape, constraints and requirements as well as the energy characteristics of other resources required to meet standards. Due to this fact, the strict addition of the sub-area battery storage characteristics (MW, MWh and duration) may not closely align with the overall local area battery storage characteristic requirements (MW, MWh and duration).

Assumptions

1) Total load serving capability includes capability from transmission system and local generation needed for LCR under the worst contingency.
2) Storage added replaces existing generation MW for MW. First the batteries will replace as much as possible of existing gas resources, Second if the area and/or sub-area has run out of gas resources to displace then other technologies may be reduced in order to determine the maximum battery charging limit.
3) Effectiveness factors are assumed not to be a factor. Battery storage is assumed to be installed at the same sites where resources are displaced or assumed to have the same effectiveness factors.
4) Deliverability of incremental storage capacity is not evaluated. It is assumed battery storage will take over deliverability from old resources through repower. Any new battery storage resource needs to go through the generation interconnection process in order to receive deliverability and it is not evaluated in this study. CAISO cannot guaranty that there is enough deliverability available for new resources. New transmission upgrades may be required in order to make such new resources deliverable to the aggregate of load.
5) Includes battery storage charging/discharging efficiency of 85%.

6) Daily charging required is distributed to all non-discharging hours proportionally using delta between net load and the total load serving capability.
7) Energy required for charging, beyond the transmission capability under contingency condition, is produced by other LCR required resources within the local area and sub-area that are available for production during off-peak hours.
8) Hydro resources are considered to be available for production during off-peak hours, however these resources are energy limited themselves and based on past availability data they can have severely limited output during off-peak hours especially during late summer peaks under either normal or dry hydro years.
9) The study assumes the ability to provide perfect dispatch and the ability to enforce charging requirements for multiple contingency conditions (like N-1-1) in the day ahead time frame while the system is under normal (no contingency) conditions. CAISO software improvements and/or augmentations are required in order to achieve this goal.

Installing battery storage with insufficient characteristics (MW, MWh and duration) will not result in a one for one reduction of the local area or sub-area need for other types of resources. The CAISO expects that the overall RA portfolio provided by all LSEs to account for the uplift, beyond the minimum LCR need, in MWs required from other type of resources for all areas and sub-areas where LSEs have procured battery storage beyond the charging capability or with incorrect characteristics (MW, MWh and duration). If uplift is not provided the CAISO may use its back stop authority to assure that reliability standards are met throughout the day, including off-peak hours.

3. Locational Capacity Requirement Study Results

3.1 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 3.1-1 2023 Local Capacity Needs vs. Peak Load and Local Area Resources

	2023 Total LCR (MW)	Peak Load (1 in10) (MW)	2023 LCR as % of Peak Load	Total NQC Local Area Resources (MW)	2023 LCR as % of Total NQC
Humboldt	141	175	81%	178	79%
North Coast/North Bay	857	1494	57%	911	94%
Sierra	1150	1812	63%	1909	60% **
Stockton	579	1090	53%	579	100% **
Greater Bay	7312	11136	66%	7770	94% **
Greater Fresno	1870	3288	57%	3411	55% **
Kern	439	940	47%	439	100% **
Big Creek/Ventura	2240	4427	51%	5475	41%
LA Basin	7529	19537	39%	9661	78%
San Diego/Imperial Valley	3332	4768	70%	5358	62%
Total*	**25449**	**48667**	**52%**	**35691**	**71%**

Table 3.1-2 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	111	144	77%	181	61%
North Coast/North Bay	834	1509	55%	834	100% **
Sierra	1220	1618	75%	2092	58% **
Stockton	562	1027	55%	586	96% **
Greater Bay	7231	10746	67%	7748	93% **
Greater Fresno	1987	3435	58%	3370	59% **
Kern	356	1029	35%	418	85% **
LA Basin	2173	4394	49%	5609	39%
Big Creek/Ventura	6646	18929	35%	8774	76%
San Diego/Imperial Valley	3993	4580	87%	4362	92%
Total*	**25113**	**47411**	**53%**	**33974**	**74%**

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

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

Table 3.1-1 and Table 3.1-2 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 2023 have been included in this 2023 LCT Study 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, "August Qualifying Capacity," reflects three 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, municipal and QFs). The second set is "market" based resources (market, net seller, wind and battery). The third set are solar resources, since they may or may not be available during the actual peak hour for the respective local area. The second column, "Capacity at Peak" identifies how much of the August Qualifying Capacity is expected to be available during the peak time for each particular local area. The third column, "YEAR LCR Need", sets forth the local capacity requirements, without the deficiencies that must be addressed, necessary to attain a service reliability level required to comply with NERC/WECC/CAISO mandatory reliability standards.

Table 3.1-3 includes estimated characteristics (MW, MWh, discharge duration) required from battery storage technology in order to seamlessly integrate in each local area and sub-area. The CAISO expects that for batteries that displace other local resource adequacy resources, the transmission capability under the most limiting contingency and the other local capacity resources must be sufficient to recharge the batteries in anticipation of the outage continuing through the night and into the next day's peak load period.

Table 3.1-3 2023 Battery Storage Characteristics Limited by Charging Capability

Area/Sub-area	Pmax MW	Energy MWh	Max. # of discharge hours	1 for 1 Replacement with 4-hour battery	Replacing mostly	Comment
Humboldt	18	173	12	9	gas	
North Coast/North Bay Overall	850	2043	9	110	geothermal	
Eagle Rock	60	486	11	14	geothermal	
Fulton	300	507	7	95	geothermal	

Area/Sub-area	Pmax MW	Energy MWh	Max. # of discharge hours	1 for 1 Replacement with 4-hour battery	Replacing mostly	Comment
Sierra	-	-	-	-	-	Flow through
Placer	60	363	9	22	hydro	
Pease	70	332	9	57	gas	Need to be eliminated
Gold Hill-Drum	170	1064	10	60	hydro	
Stockton	-	-	-	-	-	Sum of sub-areas
Lockeford	27	108	6	27	gas	Need to be eliminated
Tesla-Bellota	340	1986	12	230	gas	
Greater Bay Overall	2453	16113	12	1358	gas	
Llagas	75	501	9	33	gas	
San Jose	411	2872	12	221	gas	
South Bay-Moss Landing	652	3903	12	417	gas	
Oakland	-	-	-	-	distillate	N/A
Greater Fresno Overall	1870	2255	7	551	hydro	
Panoche	68	343	9	45	gas	
Herndon	327	1063	8	265	hydro	
Hanford	50	216	6	50	gas	
Coalinga	45	346	13	26	solar	
Borden	21	80	7	12	gas	
Reedley	89	386	9	70	hydro	
Kern Overall	-	-	-	-	-	N/A
Westpark	10	50	7	4	gas	
Kern Power-Tevis	-	-	-	-	solar	N/A
Kern Oil	60	419	10	10	gas	
South Kern PP	350	2066	11	220	gas	
Big Creek/Ventura Overall	1056	7195	11	235	gas	
Vestal	532	2001	10	395	gas	
Santa Clara	168	1328	13	29	gas	
LA Basin Overall	3200	26191	12	1120	gas	
Eastern	1157	9577	12	345	gas	
Western	2032	16553	11	710	gas	
El Nido	220	1489	11	90	gas	
San Diego/Imperial Valley Overall	1353	7814	10	850	gas	
San Diego	1353	7814	10	850	gas	
El Cajon	61	199	7	13	gas	

Area/Sub-area	Pmax MW	Energy MWh	Max. # of discharge hours	1 for 1 Replacement with 4-hour battery	Replacing mostly	Comment
Border	18	100	7	11	gas	

3.2 Summary of Zonal Needs

Based on the existing import allocation methodology, the only major 500 kV constraint not accounted for is path 26 (Midway-Vincent). Table 3.2-1 shows the total resources needed (based on the latest CEC load forecast) in each the two relevant zones, SP26 and NP26.

Table 3.2-1 Total Zonal Resource Needs

Zone	Load Forecast (MW)	15% reserves (MW)	(-) Allocated imports (MW)	(-) Maximum Path 26 Flow (MW)	Total Zonal Resource Need (MW)
SP26	28149	4222	-7594	-3750	**21027**
NP26=NP15+ZP26	20748	3112	-3411	-3000	**17449**

Where:

Load Forecast is the most recent 1 in 2 CEC forecast for year 2023 - California Energy Demand 2021-2035, Mid Demand Baseline, Mid AAEE and Mid AAFS Savings.

Reserve Margin is 15% the minimum CPUC approved planning reserve margin.

Allocated Imports are the actual 2022 Available Import Capability for loads in the CAISO control area numbers that are not expected to change much by 2023, other then the accounted for increase in MIC from the IID area.

Maximum Path 26 flow The CAISO determines the maximum amount of Path 26 transfer capacity available after accounting for (1) Existing Transmission Contracts (ETCs) that serve load outside the CAISO Balancing Area[5] and (2) loop flow[6] from the maximum path 26 rating of 4000 MW (North-to-South) and 3000 MW (South-to-North).

Both NP 26 and SP 26 load forecast, import allocation and zonal results refer to the CAISO Balancing Area only. This is done in order to be consistent with the import allocation methodology.

[5] The transfer capability on Path 26 must be de-rated to accommodate ETCs on Path 26 that are used to serve load outside of the CAISO Balancing Area. These particular ETCs represent physical transmission capacity that cannot be allocated to LSEs within the CAISO Balancing Area.

[6] "Loop flow" is a phenomenon common to large electric power systems like the Western Electricity Coordinating Council. Power is scheduled to flow point-to-point on a Day-ahead and Hour-ahead basis through the CAISO. However, electric grid physics prevails and the actual power flow in real-time will differ from the pre-arranged scheduled flows. Loop flow is real, physical energy and it uses part of the available transfer capability on a path. If not accommodated, loop flow will cause overloading of lines, which can jeopardize the security and reliability of the grid.

All resources that are counted as part of the Local Area Capacity Requirements fully count toward the Zonal Need. The local areas of San Diego, LA Basin and Big Creek/Ventura are all situated in SP26 and the remaining local areas are in NP26.

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

The load forecast went up in Northern California by about 350 MW and in Southern California by about 700 MW.

The Import Allocations are the same in Southern California and decreased by about 50 MW in Northern California.

The Path 26 maximum transfer capability has not changed and is not envisioned to change in the near future.

3.3 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.

3.3.1 Humboldt Area

3.3.1.1 *Area Definition*

The transmission tie lines into the area include:

Bridgeville-Cottonwood 115 kV line #1

Humboldt-Trinity 115 kV line #1

Laytonville-Garberville 60 kV line #1

Trinity-Maple Creek 60 kV line #1

The substations that delineate the Humboldt Area are:

Bridgeville is in, Low Gap, Wildwood and Cottonwood are out

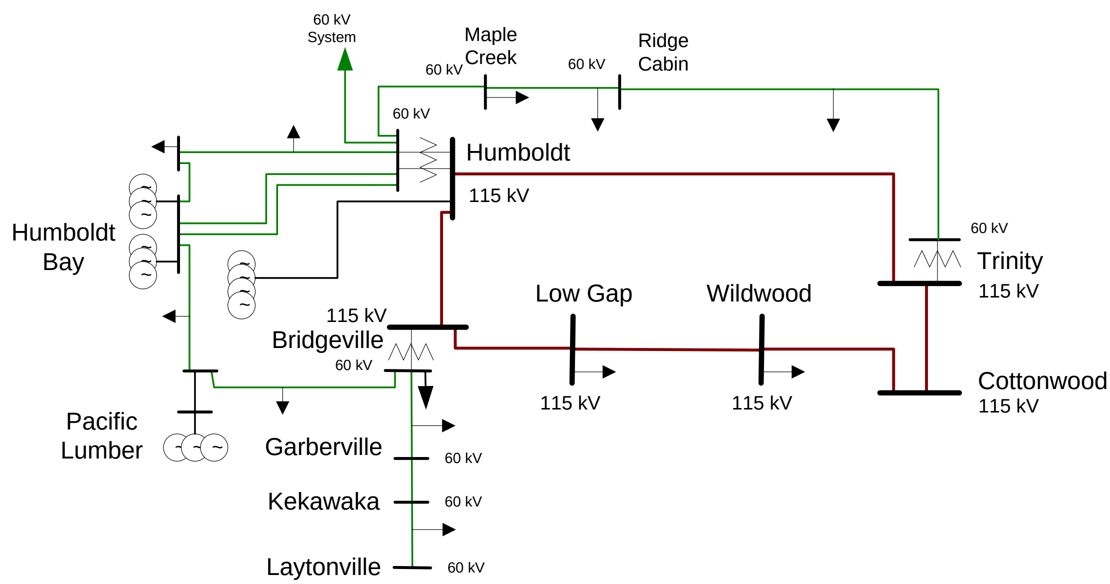
Humboldt is in, Trinity is out

Kekawaka and Garberville are in, Laytonville is out

Maple Creek is in, Trinity and Ridge Cabin are out

Humboldt LCR Area Diagram

Figure 3.3-1 Humboldt LCR Area



Humboldt LCR Area Load and Resources

Table 3.3-1 provides the forecasted load and resources. The list of generators within the LCR area are provided in Attachment A.

In year 2023 the estimated time of local area peak is 19:00 PM.

This area does not contain models of solar resources capable of providing resource adequacy.

If required, all non-solar technology type resources are dispatched at NQC.

Table 3.3-1 Humboldt LCR Area 2023 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	167	Market and Net Seller	178	178
AAEE	-3	MUNI	0	0
Behind the meter DG	0	QF	0	0
Net Load	**164**	LTPP Preferred Resources	0	0
Transmission Losses	11	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**175**	**Total**	**178**	**178**

Humboldt LCR Area Hourly Profiles

Figure 3.3-2 illustrates the forecast 2023 profile for the peak day for the Humboldt LCR area with the Category P6 transmission capability without resources. Figure 3.3-3 illustrates the forecast 2023 hourly profile for Humboldt LCR area with the Category P6 transmission capability without resources.

Figure 3.3-2 Humboldt 2023 Peak Day Forecast Profiles

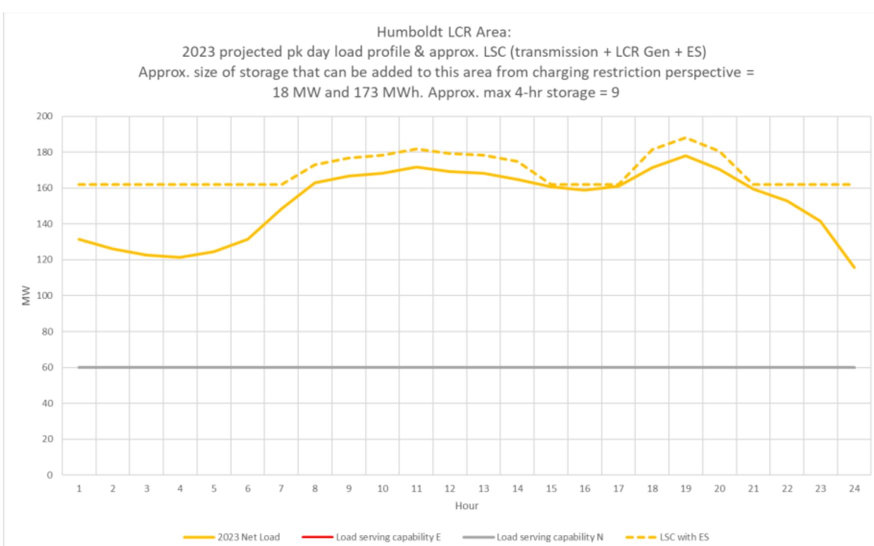
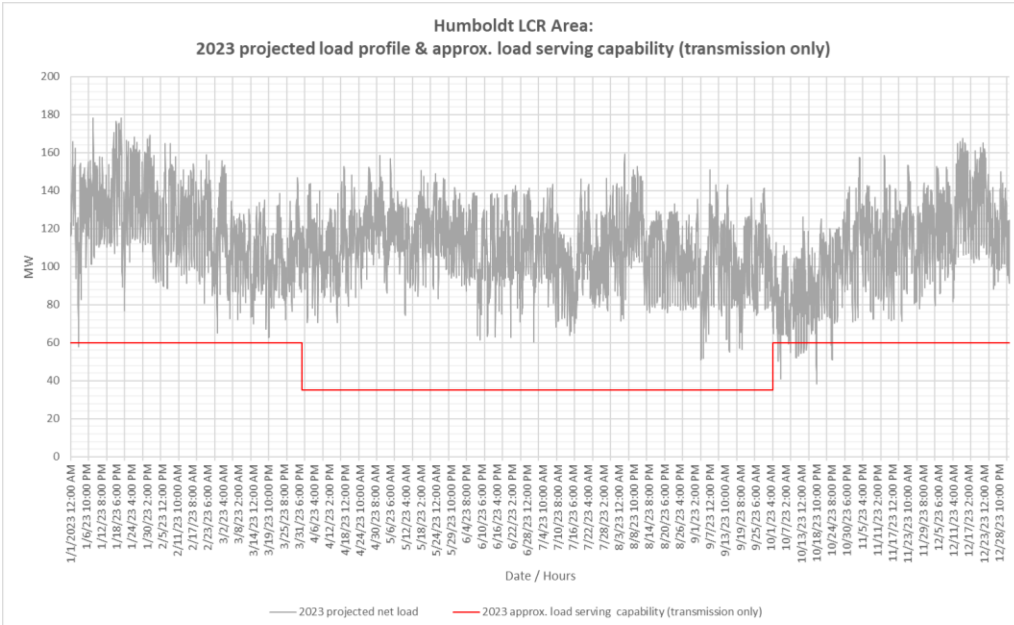


Figure 3.3-3 Humboldt 2023 Forecast Hourly Profile



Approved transmission projects included in base cases

None

3.3.1.2 *Humboldt Overall LCR Requirement*

Table 3.3-2 identifies the area LCR requirements. The LCR requirement for Category P6 contingency is 141 MW.

Table 3.3-2 Humboldt LCR Area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	First Limit	P6	Humboldt-Trinity 115 kV	Cottonwood-Bridgeville 115 kV & Humboldt - Humboldt Bay 115 kV	141

Effectiveness factors

For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7110 posted at: http://www.caiso.com/Documents/2210Z.pdf

Changes compared to last year's results

Compared with 2022 the load forecast has increased by 31 MW and the total LCR has increased by 30 MW mostly due to load forecast increase.

3.3.2 North Coast / North Bay Area

3.3.2.1 *Area Definition*

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

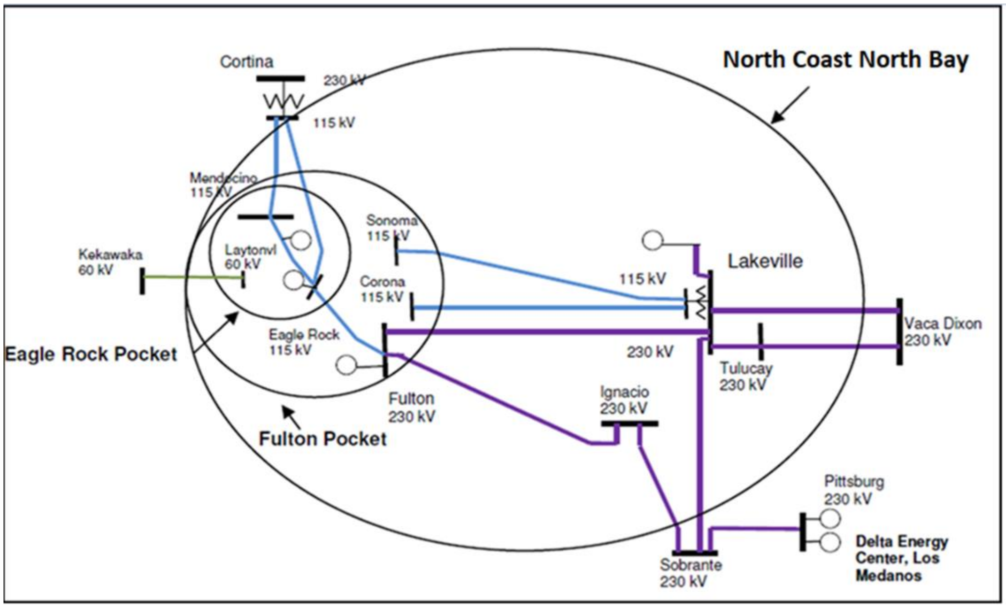
- Cortina-Mendocino 115 kV Line
- Cortina-Eagle Rock 115 kV Line
- Willits-Garberville 60 kV line #1
- Vaca Dixon-Lakeville 230 kV line #1
- Tulucay-Vaca Dixon 230 kV line #1
- Lakeville-Sobrante 230 kV line #1
- Ignacio-Sobrante 230 kV line #1

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

- Cortina is out, Mendocino and Indian Valley are in
- Cortina is out, Eagle Rock, Highlands and Homestake are in
- Willits and Lytonville are in, Kekawaka and Garberville are out
- Vaca Dixon is out, Lakeville is in
- Tulucay is in, Vaca Dixon is out
- Lakeville is in, Sobrante is out
- Ignacio is in, Sobrante and Crocket are out

North Coast and North Bay LCR Area Diagram

Figure 3.3-4 North Coast and North Bay LCR Area



North Coast and North Bay LCR Area Load and Resources

Table 3.3-3 provides the forecasted load and resources. The list of generators within the LCR area are provided in Attachment A.

In year 2023 the estimated time of local area peak is 17:50 PM.

This area does not contain models of solar resources capable of providing resource adequacy.

If required, all non-solar technology type resources are dispatched at NQC.

Table 3.3-3 North Coast and North Bay LCR Area 2023 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	1466	Market and Net Seller	761	761
AAEE	-14	MUNI	133	133
Behind the meter DG	0	QF	5	5
Net Load	**1452**	Wind	0	0
Transmission Losses	42	Existing 20-minute Demand Response	12	12
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**1494**	**Total**	**911**	**911**

North Coast and North Bay LCR Area Hourly Profiles

Figure 3.3-5 5 illustrates the forecast 2023 profile for the peak day for the North Coast North Bay LCR sub-area with the Category P3 normal and emergengy load serving capabilities without local resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-6 illustrates the forecast 2023 hourly profile for North Coast North Bay LCR sub-area with the Category P3 emergency load serving capability without local resources.

Figure 3.3-5 North Coast and North Bay 2023 Peak Day Forecast Profiles

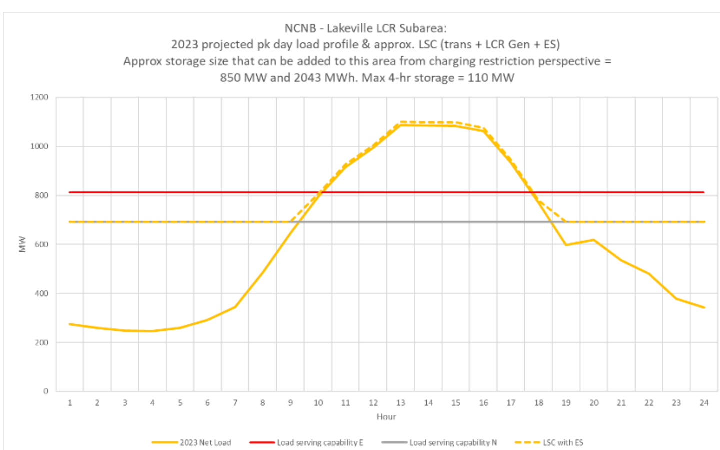
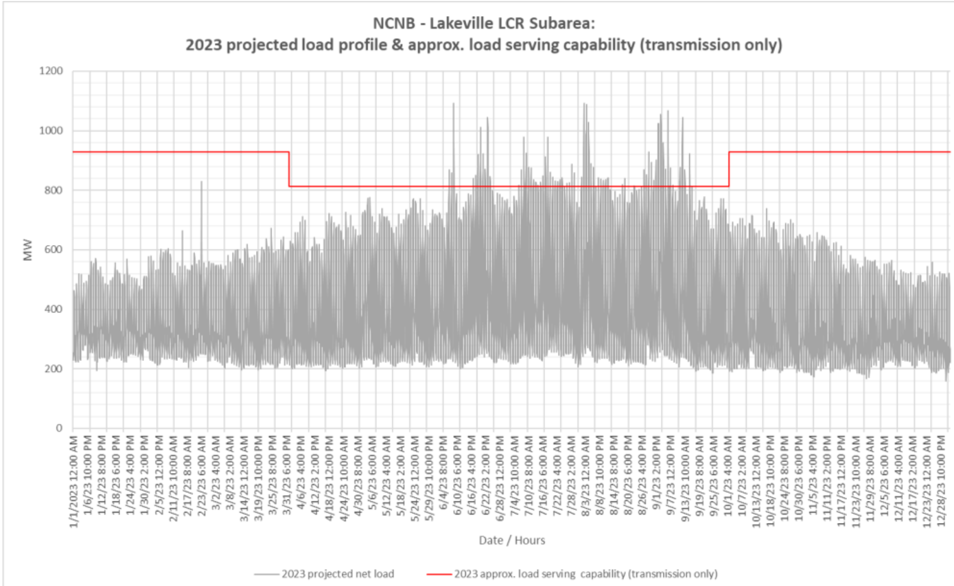


Figure 3.3-6 North Coast and North Bay 2023 Forecast Hourly Profile



Approved transmission projects modeled in base cases

Vaca Dixon-Lakeville 230 kV Corridor Series Compensation

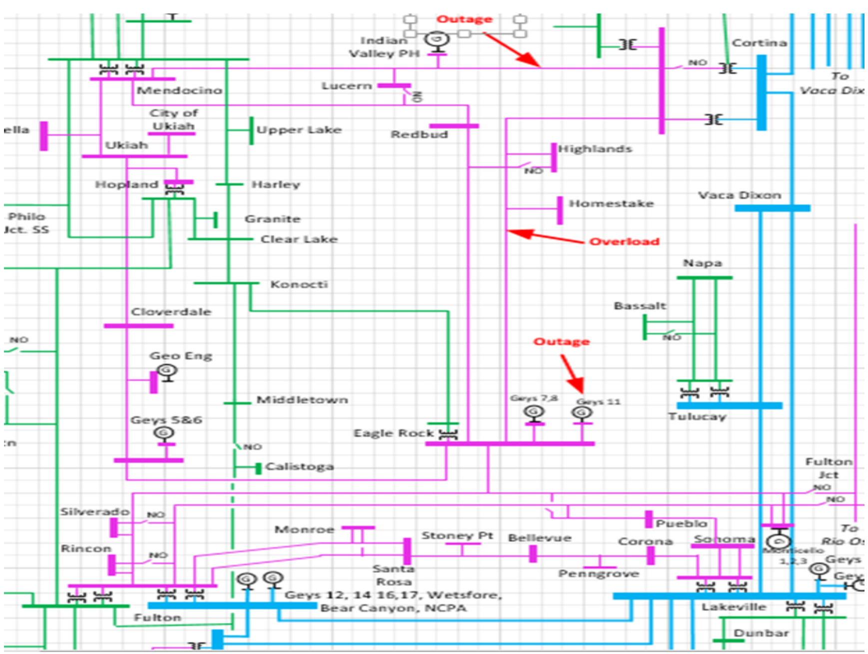
Tulucay-Napa #2 60 kV Line Capacity Increase

3.3.2.2 *Eagle Rock LCR Sub-area*

Eagle Rock is a Sub-area of the North Coast and North Bay LCR Area.

Eagle Rock LCR Sub-area Diagram

Figure 3.3-7 Eagle Rock LCR Sub-area



Eagle Rock LCR sub-area Load and Resources

Table 3.3-4 provides the forecasted load and resources. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-4 Eagle Rock LCR Sub-area 2023 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	251	Market and Net Seller	275	275
AAEE	-4	MUNI	2	2
Behind the meter DG	0	QF	0	0
Net Load	**247**	Solar	0	0
Transmission Losses	13	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**260**	**Total**	**277**	**277**

Eagle Rock LCR Sub-area Hourly Profiles

Figure 3.3-8 illustrates the forecast 2023 profile for the peak day for the Eagle Rock LCR sub-area with the Category P3 normal and emergengy load serving capabilities without local resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-9 illustrates the forecast 2023 hourly profile for Eagle Rock LCR sub-area with the Category P3 emergency load serving capability without local resources.

Figure 3.3-8 Eagle Rock LCR Sub-area 2023 Peak Day Forecast Profiles

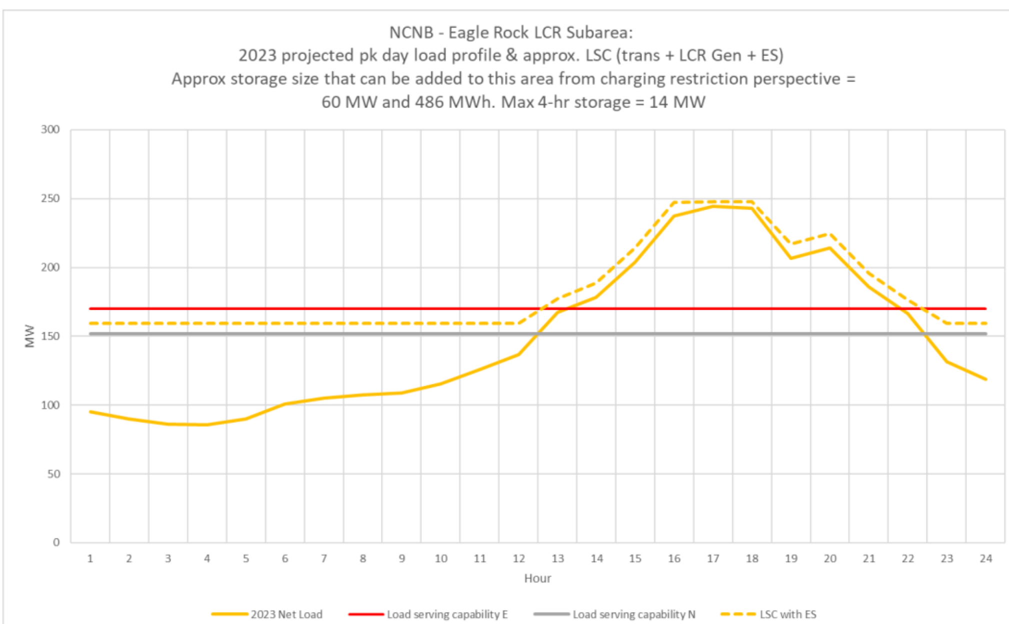
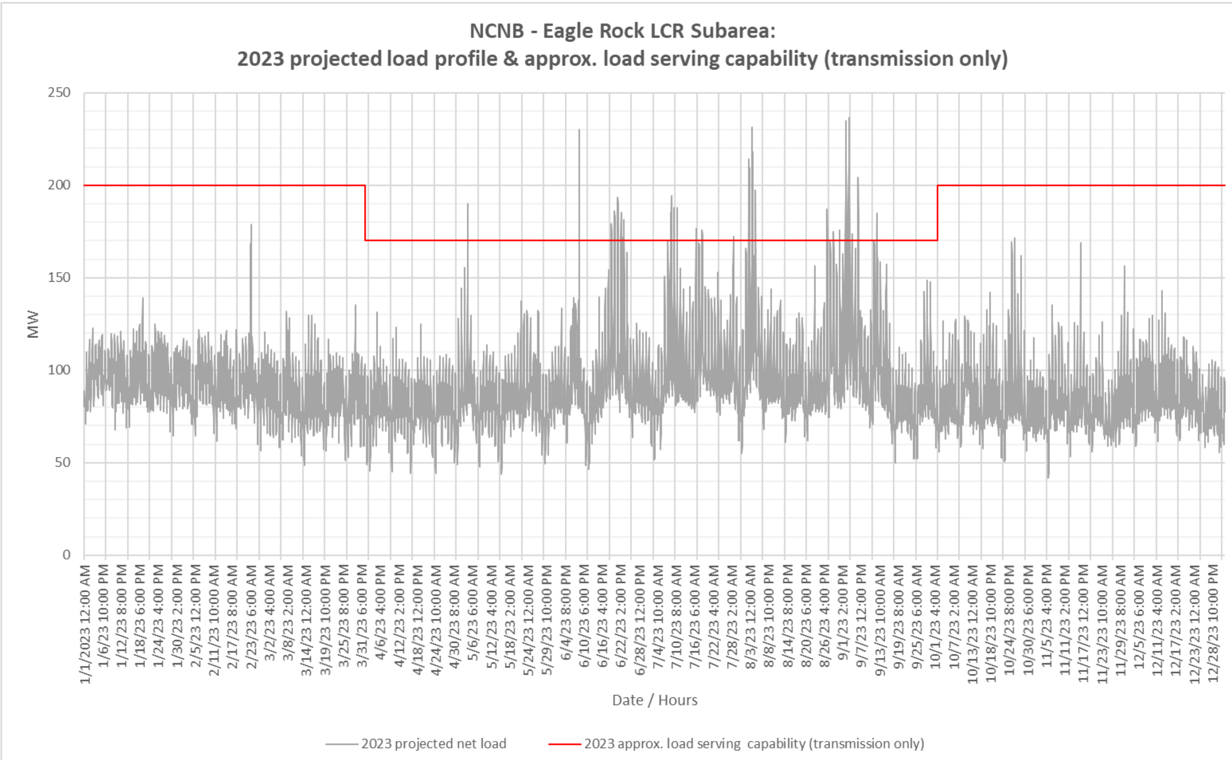


Figure 3.3-9 Eagle Rock LCR Sub-area 2023 Forecast Hourly Profiles



Eagle Rock LCR Sub-area Requirement

Table 3.3-5 identifies the sub-area LCR requirements. The LCR requirement for Category P3 contingency is 246 MW.

Table 3.3-5 Eagle Rock LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	First Limit	P3	Eagle Rock-Cortina 115 kV line	Cortina-Mendocino 115 kV with Geyser #11 unit out	246

Effectiveness factors

Effective factors for generators in the Eagle Rock LCR sub-area are in Attachment B table titled Eagle Rock.

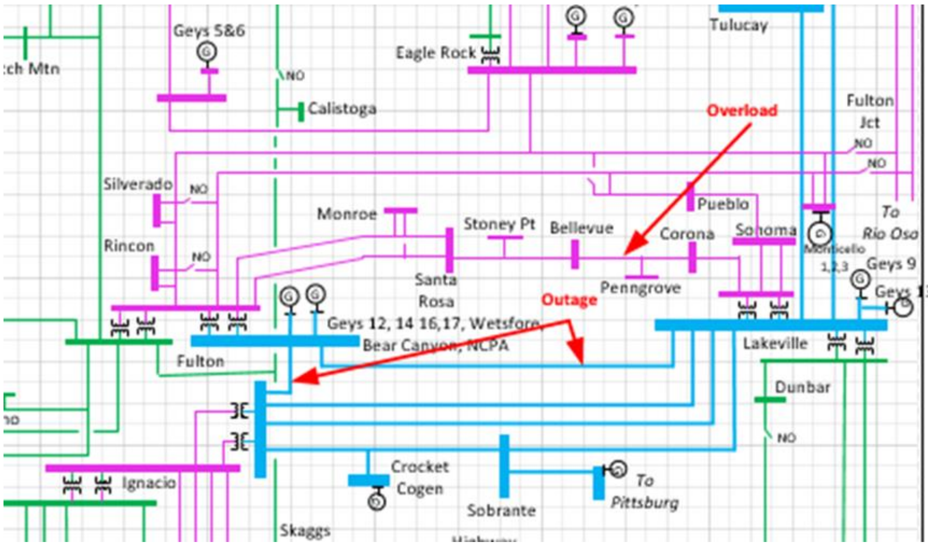
For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7120 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.2.3 *Fulton Sub-area*

Fulton is a sub-area of the North Coast and North Bay LCR area.

Fulton LCR Sub-area Diagram

Figure 3.3-10 Fulton LCR Sub-area



Fulton LCR Sub-area Load and Resources

Table 3.3-6 provides the forecasted load and resources. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-6 Fulton LCR Area 2023 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	889	Market	487	487
AAEE	-9	MUNI	54	54
Behind the meter DG	0	QF	5	5
Net Load	**880**	Solar	0	0
Transmission Losses	26	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**906**	**Total**	**546**	**546**

Fulton LCR Sub-area Hourly Profiles

Figure 3.3-11 illustrates the forecast 2023 profile for the peak day for the Fulton LCR sub-area with the Category P6 normal and emergengy load serving capabilities without local resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-12 illustrates the forecast 2023 hourly profile for Fulton LCR sub-area with the Category P6 emergency load serving capability without local resources.

Figure 3.3-11 Fulton LCR Sub-area 2023 Peak Day Forecast Profiles

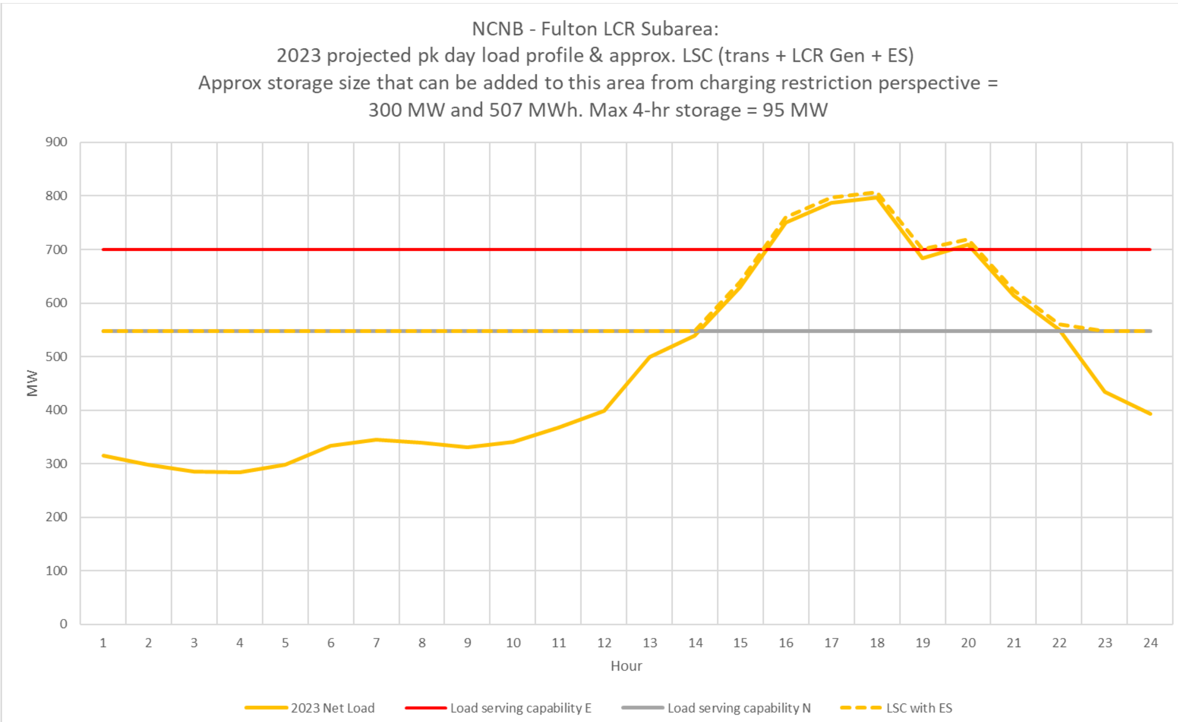
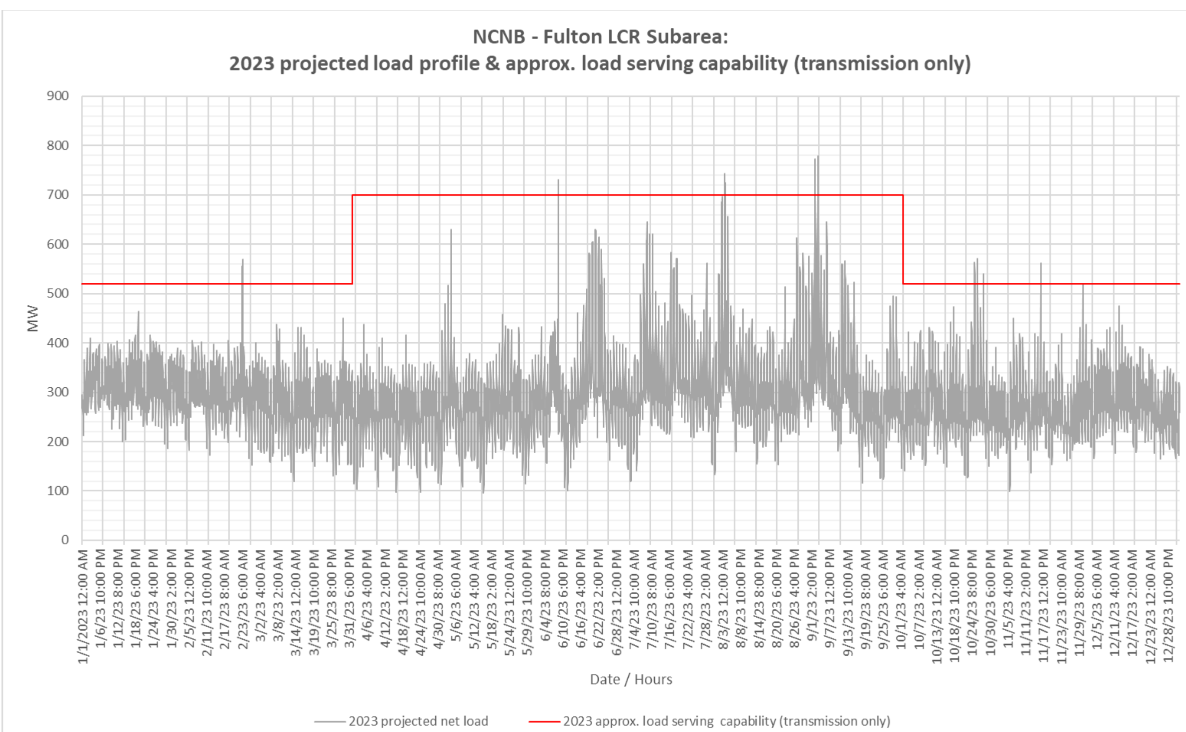


Figure 3.3-12 Fulton LCR Sub-area 2023 Forecast Hourly Profiles



Fulton LCR Sub-area Requirement

Table 3.3-7 identifies the sub-area LCR requirements. The LCR requirement for Category P6 contingency is 237 MW.

Table 3.3-7 Fulton LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	First Limit	P6	Thermal overload on Corona-Penngrove 115 kV Line	Fulton-Lakeville #1 230 kV & Fulton-Ignacio #1 230 kV	237

Effectiveness factors

Effective factors for generators in the Fulton LCR sub-area are in Attachment B table titled Fulton.

3.3.2.4 *North Coast and North Bay Overall*

North Coast and North Bay Overall Requirement

Table 3.3-8 identifies the sub-area LCR requirements. The LCR requirement for Category P3 contingency is 857 MW.

Table 3.3-8 North Coast and North Bay LCR area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	First Limit	P3	Vaca Dixon-Lakeville 230 kV line	Vaca Dixon-Tulucay 230 kV with DEC power plant out of service	857

Effectiveness factors

Effective factors for generators in the North Coast and North Bay LCR area are in Attachment B table titled North Coast and North Bay.

Changes compared to last year's results

Compared to 2022 load forecast decreased up by 15 MW; and, the total LCR need decreased up by 11 MW due to load forecast decrease.

3.3.3 Sierra Area

3.3.3.1 *Area Definition*

The transmission tie lines into the Sierra Area are:

Table Mountain-Rio Oso 230 kV line

Table Mountain-Palermo 230 kV line

Table Mt-Pease 60 kV line

Caribou-Palermo 115 kV line

Drum-Summit 115 kV line #1

Drum-Summit 115 kV line #2

Spaulding-Summit 60 kV line

Brighton-Bellota 230 kV line

Rio Oso-Lockeford 230 kV line

Gold Hill-Eight Mile Road 230 kV line

Lodi-Eight Mile Road 230 kV line

Gold Hill-Lake 230 kV line

The substations that delineate the Sierra Area are:

Table Mountain is out Rio Oso is in

Table Mountain is out Palermo is in

Table Mt is out Pease is in

Caribou is out Palermo is in

Drum is in Summit Metering Station is out

Drum is in Summit Metering Station is out

Spaulding, Tamarak and Summit (PG&E) are in Summit Metering Station is out

Brighton is in Bellota is out

Rio Oso is in Lockeford is out

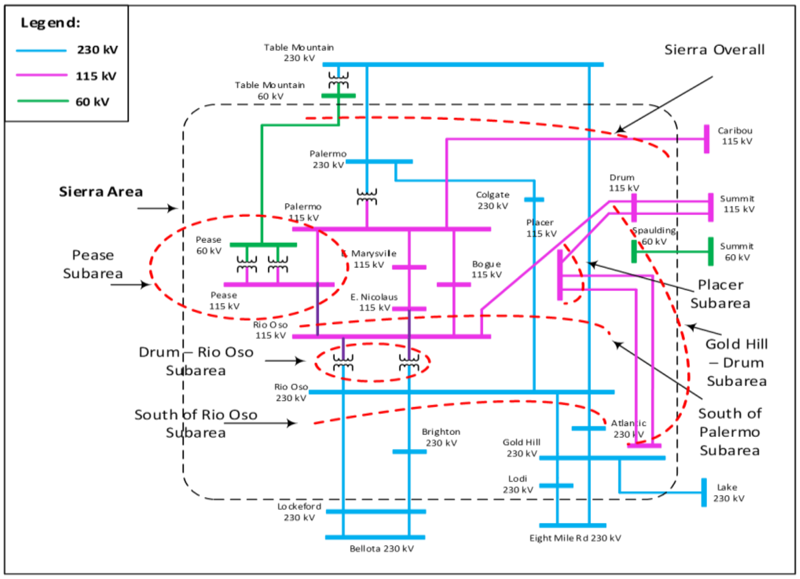
Gold Hill is in Eight Mile is out

Lodi is in Eight Mile is out

Gold Hill is in Lake is out

Sierra LCR Area Diagram

Figure 3.3-13 Sierra LCR Area



Sierra LCR Area Load and Resources

Table 3.3-9 provides the forecasted load and resources. The list of generators within the LCR area are provided in Attachment A.

In year 2023 the estimated time of local area peak is 19:10 PM.

At the local area peak time the estimated, ISO metered, solar output is 2.00%.

If required, all non-solar technology type resources are dispatched at NQC.

Table 3.3-9 Sierra LCR Area 2023 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	1761	Market, Net Seller and Battery	698	698
AAEE	-14	MUNI	1156	1156
Behind the meter DG	-8	QF	50	50
Net Load	**1740**	Solar	5	0
Transmission Losses	72	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**1812**	**Total**	**1909**	**1904**

Approved transmission projects modeled:

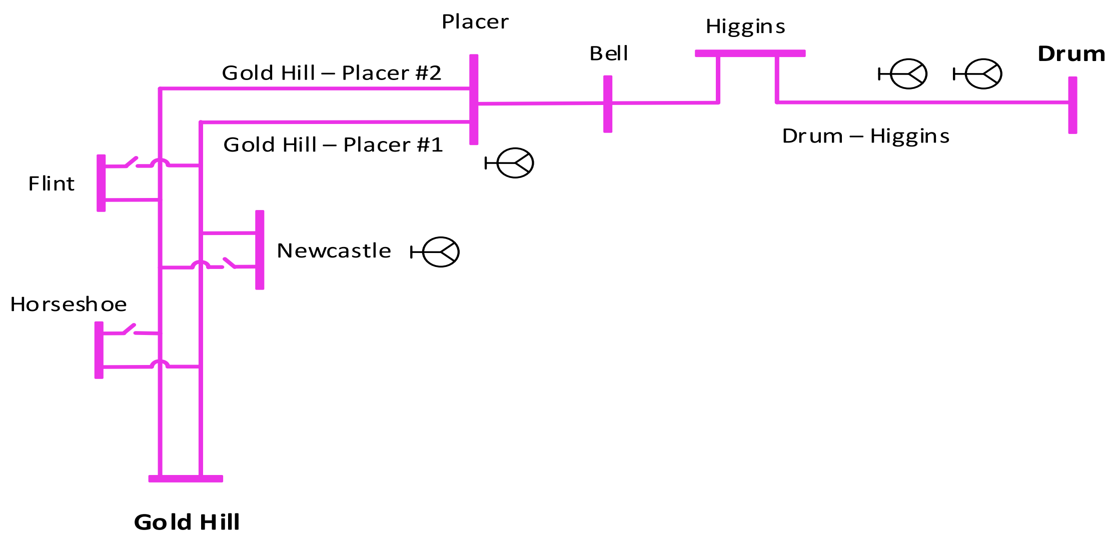
South of Palermo 115 kV Reinforcement Project (In Operation)

3.3.3.2 *Placer Sub-area*

Placer is sub-area of the Sierra LCR area.

Placer LCR Sub-area Diagram

Figure 3.3-14 Placer LCR Sub-area



Placer LCR Sub-area Load and Resources

Table 3.3-10 provides the forecasted load and resources. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-10 Placer LCR Sub-area 2023 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	180	Market and Net Seller	36	36
AAEE	-1	MUNI	27	27
Behind the meter DG	-1	QF	0	0
Net Load	**178**	Solar	0	0
Transmission Losses	3	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**181**	**Total**	**63**	**63**

Placer LCR Sub-area Hourly Profiles

Figure 3.3-15 illustrates the forecast 2023 profile for the peak day for the Placer sub-area with the Category P6 normal and emergency load serving capabilities without local resources. The chart also includes an estimated amount of energy storage that can be added to this local area. Figure

3.3-16 illustrates the forecast 2023 hourly profile for Placer sub-area with the Category P6 emergency load serving capability without local resources.

Figure 3.3-15 Placer LCR Sub-area 2023 Peak Day Forecast Profiles

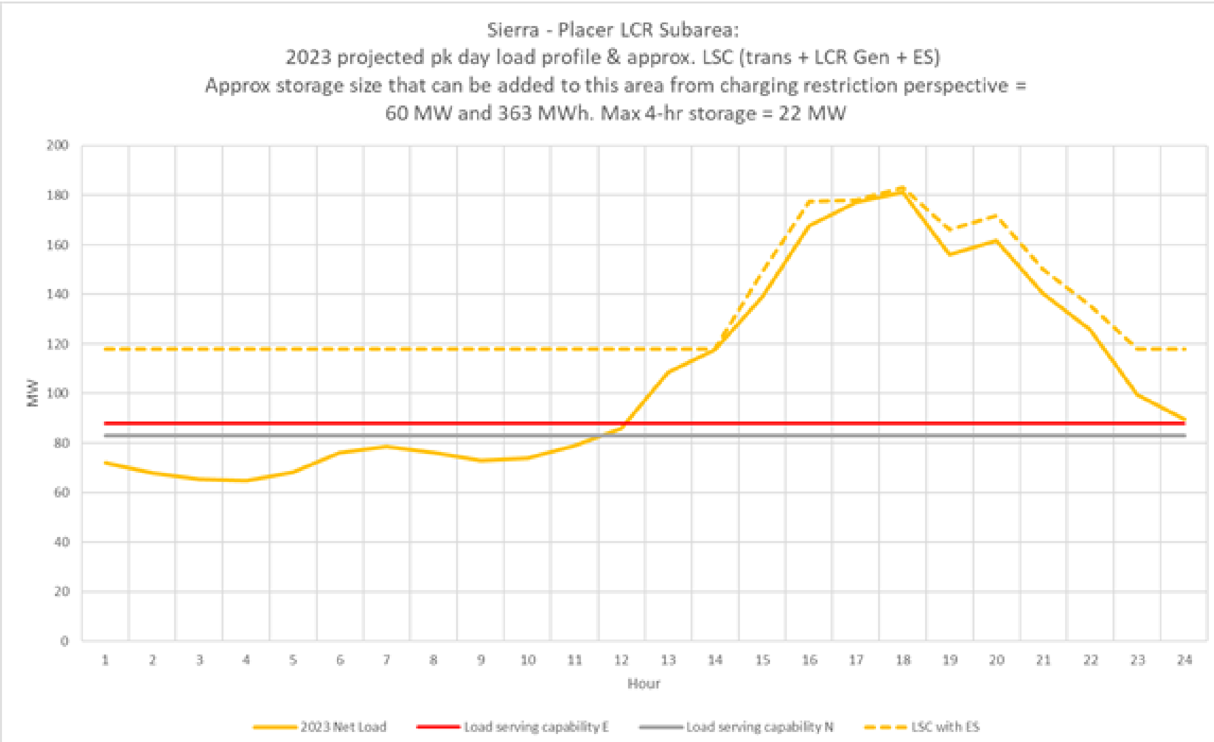
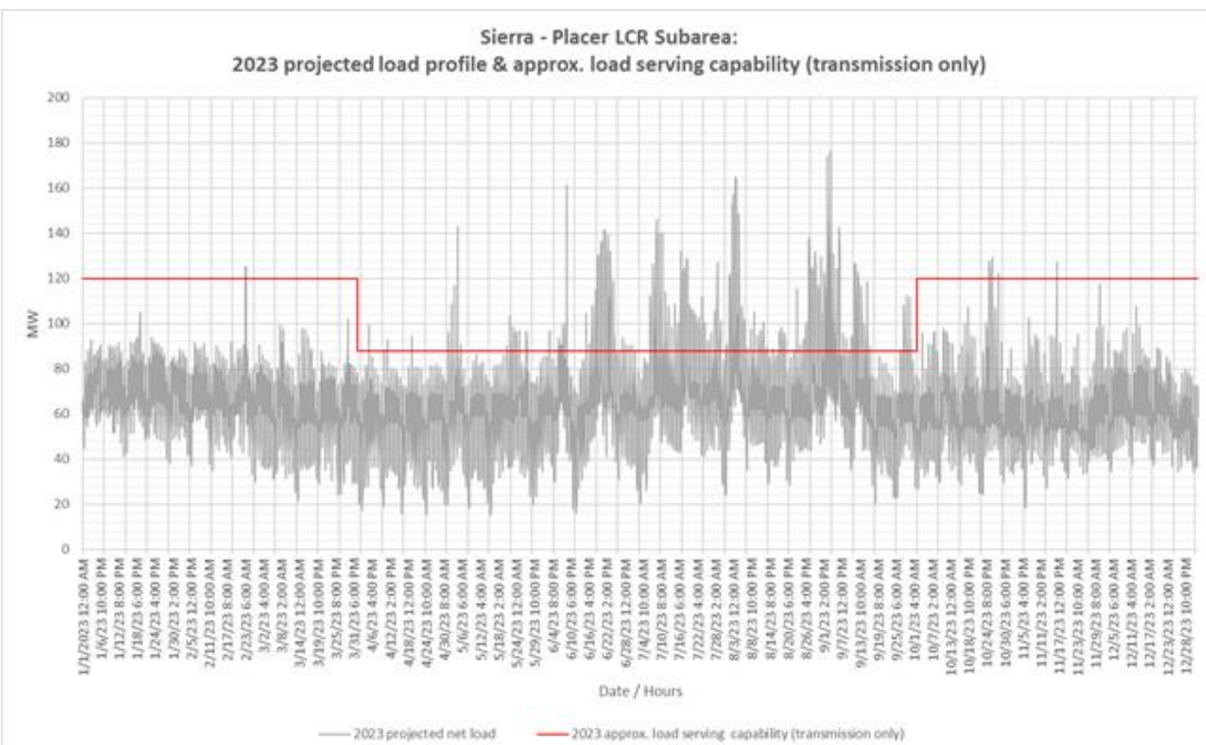


Figure 3.3-16 Placer LCR Sub-area 2023 Forecast Hourly Profiles



Placer LCR Sub-area Requirement

Table 3.3-11 identifies the sub-area requirements. The Category P6 LCR requirement is 95 MW including 32 MW of NQC and peak deficiencies..

Table 3.3-11 Placer LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	First Limit	P6	Drum–Higgins 115 kV	Gold Hill-Placer #1 115 kV & Gold Hill-Placer #2 115 kV	95 (32)

Effectiveness factors

All units within the Placer Sub-area have the same effectiveness factor.

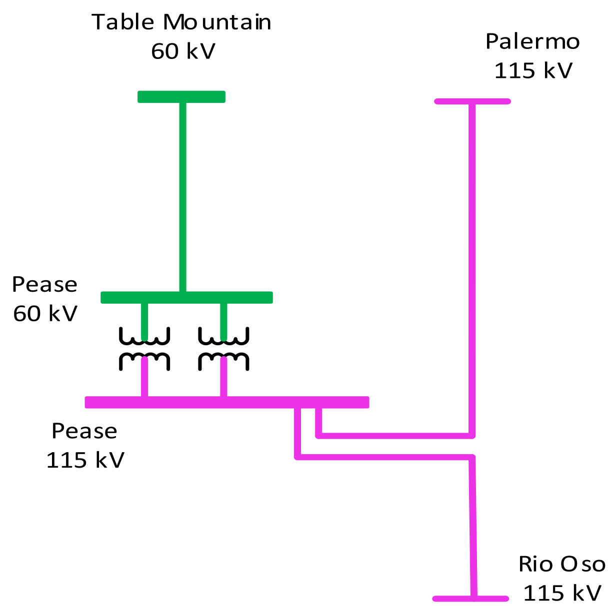
For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7240 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.3.3 *Pease Sub-area*

Pease is sub-area of the Sierra LCR area.

Pease LCR Sub-area Diagram

Figure 3.3-17 Pease LCR Sub-area



Pease LCR Sub-area Load and Resources

Table 3.3-12 provides the forecasted load and resources. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-12 Pease LCR Sub-area 2023 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	147	Market and Net Seller	98	98
AAEE	-1	MUNI	0	0
Behind the meter DG	-1	QF	49	49
Net Load	**145**	Solar	0	0
Transmission Losses	3	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**148**	**Total**	**147**	**147**

Pease LCR Sub-area Hourly Profiles

Figure 3.3-18 illustrates the forecast 2023 profile for the peak day for the Pease sub-area with the Category P6 normal and emergency load serving capabilities without local resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective.

Figure 3.3-19 illustrates the forecast 2023 hourly profile for Pease sub-area with the Category P6 load serving capability without local resources.

Figure 3.3-18 Pease LCR Sub-area 2023 Peak Day Forecast Profiles

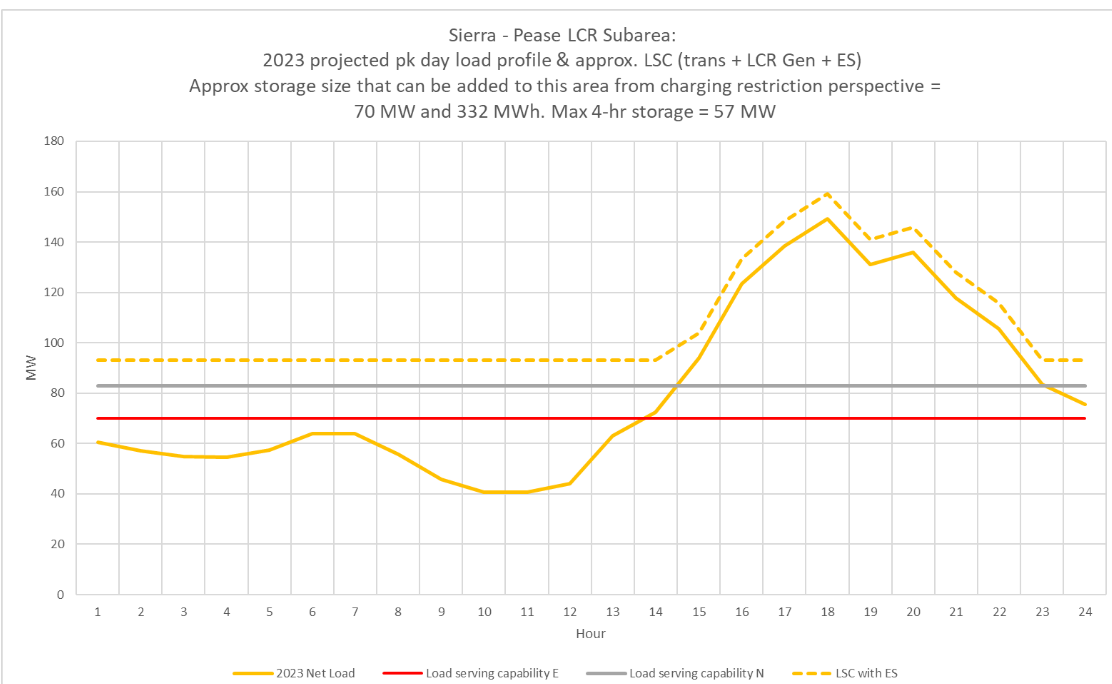
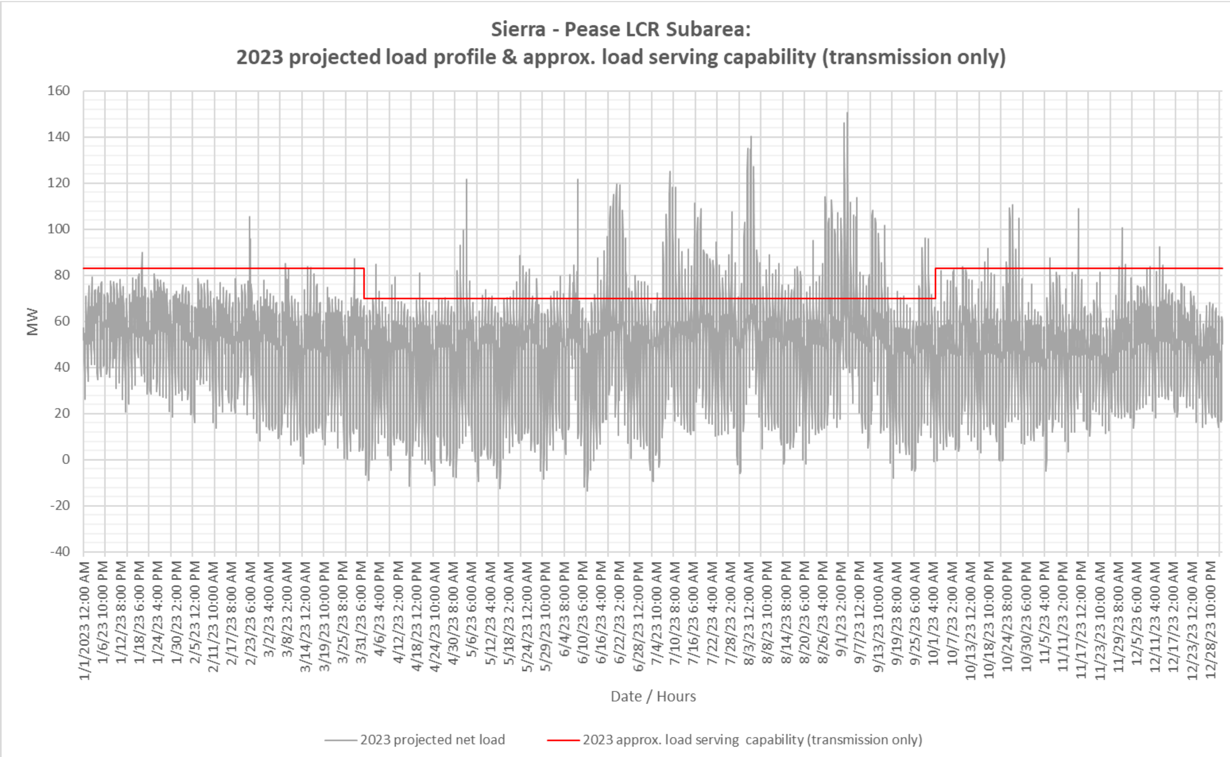


Figure 3.3-19 Pease LCR Sub-area 2023 Forecast Hourly Profiles



Pease LCR Sub-area Requirement

Table 3.3-13 identifies the sub-area LCR requirements. The Category P6 LCR requirement is 80 MW.

Table 3.3-13 Pease LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	First Limit	P6	Table Mountain – Pease 60 kV	Palermo – Pease 115 kV and Pease – Rio Oso 115 kV lines	80

Effectiveness factors:

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

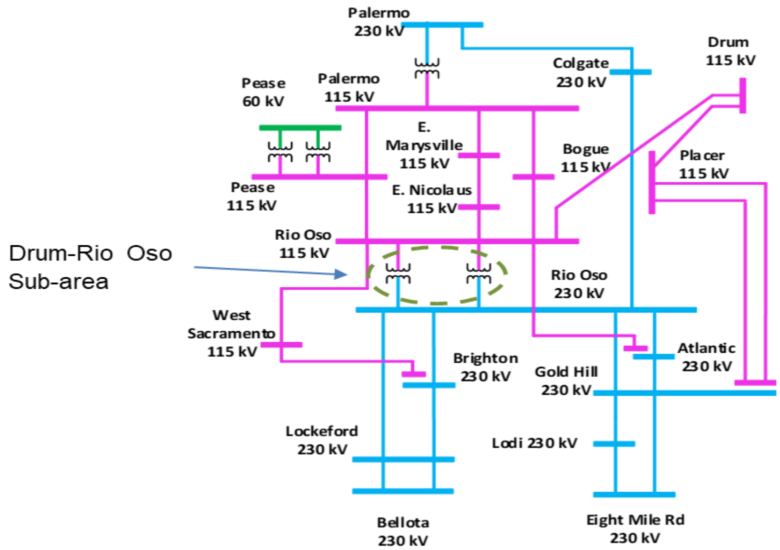
For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7230 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.3.4 *Drum-Rio Oso Sub-area*

Drum-Rio Oso is a sub-area of the Sierra LCR area.

Drum-Rio Oso LCR Sub-area Diagram

Figure 3.3-20 Drum-Rio Oso LCR Sub-area



Drum-Rio Oso LCR Sub-area Load and Resources

The Drum-Rio Oso sub-area does not have a defined load pocket with the limits based upon power flow through the area. Table 3.3-14 provides the forecasted resources in the sub-area. The list of generators within the LCR area are provided in Attachment A.

Table 3.3-14 Drum-Rio Oso LCR Sub-area 2023 Forecast Load and Resources

Load (MW)	Generation (MW)	Aug NQC	At Peak
The Drum-Rio Oso Sub-area does not have a defined load pocket with the limits based upon power flow through the area.	Market, Net Seller and Battery	326	326
	MUNI	177	177
	QF	50	50
	Solar	5	0
	Existing 20-minute Demand Response	0	0
	Mothballed	0	0
	Total	**558**	**553**

Drum-Rio Oso LCR Sub-area Hourly Profiles

The Drum-Rio Oso sub-area does not has a defined load pocket with the limits based upon power flow through the area. As such, no load profile is provided for this sub-area.

Drum-Rio Oso LCR Sub-area Requirement

Table 3.3-15 identifies the sub-area LCR requirements. The Category P6 LCR requirement is 750 MW including 192 MW of NQC deficiency or 197 MW of at peak deficiency.

Table 3.3-15 Drum-Rio Oso LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	First Limit	P6	Rio Oso #1 230/115 kV Tx	Rio Oso #2 230/115 kV & Palermo #2 230/115 kV Txrs	750 (192 NQC/ 197 Peak)

Effectiveness factors

All units within the Drum-Rio Oso sub-area have the same effectiveness factor.

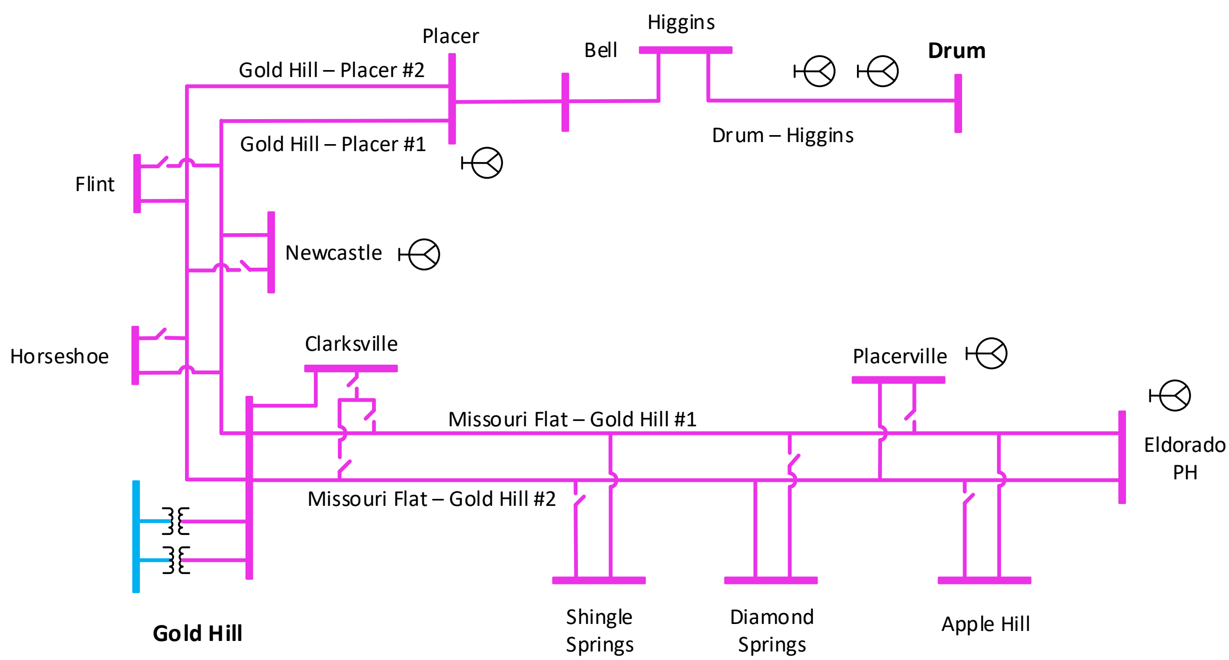
For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7240 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.3.5 *Gold Hill-Drum Sub-area*

Gold Hill-Drum is sub-area of the Sierra LCR area.

Gold Hill-Drum LCR Sub-area Diagram

Figure 3.3-21 Gold Hill-Drum LCR Sub-area



Gold Hill-Drum LCR Sub-area Load and Resources

Table 3.3-16 provides the forecasted load and resources. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-16 Gold Hill-Drum LCR Sub-area 2023 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	501	Market and Net Seller	46	46
AAEE	-3	MUNI	27	27
Behind the meter DG	-3	QF	0	0
Net Load	**495**	Solar	0	0
Transmission Losses	8	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**503**	**Total**	**73**	**73**

Gold Hill-Drum LCR Sub-area Hourly Profiles

Figure 3.3-22 illustrates the forecast 2023 profile for the peak day for the Gold Hill-Drum sub-area with the Category P6 normal and emergency load serving capabilities without local resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-23 illustrates the forecast 2023 hourly profile for Gold Hill-Drum sub-area with the Category P6 load serving capability without local resources.

Figure 3.3-22 Gold Hill-Drum LCR Sub-area 2023 Peak Day Forecast Profiles

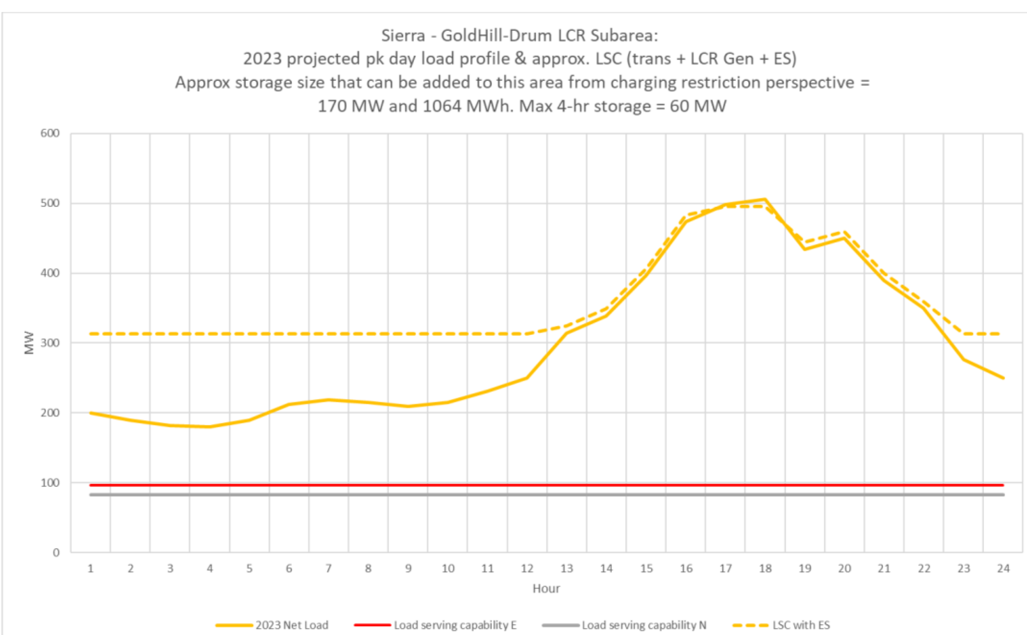
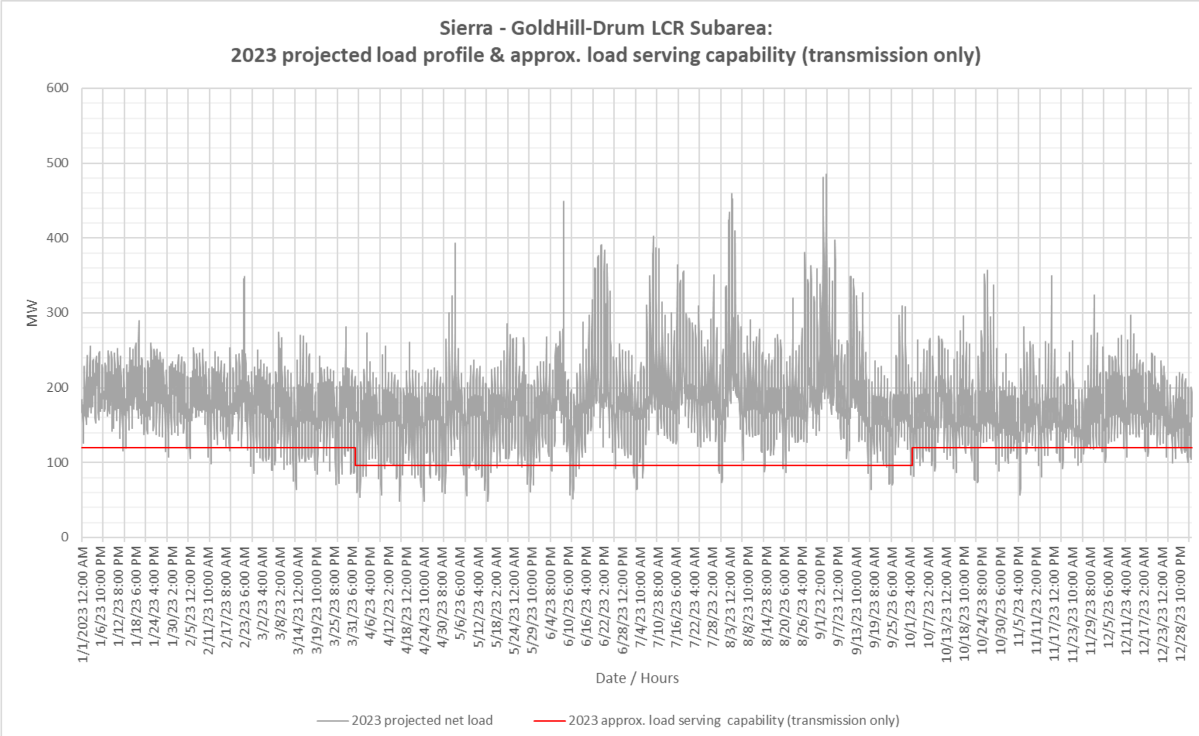


Figure 3.3-23 Gold Hill-Drum LCR Sub-area 2023 Forecast Hourly Profiles



Gold Hill-Drum LCR Sub-area Requirement

Table 3.3-17 identifies the sub-area LCR requirements. The Category P6 LCR requirement is 400 MW including 327 MW of NQC and peak deficiency.

Table 3.3-17 Gold Hill-Drum LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	First Limit	P6	Drum – Higgins 115 kV	Gold Hill 230/115 kV #1 and Gold Hill 230/115 kV #2 Txrs	400 (327)

Effectiveness factors:

All units within the Gold Hill-Drum Sub-area have the same effectiveness factor.

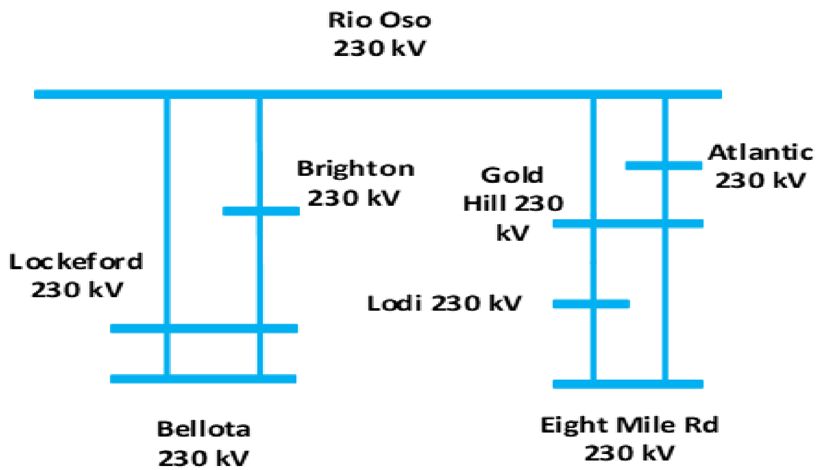
For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7230 and 7240 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.3.6 *South of Rio Oso Sub-area*

South of Rio Oso is sub-area of the Sierra LCR area.

South of Rio Oso LCR Sub-area Diagram

Figure 3.3-24 South of Rio Oso LCR Sub-area



South of Rio Oso LCR Sub-area Load and Resources

The South of Rio Oso sub-area does not have a defined load pocket with the limits based upon power flow through the area. Table 3.3-18 provides the forecasted resources in the sub-area. The list of generators within the LCR area are provided in Attachment A.

Table 3.3-18 South of Rio Oso LCR Sub-area 2023 Forecast Load and Resources

Load (MW)	Generation (MW)	Aug NQC	At Peak
The South of Rio Oso Sub-area does not have a defined load pocket with the limits based upon power flow through the area.	Market and Net Seller	83	83
	MUNI	606	606
	QF	0	0
	Solar	0	0
	Existing 20-minute Demand Response	0	0
	Mothballed	0	0
	Total	**689**	**689**

South of Rio Oso LCR Sub-area Hourly Profiles

The South of Rio Oso sub-area does not have a defined load pocket with the limits based upon power flow through the area. As such, no load profile is provided for this sub-area.

South of Rio Oso LCR Sub-area Requirement

Table 3.3-19 identifies the sub-area LCR requirements. The LCR requirement for Category P6 is 306 MW.

Table 3.3-19 South of Rio Oso LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2023	First limit	P6	Rio Oso – Atlantic 230 kV	Rio Oso – Gold Hill 230 kV Rio Oso – Brighton 230 kV	306

Effectiveness factors:

Effective factors for generators in the South of Rio Oso LCR sub-area are in Attachment B table titled Rio Oso.

For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7230 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.3.7 *South of Palermo Sub-area*

South of Palermo is a sub-area of the Sierra LCR area.

South of Palermo sub-area has been eliminated due to the South of Palermo transmission project.

3.3.3.8 *Sierra Area Overall*

Sierra LCR Area Hourly Profiles

The Sierra LCR Area limits are based upon power flow through the area. As such, no load profile is provided for the area.

Sierra LCR Area Requirement

Table 3.3-20 identifies the area requirements. The LCR requirement for Category P6 is 1150 MW.

Table 3.3-20 Sierra LCR Area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2023	First limit	P6	Table Mountain – Pease 60 kV	Table Mountain – Palermo 230 kV Table Mountain – Rio Oso 230 kV	1150

Effectiveness factors:

Effective factors for generators in the Sierra Overall LCR area are in Attachment B table titled Sierra Overall.

For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7230 and 7240 posted at: http://www.caiso.com/Documents/2210Z.pdf

Changes compared to last year's results:

The load forecast went up by 193 MW, the total LCR need has decreased by 8 MW and the total existing capacity required has decreased by 70 MW mostly due to the change in NQC values for the Sierra resources.

3.3.4 Stockton Area

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

3.3.4.1 ***Area Definition***

Tesla-Bellota Sub-Area Definition

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

Bellota 230/115 kV Transformer #1

Bellota 230/115 kV Transformer #2

Tesla-Tracy 115 kV Line

Tesla-Salado 115 kV Line

Tesla-Salado-Manteca 115 kV line

Tesla-Schulte #1 115 kV Line

Tesla-Schulte #2 115kV line

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

Bellota 230 kV is out Bellota 115 kV is in

Bellota 230 kV is out Bellota 115 kV is in

Tesla is out Tracy is in

Tesla is out Salado is in

Tesla is out Salado and Manteca are in

Tesla is out Schulte is in

Tesla is out Schulte is in

Lockeford Sub-Area Definition

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

Lockeford-Industrial 60 kV line

Lockeford-Lodi #1 60 kV line

Lockeford-Lodi #2 60 kV line

Lockeford-Lodi #3 60 kV line

The substations that delineate the Lockeford Sub-area are:

Lockeford is out Industrial is in

Lockeford is out Lodi is in

Lockeford is out Lodi is in

Lockeford is out Lodi is in

Stockton LCR Area Diagram

The Stockton LCR area is comprised of the individual noncontiguous sub-areas with diagrams provided for each of the sub-areas below.

Stockton LCR Area Load and Resources

Table 3.3-21 provides the forecast load and resources in the area. The list of generators within the LCR area are provided in Attachment A.

In year 2023 the estimated time of local area peak is 19:10 PM.

At the local area peak time the estimated, ISO metered, solar output is 2.00%.

If required, all non-solar technology type resources are dispatched at NQC.

Table 3.3-21 Stockton LCR Area 2023 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	1078	Market, Net Seller and Battery	425	425
AAEE	-6	MUNI	136	136
Behind the meter DG	-3	QF	0	0
Net Load	**1069**	Solar	12	0
Transmission Losses	21	Existing 20-minute Demand Response	6	6
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**1090**	**Total**	**579**	**567**

Stockton LCR Area Hourly Profiles

The Stockton LCR area is comprised of the individual noncontiguous sub-areas with profiles provided for each of the sub-areas below.

Approved transmission projects modeled

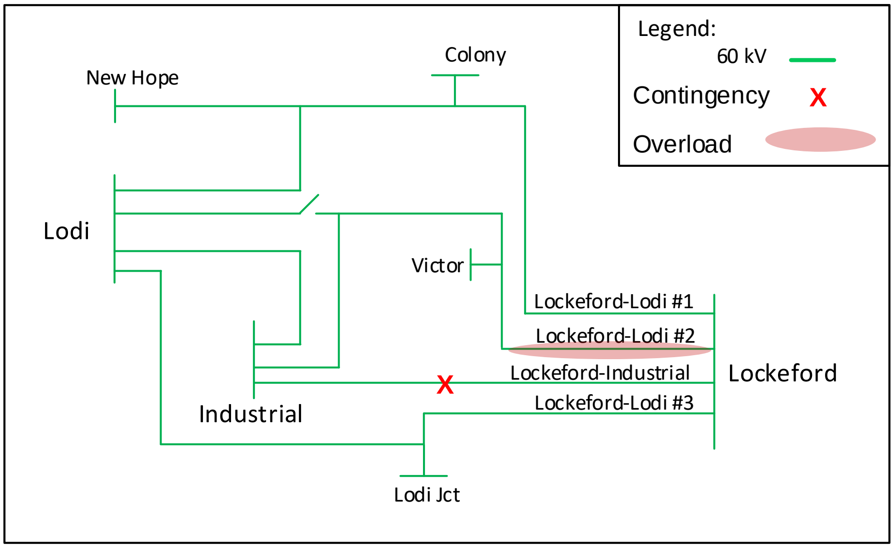
There are no new transmission project that goes into service in this area by year 2023.

3.3.4.2 ***Lockeford Sub-area***

Lockeford is a sub-area of the Stockton LCR area.

Lockeford LCR Sub-area Diagram

Figure 3.3-25 Lockeford LCR Sub-area



Lockeford LCR Sub-area Load and Resources

Table 3.3-22 provides the forecasted load and resources. The list of generators within the LCR Sub-area are provided in Attachment A.

Table 3.3-22 Lockeford LCR Sub-area 2023 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	180	Market	0	0
AAEE	-1	MUNI	24	24
Behind the meter DG	0	QF	0	0
Net Load	**179**	Solar	0	0
Transmission Losses	2	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**181**	**Total**	**24**	**24**

Lockeford LCR Sub-area Hourly Profiles

Figure 3.3-26 illustrates the forecast 2023 profile for the peak day for the Lockeford sub-area with the Category P3 normal and emergency load serving capabilities without local resources. Figure 3.3-27 illustrates the forecast 2023 hourly profile for Lockeford sub-area with the Category P3 load serving capability without local resources.

Figure 3.3-26 Lockeford LCR Sub-area 2023 Peak Day Forecast Profiles

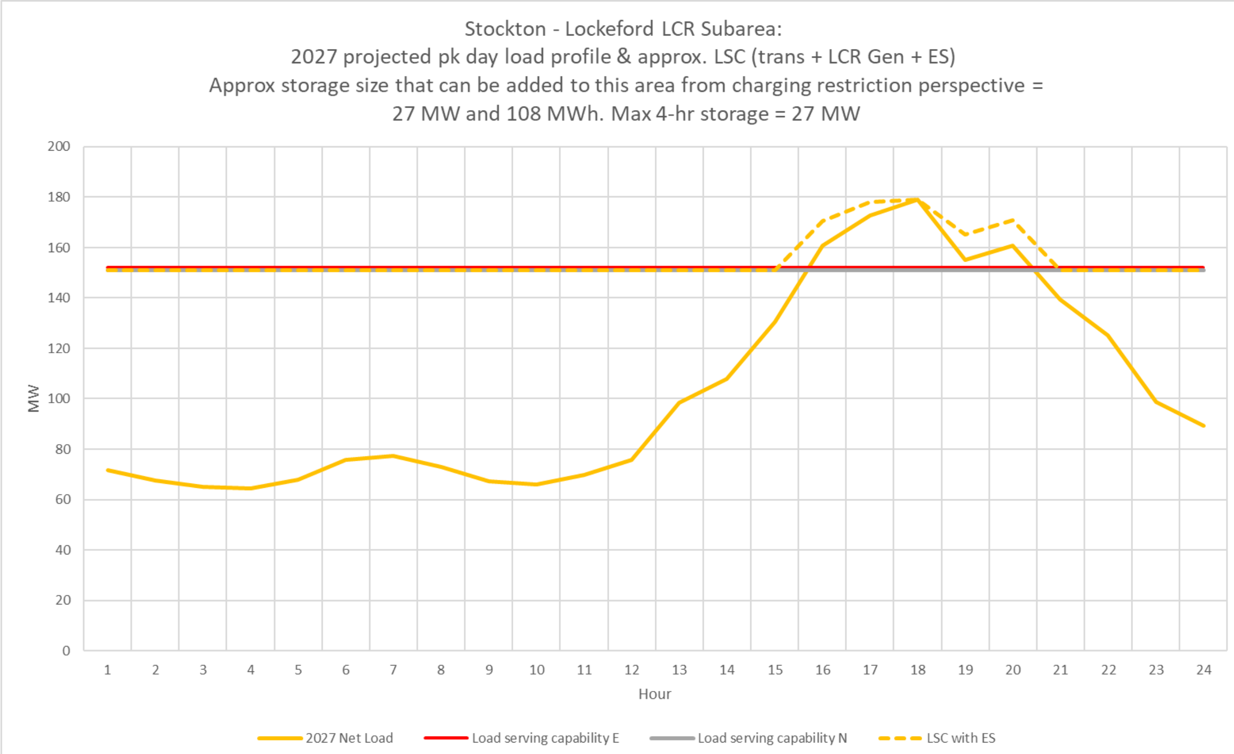
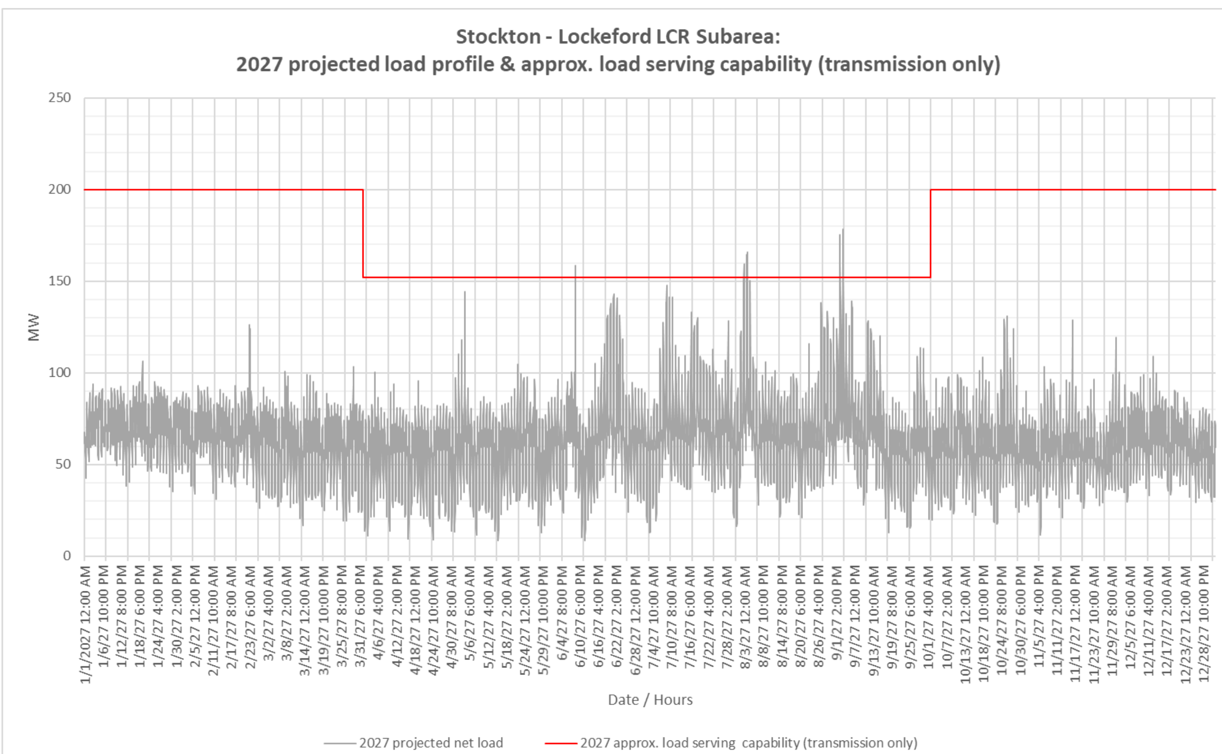


Figure 3.3-27 Lockeford LCR Sub-area 2023 Forecast Hourly Profiles



Lockeford LCR Sub-area Requirement

Table 3.3-23 identifies the sub-area requirements. The LCR requirement for for this sub-area is based on the Category P3 contingency at 27 MW with 3 MW deficiency.

Table 3.3-23 Lockeford LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	First Limit	P3	Lockeford-Lodi #2 60 kV	Lockeford-Industrial 60 kV & Lodi CT	27 (3)

Effectiveness factors:

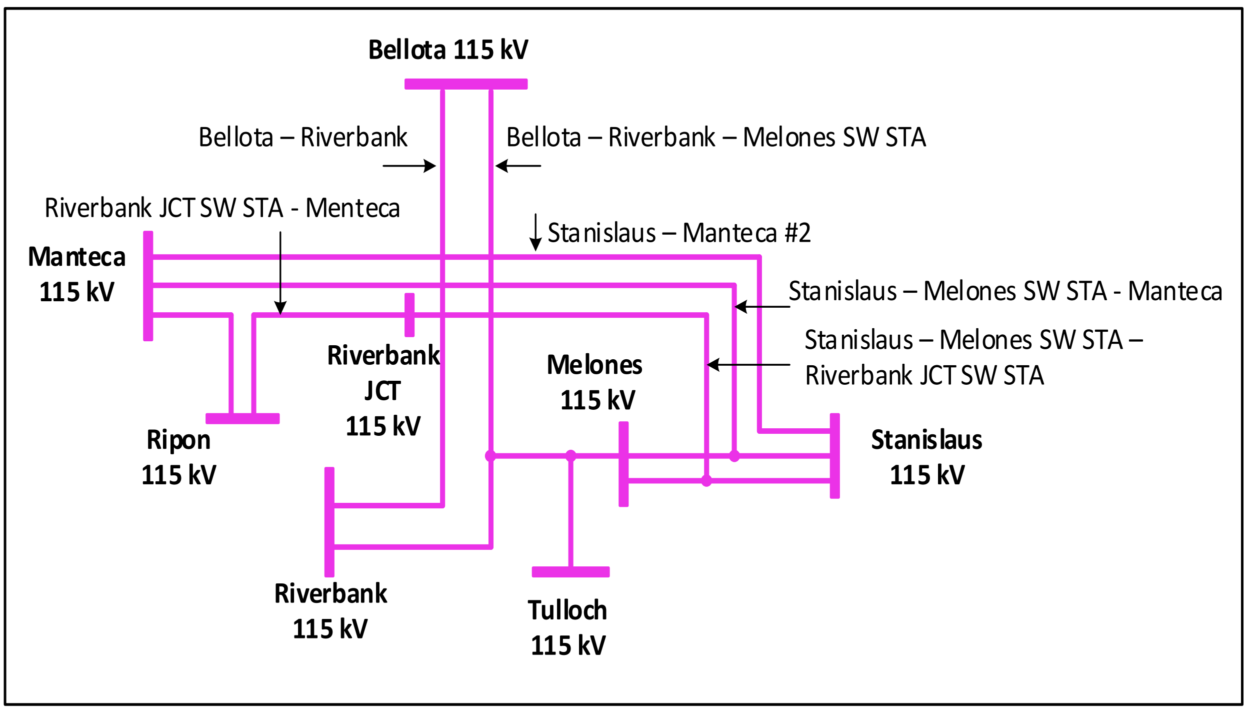
No effectiveness factor is required.

3.3.4.3 *Stanislaus Sub-area*

Stanislaus is a sub-area within the Tesla – Bellota sub-area of the Stockton LCR area.

Stanislaus LCR Sub-area Diagram

Figure 3.3-28 Stanislaus LCR Sub-area



Stanislaus LCR Sub-area Load and Resources

The Stanislaus sub-area does not has a defined load pocket with the limits based upon power flow through the area. Table 3.3-24 provides the forecasted resources in the sub-area. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-24 Stanislaus LCR Sub-area 2023 Forecast Load and Resources

Load (MW)	Generation (MW)	Aug NQC	At Peak
The Stanislaus Sub-area does not has a defined load pocket with the limits based upon power flow through the area.	Market and Net Seller	89	89
	MUNI	91	91
	QF	0	0
	Solar	0	0
	Existing 20-minute Demand Response	0	0
	Mothballed	0	0
	Total	**180**	**180**

Stanislaus LCR Sub-area Hourly Profiles

The Stanislaus sub-area does not has a defined load pocket with the limits based upon power flow through the area. As such, no load profile is provided for this sub-area.

Stanislaus LCR Sub-area Requirement

Table 3.3-25 identifies the sub-area requirements. The LCR requirement for Category P3 contingency is 155 MW.

Table 3.3-25 Stanislaus LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	First limit	P3	Ripon – Manteca 115 kV	Bellota-Riverbank-Melones 115 kV and Stanislaus PH	155

Effectiveness factors:

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

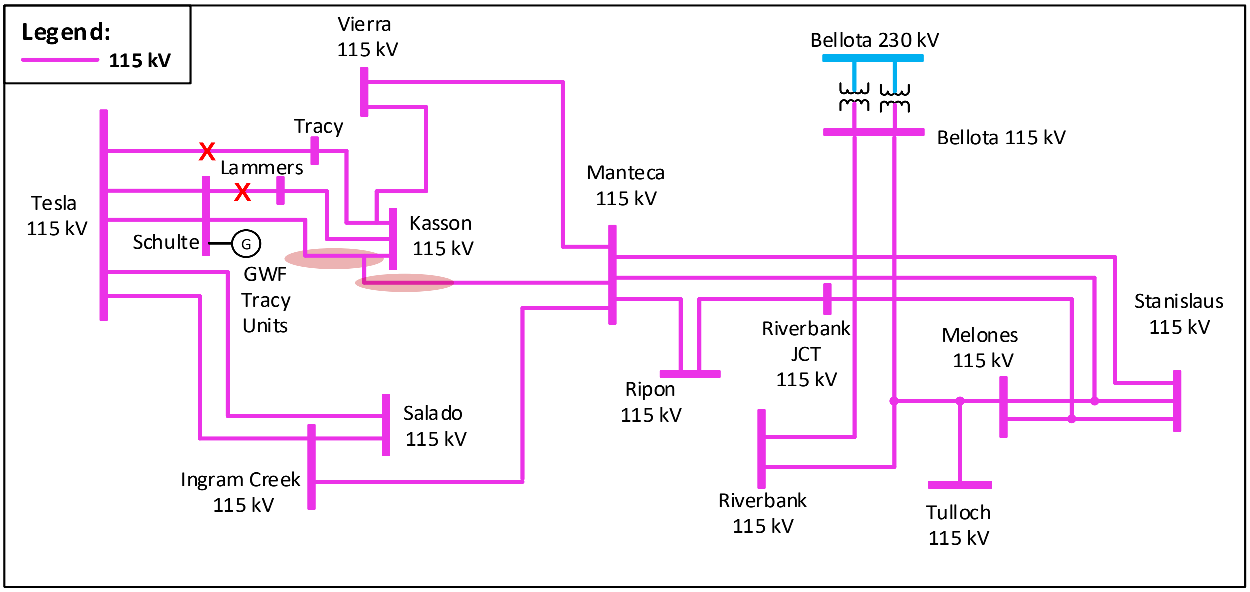
For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7410 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.4.4 *Tesla-Bellota Sub-area*

Tesla-Bellota is a sub-area of the Stockton LCR area.

Tesla-Bellota LCR Sub-area Diagram

Figure 3.3-29 Tesla-Bellota LCR Sub-area



Tesla Bellota LCR Sub-area Load and Resources

Table 3.3-26 provides the forecasted load and resources. The list of generators within the LCR Sub-area are provided in Attachment A.

Table 3.3-26 Tesla-Bellota LCR Sub-area 2023 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	897	Market, Net Seller and Battery	425	425
AAEE	-5	MUNI	112	112
Behind the meter DG	-3	QF	0	0
Net Load	**889**	Solar	12	0
Transmission Losses	20	Existing 20-minute Demand Response	6	6
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**909**	**Total**	**555**	**543**

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

Tesla-Bellota LCR Sub-area Hourly Profiles

Figure 3.3-30 illustrates the forecast 2023 profile for the peak day for the Tesla-Bellota sub-area with the Category P6 normal and emergency load serving capabilities without local resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-31 illustrates the forecast 2023 hourly profile for Tesla-Bellota sub-area with the Category P6 emergency load serving capability without local resources.

Figure 3.3-30 Tesla-Bellota LCR Sub-area 2023 Peak Day Forecast Profiles

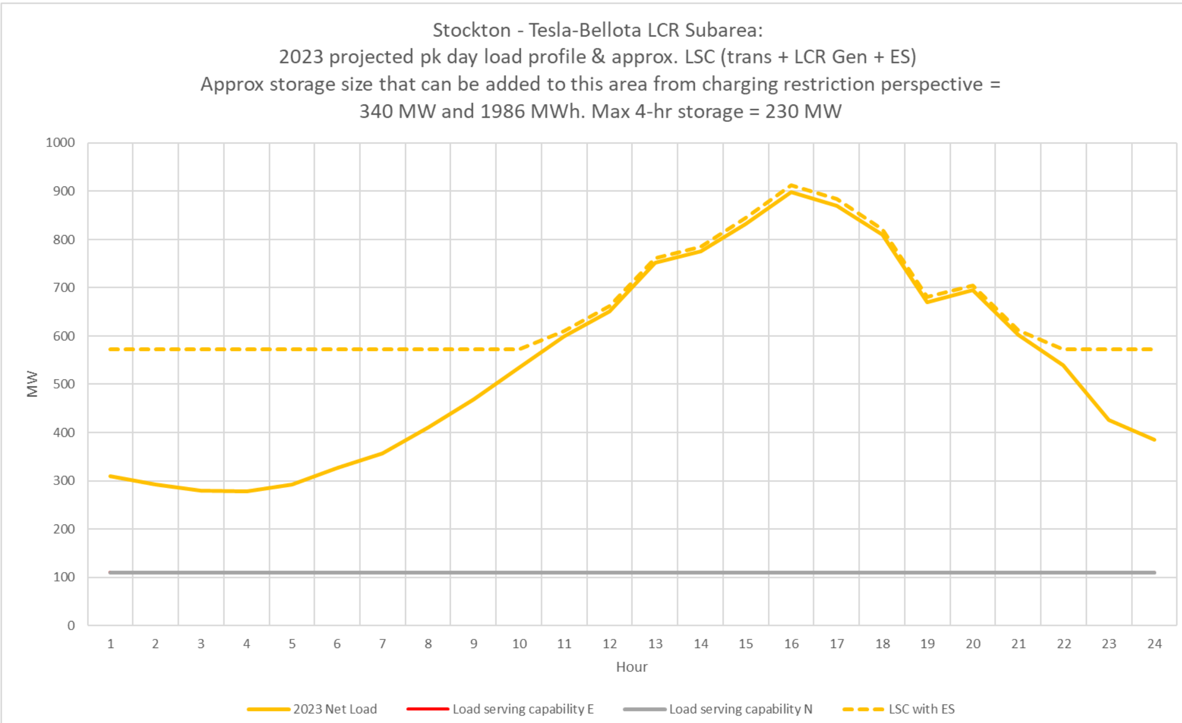
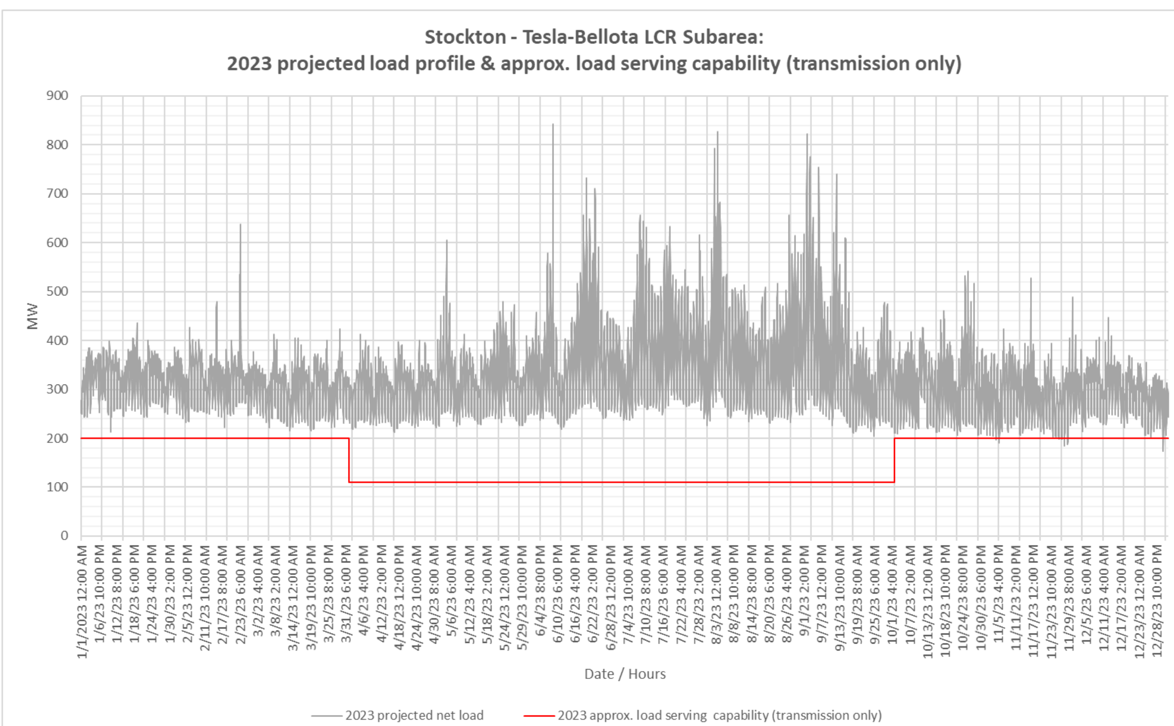


Figure 3.3-31 Tesla-Bellota LCR Sub-area 2023 Forecast Hourly Profiles



Tesla-Bellota LCR Sub-area Requirement

Table 3.3-27 identifies the sub-area requirements. The LCR requirement for Category P6 contingency is 965 MW including a 410 MW NQC and 422 MW at peak deficiency.

Table 3.3-27 Tesla-Bellota LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	First limit	P6	Schulte-Kasson-Manteca 115 kV	Schulte – Lammers 115 kV & Tesla – Tracy 115 kV	657 (410 NQC/ 422 Peak)
2023	First limit	P2-4	Stanislaus – Melones – Riverbank Jct 115 kV	Tesla 115 kV bus	668 (113 NQC/ 125 Peak)
Total LCR Need for Tesla – Bellota Sub-area in 2023					965 (410 NQC/ 422 Peak)

Effectiveness factors:

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

For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7410 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.4.5 *Stockton Overall*

Stockton LCR Area Overall Requirement

The requirement for this area is driven by the sum of requirements for the Tesla-Bellota and Lockeford sub-areas. Table 3.3-28 identifies the area requirements. The LCR requirement is 992 MW with a 413 MW NQC deficiency or 425 MW at peak deficiency.

Table 3.3-28 Stockton LCR Area Overall Requirements

Year	LCR (MW) (Deficiency)
2023	992 (413 NQC/ 425 Peak)

Changes compared to last year's results

The load forecast went up by 63 MW and the total LCR need has decreased by 381 MW due to higher line rating for Shulte-Kasson-Manteca 115 kV line.

3.3.5 Greater Bay Area

3.3.5.1 *Area Definition:*

The transmission tie lines into the Greater Bay Area are:

Lakeville-Sobrante 230 kV

Ignacio-Sobrante 230 kV

Parkway-Moraga 230 kV

Bahia-Moraga 230 kV

Lambie SW Sta-Vaca Dixon 230 kV

Peabody-Contra Costa P.P. 230 kV

Tesla-Kelso 230 kV

Tesla-Delta Switching Yard 230 kV

Tesla-Pittsburg #1 230 kV

Tesla-Pittsburg #2 230 kV

Tesla-Newark #1 230 kV

Tesla-Newark #2 230 kV

Tesla-Ravenswood 230 kV

Tesla-Metcalf 500 kV

Moss Landing-Los Banos 500 kV

Moss Landing-Coburn #1 230 kV

Moss Landing-Las Aguilas #2 230 kV

Oakdale TID-Newark #1 115 kV

Oakdale TID-Newark #2 115 kV

The substations that delineate the Greater Bay Area are:

Lakeville is out Sobrante is in

Ignacio is out Sobrante is in

Parkway is out Moraga is in

Bahia is out Moraga is in

Lambie SW Sta is in Vaca Dixon is out

Peabody is out Contra Costa P.P. is in

Tesla is out Kelso is in

Tesla is out Delta Switching Yard is in

Tesla is out Pittsburg is in

Tesla is out Pittsburg is in

Tesla is out Newark is in

Tesla is out Newark is in

Tesla is out Ravenswood is in

Tesla is out Metcalf is in

Los Banos is out Moss Landing is in

Coburn is out Moss Landing is in

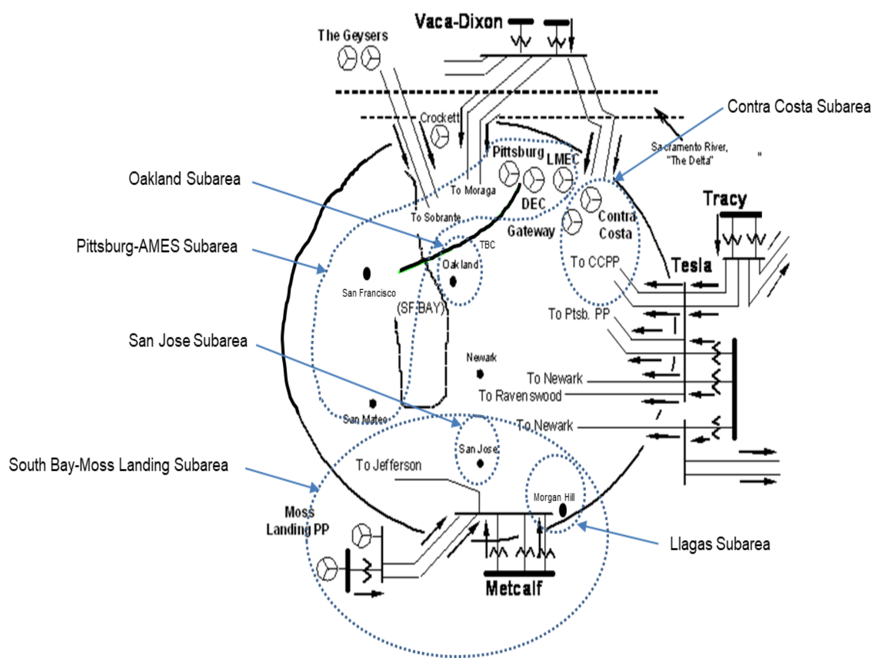
Las Aquilas is out Moss Landing is in

Oakdale TID is out Newark is in

Oakdale TID is out Newark is in

Greater Bay LCR Area Diagram

Figure 3.3-32 Greater Bay LCR Area



Greater Bay LCR Area Load and Resources

Table 3.3-29 provides the forecasted load and resources. The list of generators within the LCR area are provided in Attachment A.

In year 2022 the estimated time of local area peak is 17:50 PM.

At the local area peak time the estimated, ISO metered, solar output is 44.00%.

If required, all technology type resources, including solar, are dispatched at NQC.

Table 3.3-29 Greater Bay Area LCR Area 2023 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	10823	Market, Net Seller, Wind	6154	6154
AAEE	-51	MUNI	378	378
Behind the meter DG	-174	QF	233	233
Net Load	10598	Solar	8	8
Transmission Losses	274	Existing 20-minute Demand Response	65	65
Pumps	264	Battery	932	932
Load + Losses + Pumps	11136	**Total**	**7770**	**7770**

Approved transmission projects modeled

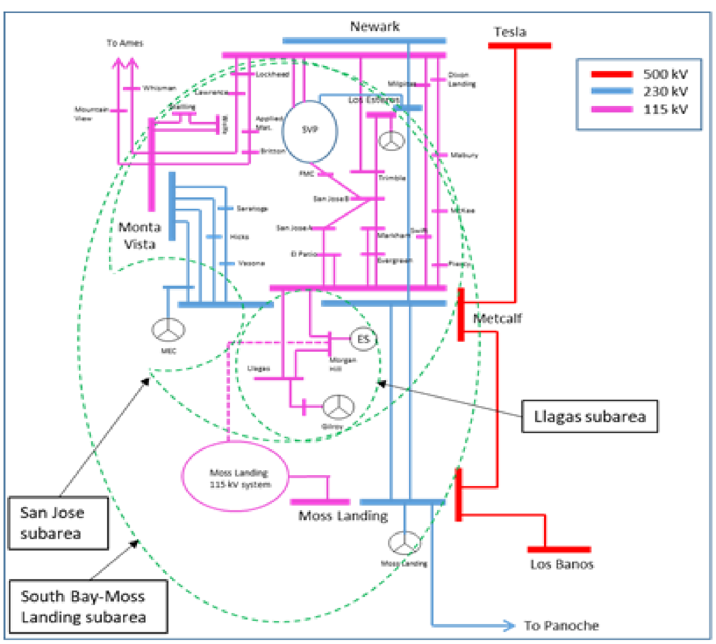
- Cooley Landing-Palo Alto and Ravenswood-Cooley Landing 115 kV Line Rerate
- EastShore-Oakland J Reconductoring Project
- Oakland Clean Energy Initiative Project

3.3.5.2 *Llagas Sub-area*

Llagas is a sub-area of the Greater Bay LCR area.

Llagas LCR Sub-area Diagram

Figure 3.3-33 Llagas LCR Sub-area



Llagas LCR Sub-area Load and Resources

Table 3.3-30 provides the forecasted load and resources. The list of generators within the LCR Sub-area are provided in Attachment A.

Table 3.3-30 Llagas LCR Sub-area 2023 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	255	Market and Battery	276	276
AAEE	-1	MUNI	0	0
Behind the meter DG	-8	QF	0	0
Net Load	246	LTPP Preferred Resources	0	0
Transmission Losses	1	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**247**	**Total**	**276**	**276**

Llagas LCR Sub-area Hourly Profiles

Figure 3.3-34 illustrates the forecast 2023 profile for the peak day for the Llagas LCR sub-area with the Category P3 normal and emergengy load serving capabilities without local resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-35 illustrates the forecast 2023 hourly profile for Llagas LCR sub-area with the Category P3 emergency load serving capability without local resources.

Figure 3.3-34 Llagas LCR Sub-area 2023 Peak Day Forecast Profiles

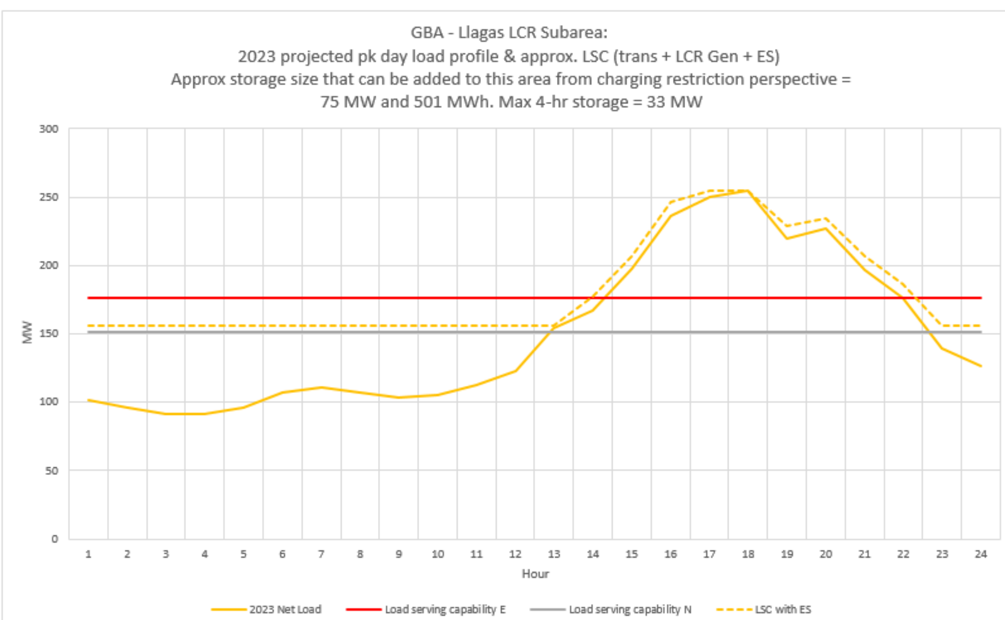
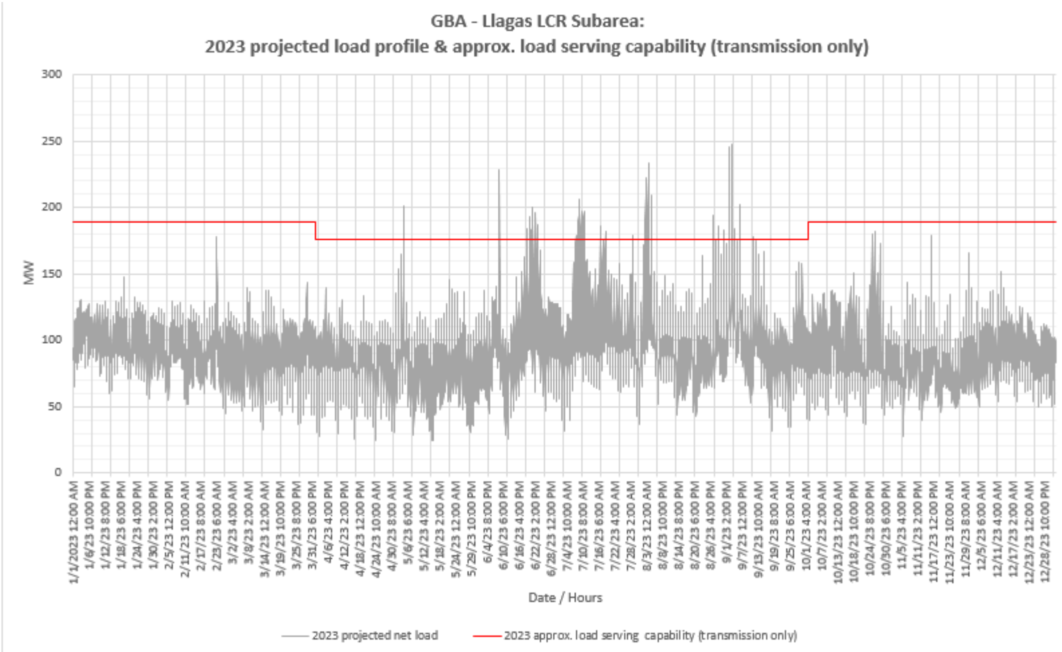


Figure 3.3-35 Llagas LCR Sub-area 2023 Forecast Hourly Profiles



Llagas LCR Sub-area Requirement

Table 3.3-31 identifies the sub-area requirements. The LCR requirement for the worst contingency is 150 MW.

Table 3.3-31 Llagas LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	First limit	P3	Metcalf-Llagas 115 kV	Metcalf-Morgan Hill 115 kV + Gilroy Cogen Unit 1	150

Effectiveness factors:

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

For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7320 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.5.3 *San Jose Sub-area*

San Jose is a Sub-area of the Greater Bay LCR Area.

San Jose LCR Sub-area Diagram

The San Jose LCR Sub-area is identified in Figure 3.3-33.

San Jose LCR Sub-area Load and Resources

Table 3.3-32 provides the forecast load and resources in San Jose LCR sub-area in 2023. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-32 San Jose LCR Sub-area 2023 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	2737	Market, Net Seller, Battery	681	681
AAEE	-13	MUNI	198	198
Behind the meter DG	-38	QF	0	0
Net Load	2686	LTPP Preferred Resources	0	0
Transmission Losses	97	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	2783	**Total**	**879**	**879**

San Jose LCR Sub-area Hourly Profiles

Figure 3.3-36 illustrates the forecast 2023 profile for the peak day for the San Jose LCR sub-area with the Category P2 normal and emergengy load serving capabilities without local resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-37 illustrates the forecast 2023 hourly profile for San Jose LCR sub-area with the Category P2 emergency load serving capability without local resources.

Figure 3.3-36 San Jose LCR Sub-area 2023 Peak Day Forecast Profiles

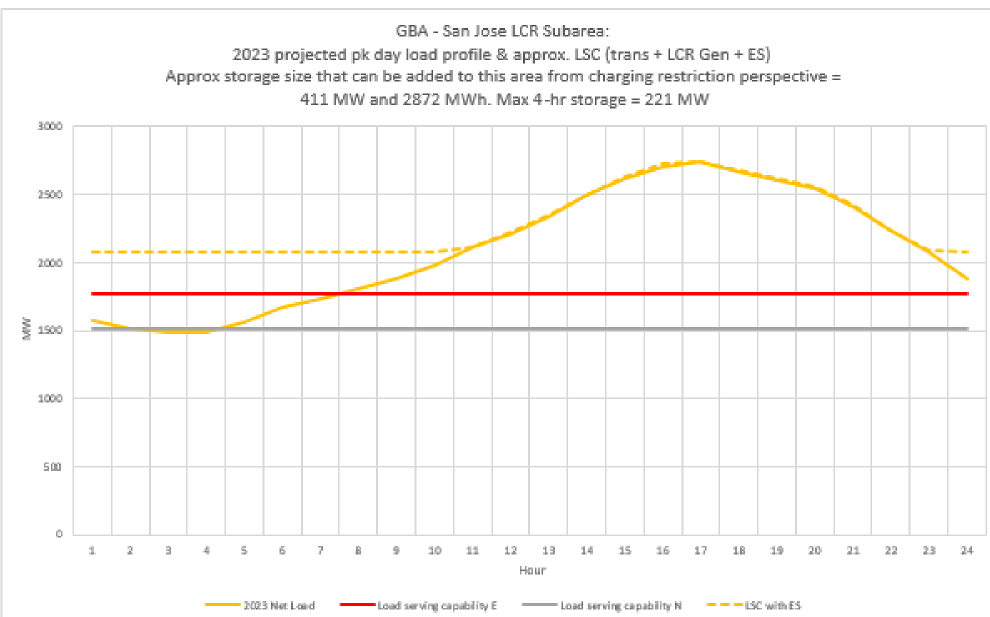
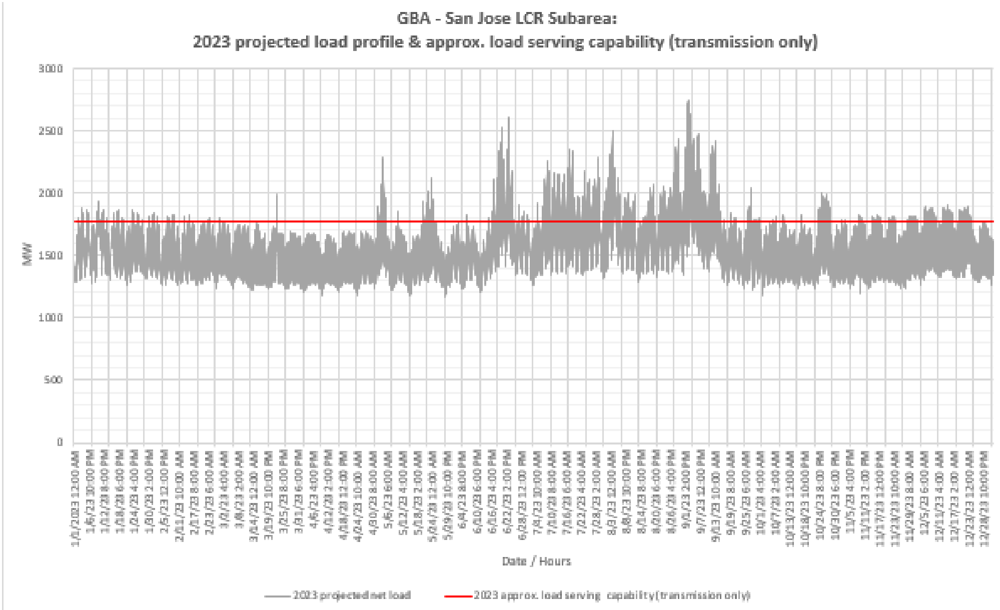


Figure 3.3-37 San Jose LCR Sub-area 2023 Forecast Hourly Profiles



San Jose LCR Sub-area Requirement

Table 3.3-33 identifies the sub-area LCR requirements. The LCR requirement for the worst contingency is 1058 MW including a deficiency of 179 MW.

Table 3.3-33 San Jose LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2023	First limit	P2	Metcalf 230/115 kV transformer # 1 or # 3	METCALF 230kV - Section 2D & 2E	1058 (179)

Effectiveness factors:

Effective factors for generators in the San Jose LCR sub-area are in Attachment B table titled San Jose.

For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7320 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.5.4 *South Bay-Moss Landing Sub-area*

South Bay-Moss Landing is a Sub-area of the Greater Bay LCR Area.

South Bay-Moss Landing LCR Sub-area Diagram

The South Bay-Moss Landing LCR sub-area is identified in Figure 3.3-33.

South Bay-Moss Landing LCR Sub-area Load and Resources

Table 3.3-34 provides the forecast load and resources in South Bay-Moss Landing LCR sub-area in 2023. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-34 South Bay-Moss Landing LCR Sub-area 2023 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	4398	Market, Net Seller, Battery	2877	2877
AAEE	-24	MUNI	198	198
Behind the meter DG	-73	QF	0	0
Net Load	4301	LTPP Preferred Resources	0	0
Transmission Losses	126	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	4427	**Total**	**3075**	**3075**

South Bay-Moss Landing LCR Sub-area Hourly Profiles

Figure 3.3-38 illustrates the forecasted 2023 profile for the peak day for the South Bay-Moss Landing LCR sub-area with the Category P6 normal and emergengy load serving capabilities without local resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. The energy storage amount is incremental to the existing system and doesn't include approved energy storage. Figure 3.3-39 illustrates the forecast 2023 hourly profile for South Bay-Moss Landing LCR sub-area with the Category P6 emergency load serving capability without local resources.

Figure 3.3-38 South Bay-Moss Landing LCR Sub-area 2023 Peak Day Forecast Profiles

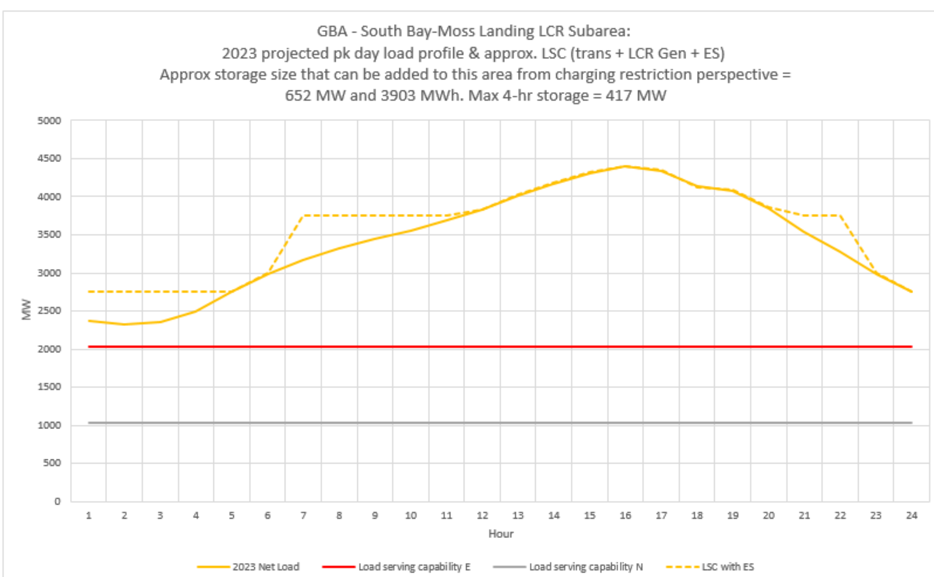
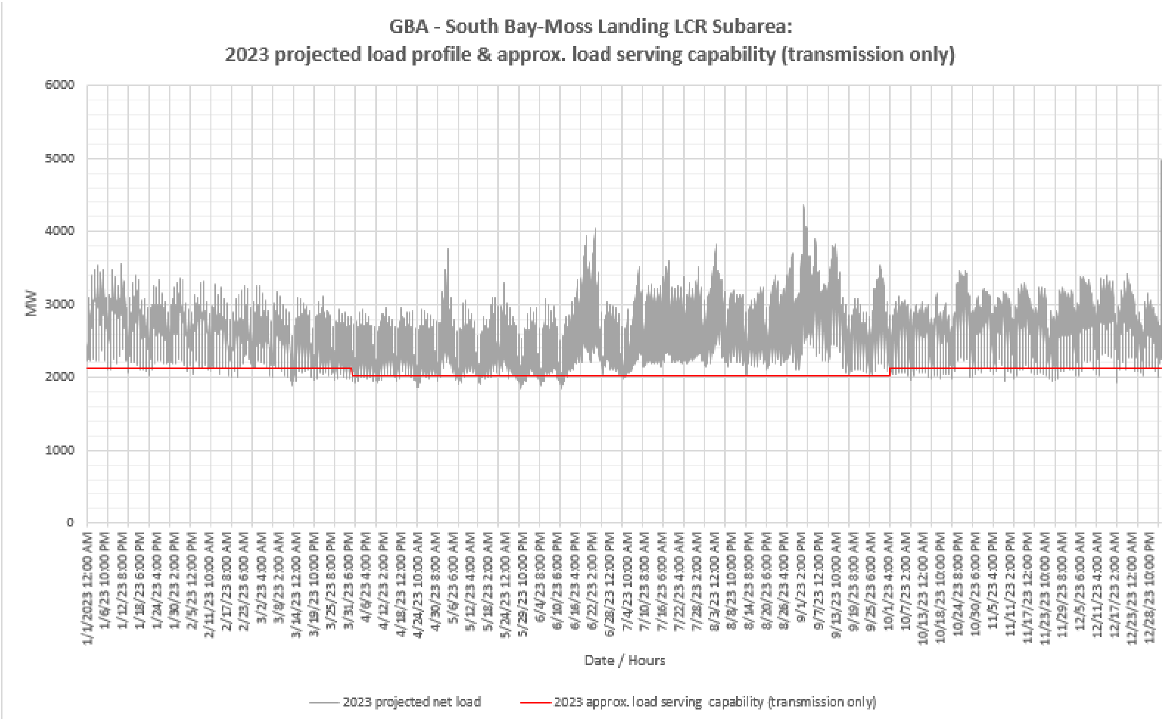


Figure 3.3-39 South Bay-Moss Landing LCR Sub-area 2023 Forecast Hourly Profiles



South Bay-Moss Landing LCR Sub- Requirement

Table 3.3-35 identifies the sub-area LCR requirements. The LCR Requirement for the worst contingency is 2487 MW.

Table 3.3-35 South Bay-Moss Landing LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2023	First Limit	P6	Moss Landing-Las Aguilas 230 kV	Tesla-Metcalf 500 kV and Moss Landing-Los Banos 500 kV	2487

Effectiveness factors:

Effective factors for generators in the South Bay-Moss Landing LCR sub-area are in Attachment B table titled South Bay-Moss Landing.

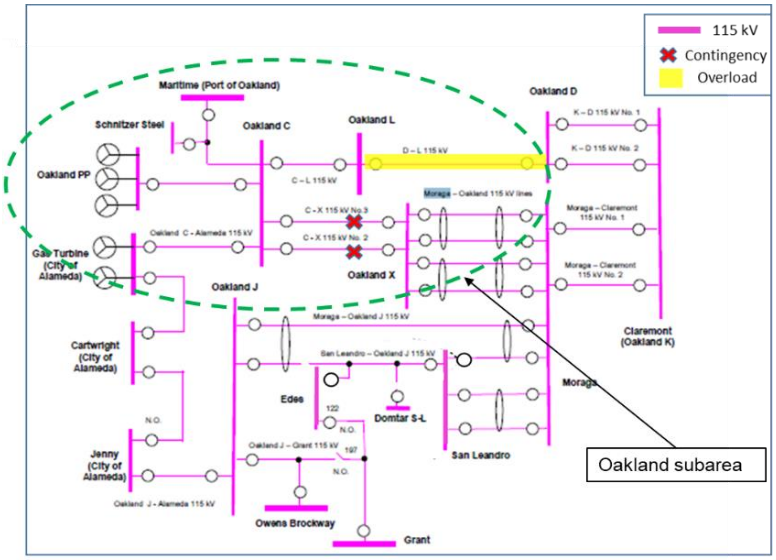
For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7320 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.5.5 *Oakland Sub-area*

Oakland is a sub-area of the Greater Bay LCR area.

Oakland LCR Sub-area Diagram

Figure 3.3-40 Oakland LCR Sub-area



Oakland LCR Sub-area Load and Resources

Table 3.3-36 provides the forecast load and resources in Oakland LCR sub-area in 2023. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-36 Oakland LCR Sub-area 2023 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	194	Market	0	0
AAEE	-1	MUNI	49	49
Behind the meter DG	-1	QF	0	0
Net Load	192	Battery	55	55
Transmission Losses	0	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	192	**Total**	**104**	**104**

Oakland LCR Sub-area Hourly Profiles

The Oakland Sub-area does not have a chart for the amount of energy storage that can be added to this local area from charging restriction perspective since there are no “non-battery” resources for replacement.

Oakland LCR Sub-area Requirement

Table 3.3-37 identifies the sub-area requirements. The LCR Requirement for the worst contingency is 35 MW.

Table 3.3-37 Oakland LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2023	First limit	P2	D-L #1 115 kV cable	C-X #2 & #3 115 kV cables	35

Effectiveness factors:

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

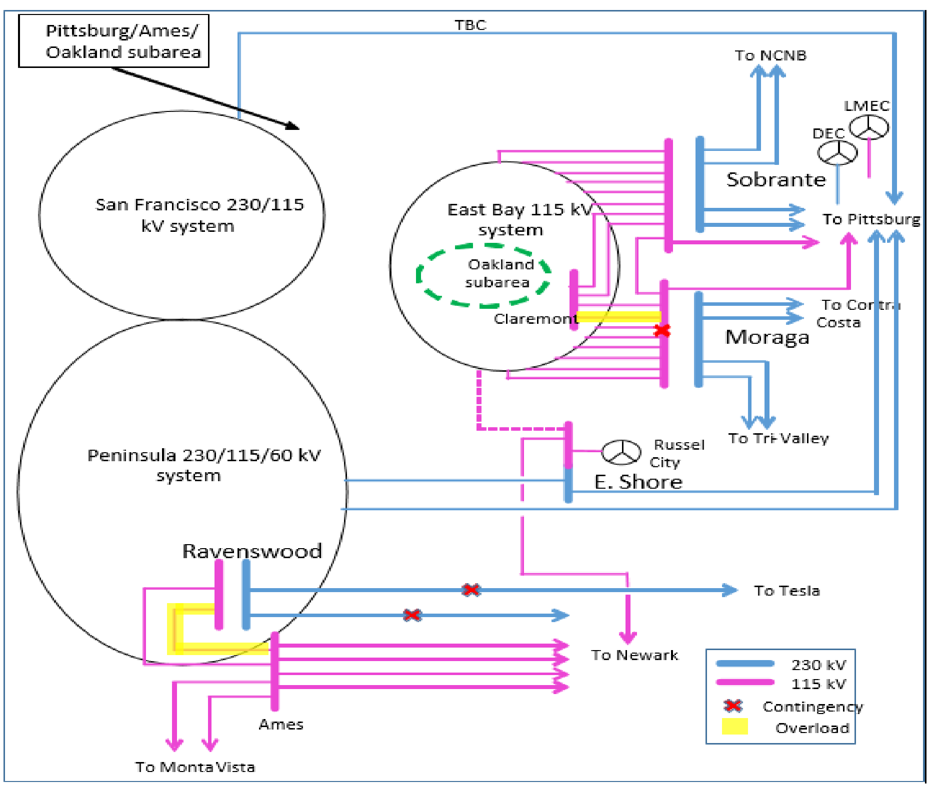
For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7320 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.5.6 *Ames-Pittsburg-Oakland Sub-areas Combined*

Ames-Pittsburg-Oakland is a sub-area of the Greater Bay LCR area.

Ames-Pittsburg-Oakland LCR Sub-area Diagram

Figure 3.3-41 Ames-Pittsburg-Oakland LCR Sub-area



Ames-Pittsburg-Oakland LCR Sub-area Load and Resources

Table 3.3-38 provides the forecast load and resources in Ames-Pittsburg-Oakland LCR sub-area in 2023. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-38 Ames-Pittsburg-Oakland LCR Sub-area 2023 Forecast Load and Resources

Load (MW)	Generation (MW)	Aug NQC	At Peak
The Ames-Pittsburg-Oakland Sub-area does not has a defined load pocket with the limits based upon power flow through the area.	Market, Net Seller	2048	2048
	MUNI	49	49
	QF	231	231
	Solar	5	5
	Existing 20-minute Demand Response	0	0
	Battery	255	255
	Total	**2588**	**2588**

Ames-Pittsburg-Oakland LCR Sub-area Hourly Profiles

The Ames-Pittsburg-Oakland sub-area does not have a defined load pocket with the limits based upon power flow through the area. As such, no load profile is provided for this sub-area.

Ames-Pittsburg-Oakland LCR Sub-area Requirement

Table 3.3-39 identifies the sub-area LCR requirements. The LCR Requirement for the worst contingency is 1898 MW.

Table 3.3-39 Ames-Pittsburg-Oakland LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2023	First limit	P6	Ames-Ravenswood #1 115 kV line	Newark-Ravenswood 230 kV & Tesla-Ravenswood 230 kV	1898
		P2	Martinez-Sobrante 115 kV line	Pittsburg Section 1D & 1E 230 kV	

Effectiveness factors:

Effective factors for generators in the Ames-Pittsburg-Oakland LCR sub-area are in Attachment B table titled Ames/Pittsburg/Oakland.

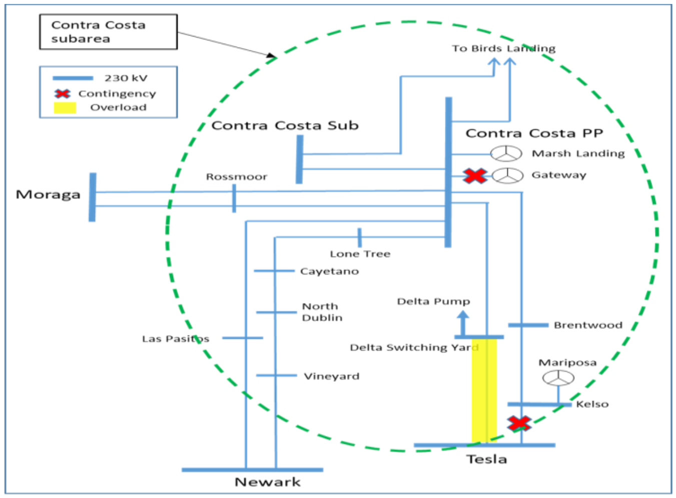
For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7320 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.5.7 *Contra Costa Sub-area*

Contra Costa is a sub-area of the Greater Bay LCR area.

Contra Costa LCR Sub-area Diagram

Figure 3.3-42 Contra Costa LCR Sub-area



Contra Costa LCR Sub-area Load and Resources

Table 3.3-40 provides the forecast load and resources in Contra Costa LCR sub-area. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-40 Contra Costa LCR Sub-area 2023 Forecast Load and Resources

Load (MW)	Generation (MW)	Aug NQC	At Peak
The Contra Costa Sub-area does not has a defined load pocket with the limits based upon power flow through the area.	Market, Net Seller, Wind	1661	1661
	MUNI	127	127
	QF	0	0
	Wind	244	244
	Existing 20-minute Demand Response	0	0
	Mothballed	0	0
	Total	**2032**	**2032**

Contra Costa LCR Sub-area Hourly Profiles

The Contra Costa sub-area does not have a defined load pocket with the limits based upon power flow through the area. As such, no load profile is provided for this sub-area.

Contra Costa LCR Sub-area Requirement

Table 3.3-41 identifies the sub-area LCR requirements. The LCR requirement for the worst contingency is 1177 MW.

Table 3.3-41 Contra Costa LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2023	First limit	P3	Delta Switching Yard-Tesla 230 kV	Kelso-Tesla 230 kV line and Gateway unit	1177

Effectiveness factors:

For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7230 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.5.8 *Bay Area overall*

Bay Area LCR Area Hourly Profiles

Figure 3.3-43 illustrates the forecast 2023 profile for the peak day for the Bay Area LCR area with the Category P6 normal and emergengy load serving capabilities without local resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-44 illustrates the forecast 2023 hourly profile for Bay Area LCR area with the Category P6 emergency load serving capability without local resources.

Figure 3.3-43 Bay Area LCR Area 2023 Peak Day Forecast Profiles

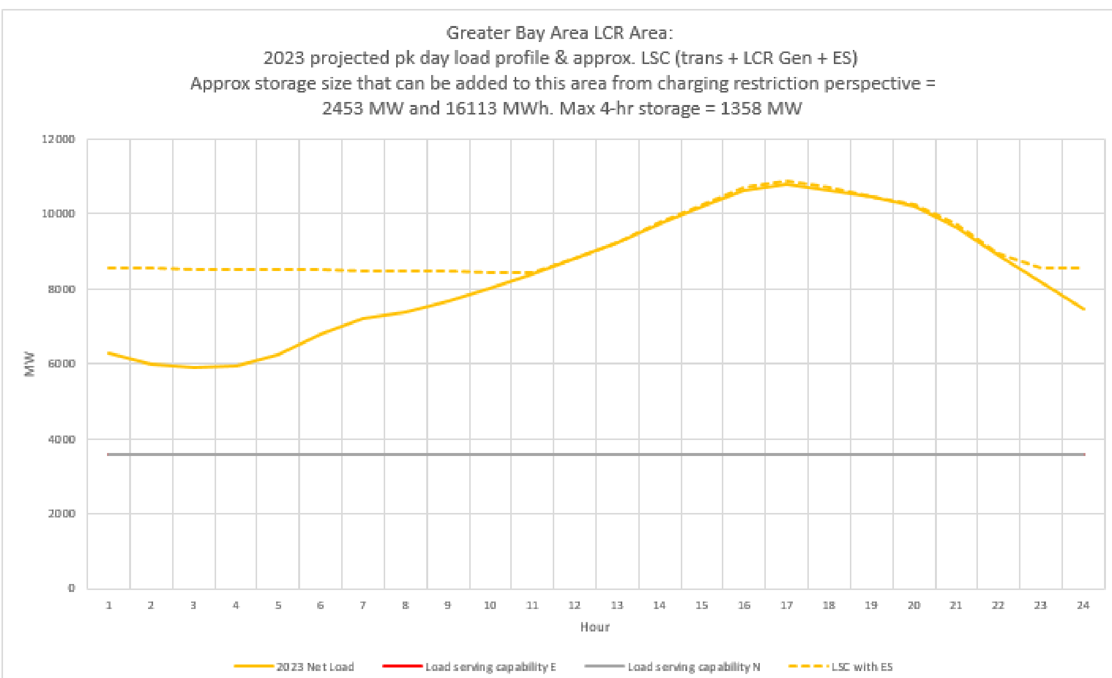
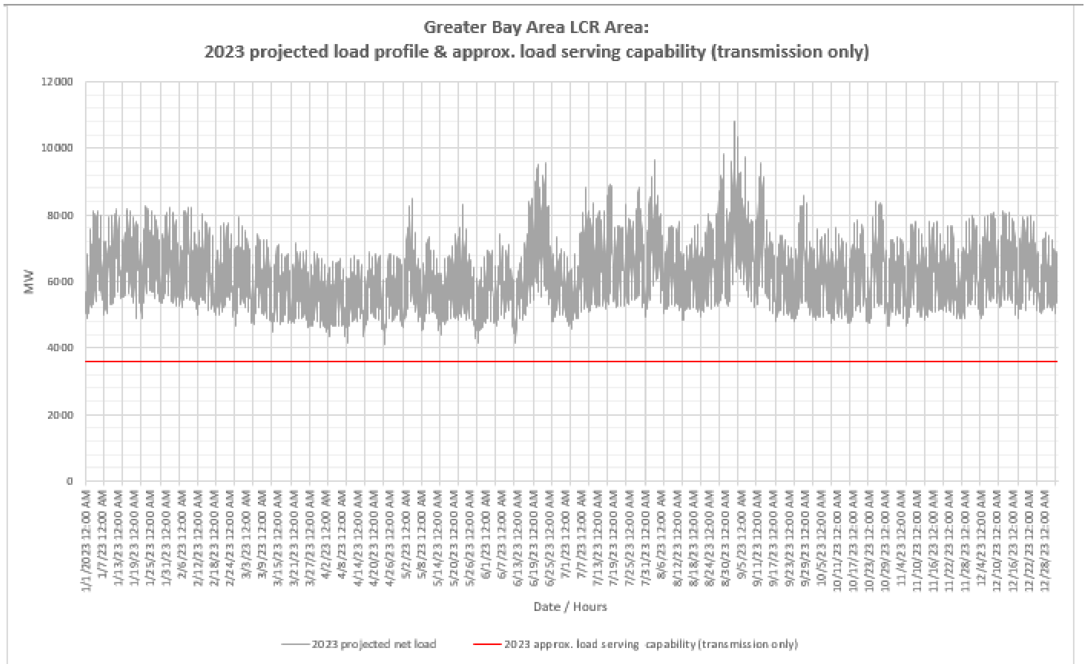


Figure 3.3-44 Bay Area LCR Area 2023 Forecast Hourly Profiles



Greater Bay LCR Area Overall Requirement

Table 3.3-42 identifies the area LCR requirements. The LCR requirement for the worst contingency is 7312 MW.

Table 3.3-42 Bay Area LCR Overall area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2023	First limit	P6	Metcalf 500/230 kV #13 transformer	Metcalf 500/230 kV #11 & #12 transformers	7312

Effectiveness factors:

Effective factors for generators in the Greater Bay Area LCR sub-area are in Attachment B table titled Greater Bay Area.

For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7320 posted at: http://www.caiso.com/Documents/2210Z.pdf

Changes compared to last year's results

Compared to 2022 load forecast went up by 390 MW and total LCR need went up by 81 MW mainly due to load growth.

3.3.6 Greater Fresno Area

3.3.6.1 *Area Definition:*

The transmission facilities coming into the Greater Fresno area are:

Gates-Mustang #1 230 kV

Gates-Mustang #2 230 kV

Gates #5 230/70 kV Transformer Bank

Mercy Spring 230 /70 Bank # 1

Los Banos #3 230/70 Transformer Bank

Los Banos #4 230/70 Transformer Bank

Warnerville-Wilson 230kV

Melones-North Merced 230 kV line

Panoche-Tranquility #1 230 kV

Panoche-Tranquility #2 230 kV

Panoche #1 230/115 kV Transformer Bank

Panoche #2 230/115 kV Transformer Bank

Corcoran-Smyrna 115kV

Coalinga #1-San Miguel 70 kV

The substations that delineate the Greater Fresno area are:

Gates is out Mustang is in

Gates is out Mustang is in

Gates 230 is out Gates 70 is in

Mercy Springs 230 is out Mercy Springs 70 is in

Los Banos 230 is out Los Banos 70 is in

Los Banos 230 is out Los Banos 70 is in

Warnerville is out Wilson is in

Melones is out North Merced is in

Panoche is out Tranquility #1 is in

Panoche is out Tranquility #2 is in

Panoche 230 is out Panoche 115 is in

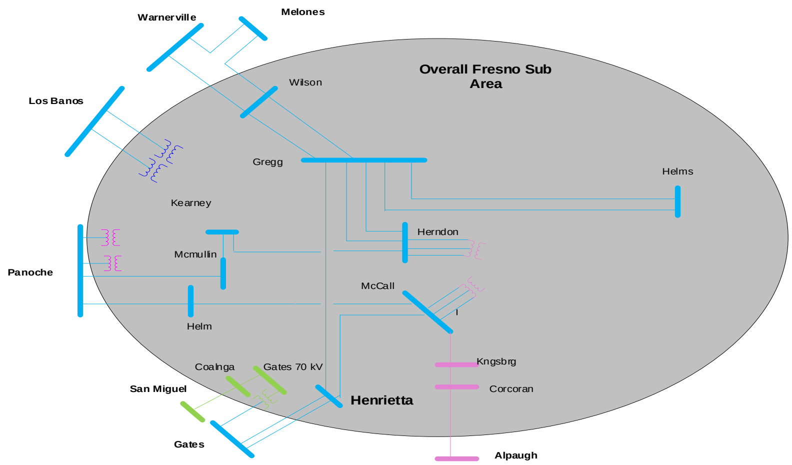
Panoche 230 is out Panoche 115 is in

Corcoran is in Smyrna is out

Coalinga is in San Miguel is out

Fresno LCR Area Diagram

Figure 3.3-45 Fresno LCR Area



Fresno LCR Area Load and Resources

Table 3.3-43 provides the forecast load and resources in Fresno LCR Area in 2023. The list of generators within the LCR sub-area are provided in Attachment A.

In year 2023 the estimated time of local area peak is 19:00 PM.

At the local area peak time the estimated, ISO metered, solar output is 1%.

If required, all non-solar technology type resources are dispatched at NQC.

Table 3.3-43 Fresno LCR Area 2023 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	3164	Market, Net Seller, Battery	2759	2759
AAEE	-21	MUNI	212	212
Behind the meter DG	0	QF	4	4
Net Load	3143	Solar	436	4
Transmission Losses	145	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**3288**	**Total**	**3411**	**2979**

Approved transmission projects modeled

Wilson 115 kV Area Reinforcement (Mar 2025)

Oro Loma 70 kV Area Reinforcement (Jan 2026)

Gifen Line Reconductoring (Jan 2023)

Borden 230/70 kV Transformer Bank #1 Capacity Increase (Jan 2027)

Wilson-Oro Loma 115 kV Line Reconductoring (Dec 2026)

Bellota-Warnerville 230 kV Reconductoring (Dec 2024)

Herndon-Bullard #1 and #2 115 kV Reconductoirng (Dec 2026)

Reedley 70 kV Area Reinforcement Projects (Includes battery at Dinuba) (Dec 2023)

Herndon-Bullard 230kV Reconductoring Project (Apr 2024)

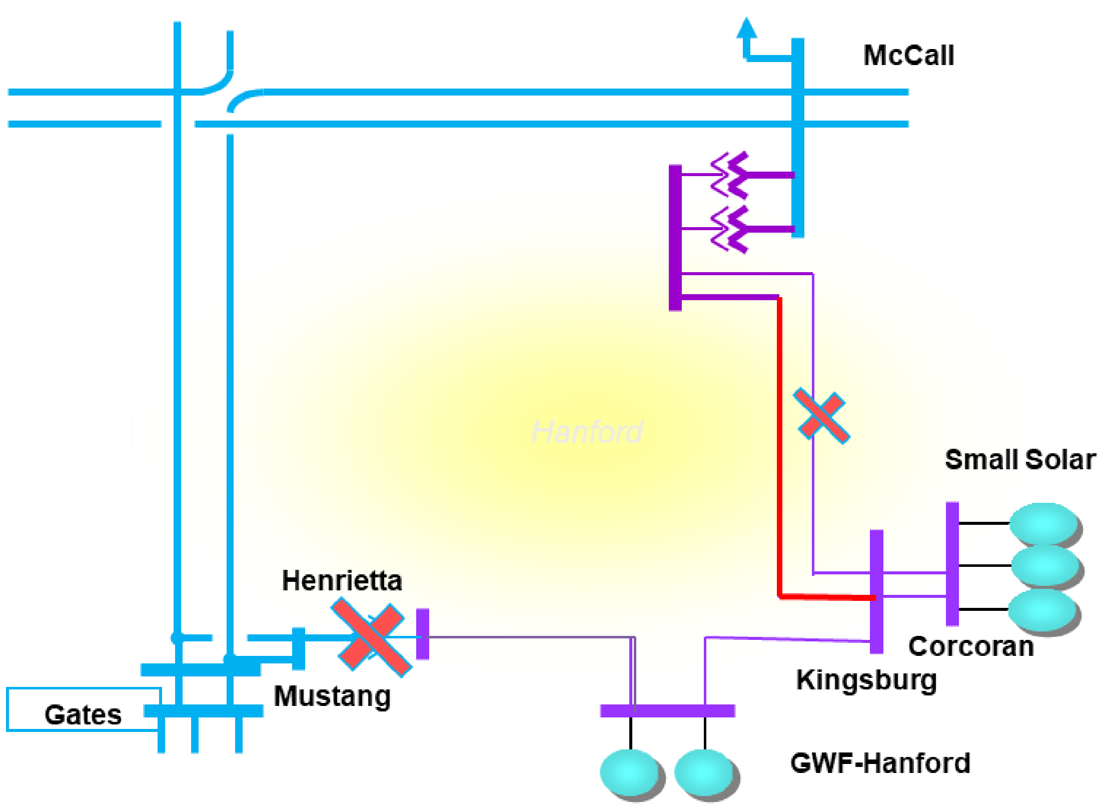
Panoche – Oro Loma 115 kV Line Reconductoring (Mar 2023)

3.3.6.2 *Hanford Sub-area*

Hanford is a sub-area of the Fresno LCR area.

Hanford LCR Sub-area Diagram

Figure 3.3-46 Hanford LCR Sub-area



Hanford LCR Sub-area Load and Resources

Table 3.3-44 provides the forecast load and resources in Hanford LCR sub-area in 2023. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-44 Hanford LCR Sub-area 2023 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	194	Market, Net Seller	124	124
AAEE	-1	MUNI	0	0
Behind the meter DG	0	QF	0	0
Net Load	193	Solar	61	1
Transmission Losses	6	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**199**	**Total**	**185**	**125**

Hanford LCR Sub-area Hourly Profiles

Figure 3.3-47 illustrates the forecast 2023 profile for the peak day for the Hanford sub-area with the Category P6 normal and emergency load serving capabilities without local resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-48 illustrates the forecast 2023 hourly profile for Hanford sub-area with the Category P6 emergency load serving capability without local resources.

Figure 3.3-47 Hanford LCR Sub-area 2023 Peak Day Forecast Profiles

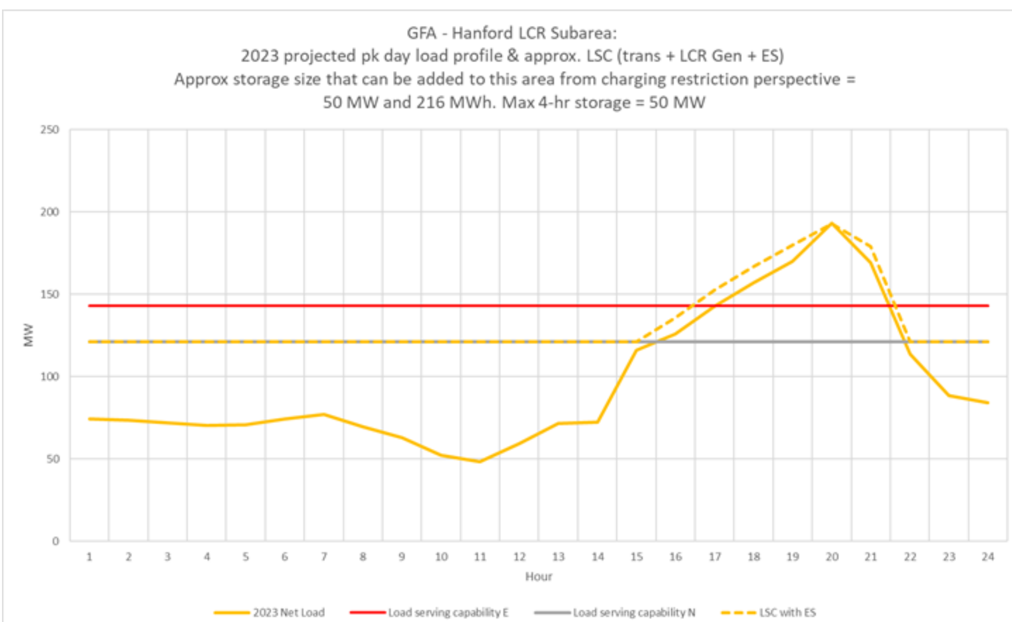
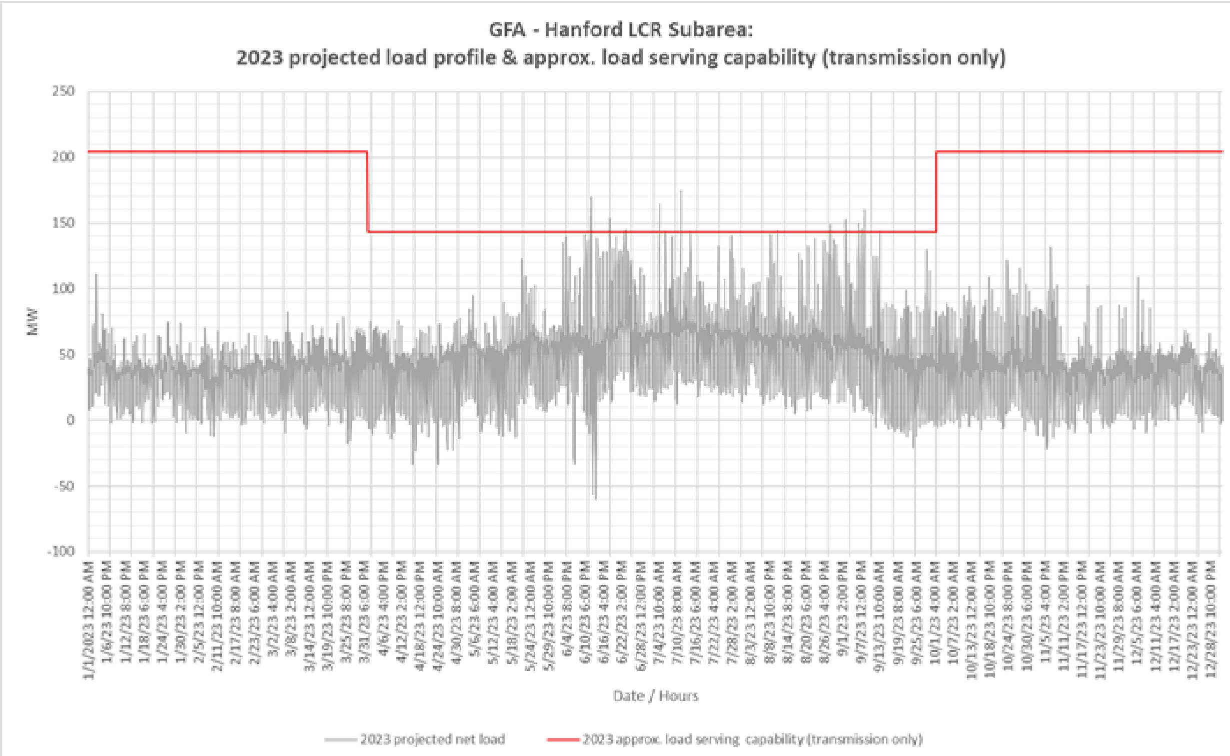


Figure 3.3-48 Hanford LCR Sub-area 2023 Forecast Hourly Profiles



Hanford LCR Sub-area Requirement

Table 3.3-45 identifies the sub-area requirements. The LCR Requirement for a Category P6 contingency is 50 MW.

Table 3.3-45 Hanford LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	First Limit	P6	McCall-Kingsburg #2 115 kV	McCall-Kingsburg #1 115 kV line and Henrietta 230/115 kV TB#3	50

Effectiveness factors:

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

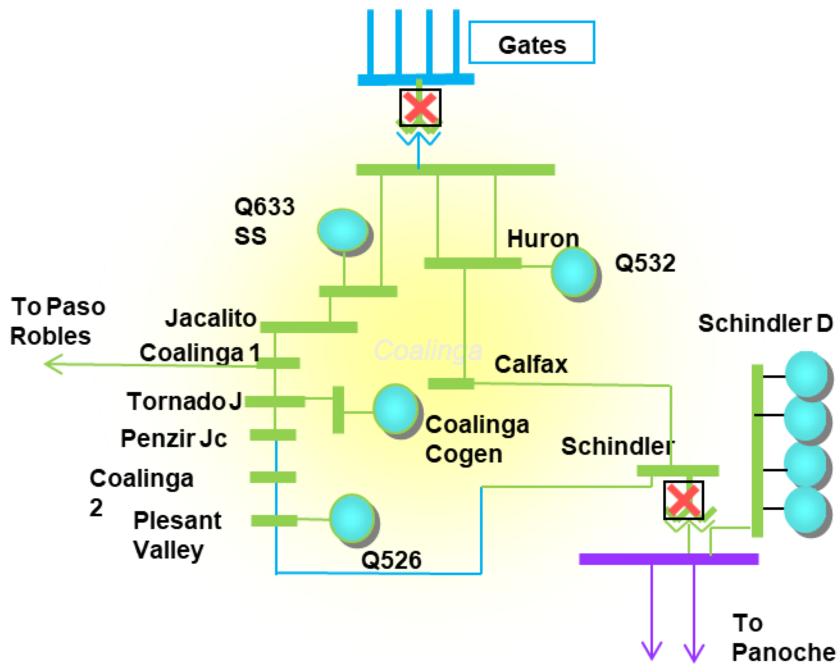
For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7430 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.6.3 *Coalinga Sub-area*

Coalinga is a sub-area of the Fresno LCR area.

Coalinga LCR Sub-area Diagram

Figure 3.3-49 Coalinga LCR Sub-area



Coalinga LCR Sub-area Load and Resources

Table 3.3-46 provides the forecast load and resources in Coalinga LCR sub-area. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-46 Coalinga LCR Sub-area 2023 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	110	Market, Net Seller	0	0
AAEE	-1	MUNI	0	0
Behind the meter DG	0	QF	3	3
Net Load	109	Solar	25	0
Transmission Losses	2	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**111**	**Total**	**28**	**3**

Coalinga LCR Sub-area Hourly Profiles

Figure 3.3-50 illustrates the forecast 2023 profile for the peak day for the Coalinga sub-area with the Category P6 normal and emergency load serving capabilities without local resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-51 illustrates the forecast 2023 hourly profile for Coalinga sub-area with the Category P6 emergency load serving capability without local resources.

Figure 3.3-50 Coalinga LCR Sub-area 2023 Peak Day Forecast Profiles

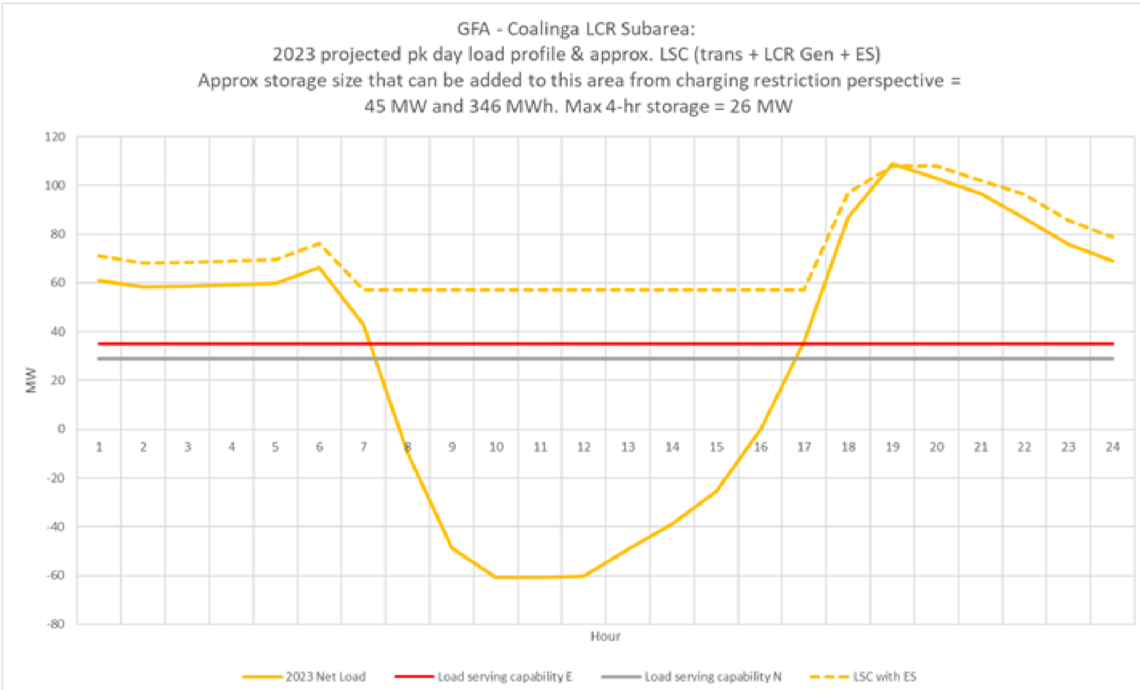
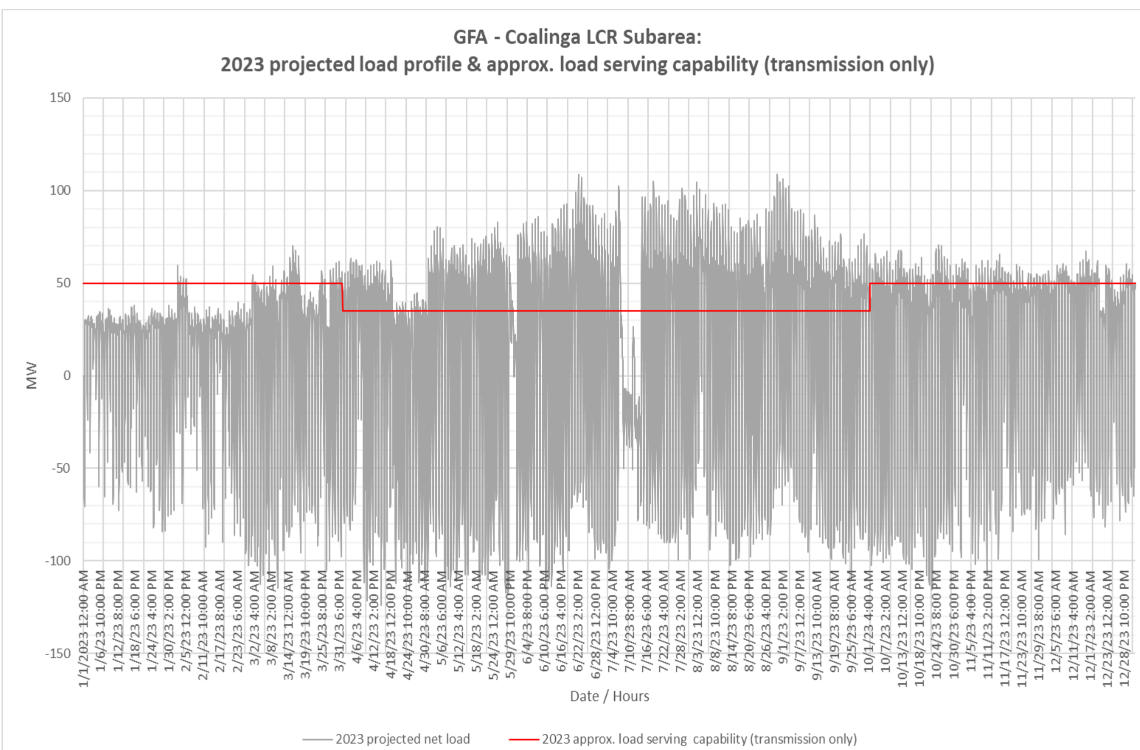


Figure 3.3-51 Coalinga LCR Sub-area 2023 Forecast Hourly Profiles



Coalinga LCR Sub-area Requirement

Table 3.3-47 identifies the sub-area requirements. The LCR Requirement for a Category P6 contingency is 73 MW including a 45 MW at peak deficiency and 70 MW NQC deficiency.

Table 3.3-47 Coalinga LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	First Limit	P6	San-Miguel-Coalinga 70 kV Line and Voltage Instability	T-1/T-1: Gates 230/70 kV TB #5 and Schindler 115/70 kV TB#1	73 (70 Peak; 45 NQC)

Effectiveness factors:

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

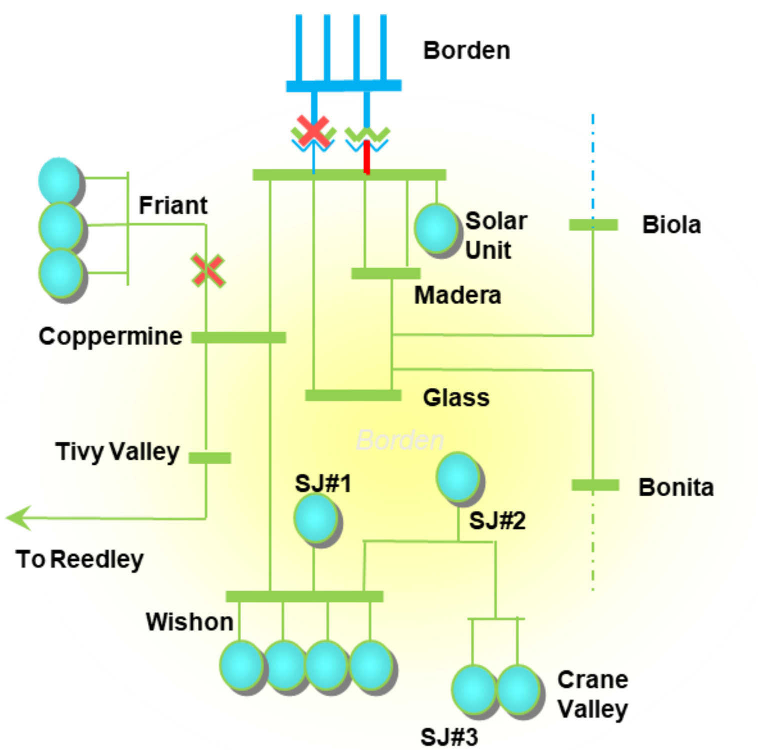
For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7430 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.6.4 *Borden Sub-area*

Borden is a sub-area of the Fresno LCR area.

Borden LCR Sub-area Diagram

Figure 3.3-52 Borden LCR Sub-area



Borden LCR Sub-area Load and Resources

Table 3.3-48 provides the forecast load and resources in Borden LCR sub-area. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-48 Borden LCR Sub-area 2023 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	142	Market, Net Seller	13	13
AAEE	-2	MUNI	0	0
Behind the meter DG	0	QF	0	0
Net Load	140	Solar	14	0
Transmission Losses	3	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**143**	**Total**	27	**13**

Borden LCR Sub-area Hourly Profiles

Figure 3.3-53 illustrates the forecast 2023 profile for the peak day for the Borden sub-area with the Category P6 normal and emergency load serving capabilities without local resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-54 illustrates the forecast 2023 hourly profile for Borden sub-area with the Category P6 emergency load serving capability without local resources.

Figure 3.3-53 Borden LCR Sub-area 2023 Peak Day Forecast Profiles

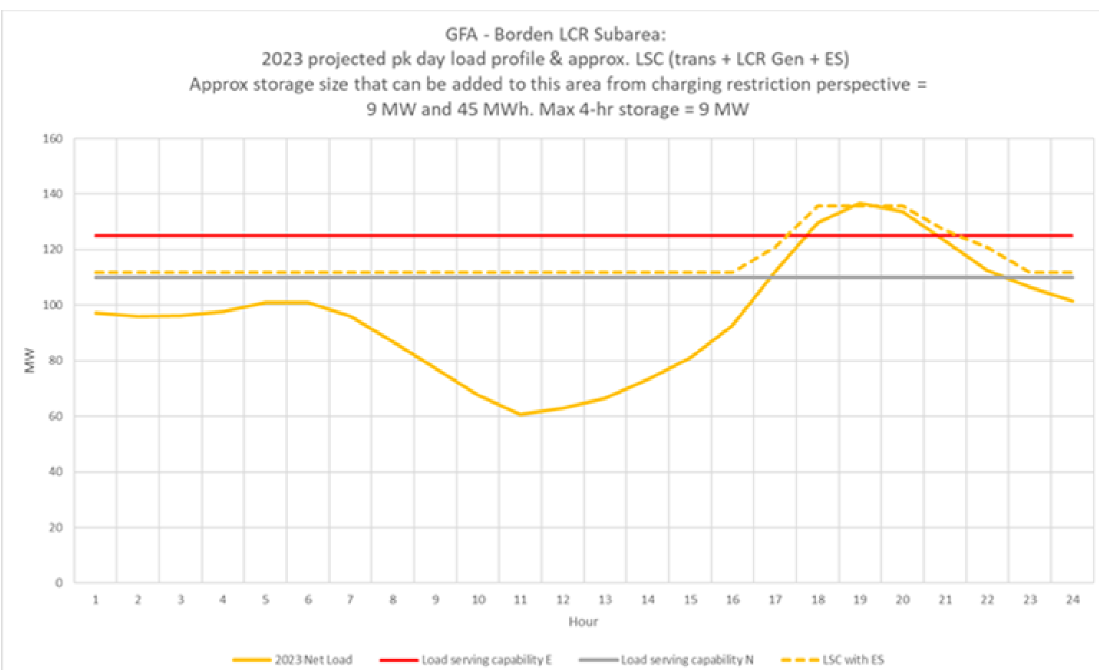
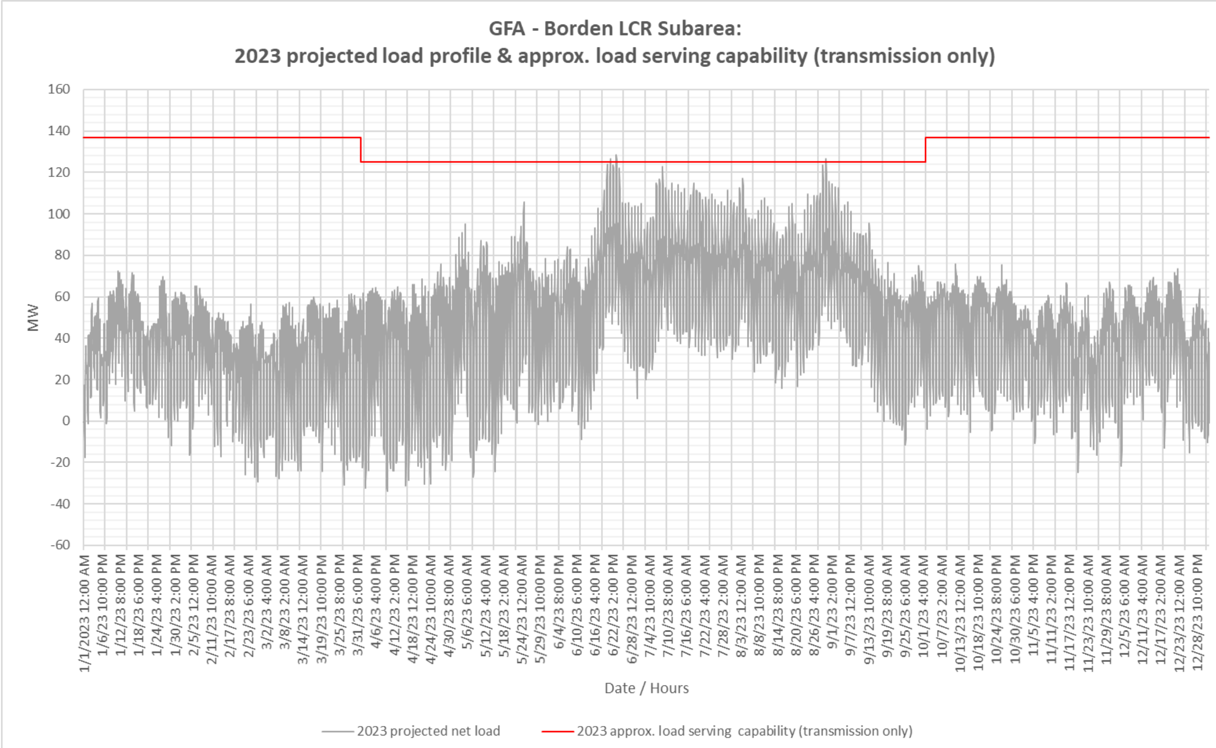


Figure 3.3-54 Borden LCR Sub-area 2023 Forecast Hourly Profiles



Borden LCR Sub-area Requirement

Table 3.3-49 identifies the sub-area requirements. The LCR Requirement for a Category P6 contingency is 9 MW.

Table 3.3-49 Borden LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	First Limit	P6	Borden 230/70 kV TB # 1	Friant- Coppermine 70 kV Line and Borden 230/70 kV TB # 4	9

Effectiveness factors:

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

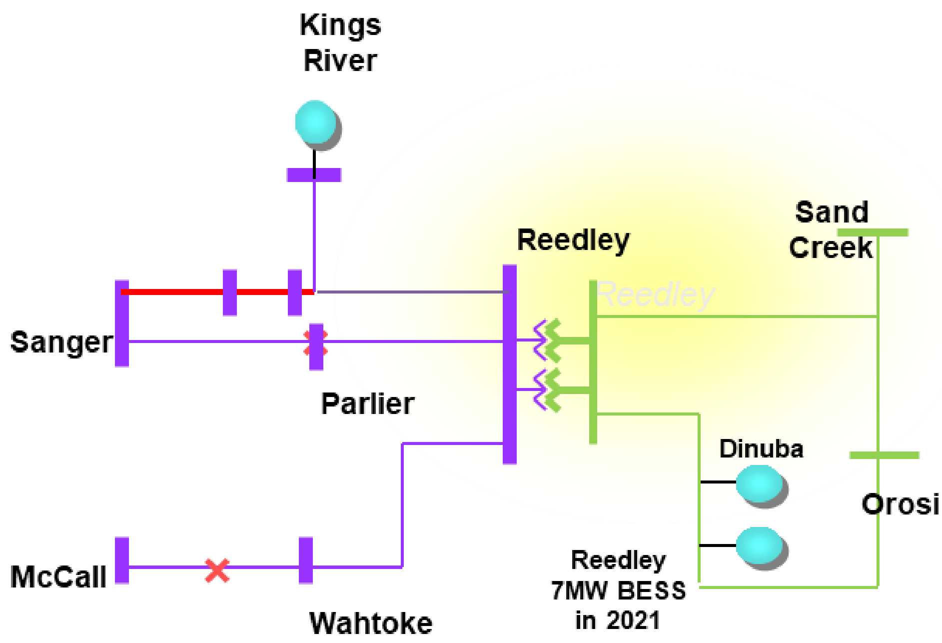
For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7430 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.6.5 *Reedley Sub-area*

Reedley is a sub-area of the Fresno LCR area.

Reedley LCR Sub-area Diagram

Figure 3.3-55 Reedley LCR Sub-area



Reedley LCR Sub-area Load and Resources

Table 3.3-50 provides the forecast load and resources in Reedley LCR sub-area. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-50 Reedley LCR Sub-area 2023 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	208	Market, Net Seller	37	37
AAEE	-2	MUNI	0	0
Behind the meter DG	0	QF	0	0
Net Load	206	LTPP Preferred Resources	0	0
Transmission Losses	11	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**217**	**Total**	**37**	**37**

Reedley LCR Sub-area Hourly Profiles

Figure 3.3-56 illustrates the forecast 2023 profile for the peak day for the Reedley sub-area with the Category P6 normal and emergency load serving capabilities without local resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-57 illustrates the forecast 2023 hourly profile for Reedley sub-area with the Category P6 emergency load serving capability without local resources.

Figure 3.3-56 Reedley LCR Sub-area 2023 Peak Day Forecast Profiles

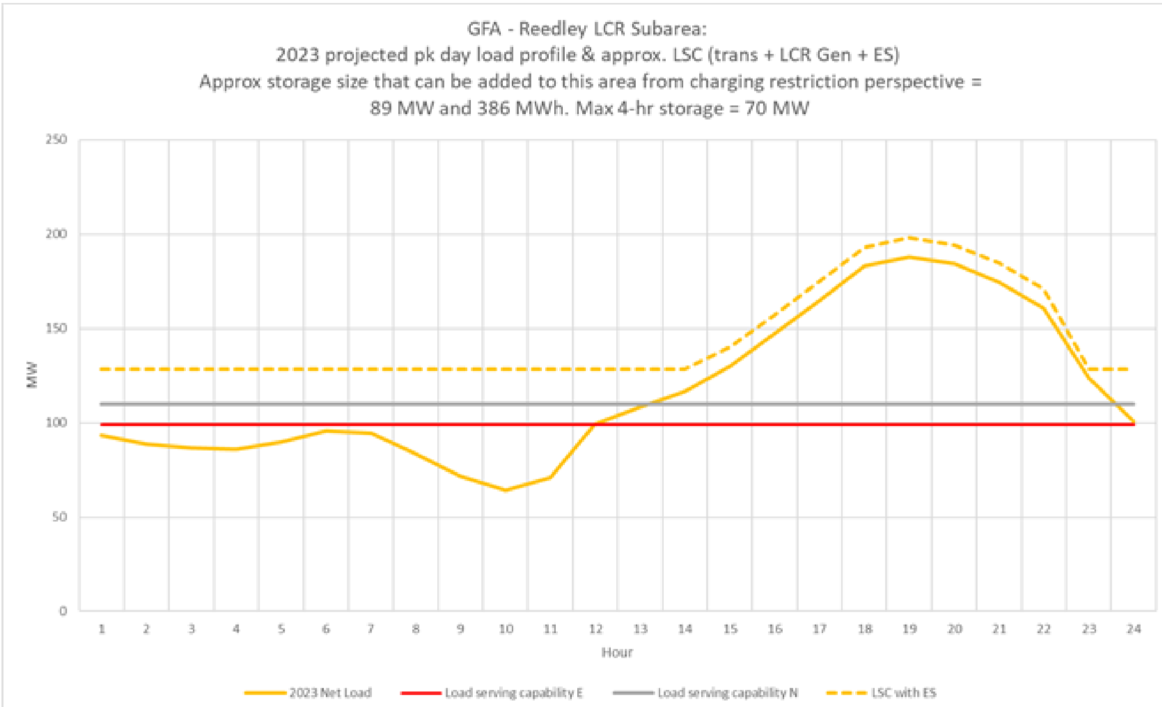
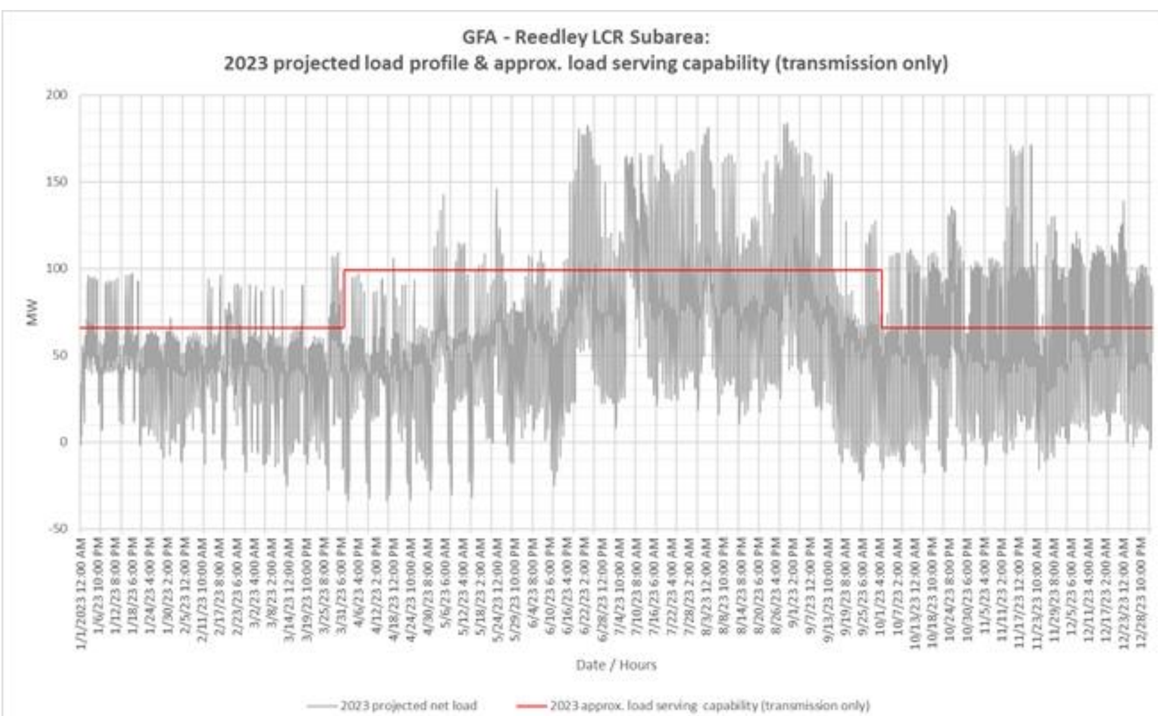


Figure 3.3-57 Reedley LCR Sub-area 2023 Forecast Hourly Profiles



Reedley LCR Sub-area Requirement

Table 3.3-51 identifies the sub-area requirements. The LCR Requirement for a Category P6 contingency is 118 MW with a 81 MW deficiency.

Table 3.3-51 Reedley LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	First Limit	P6	Kings River-Sanger-Reedley 115 kV line with Wahtoke load online	McCall-Reedley 115 kV & Sanger-Reedley 115 kV	118 (81)

Effectiveness factors:

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

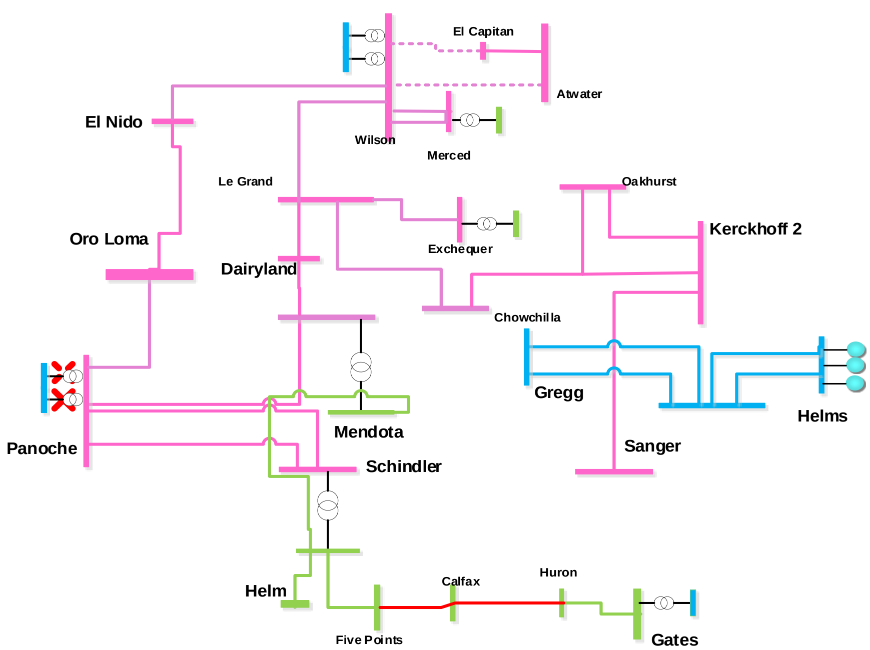
For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7430 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.6.6 *Panoche Sub-area*

Panoche is a sub-area of the Fresno LCR area.

Panoche LCR Sub-area Diagram

Figure 3.3-58 Panoche LCR Sub-area



Panoche LCR Sub-area Load and Resources

Table 3.3-52 provides the forecast load and resources in Panoche LCR sub-area. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-52 Panoche LCR Sub-area 2023 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	455	Market, Net Seller	282	282
AAEE	-3	MUNI	100	100
Behind the meter DG	-1	QF	3	3
Net Load	451	Solar	95	1
Transmission Losses	12	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**463**	**Total**	**480**	**386**

Panoche LCR Sub-area Hourly Profiles

Figure 3.3-59 illustrates the forecast 2023 profile for the peak day for the Panoche sub-area with the Category P6 normal and emergency load serving capabilities without local resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-60 illustrates the forecast 2023 hourly profile for Panoche sub-area with the Category P6 emergency load serving capability without local resources.

Figure 3.3-59 Panoche LCR Sub-area 2023 Peak Day Forecast Profiles

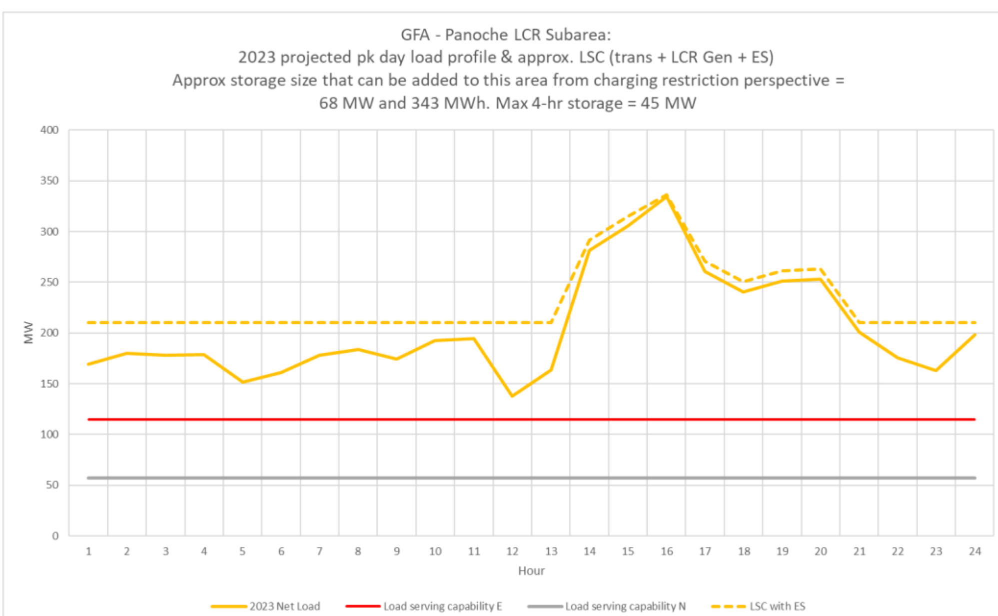
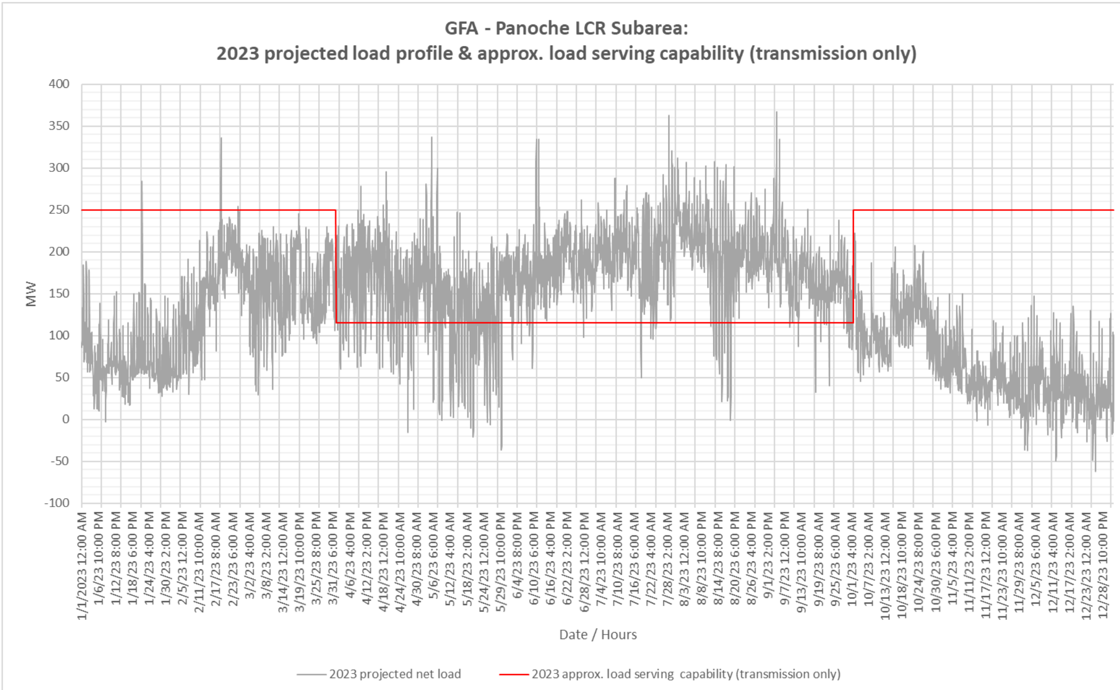


Figure 3.3-60 Panoche LCR Sub-area 2023 Forecast Hourly Profiles



Panoche LCR Sub-area Requirement

Table 3.3-53 identifies the sub-area LCR requirements. The LCR Requirement for a Category P6 contingency is 295 MW.

Table 3.3-53 Panoche LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	First limit	P6	Five Points-Huron-Gates 70 kV line	Panoche 230/115 kV TB #2 and Panoche 230/115 kV TB #	295

Effectiveness factors:

Effective factors for generators in the Panoche LCR sub-area are in Attachment B table title Panoche.

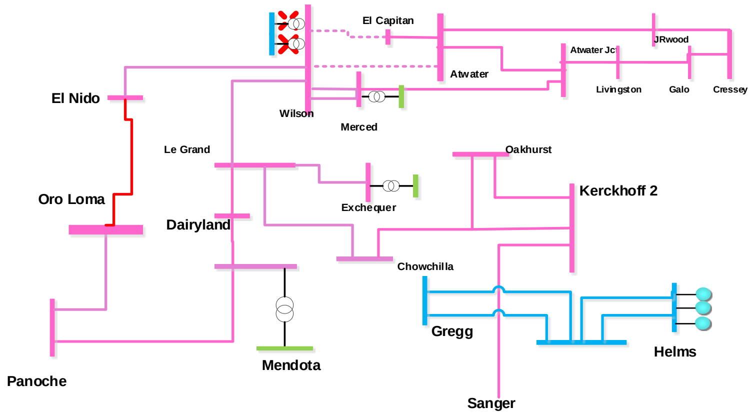
For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7430 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.6.7 *Wilson Sub-area*

Wilson is a sub-area of the Fresno LCR area.

Wilson LCR Sub-area Diagram

Figure 3.3-61 Wilson LCR Sub-area



Wilson LCR Sub-area Load and Resources

The Wilson sub-area does not has a defined load pocket with the limits based upon power flow through the area. Table 3.3-54 provides the forecasted resources in the sub-area. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-54 Wilson LCR Sub-area 2023 Forecast Load and Resources

Load (MW)	**Generation (MW)**	**Aug NQC**	**At Peak**
The Wilson sub-area does not have a defined load pocket with the limits based upon power flow through the area.	Market and Net Seller	156	156
	MUNI	100	100
	QF	0	0
	Solar	59	1
	Existing 20-minute Demand Response	0	0
	Mothballed	0	0
	Total	**315**	**257**

Wilson LCR Sub-area Hourly Profiles

The Wilson sub-area is a flow-through sub-area therefore hourly profiles are not provided.

Wilson LCR Sub-area Requirement

Table 3.3-55 identifies the sub-area LCR requirements. The LCR Requirement for a Category P6 contingency is 422 MW with a 165 MW deficiency at Peak and 107 MW NQC deficiency.

Table 3.3-55 Wilson LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	First Limit	P6	Panoche - Oro Loma 115 kV Line	Wilson 230/115kV TB #1 and Wilson 230/115kV TB #2	422 (107 NQC; 165 Peak)

Effectiveness factors:

Effective factors for generators in the Wilson 115 kV LCR sub-area are in Attachment B table titled Wilson 115 kV.

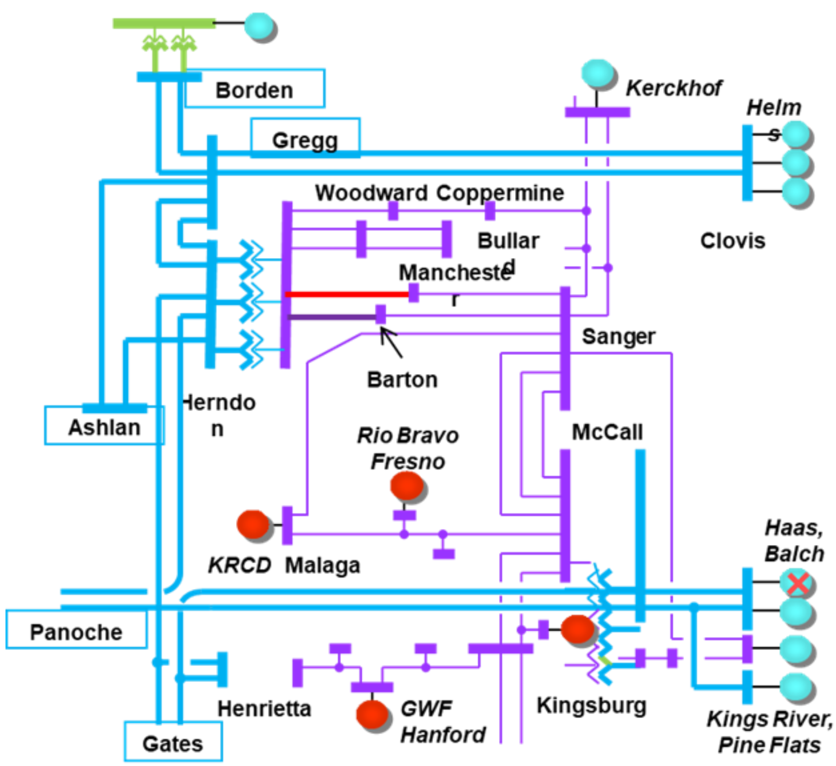
For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7430 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.6.8 *Herndon Sub-area*

Herndon is a sub-area of the Fresno LCR area.

Herndon LCR Sub-area Diagram

Figure 3.3-62 Herndon LCR Sub-area



Herndon LCR Sub-area Load and Resources

Table 3.3-56 provides the forecast load and resources in Herndon LCR sub-area. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-56 Herndon LCR Sub-area 2023 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	1473	Market, Net Seller	873	873
AAEE	-8	MUNI	110	110
Behind the meter DG	0	QF	1	1
Net Load	1465	Solar	63	1
Transmission Losses	29	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**1494**	**Total**	**1047**	**985**

Herndon LCR Sub-area Hourly Profiles

Figure 3.3-63 illustrates the forecast 2023 profile for the peak day for the Herndon sub-area with the Category P6 normal and emergency load serving capabilities without local resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-64 illustrates the forecast 2023 hourly profile for Herndon sub-area with the Category P6 emergency load serving capability without local resources.

Figure 3.3-63 Herndon LCR Sub-area 2023 Peak Day Forecast Profiles

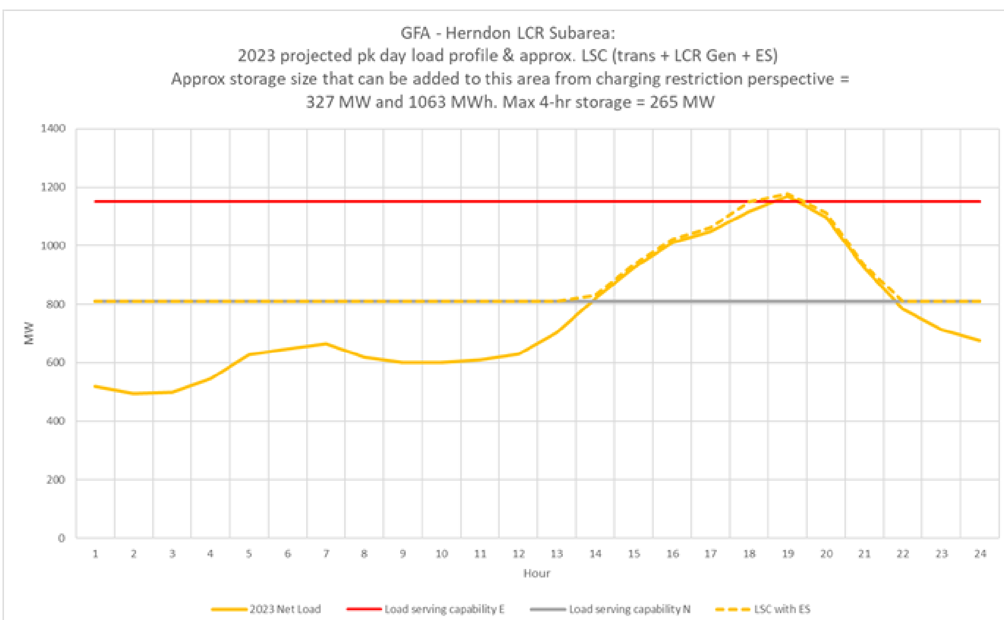
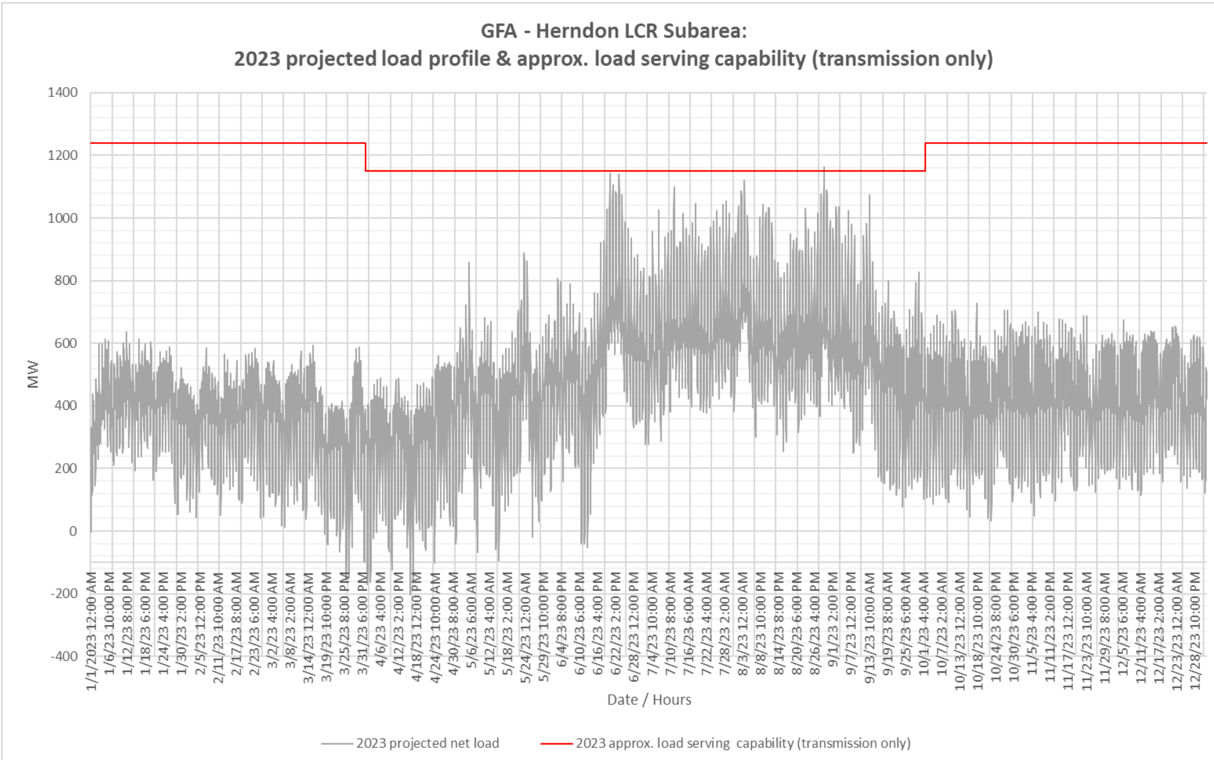


Figure 3.3-64 Herndon LCR Sub-area 2023 Forecast Hourly Profiles



Herndon LCR Sub-area Requirement

Table 3.3-57 identifies the sub-area LCR requirements. The LCR Requirement for a Category P6 contingency is 327 MW.

Table 3.3-57 Herndon LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	First limit	P6	Herndon-Woodward 115 kV	Herndon-Manchester 115 kV line & Herndon-Barton 115 kV line	327

Effectiveness factors:

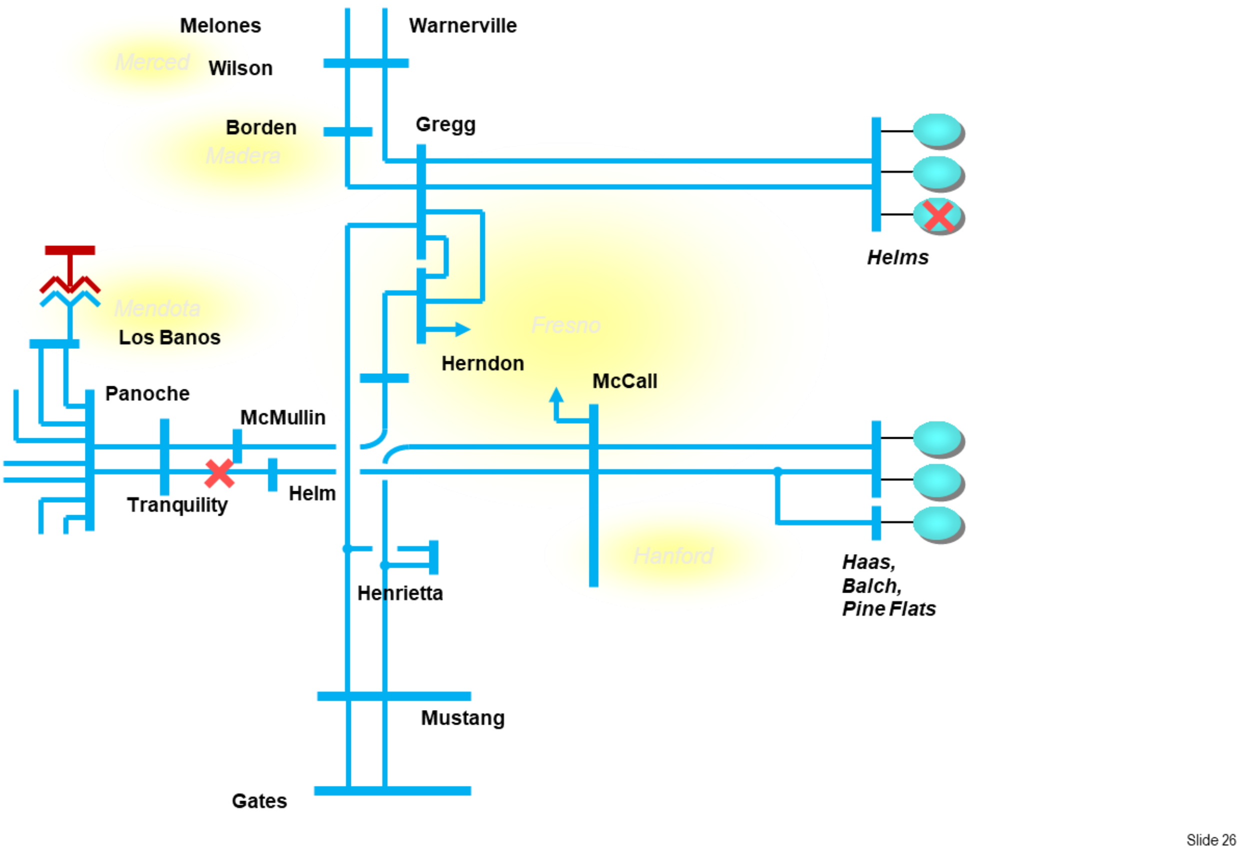
Effective factors for generators in the Herndon LCR Sub-area are in Attachment B table titled Herndon.

For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7430 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.6.9 *Fresno Overall area*

Fresno LCR area Diagram

Figure 3.3-65 Fresno LCR area



Fresno Overall LCR area Load and Resources

Table 3.3-43 provides the forecast load and resources in Fresno LCR area in 2023. The list of generators within the LCR area are provided in Attachment A.

Fresno Overall LCR area Hourly Profiles

Figure 3.3-66 illustrates the forecast 2023 profile for the peak day for the Fresno Overall sub-area with the Category P6 normal and emergency load serving capabilities without local resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-67 illustrates the forecast 2023 hourly profile for Fresno Overall sub-area with the Category P6 emergency load serving capability without local resources.

Figure 3.3-66 Fresno LCR area 2023 Peak Day Forecast Profiles

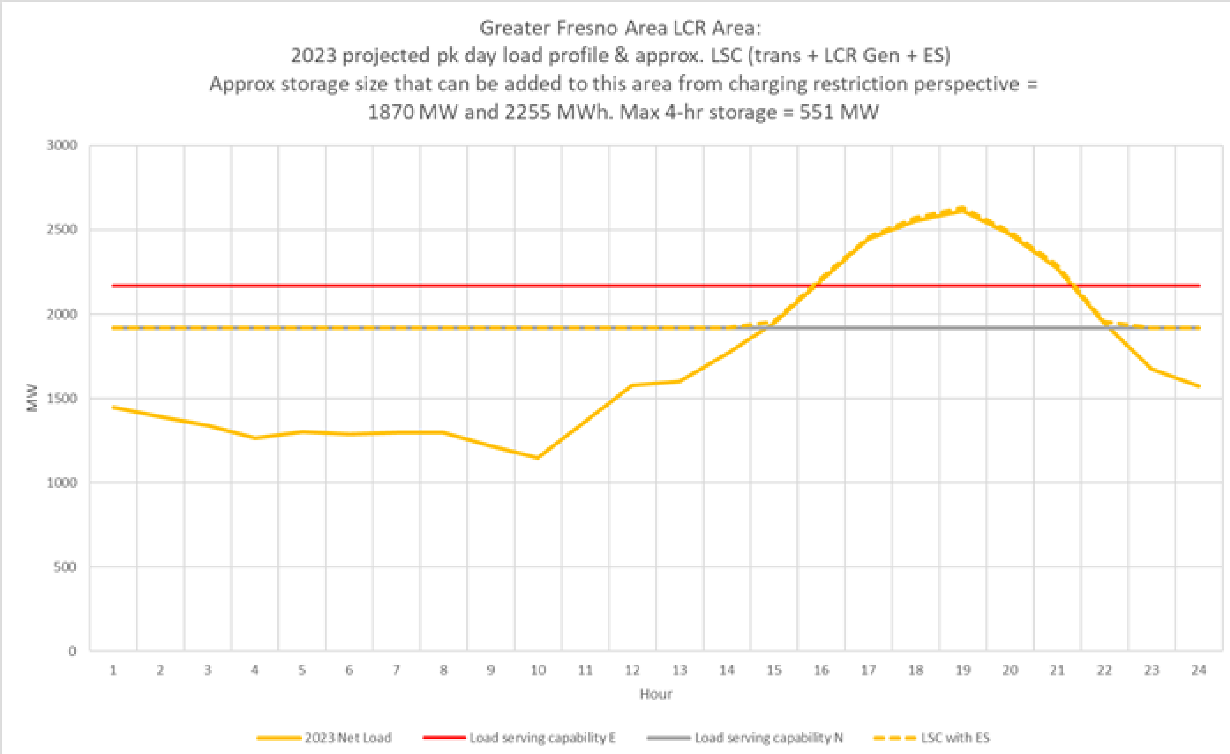
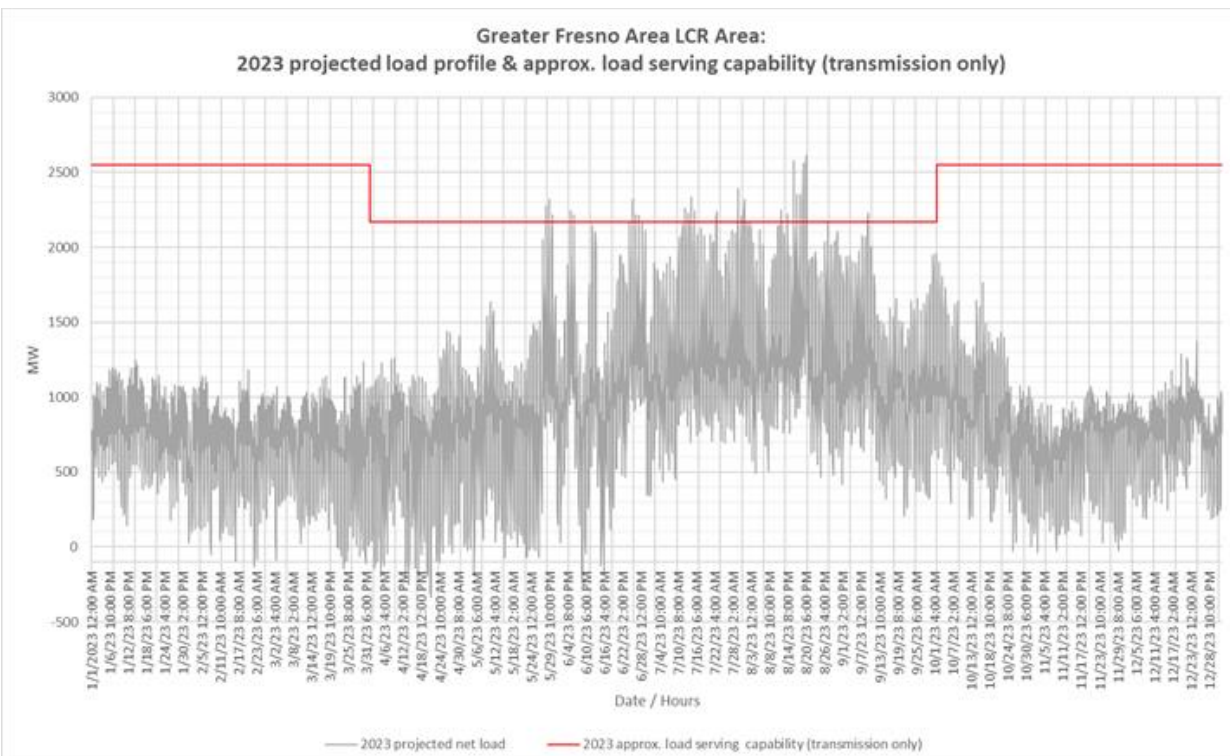


Figure 3.3-67 Fresno LCR area 2023 Forecast Hourly Profiles



Fresno Overall LCR Area Requirement

Table 3.3-58 identifies the area LCR requirements. The LCR Requirement for a Category P6 contingency is 1870 MW.

Table 3.3-58 Fresno Overall LCR Area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	First limit	P6	GWF-Contandida 115 kV Line	Panoche-Helm 230 kV Line and Gates-McCall 230 kV Line	1870

Effectiveness factors:

For most helpful procurement information please read procedure 2210 Z Effectiveness Factors under 7430 posted at: http://www.caiso.com/Documents/2210Z.pdf

Changes compared to last year's results

Compared with 2022 the load forecast decreased by 147 MW and the LCR need decreased by 117 MW mostly due to load forcast decrease.

3.3.7 Kern Area

3.3.7.1 *Area Definition:*

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

- Midway-Kern PP #1 230 kV Line
- Midway-Kern PP #3 230 kV Line
- Midway-Kern PP #4 230 kV Line
- Famoso-Lerdo 115 kV Line (Seasonal Open)
- Adobe Switching Station #1 115 kV Tap (Normal Open)
- Wasco-Famoso 70 kV Line (Seasonal Open)
- Kern-Magunden 70 kV Line (Seasonal Open)
- Copus-Old River 70 kV Line (Seasonal Open)
- Copus-Old River 70 kV Line (Normal Open)

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

- Midway 230 kV is out and Bakersfield 230 kV is in
- Midway 230 kV is out and Kern PP 230 kV is in

Midway 230 kV is out and Kern PP 230 kV is in

Famoso 115 kV is out and Cawelo 115 kV is in

Adobe Switching Station 115 kV is out and Wheeler Ridge Junction 115 kV is in

Wasco 70 kV is out and Mc Farland 70 kV is in

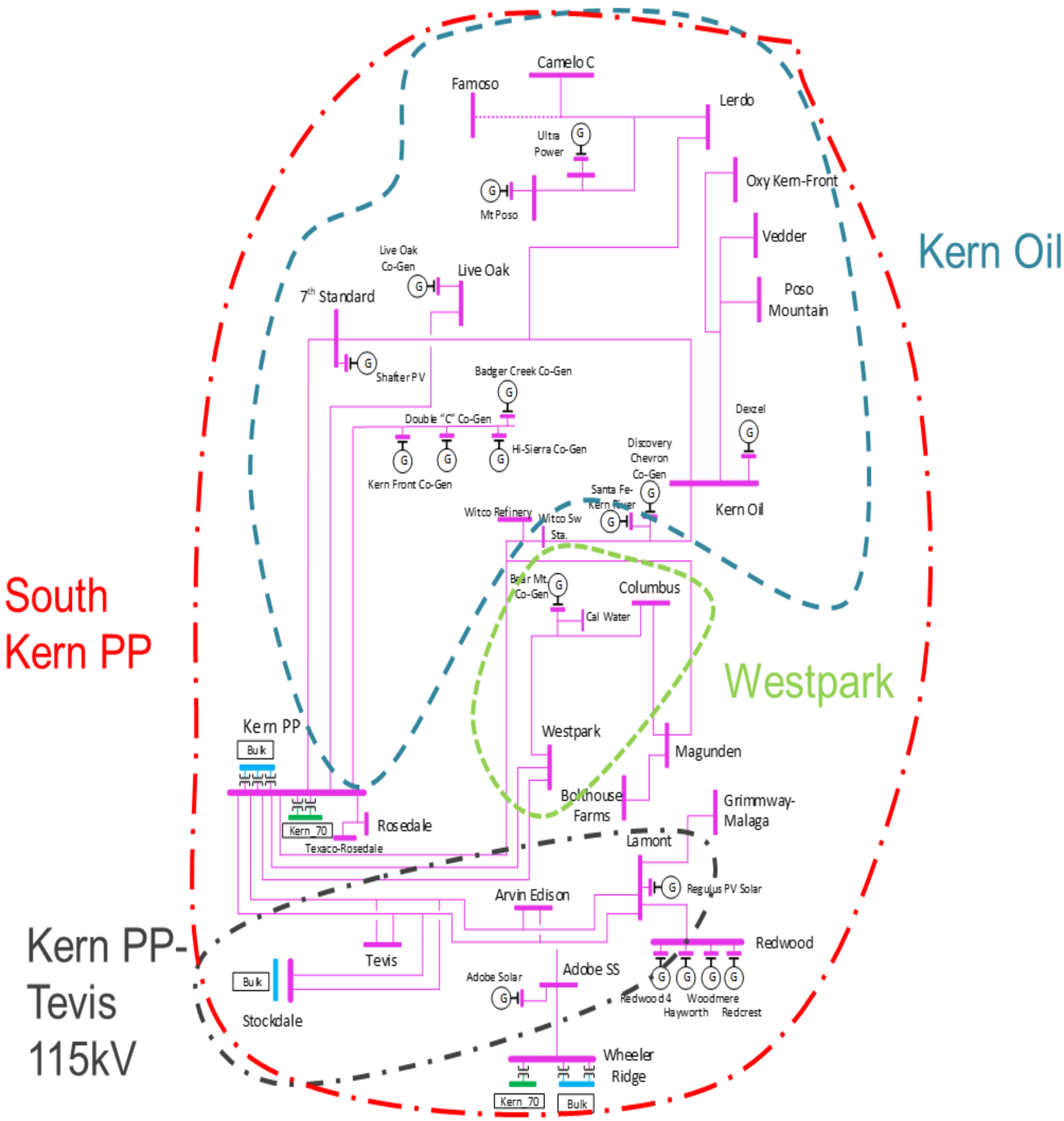
Magunden 70 kV is out and Bakersfield Junction 70 kV is in

Copus 70 kV is out and South Kern Solar 70 kV is in

Lakeview 70 kV is out and San Emidio Junction 70 kV is in

Kern LCR Area Diagram

Figure 3.3-68 Kern LCR Area



Kern LCR Area Load and Resources

Table 3.3-59 provides the forecast load and resources in Kern LCR Area in 2023. The list of generators within the LCR area are provided in Attachment A.

In year 2023 the estimated time of local area peak is 19:20 PM.

At the local area peak time the estimated, ISO metered, solar output is 0.00%.

If required, all non-solar technology type resources are dispatched at NQC.

Table 3.3-59 Kern LCR Area 2023 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	937	Market, Net Seller	351	351
AAEE	-5	MUNI	0	0
Behind the meter DG	0	QF	6	6
Net Load	**932**	Solar	73	0
Transmission Losses	8	Existing 20-minute Demand Response	9	9
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**940**	**Total**	**439**	**366**

Approved transmission projects modeled

None

3.3.7.2 *Kern 70 kV Sub-area*

Kern 70 kV sub-area has been eliminated due to Magunden – Magunden Jct 70 kV being modeled as open in the basecase.

3.3.7.3 *Kern Power-Tevis Sub Area*

Kern Power-Tevis is a sub-area of the Kern LCR area.

Kern Power-Tevis Sub-area Diagram

Please see Figure 3.3-68 for Kern PWR-Tevis sub-area diagram

Kern Power-Tevis Sub-area Load and Resources

Table 3.3-60 provides the forecast load and resources in Kern Power-Tevis sub-area. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-60 Kern Power-Tevis LCR Sub-area 2023 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	149	Market, Net Seller	0	0
AAEE	-1	MUNI	0	0
Behind the meter DG	0	QF	0	0
Net Load	**148**	Solar	51	0
Transmission Losses	0	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**148**	**Total**	**51**	**0**

Kern Power-Tevis LCR Sub-area Requirement

Table 3.3-61 identifies the sub-area LCR requirements. The LCR requirement for Category P2 contingency is 0 MW .

Table 3.3-61 Kern Power-Tevis LCR Sub-area Requirements

Year	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	P2	Kern-Lamont 115 kV Lines (Kern-Tevis Jct 2/Tevis J1)	KERN PWR 115kV - Section 1E & 1D	0

Effectiveness factors:

All units within the Kern PWR-Tevis sub-area have the same effectiveness factor.

For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7450 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.7.4 *Westpark Sub-area*

Westpark is a sub-area of the Kern LCR area.

Westpark LCR Sub-area Diagram

Please see Figure 3.3-68 for Westpark sub-area diagram.

Westpark LCR Sub-area Load and Resources

Table 3.3-62 provides the forecast load and resources in Westpark LCR sub-area. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-62 Westpark LCR Sub-area 2023 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	127	Market, Net Seller	45	45
AAEE	-1	MUNI	0	0
Behind the meter DG	0	QF	0	0
Net Load	**126**	LTPP Preferred Resources	0	0
Transmission Losses	0	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**126**	**Total**	**45**	**45**

Westpark LCR Sub-area Hourly Profiles

Figure 3.3-69 illustrates the forecast 2023 profile for the peak day for the Westpark LCR sub-area with the Category P3 normal and emergengy load serving capabilities without local resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-70 illustrates the forecast 2023 hourly profile for Westpark LCR sub-area with the Category P2 emergency load serving capability without local resources.

Figure 3.3-69 Westpark LCR Sub-area 2023 Peak Day Forecast Profiles

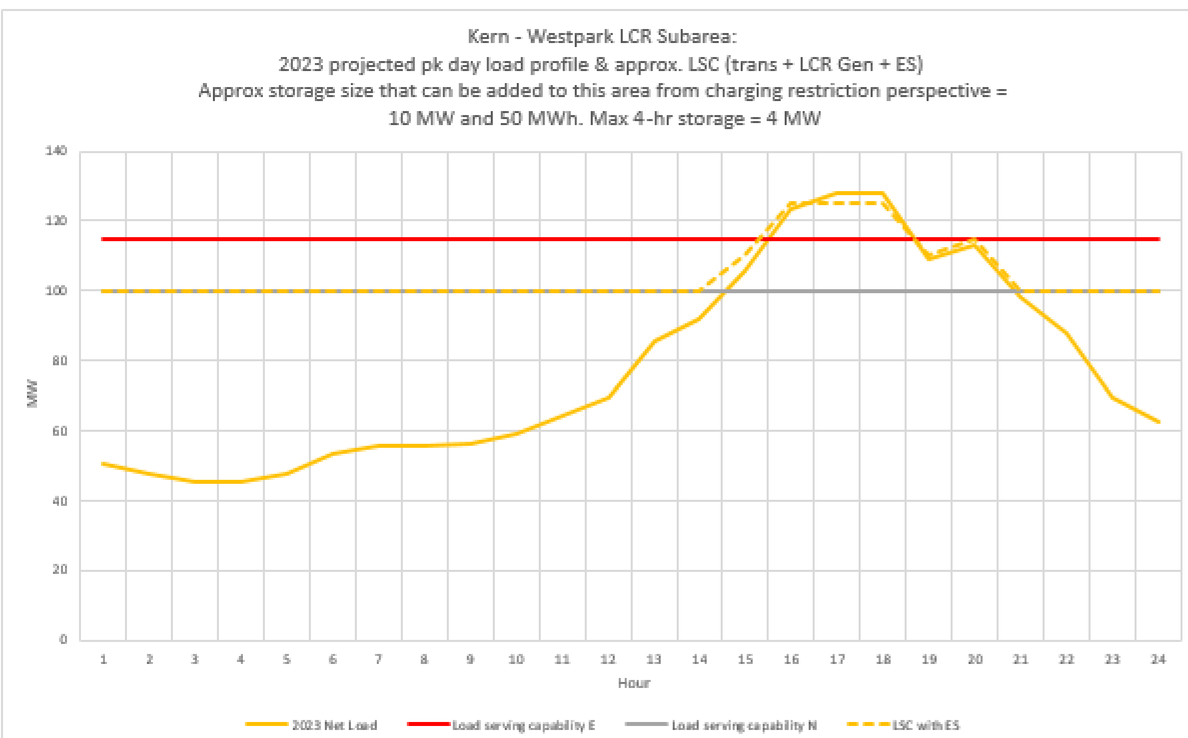
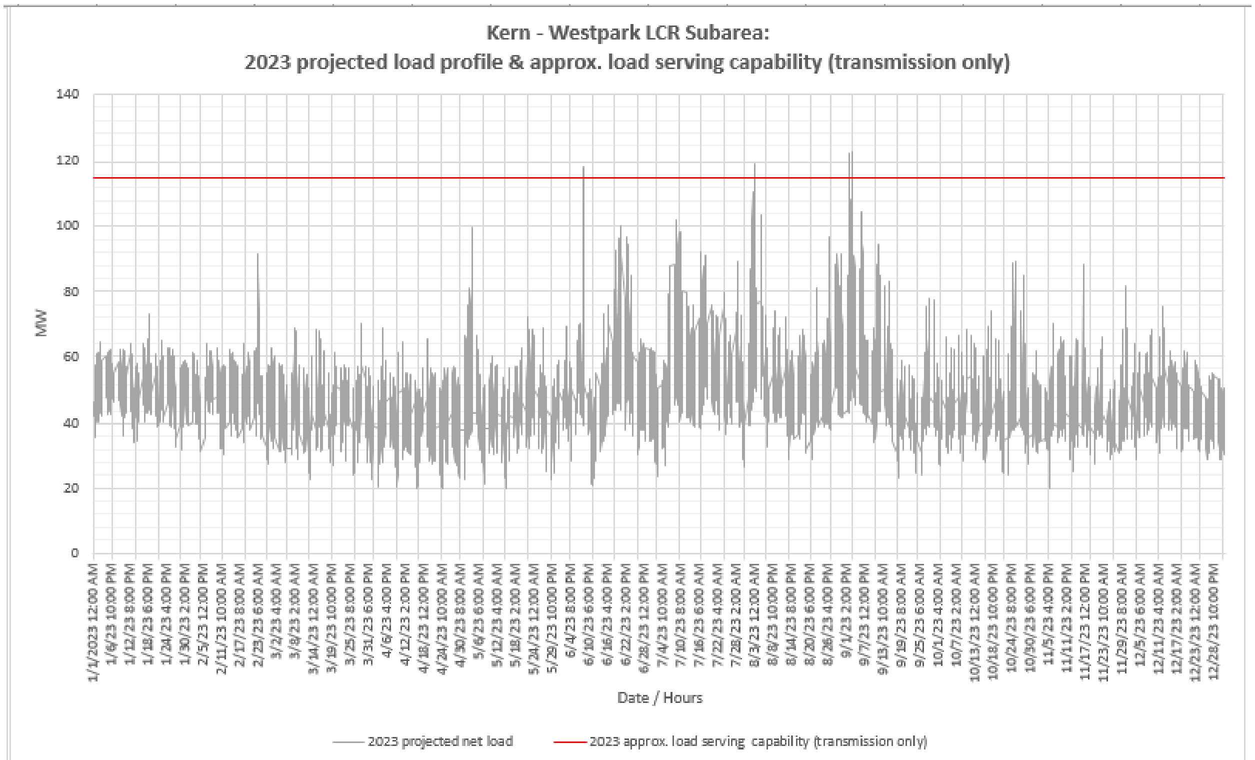


Figure 3.3-70 Westpark LCR Sub-area 2023 Forecast Hourly Profiles



Westpark LCR Sub-area Requirement

Table 3.3-63 identifies the sub-area LCR requirements. The LCR requirement for Category P2 contingency is 10 MW.

Table 3.3-63 Westpark LCR Sub-area Requirements

Year	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	P2	Kern-West Park #2 115 kV	KERN PWR 115kV - Section 1E & 1D	10

Effectiveness factors:

All units within the Westpark Sub-area have the same effectiveness factor.

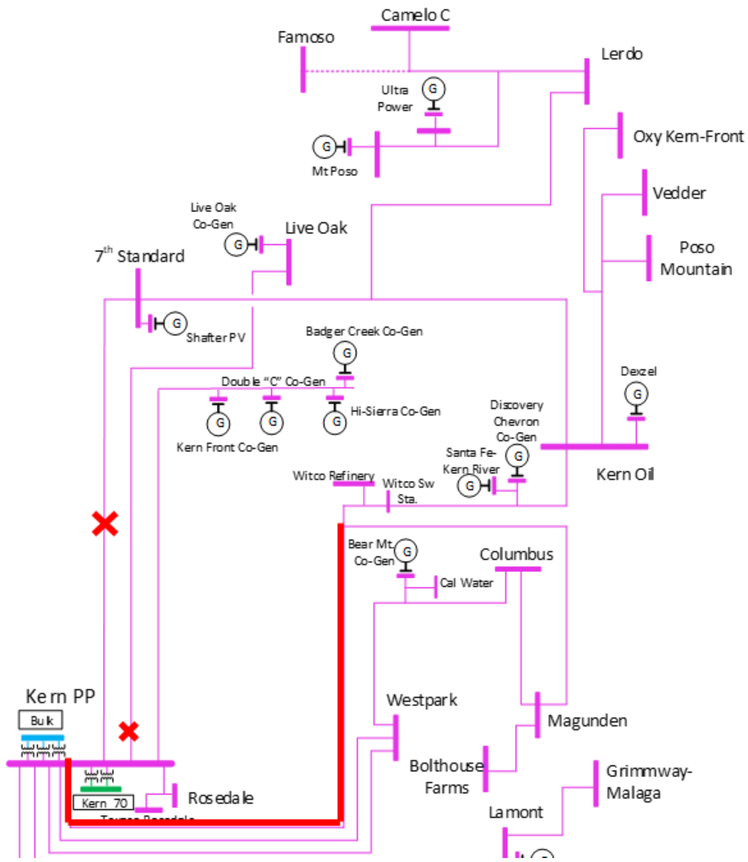
For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7450 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.7.5 *Kern Oil Sub-area*

Kern Oil is a sub-area of the Kern LCR area.

Kern Oil LCR Sub-area Diagram

Figure 3.3-71 Kern Oil LCR Sub-area



Kern Oil LCR Sub-area Load and Resources

Table 3.3-64 provides the forecast load and resources in Kern Oil LCR sub-area. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-64 Kern Oil LCR Sub-area 2023 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	270	Market, Net Seller	103	103
AAEE	-1	MUNI	0	0
Behind the meter DG	0	QF	6	6
Net Load	**269**	Solar	7	0
Transmission Losses	1	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**270**	**Total**	**116**	**109**

Kern Oil LCR Sub-area Hourly Profiles

Figure 3.3-72 illustrates the forecast 2023 profile for the peak day for the Kern Oil LCR sub-area with the Category P6 normal and emergengy load serving capabilities without local resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective. Figure 3.3-73 illustrates the forecast 2023 hourly profile for Kern Oil LCR sub-area with the Category P6 emergency load serving capability without local resources.

Figure 3.3-72 Kern Oil LCR Sub-area 2023 Peak Day Forecast Profiles

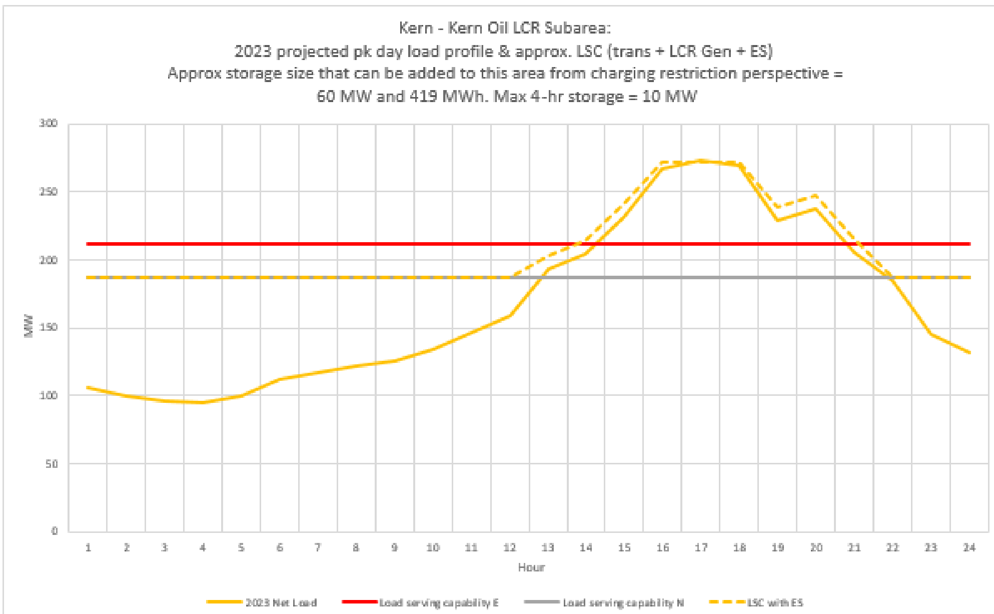
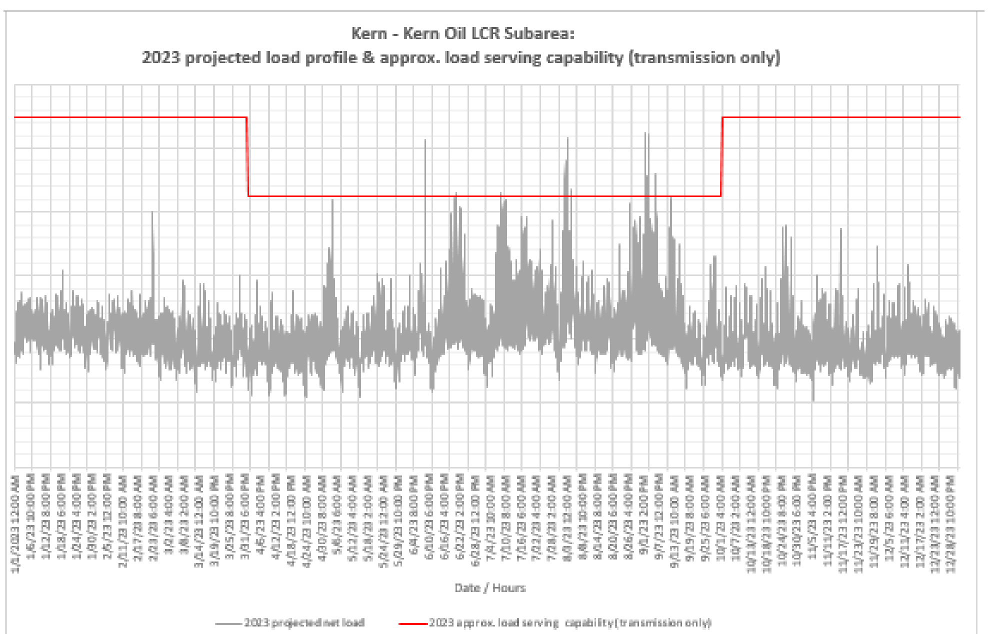


Figure 3.3-73 Kern Oil LCR Sub-area 2023 Forecast Hourly Profiles



Kern Oil LCR Sub-area Requirement

Table 3.3-65 identifies the sub-area LCR requirements. The LCR requirement for Category P6 contingency is 60 MW.

Table 3.3-65 Kern Oil LCR Sub-area Requirements

Year	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	P6	Kern Oil Jct –Kernwater 115 kV Line	7th Standard – Kern 115 kV line & Kern Oil – Live Oak – Poso Mt 115 kV Line	60

Effectiveness factors:

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

For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7450 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.7.6 *South Kern PP Sub-area*

South Kern PP is sub-area of the Kern LCR area.

South Kern PP LCR Sub-area Diagram

Please see Figure 3.3-68 for South Kern PP area diagram.

South Kern PP LCR Sub-area Load and Resources

Refer to Table 3.3-59 Kern Area Load and Resources table.

South Kern PP LCR Sub-area Hourly Profiles

Figure 3.3-74 illustrates the forecast 2023 profile for the peak day for the South Kern PP LCR sub-area with the Category P6 normal and emergengy load serving capabilities without local resources. The chart also includes an estimated amount of energy storage that can be added to this local area from charging restriction perspective.

Figure 3.3-75 illustrates the forecast 2023 hourly profile for South Kern PP LCR sub-area with the Category P6 emergency load serving capability without local resources.

Figure 3.3-74 South Kern PP LCR Sub-area 2023 Peak Day Forecast Profiles

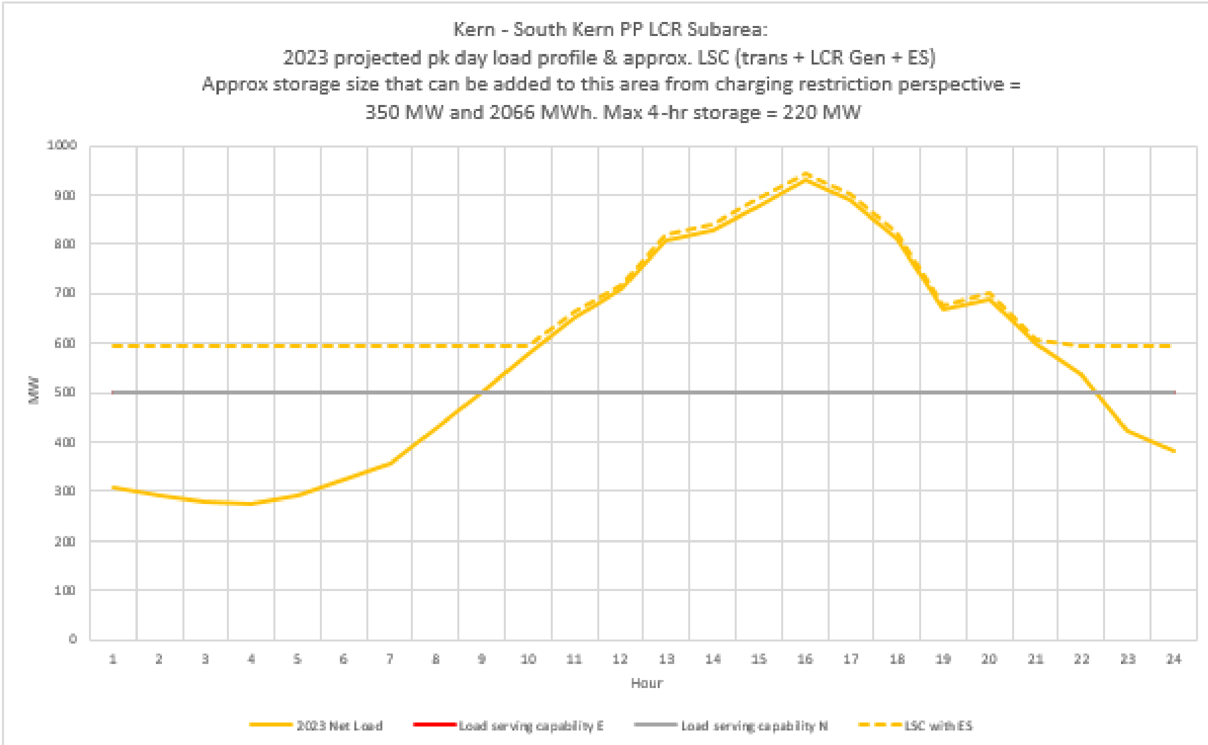
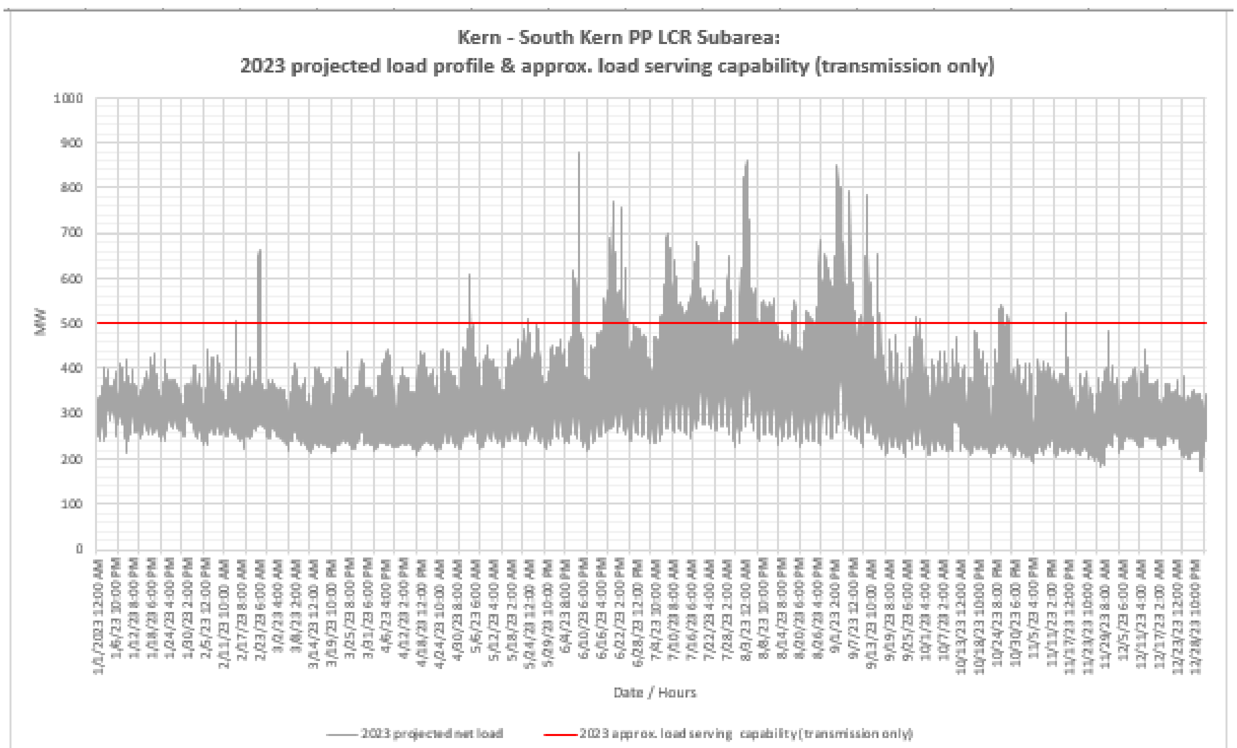


Figure 3.3-75 South Kern PP LCR Sub-area 2023 Forecast Hourly Profiles



South Kern PP LCR Sub-area Requirement

Table 3.3-66 identifies the sub-area LCR requirements. The LCR requirement for Category P6 contingency is 443 MW including a 77 MW at peak deficiency as well as 4 MW NQC deficiency.

Table 3.3-66 South Kern PP LCR Sub-area Requirements

Year	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	P6	Kern PP – Stockdale Junction 1 230 kV Line	Midway-Kern 230 kV Line # 3 & Midway-Kern 230 kV Line # 1	443 (4 NQC, 77 Peak)

Effectiveness factors:

All units within the South Kern PP sub-area have the same effectiveness factor.

For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7450 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.7.7 *Kern Area Overall Requirements*

Kern LCR Area Overall Requirement

Table 3.3-67 identifies the limiting facility and contingency that establishes the Kern Area 2023 LCR requirements. The LCR requirement for Category P6 (Multiple Contingency) is 443 MW including a 77 MW at peak deficiency as well as a 4 MW NQC deficiency.

Table 3.3-67 Kern Overall LCR Sub-area Requirements

Year	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	P6	Aggregate of Sub-areas.		443 (4 NQC: 77 Peak)

Kern Overall LCR Area Hourly Profile

Refer to South Kern PP LCR area profiles.

Changes compared to last year's results

Compared with 2023, the load forecast decreased by 89 MW but the LCR requirement has increased by 87 MW mainly due to more restricted contingency and limiting element identified.

3.3.8 Big Creek/Ventura Area

3.3.8.1 *Area Definition:*

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

Antelope #1 500/230 kV Transformer

Antelope #2 500/230 kV Transformer

Sylmar - Pardee 230 kV #1 and #2 Lines

Vincent - Pardee 230 kV #2 Line

Vincent - Santa Clara 230 kV Line

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

Antelope 500 kV is out Antelope 230 kV is in

Antelope 500 kV is out Antelope 230 kV is in

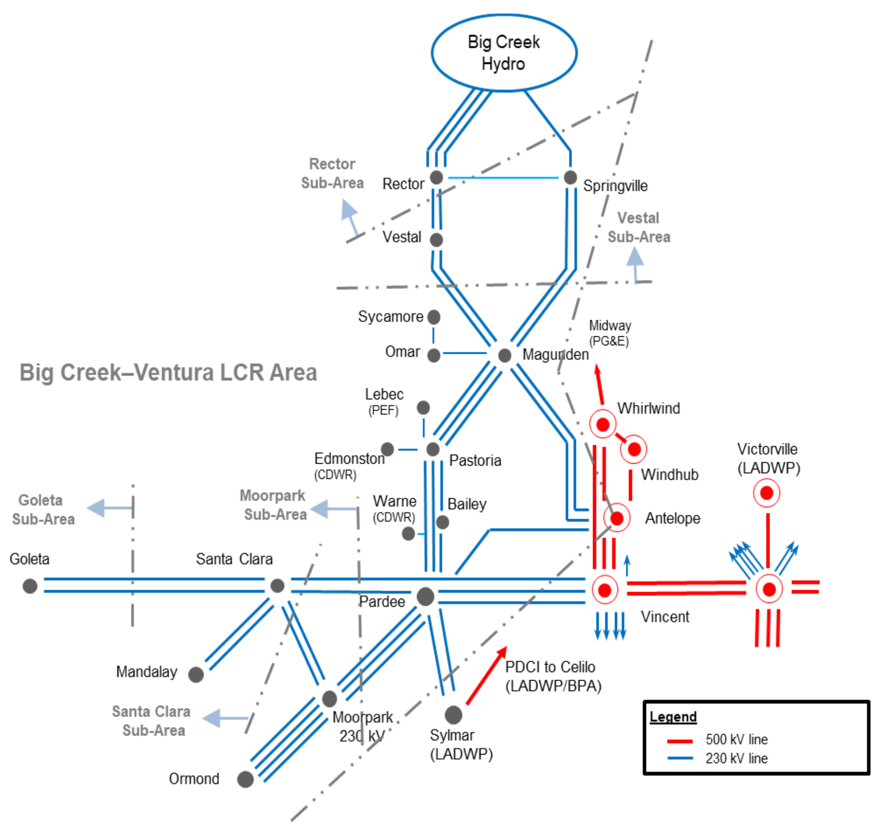
Sylmar is out Pardee is in

Vincent is out Pardee is in

Vincent is out Santa Clara is in

Big Creek/Ventura LCR Area Diagram

Figure 3.3-76 Big Creek/Ventura LCR Area



Big Creek/Ventura LCR Area Load and Resources

Table 3.3-68 provides the forecast load and resources in the Big Creek/Ventura LCR Area in 2023. The list of generators within the LCR area are provided in Attachment A.

In year 2023 the estimated time of local area peak is 4:00 PM (PST).

At the local area peak time the estimated ISO-metered solar output is about 56%.

If required, all non-solar technology type resources are dispatched at NQC.

Table 3.3-68 Big Creek/Ventura LCR Area 2023 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	4459	Market, Net Seller	4026	4026
AAEE	-12	MUNI	307	307
Behind the meter DG	-379	QF	100	100
Net Load	**4068**	Solar	475	475
Transmission Losses	65	Battery	503	503
Pumps	294	Demand Response	63	63
Load + Losses + Pumps	**4427**	**Total**	**5475**	**5475**

Approved transmission projects modeled:

- Pardee-Moorpark No. 4 230 kV Transmission Project (ISD-March 2023)
- Pardee-Sylmar 230 kV Rating Increase Project (ISD - December 2025)

3.3.8.2 *Rector Sub-area*

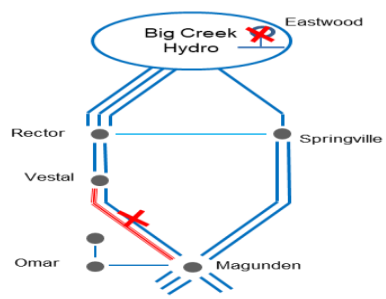
LCR need is satisfied by the need in the larger Vestal sub-area.

3.3.8.3 *Vestal Sub-area*

Vestal is a sub-area of the Big Creek/Ventura LCR area.

Vestal LCR Sub-area Diagram

Figure 3.3-77 Vestal LCR Sub-area



Vestal LCR Sub-area Load and Resources

Table 3.3-69 provides the forecast load and resources in Vestal LCR sub-area in 2023. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-69 Vestal LCR Sub-area 2023 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	N/A	Market, Net Seller	962	962
AAEE	4	MUNI	0	0
Behind the meter DG	N/A	QF	12	12
Net Load	**1187**	Solar	119	119
Transmission Losses	22	Battery	0	0
Pumps	0	Existing 20-minute Demand Response	41	41
Load + Losses + Pumps	**1209**	**Total**	**1134**	**1134**

Vestal LCR Sub-area Hourly Profiles

Figure 3.3-78 illustrates the forecast 2023 annual load profile in the Vestal LCR sub-area with the Category P3 normal and emergengy load serving capabilities without local capacity resources.

Figure 3.3-79 provides the load shape for the peak load day, estimated energy storage maximum capacity and energy based on area maximum charging capability under the most critical contingency as well as estimated 1 for 1 replacement with four-hour capacity battery.

Figure 3.3-78 Vestal LCR Sub-area 2023 Annual Load Profile with Estimated Transmission Only Load Serving Capability

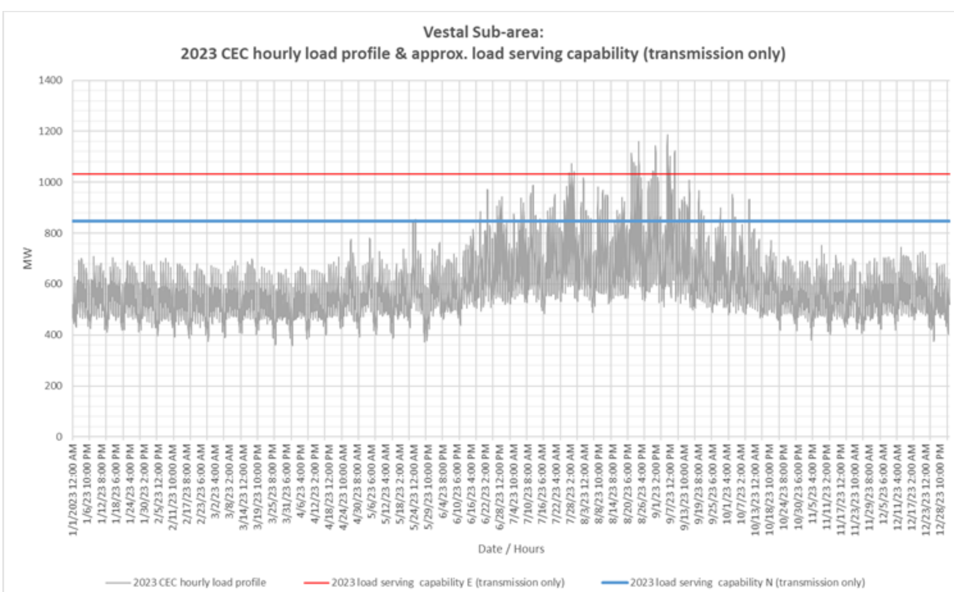
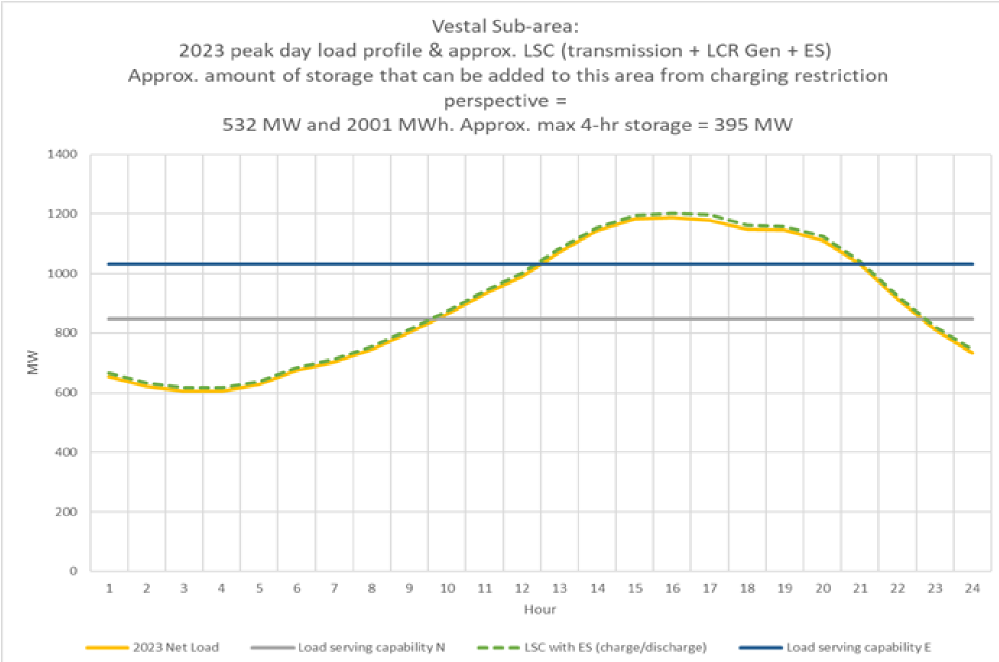


Figure 3.3-79 Vestal LCR Sub-area 2023 Load Shape and Estimated Maximum Energy Storage Capacity and Energy Based on Charging Capability Under Critical Contingency



Vestal LCR Sub-area Requirement

Table 3.3-70 identifies the sub-area LCR requirements. The LCR requirement for Category P3 contingency is 344 MW.

Table 3.3-70 Vestal LCR Sub-area Requirements

Year	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	P3	Magunden–Vestal #1 230 kV line	Magunden–Vestal #2 230 kV line with Eastwood out of service	344

Effectiveness factors:

For helpful procurement information please read procedure 2210Z Effectiveness Factors under 7500 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.8.4 *Goleta Sub-area*

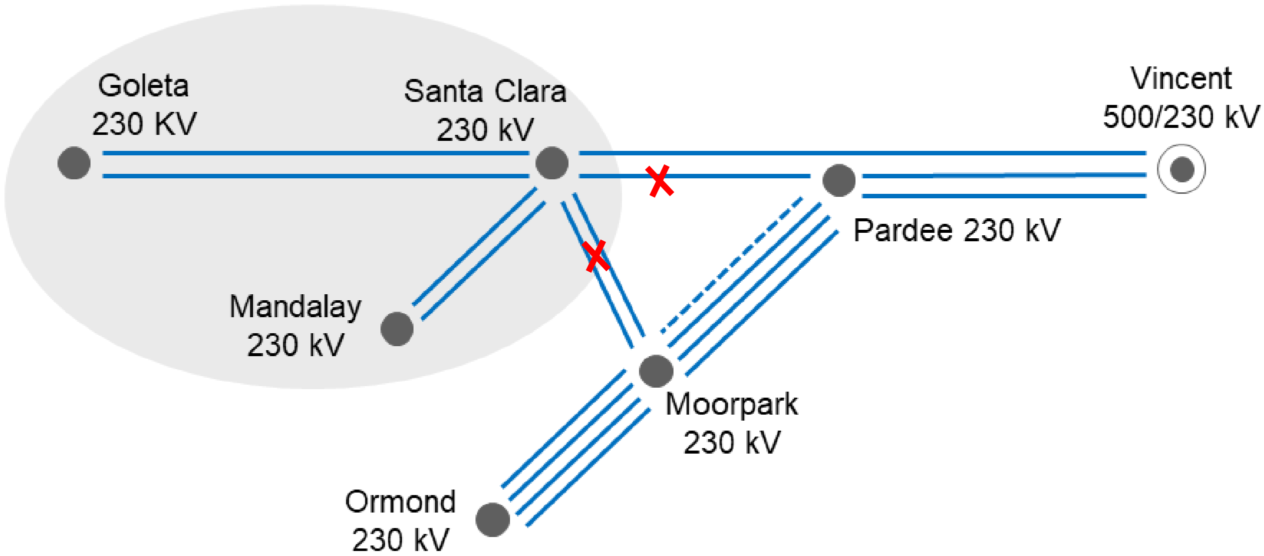
Goleta is a sub-area of the Santa Clara sub-area. LCR need in Goleta is satisfied by the need in the larger Santa Clara sub-area.

3.3.8.5 *Santa Clara Sub-area*

Santa Clara is a sub-area of the Big Creek/Ventura LCR area.

Santa Clara LCR Sub-area Diagram

Figure 3.3-80 Santa Clara LCR Sub-area



Santa Clara LCR Sub-area Load and Resources

Table 3.3-71 provides the forecast load and resources in Santa Clara LCR sub-area in 2023. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-71 Santa Clara LCR Sub-area 2023 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	N/A	Market, Net Seller	147	147
AAEE	2	MUNI	0	0
Behind the meter DG	N/A	QF	88	88
Net Load	**772**	Solar	0	0
Transmission Losses	3	Existing Demand Response	7	7
Pumps	0	Battery	211	211
Load + Losses + Pumps	**775**	**Total**	**453**	**453**

Santa Clara LCR Sub-area Hourly Profiles

Figure 3.3-81 illustrates the forecast 2023 annual load profile in the Santa Clara LCR sub-area with the Category P1/P7 voltage stability related load serving capabily without local capacity resources. Figure 3.3-82 provides the load shape for the peak load day, estimated energy storage maximum capacity and energy based on area maximum charging capability under the most critical contingency as well as estimated 1 for 1 replacement with four-hour capacity battery.

Figure 3.3-81 Santa Clara LCR Sub-area 2023 Annual Load Profile with Estimated Transmission Only Load Serving Capability

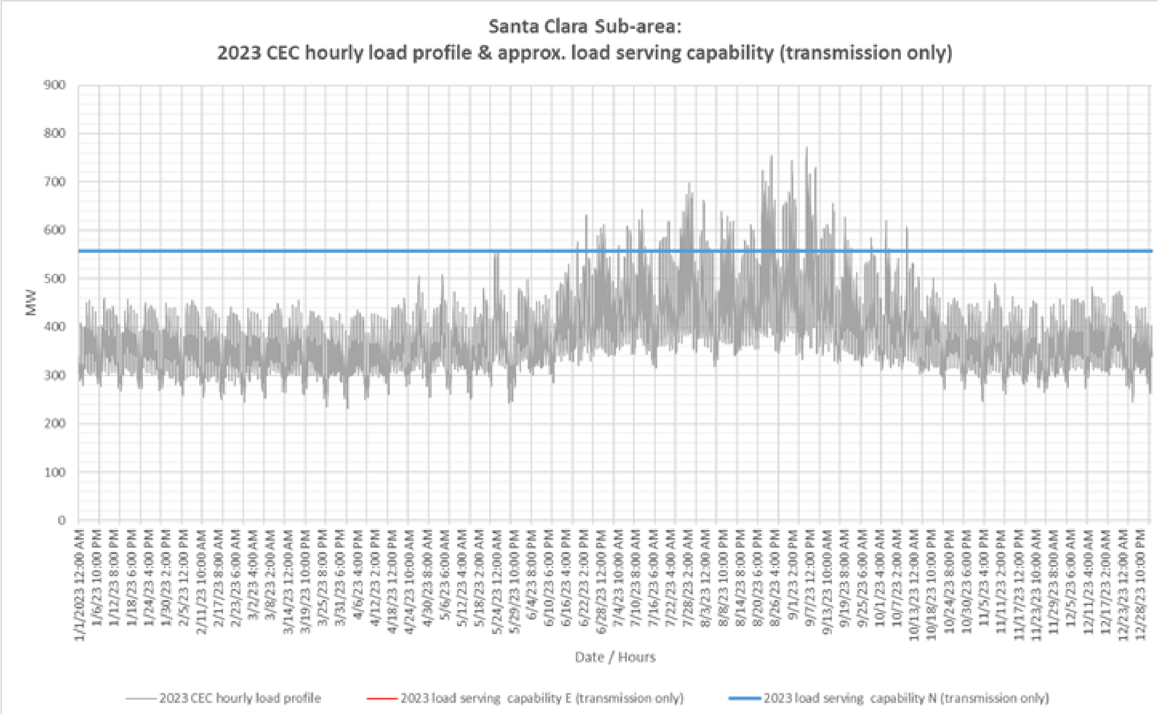
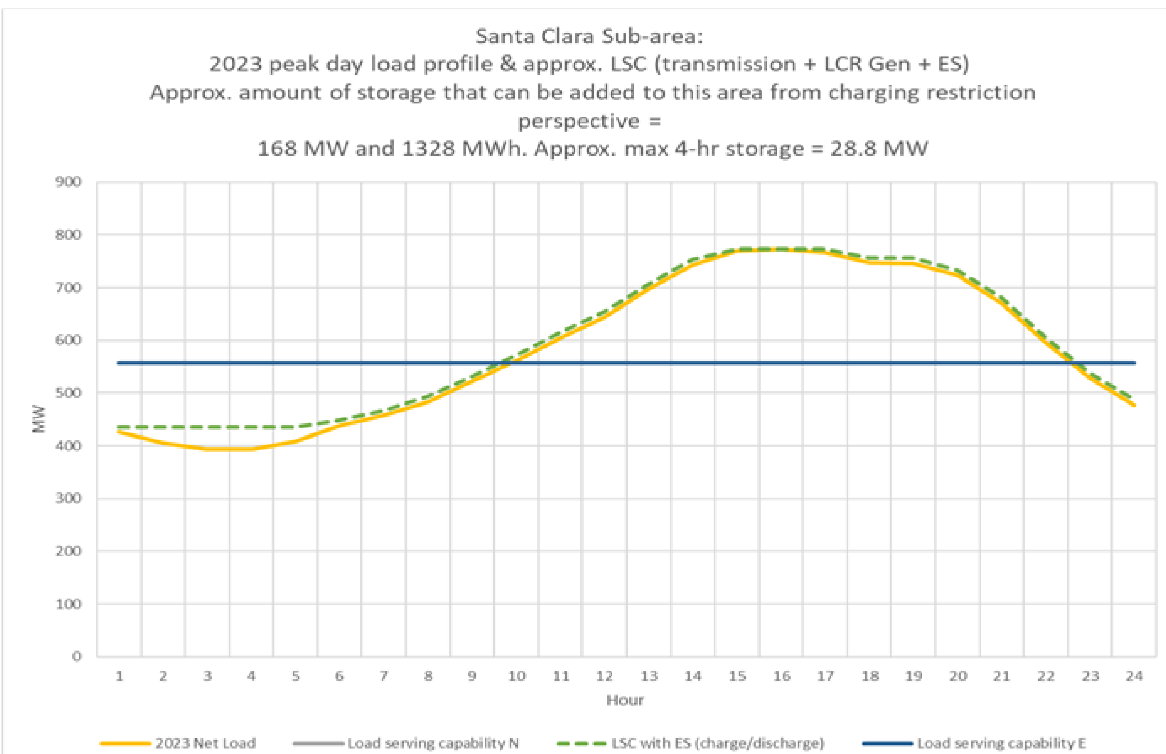


Figure 3.3-82 Santa Clara LCR Sub-area 2023 Load Shape and Estimated Maximum Energy Storage Capacity and Energy Based on Charging Capability Under Critical Contingency



Santa Clara LCR Sub-area Requirement

Table 3.3-72 identifies the sub-area requirements. The LCR requirement for Category P1 followed by P7 contingency is 184 MW.

Table 3.3-72 Santa Clara LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	First Limit	P1 + P7	Voltage collapse	Pardee - Santa Clara 230 kV followed by Moorpark - Santa Clara #1 & #2 230 kV	184

Effectiveness factors:

For helpful procurement information please read procedure 2210Z Effectiveness Factors under 7550 and 7680 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.8.6 *Moorpark Sub-area*

Moorpark sub-area will be eliminated when the Pardee-Moorpark No. 4 230 kV Transmission Project is completed.

3.3.8.7 *Big Creek/Ventura Overall*

Big Creek/Ventura LCR Sub-area Hourly Profiles

Figure 3.3-83 illustrates the forecast 2023 annual load profile in the Big Creek/Ventura LCR area with the Category P6 normal and emergency load serving capabilities without local capacity resources. The normal and emergency ratings for the limiting element are the same.

Figure 3.3-84 provides the load shape for the peak load day, estimated energy storage maximum capacity and energy based on area maximum charging capability under the most critical contingency as well as estimated 1 for 1 replacement with four-hour capacity battery.

Figure 3.3-83 Big Creek/Ventura LCR area 2023 Annual Load Profile with Estimated Transmission Only Load Serving Capability

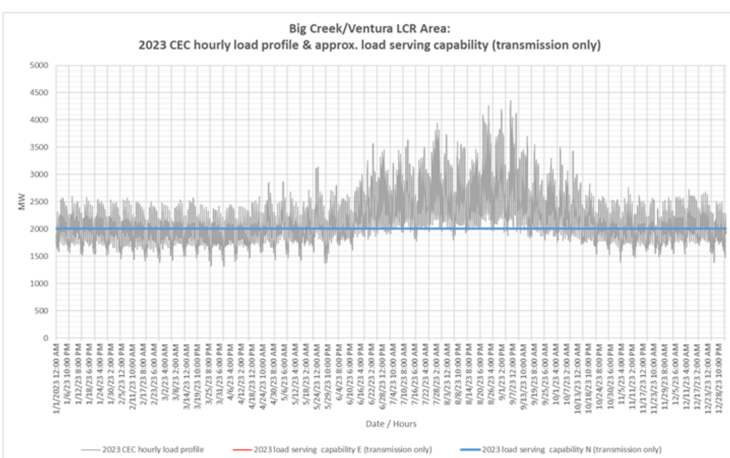
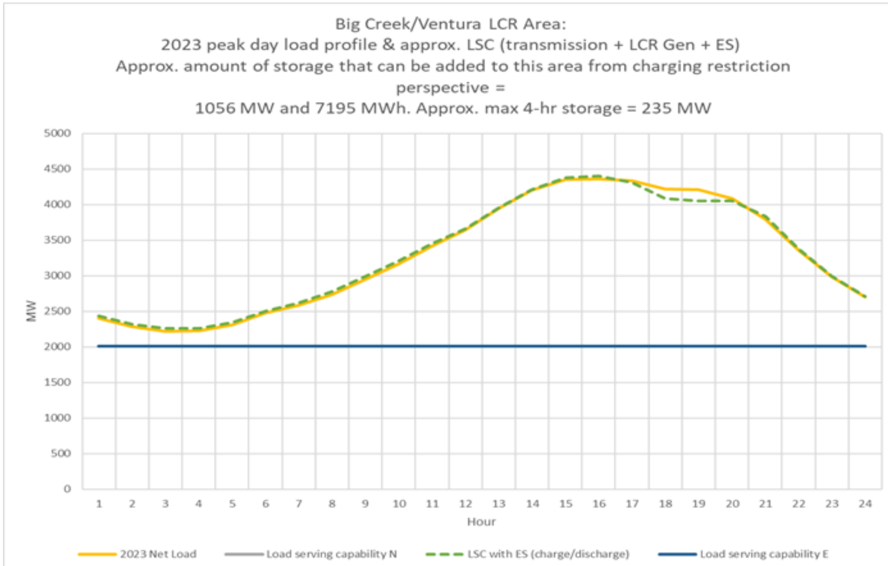


Figure 3.3-84 Big Creek/Ventura LCR area 2023 Load Shape and Estimated Maximum Energy Storage Capacity and Energy Based on Charging Capability Under Critical Contingency



Big Creek/Ventura LCR area Requirement

Table 3.3-73 identifies the area LCR requirements. The LCR requirement for Category P6 contingency is 2240 MW.

Table 3.3-73 Big Creek/Ventura LCR area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	First Limit	P6	Remaining Sylmar - Pardee 230 kV	Lugo - Victorville 500 kV line followed by one of the Sylmar - Pardee #1 or #2 230 kV lines	2240

Effectiveness factors:

For helpful procurement information please read procedure 2210Z Effectiveness Factors under 7500, 7510, 7550 and 7680 posted at: http://www.caiso.com/Documents/2210Z.pdf

Changes compared to last year's results

Compared with the results for 2022, the load forecast is up by 33 MW and the LCR has increased by 67 MW mainly due to the increase in the load forecast.

3.3.9 LA Basin Area

3.3.9.1 *Area Definition:*

The transmission tie lines into the LA Basin Area are:

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

San Onofre - Talega #1 & #2 230 kV Lines

Lugo - Mira Loma #2 & #3 500 kV Lines

Lugo - Rancho Vista #1 500 kV Line

Vincent – Mira Loma 500 kV Line

Sylmar - Eagle Rock 230 kV Line

Sylmar - Gould 230 kV Line

Vincent - Mesa #1 & #2 230 kV Lines

Vincent - Rio Hondo #1 & #2 230 kV Lines

Devers - Red Bluff 500 kV #1 and #2 Lines

Mirage – Coachella Valley # 1 230 kV Line

Mirage - Ramon # 1 230 kV Line

Mirage - Julian Hinds 230 kV Line

The substations that delineate the LA Basin Area are:

San Onofre is in San Luis Rey is out

San Onofre is in Talega is out

Mira Loma is in Lugo is out

Rancho Vista is in Lugo is out

Eagle Rock is in Sylmar is out

Gould is in Sylmar is out

Mira Loma is in Vincent is out

Mesa is in Vincent is out

Rio Hondo is in Vincent is out

Devers is in Red Bluff is out

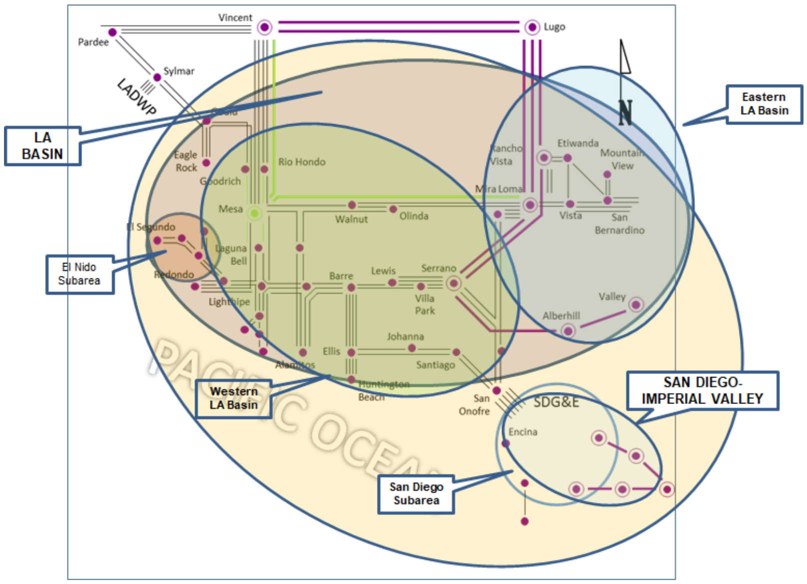
Mirage is in Coachella Valley is out

Mirage is in Ramon is out

Mirage is in Julian Hinds is out

LA Basin LCR Area Diagram

Figure 3.3-85 LA Basin LCR Area



LA Basin LCR Area Load and Resources

Table 3.3-74 provides the forecast load and resources in the LA Basin LCR Area in 2023. The list of generators within the LCR area are provided in Attachment A and does not include the CPUC-approved local capacity preferred resources or DR.

In year 2023 the estimated time of local area peak is 5:00 PM (PDT) based on the CEC hourly forecast for the 2021-2035 California Energy Demand Forecast.

At the local area peak time the estimated, ISO metered, solar output is 14%.

If required, all non-solar technology type resources are dispatched at NQC.

Table 3.3-74 LA Basin LCR Area 2023 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	20856	Market, Net Seller, Wind, Battery	8162	8162
AAEE	-158	MUNI	966	966
Behind the meter DG	-1450	QF	114	114
Net Load	**19248**	Local Capacity Preferred Resources (BTM BESS, EE, DR, PV)	165	165
Transmission Losses	289	Existing Demand Response	243	243
Pumps	0	Solar	11	6
Load + Losses + Pumps	**19537**	**Total**	**9661**	**9656**

Approved new transmission and resource projects modeled:

Mesa Loop-In Project (500 kV and 230 kV)

West of Devers 230 kV Upgrades

Local capacity area preferred resources in western LA Basin (BTM BESS, EE, DR, PV)

3.3.9.2 *El Nido Sub-area*

El Nido is a Sub-area of the LA Basin LCR Area.

El Nido LCR Sub-area Diagram

Please refer to Figure 3.3-85 above.

El Nido LCR Sub-area Load and Resources

Table 3.3-75 provides the forecast load and resources in El Nido LCR sub-area in 2023. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-75 El Nido LCR Sub-area 2023 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	953	Market, Net Seller	549	549
AAEE	-13	MUNI	0	0
Behind the meter DG	-31	QF	0	0
Net Load	**909**	LTPP Preferred Resources	11	11
Transmission Losses	2	Existing Demand Response	4	4
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**911**	**Total**	**564**	**564**

El Nido LCR Sub-area Hourly Profiles

Figure 3.3-86 illustrates the forecast 2023 annual load profile in the El Nido LCR sub-area with the Category P7 normal and emergengy load serving capabilities without local gas resources.

Figure 3.3-87 provides load shape for peak load day, estimated energy storage maximum capacity and energy as well as estimated four-hour capacity amount based on its maximum charging capability under the most critical contingency.

Figure 3.3-86 El Nido LCR Sub-area 2023 Annual Load Profile with Estimated Transmission Load Serving Capability Only

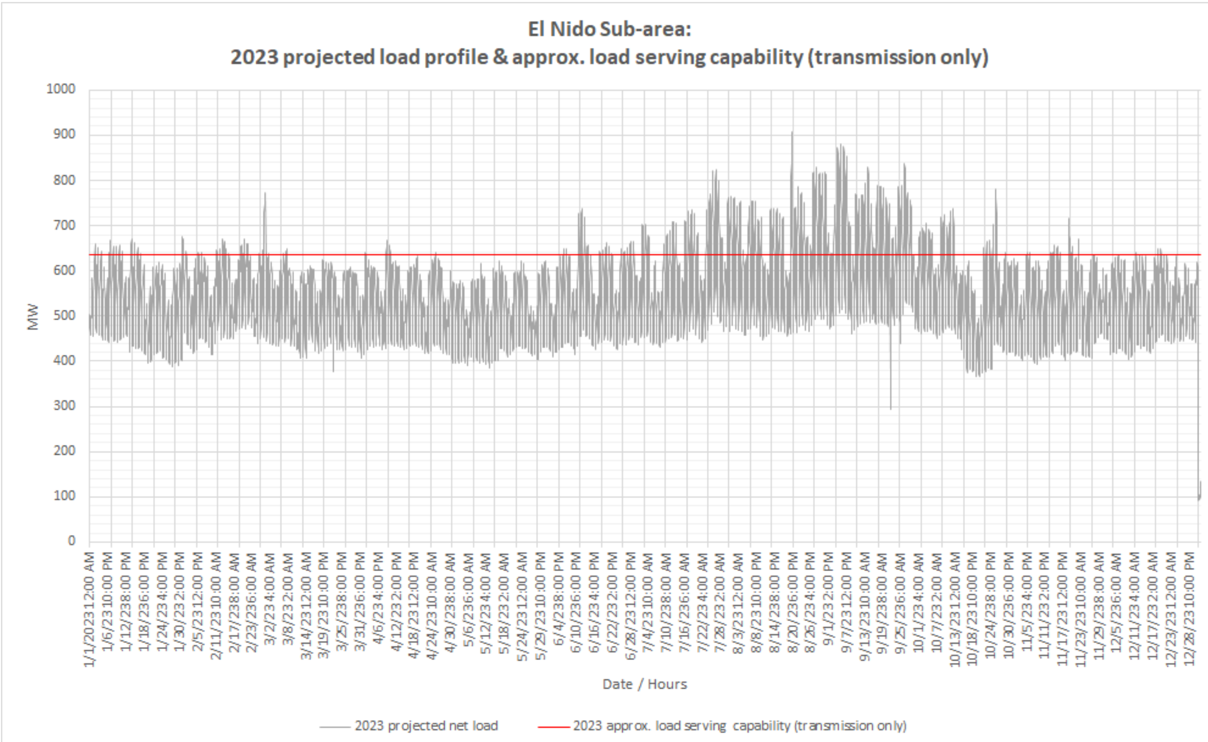
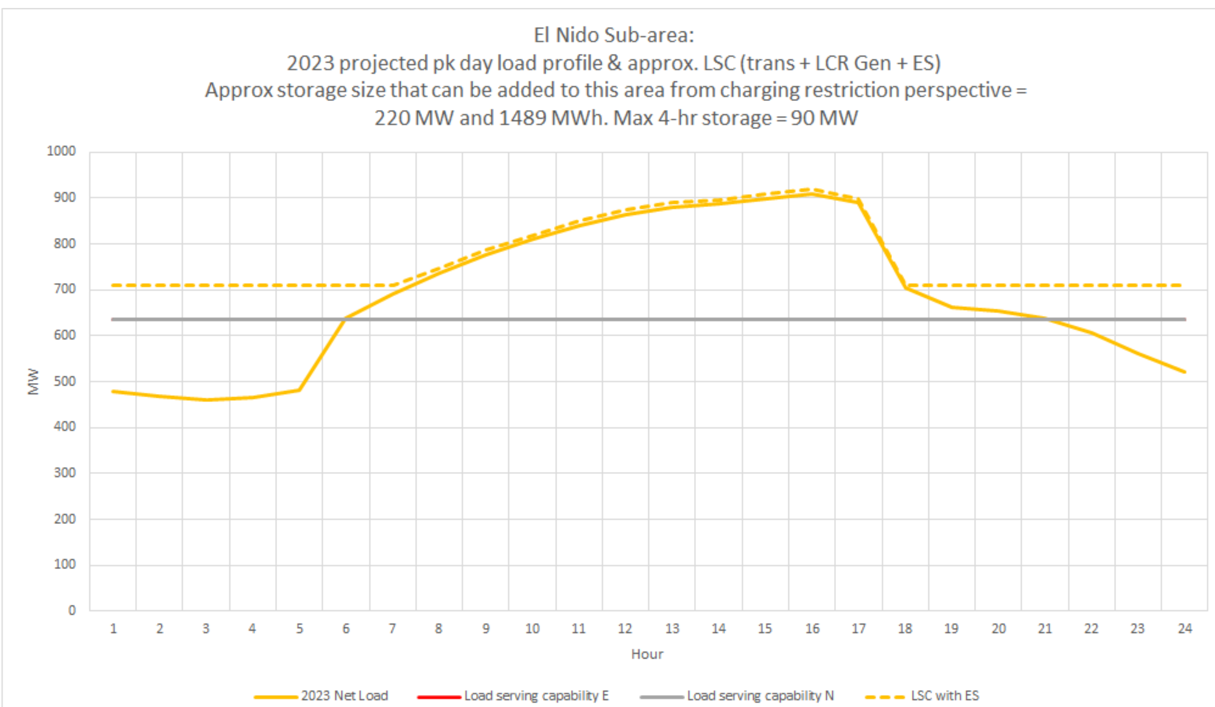


Figure 3.3-87 El Nido LCR Sub-area 2023 Load Shape and Estimated Maximum Energy Storage Capacity and Energy Based on Charging Capability Under Critical Contingency



El Nido LCR Sub-area Requirement

Table 3.3-76 identifies the sub-area requirements. The LCR requirement for Category P7 contingency is 294 MW. The LCR need decreases compared to the 2022 requirements due to lower demand forecast for the sub-area.

Table 3.3-76 El Nido LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	First Limit	P7	La Fresa - La Cienega 230 kV	La Fresa – El Nido #3 & 4 230 kV lines	294

Effectiveness factors:

All units within the El Nido Sub-area have the same effectiveness factor.

For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7630 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.9.3 *Western LA Basin Sub-area*

Western LA Basin is a sub-area of the LA Basin LCR area.

Western LA Basin LCR Sub-area Diagram

Please refer to Figure 3.3-85 above.

Western LA Basin LCR Sub-area Load and Resources

Table 3.3-77 provides the forecast load and resources in Western LA Basin LCR sub-area in 2023. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-77 Western LA Basin Sub-area 2023 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	12181	Market, Net Seller, Battery, Solar	5676	5675
AAEE	-135	MUNI	532	532
Behind the meter DG	-464	QF	57	57
Net Load	**11582**	LTPP Preferred Resources	165	165
Transmission Losses	165	Existing Demand Response	128	128
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**11747**	**Total**	**6558**	**6557**

Western LA Basin LCR Sub-area Hourly Profiles

Figure 3.3-88 illustrates the forecast 2023 annual load profile in the Western LA Basin LCR sub-area with the transmission load serving capability only.

Figure 3.3-89 provides load shape for peak load day, estimated energy storage maximum capacity and energy as well as estimated four-hour capacity amount based on its maximum charging capability under the most critical contingency.

Figure 3.3-88 Western LA Basin LCR Sub-area 2023 Annual Load Profile with Estimated Transmission Load Serving Capability Only

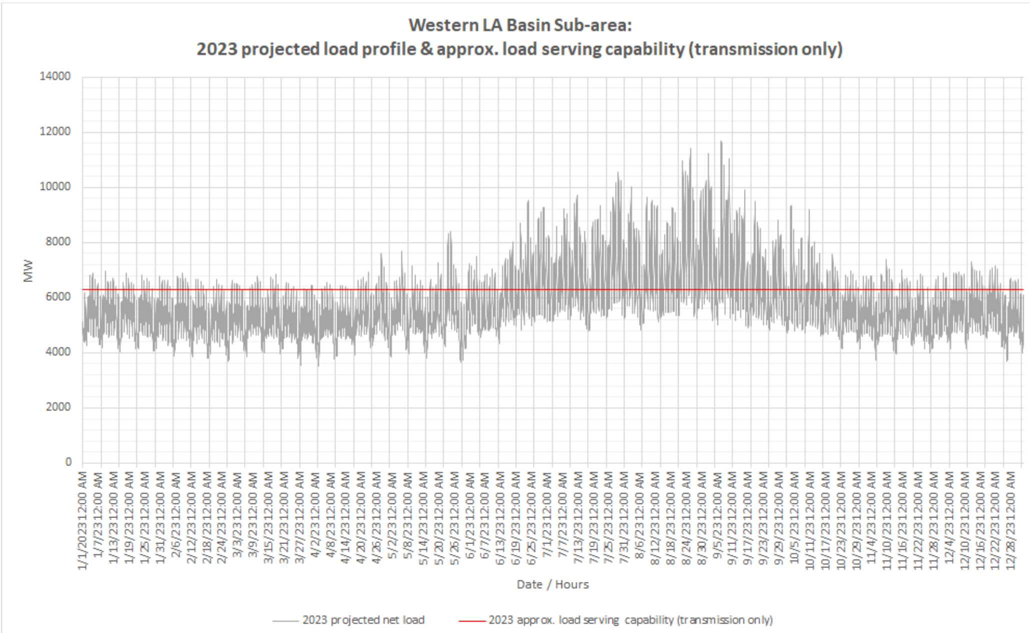
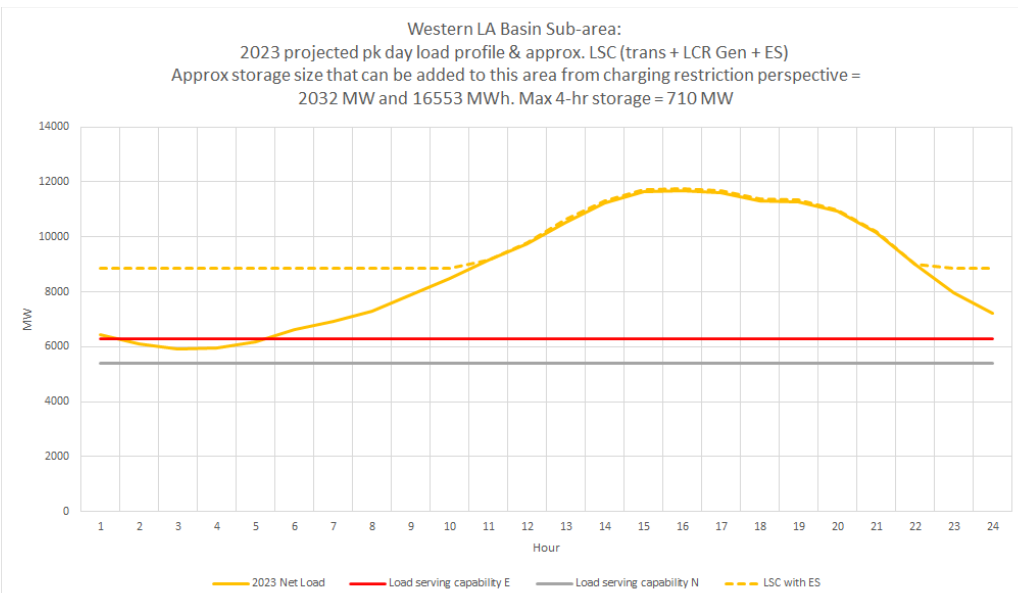


Figure 3.3-89 Western LA Basin LCR Sub-area 2023 Load Shape and Estimated Maximum Energy Storage Capacity and Energy Based on Charging Capability Under Critical Contingency



Western LA Basin LCR Sub-area Requirement

Table 3.3-78 identifies the Western LA Basin 2023 LCR sub-area requirements. The 2023 LCR need is higher than the 2022 LCR need due to the following reasons:

- The CEC demand forecast is higher compared to the 2022 study;
- New identified constraint due to higher demand as well as resources moving in the northbound direction to the LA Basin from San Diego

Table 3.3-78 Western LA Basin LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	First Limit	P7	San Onofre – San Luis Rey #1 230 kV line (line flow in the South to North direction)	San Onofre – San Luis Rey #2 and #3 230 kV lines	5487

Effectiveness factors:

See Attachment B - Table titled LA Basin.

For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7630 (G-219Z) posted at: http://www.caiso.com/Documents/2210Z.pdf

There are other combinations of contingencies in the area that could overload a significant number of 230 kV lines in this sub-area have 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 be the best indicator towards informed procurement.

3.3.9.4 *West of Devers Sub-area*

West of Devers is a sub-area of the LA Basin LCR area. The LCT study identified that the West of Devers sub-area need is satisfied by the need in the larger Eastern LA Basin sub-area.

3.3.9.5 *Valley-Devers Sub-area*

Valley-Devers is a sub-area of the LA Basin LCR area. The LCT study identified that the Valley-Devers sub-area need is satisfied by the need in the larger Eastern LA Basin sub-area.

3.3.9.6 *Valley Sub-area*

Valley is a sub-area of the LA Basin LCR area. The LCT study identified that the Valley sub-area need is satisfied by the need in the larger Eastern LA Basin sub-area.

3.3.9.7 *Eastern LA Basin Sub-area*

Eastern LA Basin is a sub-area of the LA Basin LCR area.

Eastern LA Basin LCR Sub-area Diagram

Please refer to Figure 3.3-85 above.

Eastern LA Basin LCR Sub-area Load and Resources

Table 3.3-79 provides the forecast load and resources in Eastern LA Basin LCR sub-area. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-79 Eastern LA Basin Sub-area 2023 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	8220	Market, Net Seller, battery, Wind	2422	2422
AAEE	-61	MUNI	434	434
Behind the meter DG	-493	QF	57	57
Net Load	**7666**	LTPP Preferred Resources	0	0
Transmission Losses	114	Existing Demand Response	114	114
Pumps	0	Solar	9	5
Load + Losses + Pumps	**7780**	**Total**	**3036**	**3032**

Eastern LA Basin LCR Sub-area Hourly Profiles

Figure 3.3-90 illustrates the forecast 2023 annual load profile in the Eastern LA Basin LCR sub-area with the transmission load serving capability only.

Figure 3.3-91 provides load shape for peak load day, estimated energy storage maximum capacity and energy as well as estimated four-hour capacity amount based on its maximum charging capability under the most critical contingency.

Figure 3.3-90 Eastern LA Basin LCR Sub-area 2023 Annual Load Profile with Estimated Transmission Load Serving Capability Only

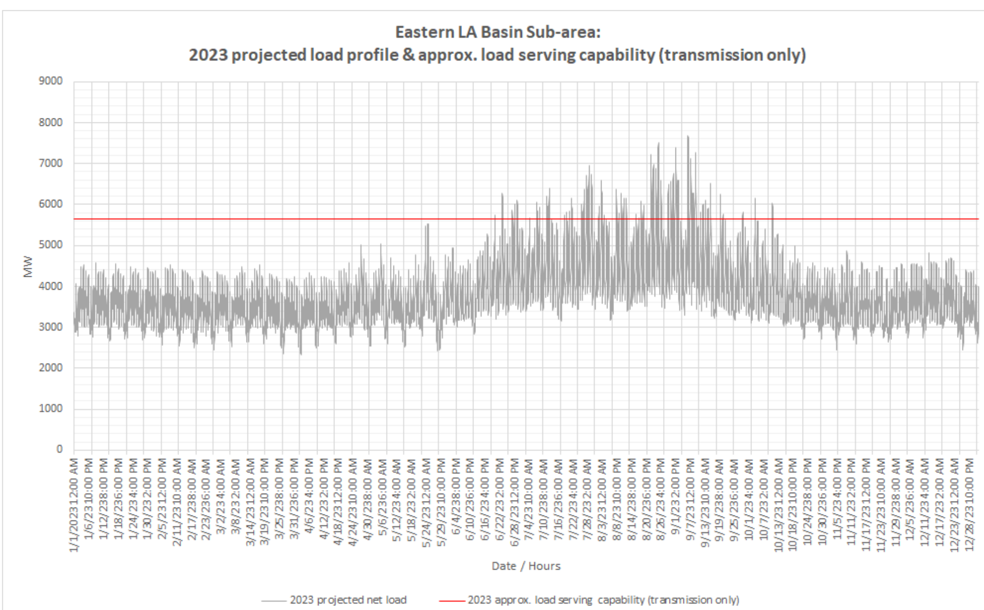
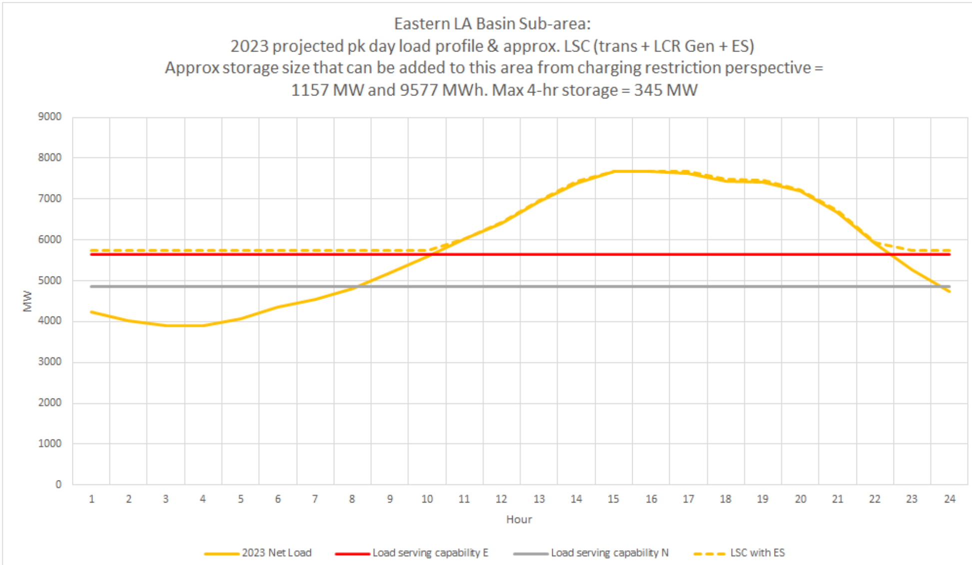


Figure 3.3-91 Eastern LA Basin LCR Sub-area 2023 Load Shape and Estimated Maximum Energy Storage Capacity and Energy Based on Charging Capability Under Critical Contingency



Eastern LA Basin LCR Sub-area Requirement

Table 3.3-80 identifies the sub-area LCR requirements. The LCR need for the Eastern LA Basin is lower than the 2022 LCR need due to the following:

- Different transmission constraint (P7) from the previously identified P1 & P7 contingency of the Serrano-Valley 500 kV and the Devers-Red Bluff 500 kV Lines #1 and 2 due to retirement of the common corridor contingency criteria from WECC. The new constraint due to the P7 contingency as mentioned in the following table requires lower local capacity requirement in the eastern LA Basin sub-area.
- Higher LCR need for the western LA Basin (see western LA Basin section). Higher resource dispatch in the western LA Basin helps reduce the power transfer from the eastern to western LA Basin, thus reducing the LCR need in the eastern LA Basin.

Table 3.3-80 Eastern LA Basin LCR Sub-area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	First Limit	P7	San Onofre – San Luis Rey #1 230 kV line (line flow in the South to North direction)	San Onofre – San Luis Rey #2 and #3 230 kV lines	2042

Effectiveness factors:

All units within the Eastern LA Basin Sub-area have the same effectiveness factor.

For most helpful procurement information please read procedure 2210Z Effectiveness Factors under 7580, 7590, 7630 and 7750 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.9.8 *LA Basin Overall*

LA Basin LCR Hourly Profiles

Figure 3.3-92 illustrates the forecast 2023 annual load profile in the LA Basin LCR sub-area with the transmission load serving capability only.

Figure 3.3-93 provides load shape for peak load day, estimated energy storage maximum capacity and energy as well as estimated four-hour capacity amount based on its maximum charging capability under the most critical contingency.

Figure 3.3-92 LA Basin LCR Area 2023 Annual Load Profile with Estimated Transmission Load Serving Capability Only

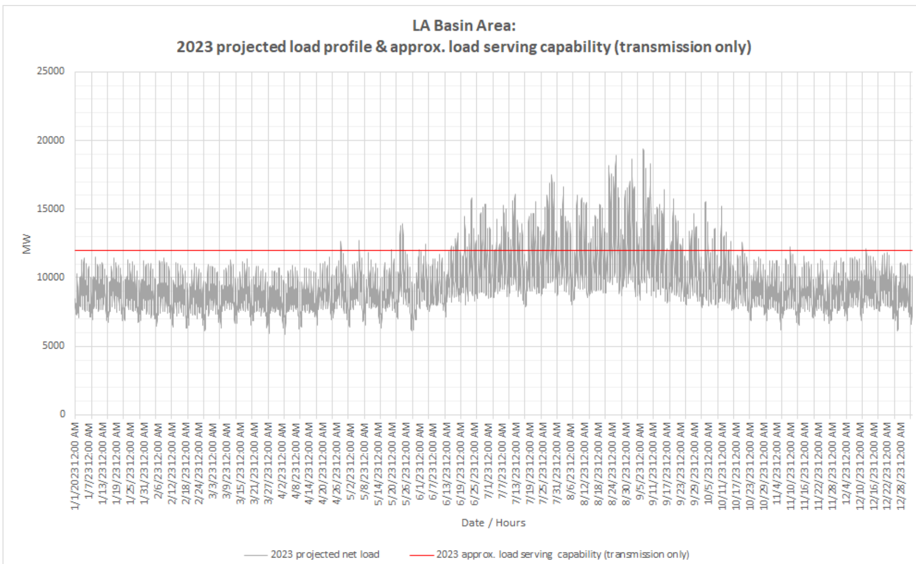
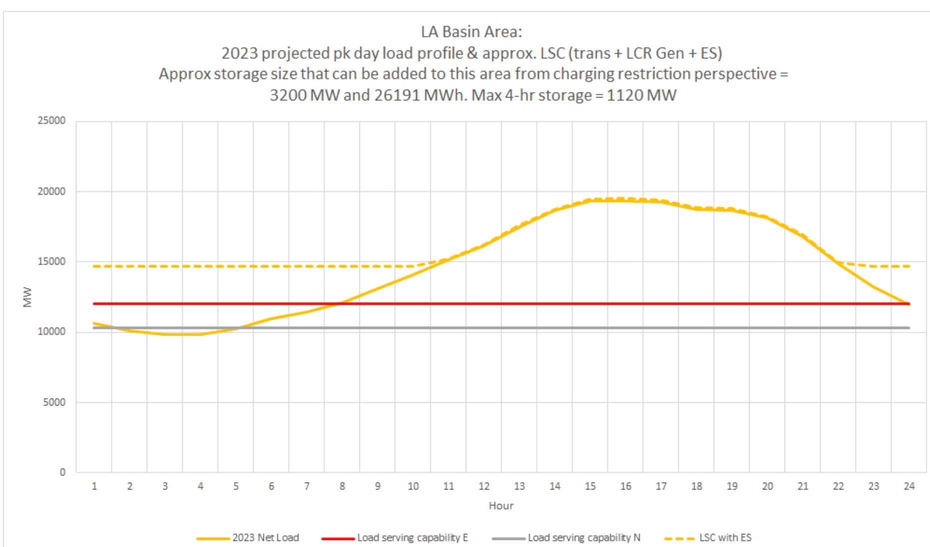


Figure 3.3-93 LA Basin LCR Area 2023 Load Shape and Estimated Maximum Energy Storage Capacity and Energy Based on Charging Capability Under Critical Contingency



The following is a summary of estimated amount of storage for the sub-areas and the overall area based on maximum charging capability perspective. Due to non-linearity of power system and the various critical contingencies and load shapes for each sub-area and the overall area, it is noted that the estimated maximum amount of storage for the sub-areas many not add up to be sum of the overall area. The estimated maximum amount of storage for the LCR area is the amount listed in the last row in the table.

Table 3.3-81 Estimated LA Basin Subareas and Overall Area Energy Storage Capacity and Energy Based on Maximum Charging Capability Perspective

Area/Sub-area	Estimated Energy Storage Maximum Capacity (MW)	Estimated Energy Storage Maximum Energy (MWh)	1 for 1 Replacement with 4-hour Energy Storage Capacity (MW)
El Nido sub-area	220	1489	90
Western LA Basin sub-area	2032	16553	710
Eastern LA Basin sub-area	1157	9577	345
Overall LA Basin area	3200	26191	1120

LA Basin LCR area Requirement

Table 3.3-82 identifies the area requirements. The LCR requirement for the LA Basin is the sum of the Western and Eastern LA Basin local capacity requirements.

Table 3.3-82 LA Basin LCR area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	First Limit	P7	San Onofre – San Luis Rey #1 230 kV line (line flow in the South to North direction) – Sum of Western and Eastern LA Basin	San Onofre – San Luis Rey #2 and #3 230 kV lines	7529

Effectiveness factors:

See Attachment B - Table titled LA Basin.

For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7550, 7570, 7580, 7590, 7630, and 7750 posted at: http://www.caiso.com/Documents/2210Z.pdf

There are other combinations of contingencies in the area that could overload other 230 kV lines in this sub-area resulting in 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 be the best indicator towards informed procurement.

Changes compared to last year's results

Compared with 2022, the demand modeled for the LA Basin is 608 MW higher and the LCR needs have increased by 883 MW. The increase in LCR need for the overall LA Basin is driven by the higher demand forecast and newly identified constraint.

3.3.10 San Diego-Imperial Valley Area

3.3.10.1 *Area Definition:*

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

Imperial Valley – North Gila 500 kV Line

Otay Mesa – Tijuana 230 kV Line

San Onofre - San Luis Rey #1 230 kV Line

San Onofre - San Luis Rey #2 230 kV Line

San Onofre - San Luis Rey #3 230 kV Line

San Onofre – Talega 230 kV #1 and #2 Lines

Imperial Valley – El Centro 230 kV Line

Imperial Valley – La Rosita 230 kV Line

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

Imperial Valley is in North Gila is out

Otay Mesa is in Tijuana is out

San Onofre is out San Luis Rey is in

San Onofre is out San Luis Rey is in

San Onofre is out San Luis Rey is in

San Onofre is out Talega is in

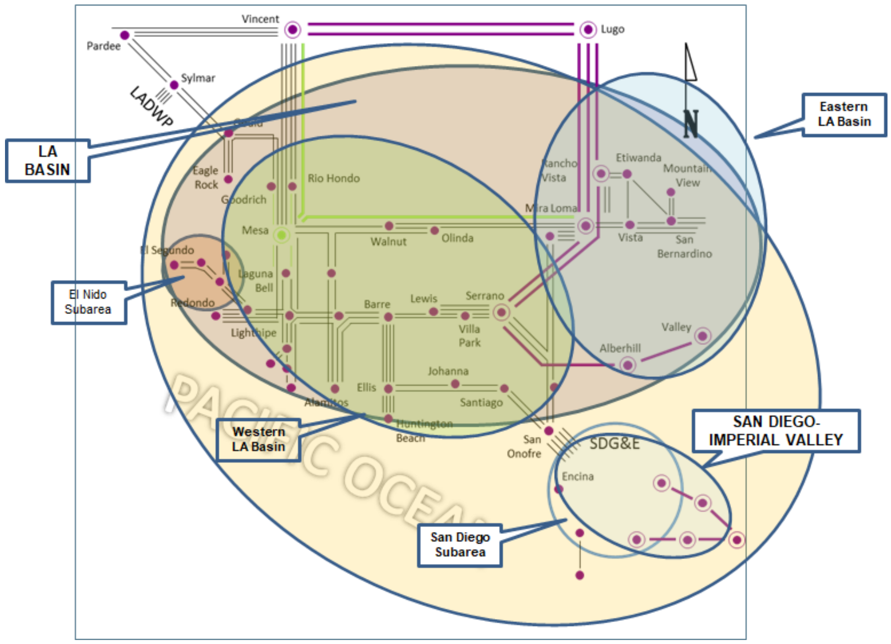
San Onofre is out Capistrano is in

Imperial Valley is in El Centro is out

Imperial Valley is in La Rosita is out

San Diego-Imperial Valley LCR Area Diagram

Figure 3.3-94 San Diego-Imperial Valley LCR Area



San Diego-Imperial Valley LCR Area Load and Resources

Table 3.3-83 provides the forecast load and resources in the San Diego-Imperial Valley LCR Area in 2023. The list of generators within the LCR area are provided in Attachment A.

In the year 2023 the estimated time of local area peak is 8:00 PM (PDT).

At the local area peak time the estimated, ISO metered, solar output is 0.00%.

If required, all non-solar technology type resources are dispatched at NQC.

Table 3.3-83 San Diego-Imperial Valley LCR Area 2023 Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	4649	Market, Net Seller, Wind	3763	3763
AAEE	-28	Solar (production is "0" at 20:00 hr.)	396	0
Behind the meter DG	0	QF	2	2
Net Load	**4621**	LTPP Preferred Resources	0	0
Transmission Losses	147	Existing Demand Response	26	26
Pumps	0	Battery, Hybrid	1171	1171
Load + Losses + Pumps	**4768**	**Total**	**5358**	**4962**

Approved transmission projects modeled:

1. TL644, South Bay-Sweetwater: Reconductor
2. Artesian 230 kV expansion with 69 kV upgrade
3. Second San Marcos–Escondido 69 kV line
4. TL674A Loop-in (Del Mar-North City West) & Removal of TL666D (Del Mar-Del Mar Tap)
5. Reconductor TL692: Japanese Mesa - Las Pulgas
6. Rose Canyon-La Jolla 69 kV T/L upgrade
7. S-Line (aka Imperial Valley – El Centro 230kV) upgrade

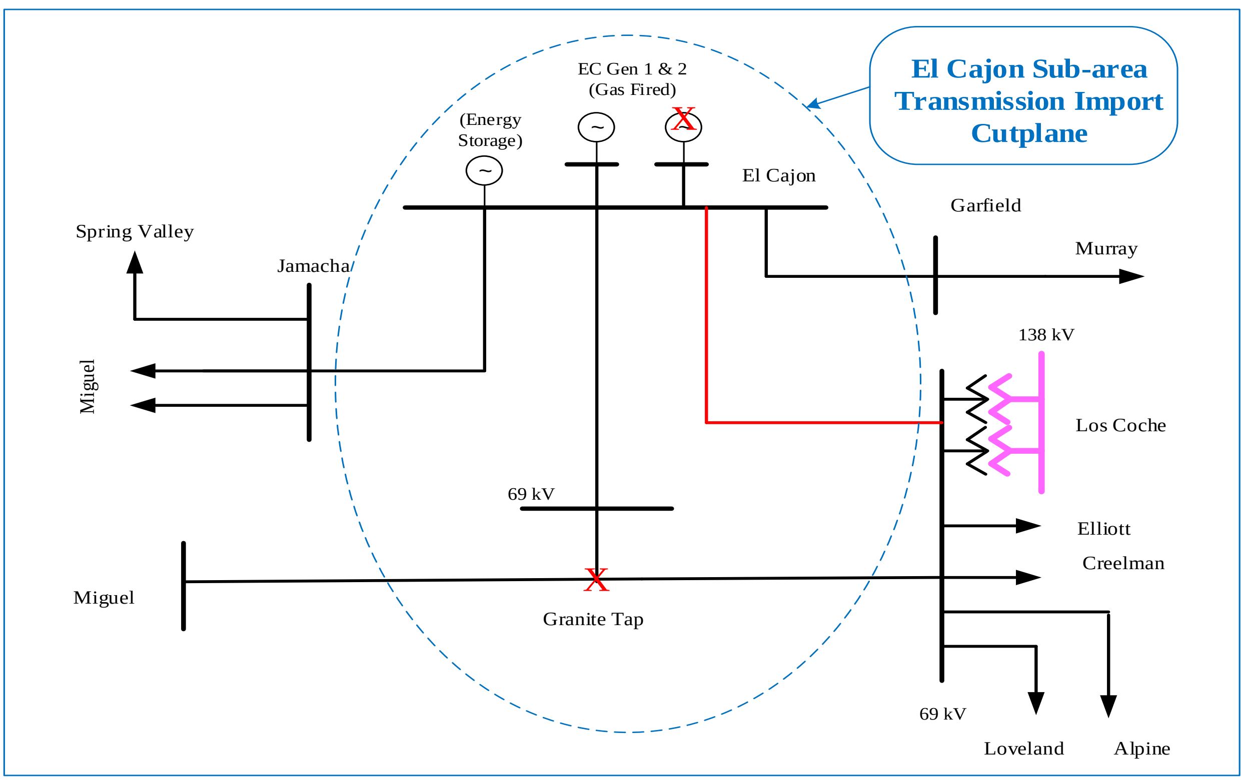
Also the 500kV line series capacitors on the on the Southwest Powerlink and Sunrise Powerlink lines are bypassed in the study case.

3.3.10.2 *El Cajon Sub-area*

El Cajon is sub-area of the San Diego-Imperial Valley LCR area.

El Cajon LCR Sub-area Diagram

Figure 3.3-95 El Cajon LCR Sub-area



El Cajon LCR Sub-area Load and Resources

Table 3.3-84 provides the forecast load and resources in El Cajon LCR sub-area in 2023. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-84 El Cajon LCR Sub-area 2023 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	184	Market, Net Seller	94	94
AAEE	-1	MUNI	0	0
Behind the meter DG	0	QF	0	0
Net Load	**183**	LTPP Preferred Resources	0	0
Transmission Losses	1	Existing 20-minute Demand Response	0	0
Pumps	0	Battery	7	7
Load + Losses + Pumps	**184**	**Total**	**101**	**101**

El Cajon LCR Sub-area Hourly Profiles

Figure 3.3-96 illustrates the forecast 2023 annual load forecast profile in the El Cajon LCR sub-area and the Category P1 (L-1 Contingency) transmission load serving capability without generation.

Figure 3.3-97 provides the 2023 daily load forecast profile for the peak day, estimated amount of energy storage that can be added to this local area from charging restriction perspective, and estimated four-hour capacity amount under the most critical contingency.

Figure 3.3-96 El Cajon LCR Sub-area 2023 Annual Load Forecast Profiles

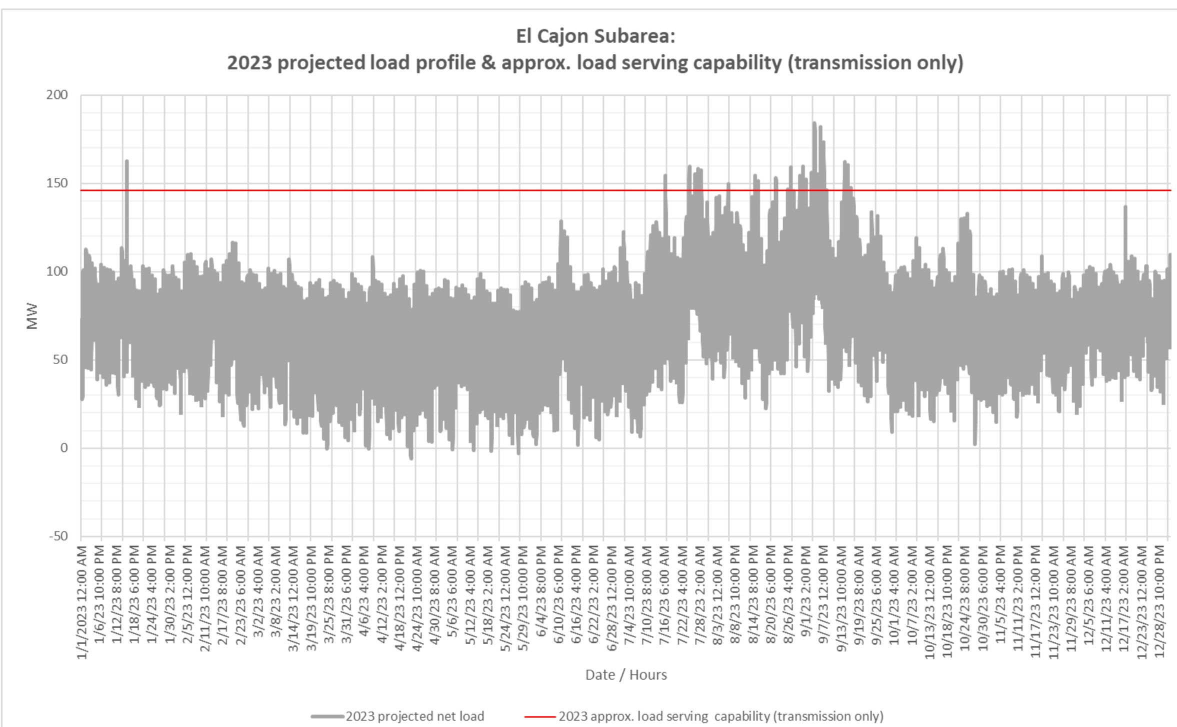
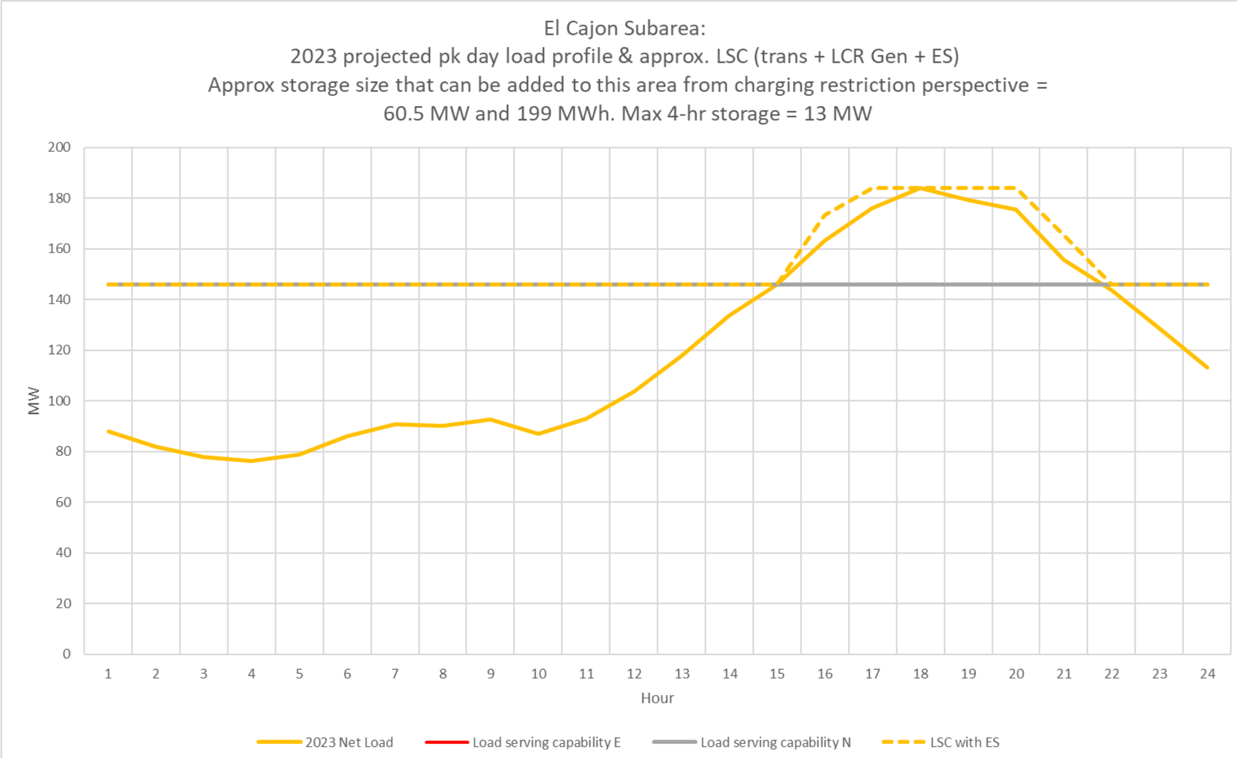


Figure 3.3-97 El Cajon LCR Sub-area 2023 Peak Day Forecast Profiles



El Cajon LCR Sub-area Requirement

Table 3.3-85 identifies the sub-area 2023 LCR requirements. The Category P3 (Single Contingency) LCR requirement is 86 MW.

Table 3.3-85 El Cajon LCR Sub-area Requirements

Year	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	P3	El Cajon – Los Coches 69 kV Line (TL631)	El Cajon unit out of service followed by TL632 Granite–Los Coches–Miguel 69 kV 3-Terminal Line	86

Effectiveness factors:

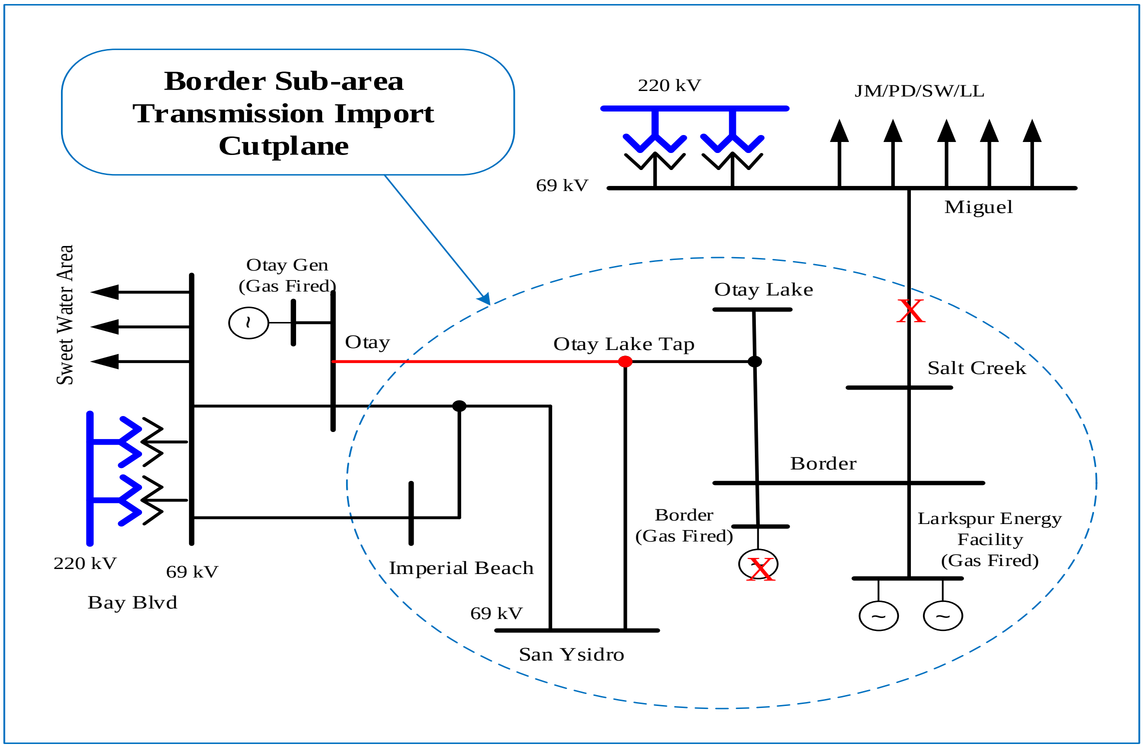
All units within the El Cajon sub-area have the same effectiveness factor.

3.3.10.3 *Border Sub-area*

Border is sub-area of the San Diego – Imperial Valley LCR area.

Border LCR Sub-area Diagram

Figure 3.3-98 Border LCR Sub-area



Border LCR Sub-area Load and Resources

Table 3.3-86 provides the forecast load and resources in Border LCR sub-area. The list of generators within the LCR Sub-area are provided in Attachment A.

Table 3.3-86 Border Sub-area Forecast Load and Resources

Load (MW)		**Generation (MW)**	**Aug NQC**	**At Peak**
Gross Load	141	Market, Net Seller, Battery	145	145
AAEE	-1	MUNI	0	0
Behind the meter DG	0	QF	0	0
Net Load	**140**	LTPP Preferred Resources	0	0
Transmission Losses	1	Existing 20-minute Demand Response	0	0
Pumps	0	Mothballed	0	0
Load + Losses + Pumps	**141**	**Total**	**145**	**145**

Border LCR Sub-area Hourly Profiles

Figure 3.3-99 illustrates the 2023 annual load forecast profile in the Border LCR sub-area and the Category P1 transmission load serving capability without gas generation.

Figure 3.3-100 illustrates the 2023 daily load forecast profile for the peak day, estimated amount of energy storage that can be added to this local area from charging restriction perspective, and estimated four-hour capacity amount under the most critical contingency.

Figure 3.3-99 Borden LCR Sub-area 2023 Annual Day Forecast Profiles

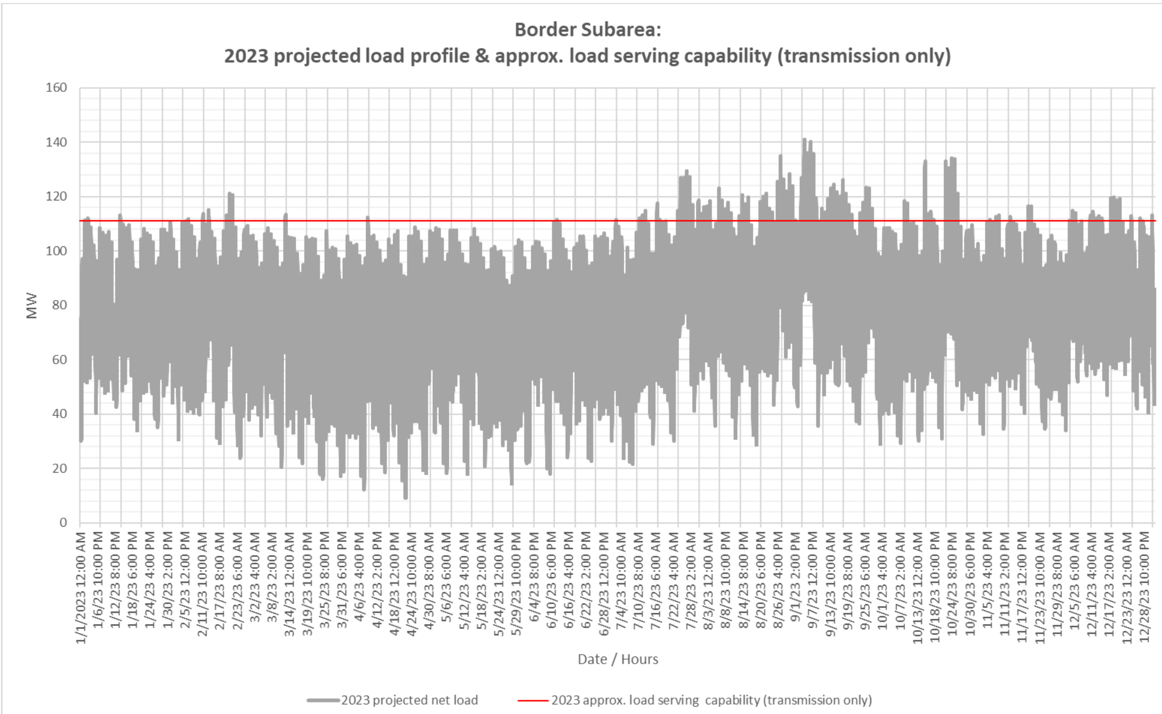
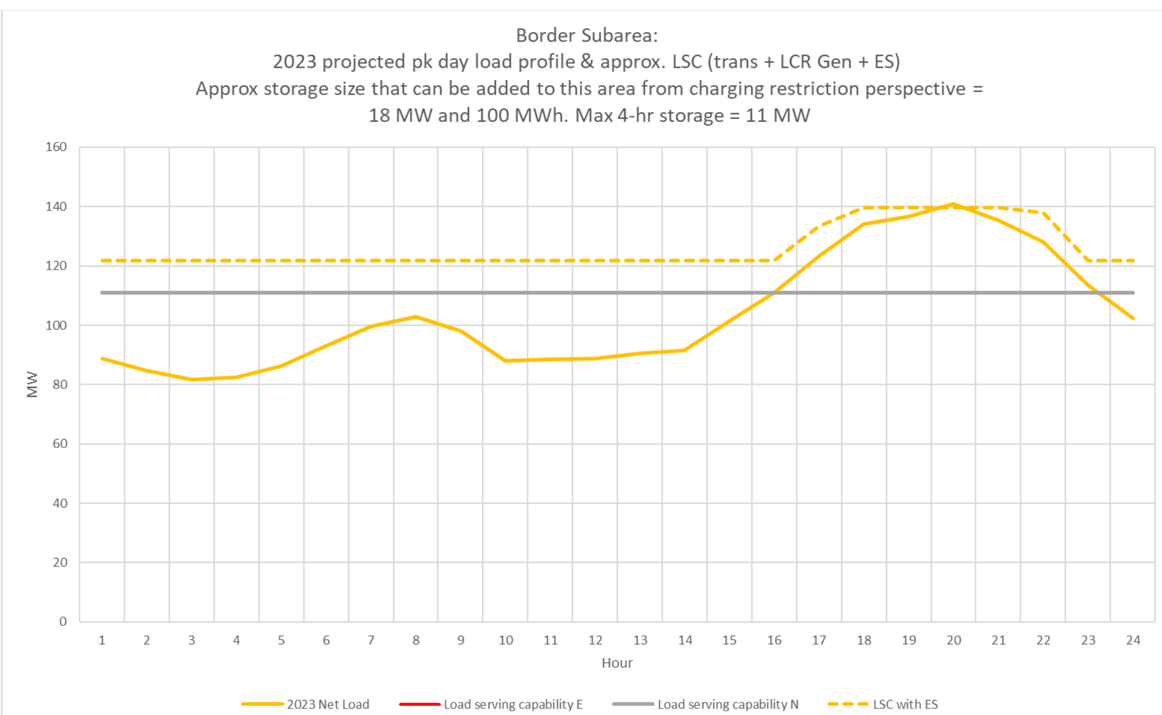


Figure 3.3-100 Border LCR Sub-area 2023 Peak Day Forecast Profiles



Border LCR sub-area requirement

Table 3.3-87 identifies the sub-area requirements. The LCR requirement for Category P3 contingency is 69 MW.

Table 3.3-87 Border LCR Sub-area Requirements

Year	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	P3	Otay – Otay Lake Tap 69 kV (TL649)	Border unit out of service followed by the outage of Miguel-Salt Creek 69 kV #1 (TL6910)	69

Effectiveness factors:

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

3.3.10.4 *San Diego Sub-area*

San Diego is a sub-area of the San Diego-Imperial Valley LCR area.

San Diego LCR Sub-area Diagram

Please refer to Figure 3.3-94 above.

San Diego LCR Sub-area Load and Resources

Table 3.3-88 provides the forecast load and resources in San Diego LCR sub-area. The list of generators within the LCR sub-area are provided in Attachment A.

Table 3.3-88 San Diego Sub-area 2023 Forecast Load and Resources

Load (MW)		Generation (MW)	Aug NQC	At Peak
Gross Load	4649	Market, Net Seller, Wind	2725	2725
AAEE	-28	Solar	15	0
Behind the meter DG	0	QF	2	2
Net Load	**4621**	LTPP Preferred Resources	0	0
Transmission Losses	147	Existing Demand Response	26	26
Pumps	0	Battery, Hybrid	957	957
Load + Losses + Pumps	**4768**	**Total**	**3725**	**3710**

San Diego LCR Sub-area Hourly Profiles

Figure 3.3-101 illustrates the forecast 2023 annual load profile in the San Diego LCR sub-area with the transmission load serving capability only.

Figure 3.3-102 provides load shape for peak load day, estimated energy storage maximum capacity and energy as well as estimated four-hour capacity amount based on its maximum charging capability under the most critical contingency.

Figure 3.3-101 San Diego LCR Sub-area 2023 Annual Load Profile with Estimated Transmission Load Serving Capability Only

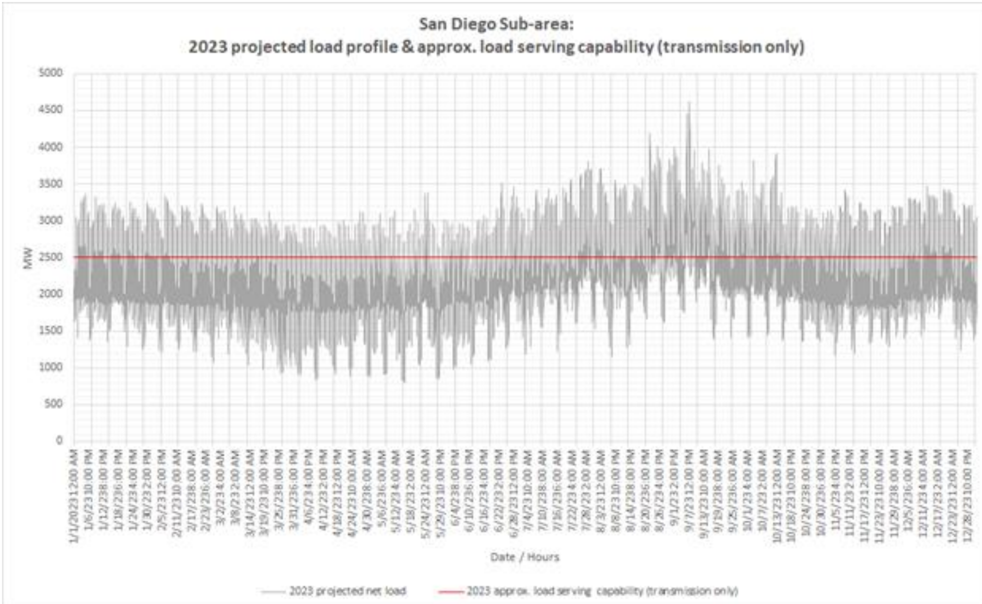
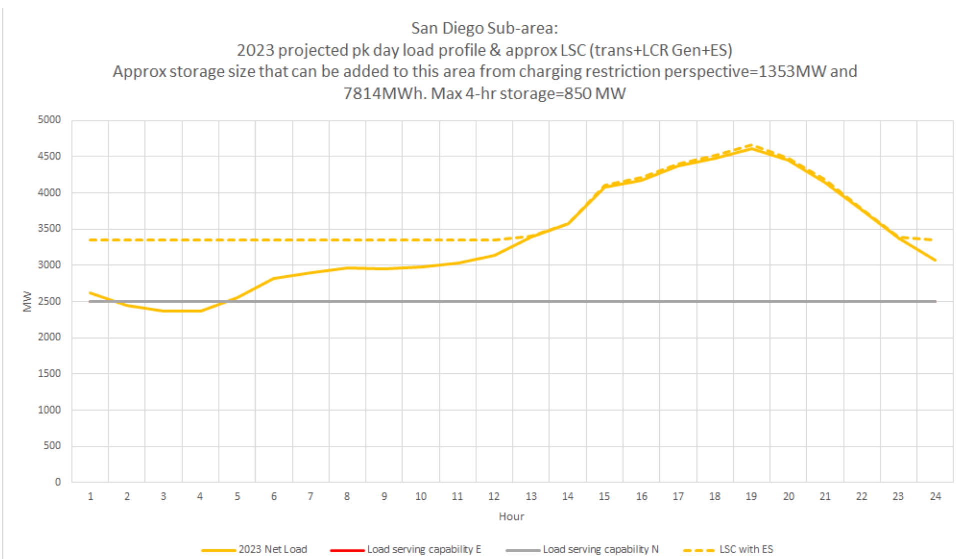


Figure 3.3-102 San Diego LCR Sub-area 2023 Load Shape and Estimated Maximum Energy Storage Capacity and Energy Based on Charging Capability Under Critical Contingency



San Diego LCR Sub-area Requirement

Table 3.3-89 identifies the sub-area LCR requirements. The Category P6 contingency LCR requirement is 2659 MW. The LCR need is higher due to higher demand forecast from the CEC for the San Diego area.

Table 3.3-89 San Diego Sub-area LCR Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	First Limit	P6	Remaining Sycamore-Suncrest 230 kV line Tijuana-Otay Mesa 230 kV line	ECO-Miguel 500 kV line, system readjustment, followed by one of the Sycamore-Suncrest 230 kV lines	2659

Effectiveness factors:

See Attachment B - Table titled San Diego.

For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7820 posted at: http://www.caiso.com/Documents/2210Z.pdf

3.3.10.5 *San Diego-Imperial Valley Overall*

San Diego-Imperial Valley LCR area Hourly Profiles

Since the San Diego sub-area has all the substation loads, the overall San Diego-Imperial Valley area has the same load profile as the San Diego bulk sub-area. The Imperial Valley area has generating resources.

Figure 3.3-103 illustrates the forecast 2023 annual load profile in the San Diego-Imperial LCR area with the transmission load serving capability only.

Figure 3.3-104 provides load shape for peak load day, estimated energy storage maximum capacity and energy as well as estimated four-hour capacity amount based on its maximum charging capability under the most critical contingency. Table 3.3-90 provides a summary of the estimated amount of energy storage that can be accommodated from the charging limitation perspective for the subareas and the overall LCR area.

Figure 3.3-103 San Diego-Imperial Valley LCR Area 2023 Annual Load Profile with Estimated Transmission Load Serving Capability Only

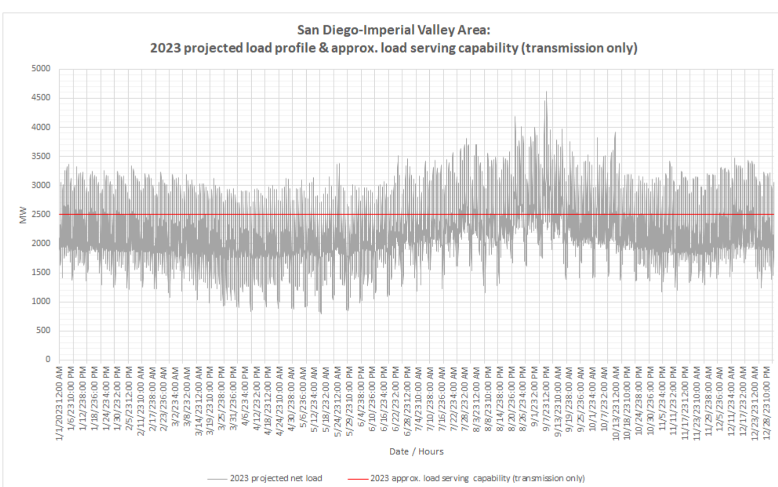
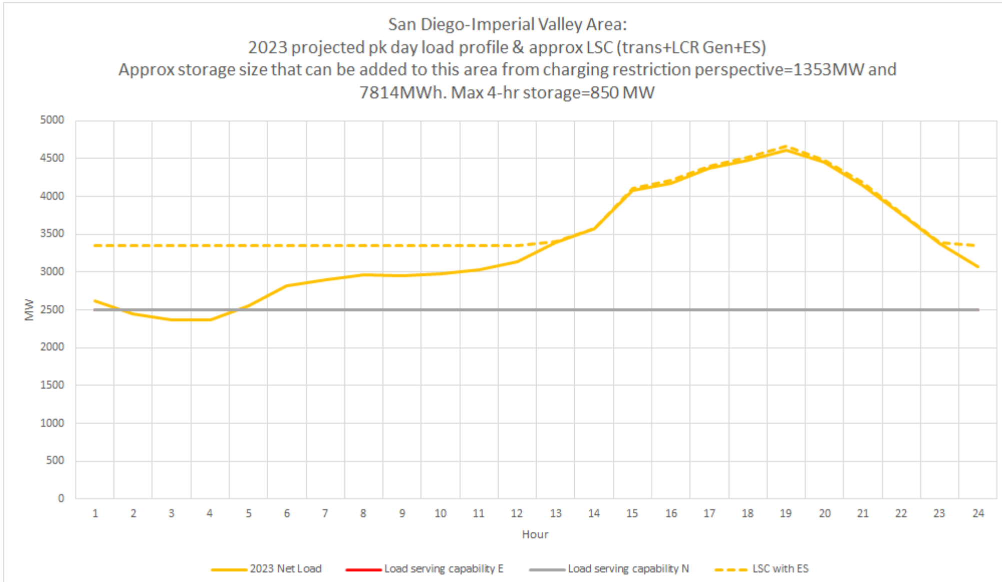


Figure 3.3-104 San Diego-Imperial Valley LCR Area 2023 Load Shape and Estimated Maximum Energy Storage Capacity and Energy Based on Charging Capability Under Critical Contingency



The following is a summary of estimated amount of storage for the sub-areas and the overall area based on maximum charging capability perspective. Due to non-linearity of power system and the various critical contingencies and load shapes for each sub-area and the overall area, it is noted that the estimated maximum amount of storage for the sub-areas many not add up to be sum of the overall area. Since the San Diego sub-area has all the substation loads, the overall San Diego-Imperial Valley area has the same load profile as the San Diego bulk sub-area and therefore same amount of energy storage for the San Diego sub-area. The Imperial Valley area (of the overall San Deigo-Imperial Valley) has generating resources only.

Table 3.3-90 Estimated San Diego Sub-areas and Overall Area Energy Storage Capacity and Energy Based on Maximum Charging Capability Perspective

Area/Sub-area	Estimated Energy Storage Maximum Capacity (MW)	Estimated Energy Storage Maximum Energy (MWh)	1 for 1 Replacement with 4-hour Energy Storage Capacity (MW)
El Cajon sub-area	61	199	13
Border sub-area	18	100	11
San Diego sub-area	1353	7814	850
Overall San Diego-Imperial Valley Area	1353	7814	850

San Diego-Imperial Valley LCR area Requirement

Table 3.3-91 identifies the area LCR requirements. The LCR requirement for Category P3 contingency is 3332 MW.

Table 3.3-91 San Diego-Imperial Valley LCR area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2023	First Limit	P3	Yucca-Pilot Knob 161 kV line, Pilot Knob-El Centro 161 kV line, Yucca 161/69 kV transformers Calipat-CSF Tap 92 kV	TDM generation, system readjustment, followed by Imperial Valley-North Gila 500 kV	3332

Effectiveness factors:

See Attachment B - Table titled San Diego.

For other helpful procurement information please read procedure 2210Z Effectiveness Factors under 7820 posted at: http://www.caiso.com/Documents/2210Z.pdf

Changes compared to last year's results

Compared with the 2022 LCT Study results, the demand forecast is higher by 188 MW. The overall LCR needs for the San Diego-Imperial Valley decreases by 661 MW due to the following:

a) Implementation of the S-line upgrade project;
b) Addition of the transmission upgrades in IID (i.e., addition of El Centro 230/92 kV Bank #2); and
c) Utilization of APS and WAPA RAS/protection schemes for the Yucca and Gila 161/69kV transformers under contingency condition.

3.3.11 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

3.4 Summary of Engineering Estimates for Intermediate Years by Local Area

Engineering estimates, along with detailed explanations for contributing factors in each local area are given below per methodology explained in Chapter 2 above. The estimates represent an engineering approximation. They are not actual technical studies and they may be superseded by actual technical studies.

3.4.19.1 *Humboldt Area*

The net peak load growth from 2023 to 2027 is estimated at 0.75 MW/year.

There is no new transmission project that directly affects the LCR change from 2023 to 2027, although the Maple Creek reactive support is now rescoped to Willow Creek 60 kV substation.

There is no new resource that directly affects the LCR change from 2023 to 2027.

There is no projected change in resource contractual status that directly affects the LCR change from 2023 to 2027.

There is no resource projected to retire that directly affects the LCR change from 2023 to 2027.

The total increase for each intermediate year depends only on the load forecast and the study results for year 2023 and it is estimated at about 1.5 MW/year for Category P6.

Table 3.4-1 ISO's estimated Humboldt LCR need:

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2024	First Limit	P6	Humboldt-Trinity 115 kV	Cottonwood-Bridgeville 115 kV & Humboldt - Humboldt Bay 115 kV	143
2025	First Limit	P6	Humboldt-Trinity 115 kV	Cottonwood-Bridgeville 115 kV & Humboldt - Humboldt Bay 115 kV	144

3.4.19.2 *North Coast/ North Bay Area*

The net peak load growth from 2023 to 2027 is estimated at about 6.75 MW/year.

There is no new transmission project that directly affects the LCR change from 2023 to 2027.

There is no new resource that directly affects the LCR change from 2023 to 2027.

There is no projected change in resource contractual status that directly affects the LCR change from 2023 to 2027.

There is no resource projected to retire that directly affects the LCR change from 2023 to 2027.

The total increase for each intermediate year depends on load growth and the study results for both year 2023 and 2027 and it is estimated at about 42 MW/year for Category P3. However starting year 2025 the area will also be deficient since there are only 911 MW of NQC available.

Table 3.4-2 ISO's estimated North Coast/ North Bay LCR need:

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2024	First Limit	P3	Tulucay - Vaca Dixon 230 kV Line	Vaca Dixon - Lakeville 230 kV with DEC out of service	899
2025	First Limit	P3	Tulucay - Vaca Dixon 230 kV Line	Vaca Dixon - Lakeville 230 kV with DEC out of service	911

3.4.19.3 *Sierra Area*

The net peak load growth from 2023 to 2027 is estimated at 22.25 MW/year.

There are 2 new transmission projects that directly affects the LCR change from 2023 to 2027.

- Rio Oso 230/115 kV transformer upgrade (July 2023)
- Rio Oso Area 230 kV Voltage Support (Sept 2023)

Both projects inpact years 2024 and 2025, however the impact only relates to the deficiency numbers for certain sub-areas and has no effect on the overall Sierra requirement.

There is no new resource that directly affects the LCR change from 2023 to 2027.

There is no projected change in resource contractual status that directly affects the LCR change from 2023 to 2027.

There is no resource projected to retire that directly affects the LCR change from 2023 to 2027.

The total requirement for both year 2024 and 2025 depend on the result for year 2023 only plus an estimated increase of 48.75 MW/year for Category P3.

Table 3.4-3 ISO's estimated Sierra LCR need:

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2024	First limit	P6	Table Mountain – Pease 60 kV	Table Mountain – Palermo 230 kV Table Mountain – Rio Oso 230 kV	1199
2025	First limit	P6	Table Mountain – Pease 60 kV	Table Mountain – Palermo 230 kV Table Mountain – Rio Oso 230 kV	1248

3.4.19.4 *Stockton Area*

The net peak load growth from 2023 to 2027 is estimated at 14.25 MW/year.

There is one new transmission project that directly affects the LCR change from 2023 to 2027. The in-service date is in 2027 and therefore it will not impact the LCR results in 2024 and 2025.

There is no projected change in resource contractual status that directly affects the LCR change from 2023 to 2027.

There is no resource projected to retire that directly affects the LCR change from 2023 to 2027.

The total increase for each intermediate year depends only on the available resources in the Lockeford and Tesla-Bellota sub-area, and since they are both deficient in 2023, they will remain deficient in 2024 and 2025.

Table 3.4-4 ISO's estimated Stockton LCR need:

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2024	First Limit	N/A	Stockton Overall		579
2025	First Limit	N/A	Stockton Overall		579

3.4.19.5 *Bay Area*

The net peak load growth from 2023 to 2027 is estimated at 149.25 MW/year.

There are a few new transmission projects that directly affect the LCR change from 2023 to 2027.

However for both years the TPP project impact is minimal to the Bay Area overall requirement.

There are no new resources that directly affect the LCR change from 2023 to 2027.

There is no projected change in resource contractual status that directly affects the LCR change from 2023 to 2027.

There are no resources projected to retire that directly affects the LCR change from 2023 to 2027.

The total decrease for each intermediate year depends on the load increase and the study results between years 2023 and 2027 and it is estimated at about 57 MW/year for Category P6.

Table 3.4-5 ISO's estimated Bay Area LCR need:

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2024	First limit	P6	Metcalf 500/230 kV #13 transformer	Metcalf 500/230 kV #11 & #12 transformers	7369
2025	First limit	P6	Metcalf 500/230 kV #13 transformer	Metcalf 500/230 kV #11 & #12 transformers	7426

3.4.19.6 *Fresno Area*

The net peak load growth from 2023 to 2027 is estimated at 26 MW/year.

There are a few new transmission projects that directly affect the LCR change from 2023 to 2027.

The TPP project impact is minimal to both years because none of the projects directly impact the Fresno overall LCR need.

There are no new resources that directly affect the LCR change from 2023 to 2027.

There is no projected change in resource contractual status that directly affects the LCR change from 2023 to 2027.

There is no resource projected to retire that directly affects the LCR change from 2023 to 2027.

The total increase for each intermediate year depends on load growth and the study results between years 2023 and 2027 and it is estimated at about 77.25 MW/year for Category P6.

Table 3.4-6 ISO's estimated Fresno LCR need:

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2024	First limit	P6	GWF-Contandida 115 kV Line	Panoche-Helm 230 kV Line and Gates-McCall 230 kV line	1947
2025	First limit	P6	GWF-Contandida 115 kV Line	Panoche-Helm 230 kV Line and Gates-McCall 230 kV line	2025

3.4.19.7 *Kern Area*

The net peak load growth from 2023 to 2027 is estimated at 1.25 MW/year.

There are one new transmission projects that directly affect the LCR change from 2023 to 2027. (With an April 2024 in-service date.)

There are no new resources that directly affect the LCR change from 2023 to 2027.

There is no projected change in resource contractual status that directly affects the LCR change from 2023 to 2027.

There is no resource projected to retire that directly affects the LCR change from 2023 to 2027.

The total requirement for each intermediate year depends on the load increase and the study results regarding South Kern PP sub-area in year 2027 (with the project in-service) and it is estimated to be a reduction by about 1.25 MW/year for Category P6.

Table 3.4-7 ISO's estimated Kern LCR need:

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2024	N/A	P6	Aggregate of Sub-areas.		316
2025	N/A	P6	Aggregate of Sub-areas.		318

3.4.19.8 *Big Creek/Ventura Area*

The net peak load growth from 2023 to 2027 is estimated at 17.50 MW/year.

There are one new transmission project that directly affect the LCR change from 2023 to 2027.

The Sylmar-Pardee 230 kV Rating Increase Project does not influences years 2024 and 2025 however does influence year 2026 and 2027 as a step down decrease of LCR needs.

There are no new resources that directly affect the LCR change from 2023 to 2027.

There is no projected change in resource contractual status that directly affects the LCR change from 2023 to 2027.

There are 2 resources projected to retire that directly affects the LCR change from 2023 to 2027. This change will not significantly impact the overall LCR needs.

The total LCR requirement for year 2024 and 2025 are only dependent on year 2023 results and load growth between years.

Table 3.4-8 ISO's estimated Big Creek/Ventura LCR need:

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2024	First Limit	P6	Remaining Sylmar - Pardee 230 kV	Lugo - Victorville 500 kV line followed by one of the Sylmar - Pardee #1 or #2 230 kV lines	2258
2025	First Limit	P6	Remaining Sylmar - Pardee 230 kV	Lugo - Victorville 500 kV line followed by one of the Sylmar - Pardee #1 or #2 230 kV lines	2275

3.4.19.9 *LA Basin Area*

The net peak load growth from 2023 to 2027 is estimated at 93.50 MW/year.

There are two new transmission projects that directly affect the LCR change from 2023 to 2027. They will both be operational before summer of 2024.

There are no new resources that directly affect the LCR change from 2023 to 2027.

There is no projected change in resource contractual status that directly affects the LCR change from 2023 to 2027.

There are 7 resources projected to retire that directly affect the LCR change from 2023 to 2027. These resources are all projected to retire after 2023 due to OTC compliance dates, however they do not influence in a meaningfull way the change in LCR results between 2024 and 2025.

There will be a step function decrease in 2024 due to new transmission projects and an load grwth increase after that.

Table 3.4-9 ISO's estimated LA Basin LCR need:

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2024	First Limit	N/A	Sum of Western and Eastern	See Western and Eastern	5851
2025	First Limit	N/A	Sum of Western and Eastern	See Western and Eastern	5944

3.4.19.10 *San Diego-Imperial Valley Area*

The net peak load growth from 2023 to 2027 is estimated at 56.75 MW/year.

There are a few transmission projects that directly affect the LCR change from 2023 to 2027.

The projects do not meaningfully impact the overall LCR results.

There are 3 new resources that directly affect the LCR change from 2023 to 2027. About 330 MW NQC of new resources are available for both 2024 and 2025. The majority of the new resources available at the time of the peak slightly change the LCR needs in the San Diego-Imperial Valley area.

There is no projected change in resource contractual status that directly affects the LCR change from 2023 to 2027.

There is no resource projected to retire that directly affects the LCR change from 2023 to 2027.

The total increase for each intermediate year depends on load growth and the study results between years 2023 and 2027 and it is estimated at about 9.25 MW/year for Category P3.

Table 3.4-10 ISO's estimated San Diego-Imperial Valley LCR need:

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2024	First Limit	P3	Yucca-Pilot Knob 161 kV line, Pilot Knob-El Centro 161 kV line, Yucca 161/69 kV transformers Calipat-CSF Tap 92 kV	TDM power plant, system readjustment and Imperial Valley–North Gila 500 kV	3341

2025	First Limit	P3	Yucca-Pilot Knob 161 kV line, Pilot Knob-El Centro 161 kV line, Yucca 161/69 kV transformers Calipat-CSF Tap 92 kV	TDM power plant, system readjustment and Imperial Valley–North Gila 500 kV line	3351

4. Energy Storage Assessment as Part of LCR Study

4.1 Introduction

Energy storage is emerging as an essential part of the of the resource mix due to its characteristic of being able to store and release energy as required. Due to this flexibility, the energy storage compliments the development of renewable generation like wind and solar which are intermittent in nature. However, similar to wind and solar, energy storage resources are also use limited. As such, when energy storage is considered as a solution to the transmission system reliability needs, the sufficiency of the alternative needs to be validated for every hour of the day. Unlike other use limited resources, energy storage is also a load when it is operating in a charging mode. Therefore, the 24-hour validation also need to make sure that the transmission system has sufficient capability to charge the energy storage resource.

As part of the annual LCR study, the ISO has been performing assessment to estimate a maximum amount of energy storage that can be added to a local capacity area from the charging restriction perspective. The purpose of this section is to outline the approach of the evaluation of energy storage as part of the LCR study.

4.2 Energy Storage Assessment Approach

The basic concept of the energy storage assessment is to perform a 24-hour validation. The 24-hour validation is performed to make sure that there will be sufficient window and system capacity to be able to charge the storage for the next day peak under the worst contingency condition. The validation includes hour-by-hour comparison of the net load[7] versus the total (transmission + generation) load serving capability.

Peak day 24-hour load profile is used, either directly from the CEC hourly load forecast for the year of study or, if the study area is smaller (local) and the corresponding CEC hourly load forecast is not available, the future year load profile is developed by escalating from the historical load profile for the study area. In the latter approach, the historical load profile is escalated in a manner that accounts for the change in load shape from historical due to forecasted incremental behind-the-meter PV generation (BTM-PV) in the area.

System load serving capability includes transmission system load serving capability and local generation load serving capability. The transmission system load serving capability is calculated under the worst contingency condition without any local generation. The local generation load serving capability is calculated under the worst contingency condition with amount of generation needed according to the local capacity requirement considering effectiveness of the aggregate of local generation to the worst constraint.

[7] Net load here is defined as gross load minus contribution from behind-the-meter generation and load modifier, like additional achievable energy efficiency (AAEE).

Table below includes key assumptions used in the energy storage assessment.

Table 4.2-1 Key assumptions used in the energy storage assessment

Assumption	Rationale
Storage added displaces existing generation (all types) MW to MW in aggregation.	To maintain local RA capacity. Any incremental storage is assumed to be an local RA resource
Maximum storage addition cannot exceed LCR amount.	To maintain local RA capacity. Any incremental storage is assumed to be an local RA resource
Includes storage charging/discharging efficiency of 85%.	Based on general battery efficiency
Storage is charged in all hours where the storage is not discharged. Maximum charging is capped at the amount of storage size (Pmin).	Under worst contingency condition, for battery to have sufficient discharge energy, it is assumed that battery is charged in all hours it is not discharged.
An hourly energy margin of 5% or 10 MW, the larger of the two, is applied to both charging and discharging need.	To add margin when battery is discharging so it does not have to follow load curve exactly. For charging same margin is added to discount available system capability each hour.

4.2.1 Load Data

The first step in preforming the 24-hour validation is to develop a peak-day load profile. For the local capacity areas for which the area definition match with the definition of areas in CEC load forecast, the 24-hour peak day profile can be extracted directly from the CEC hourly load forecast data. For other local capacity areas, future year load profile need to be developed by escalating from the historical load profile for the study area. In the latter approach, the historical load profile is escalated in a manner that accounts for the change in load shape from historical due to forecasted incremental behind-the-meter PV generation (BTM-PV) in the area.

4.2.2 Load Serving Capabilities

Second step in performing the 24-hour validation is to calculate load serving capabilities. Transmission-only load serving capabilities are calculated in power flow under the worst LCR contingency by turning off all local generation following by scaling down load in the local area until the constraint is addressed. For some local areas, it may not be feasible to achieve this with AC solution in the power flow and may need to rely on the spreadsheet based calculation using DC effectiveness factors. The transmission-only load serving capability is used uniformly for each hour within the 24-hour validation. Local generation load serving capability is calculated under the same worst LCR contingency condition with amount of generation needed according to the local capacity requirement considering effectiveness of the aggregate of local generation to the constraint. The generation load serving capability needs to be captured separately for different technologies due to having different output profiles within the 24-hour period. The conventional thermal resources are assumed to have uniform capability throughout the 24-hour period. Whereas, the renewables, like solar and wind are dispatched using appropriate output profiles. The use-limited resources, like storage and demand response are to be dispatched within the period of peak load hours staying within the available total energy. The transmission-only and the local generation load serving capabilities are then added together to get the total load serving capabilities for each hour.

With the transmission-only load serving capability and generation load serving capabilities using LCR resources calculated, each hour should have sufficient load serving capability to serve the net load and provides the setup for energy storage addition estimation.

4.2.3 Estimating Energy Storage Addition

Once the hourly data for the net load and load serving capabilities are stablished, additional amount storage can be estimated by adding storage and displacing existing local area LCR resource by the same amount. Because of the displacement of the existing local resources, generation load serving capability will be reduced, which will result in the total load serving capability being less than the net load for certain hours. The storage added then can be dispatched within those hours. An hourly energy margin of 5% or 10 MW, the larger of the two, is added to the storage MW needed for each of the deficient hours. This is done to create a step dispatch in the storage operation instead of following the load curve perfectly. Once the storage is dispatched for all the deficient hours with appropriate amount, the storage MW dispatched are added together to get the total storage energy (MWh) need associated with the storage MW chosen. The storage is charged within the hours that it is not discharged by using the surplus load serving capability. An hourly energy margin of 5% or 10 MW, the larger of the two, is reduced from the surplus load serving capabilities to account for potential inaccuracies load forecasting and in calculating various load serving capabilities. The process is repeated by increasing or decreasing the chosen storage MW until the total discharging energy becomes equal to the total available charging energy, which establishes the maximum amount of energy storage that can be added to the local area from the charging restriction perspective.

The energy storage addition estimation is performed only for the LCR area /subareas with a defined load pocket. The energy storage addition estimation is not performed for flow-through areas as these don’t have defined load pocket and as such, don’t have a particular load profile.

4.2.4 1-to-1 Replacement with 4-hour Storage

The maximum 4-hour energy storage amount is also estimated as part of this assessment. The maximum 4-hour MW is not a physical limit. Instead, it is a limit up to which a 4-hour energy storage can replace the existing local resource 1-to-1.

Attachment 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	23.40	1	Bay Area	Oakland		MUNI
PG&E	ALMEGT_1_UNIT 2	38119	ALMDACT2	13.8	23.50	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	34.02	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_MTZUM2	32179	MNTZUMA2	0.69	16.42	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_MTZUMA	32188	HIGHWND3	0.69	7.73	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_SHILO1	32176	SHILOH	34.5	31.50	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_SHILO2	32177	SHILOH 2	34.5	31.50	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_SHLO3A	32191	SHILOH3	0.58	21.53	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	BRDSLD_2_SHLO3B	32194	SHILOH4	0.58	21.00	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	CALPIN_1_AGNEW	35860	OLS-AGNE	13.8	28.56	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	CAYTNO_2_VASCO	30532	0162-WD	21	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	192.29	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	COCOPP_2_CTG2	33188	MARSHCT2	16.4	189.21	2	Bay Area	Contra Costa	Aug NQC	Market
PG&E	COCOPP_2_CTG3	33189	MARSHCT3	16.4	190.77	3	Bay Area	Contra Costa	Aug NQC	Market
PG&E	COCOPP_2_CTG4	33189	MARSHCT4	16.4	189.89	4	Bay Area	Contra Costa	Aug NQC	Market

PG&E	COCOSB_6_SOLAR				0.00		Bay Area	Contra Costa	Not modeled Energy Only	Solar
PG&E	CROKET_7_UNIT	32900	CRCKTCOG	18	220.80	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	5.13	1	Bay Area	Pittsburg	Aug NQC	Solar
PG&E	DELTA_2_PL1X4	33107	DEC STG1	24	276.23	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	DELTA_2_PL1X4	33108	DEC CTG1	18	185.59	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	DELTA_2_PL1X4	33109	DEC CTG2	18	185.59	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	DELTA_2_PL1X4	33110	DEC CTG3	18	185.59	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	DIXNLD_1_LNDFL				0.70		Bay Area		Not modeled Aug NQC	Market
PG&E	DUANE_1_PL1X3	36863	DVRaGT1	13.8	48.27	1	Bay Area	San Jose, South Bay-Moss Landing		MUNI
PG&E	DUANE_1_PL1X3	36864	DVRbGT2	13.8	48.27	1	Bay Area	San Jose, South Bay-Moss Landing		MUNI
PG&E	DUANE_1_PL1X3	36865	DVRaST3	13.8	46.96	1	Bay Area	San Jose, South Bay-Moss Landing		MUNI
PG&E	GATWAY_2_PL1X3	33118	GATEWAY1	18	180.78	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	GATWAY_2_PL1X3	33119	GATEWAY2	18	171.17	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	GATWAY_2_PL1X3	33120	GATEWAY3	18	171.17	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	GILROY_1_UNIT	35850	GLRY COG	13.8	69.00	1	Bay Area	Llagas, San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	GILROY_1_UNIT	35850	GLRY COG	13.8	36.00	2	Bay Area	Llagas, San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	GILRPP_1_PL1X2	35851	GROYPKR1	13.8	47.60	1	Bay Area	Llagas, San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	GILRPP_1_PL1X2	35852	GROYPKR2	13.8	47.60	1	Bay Area	Llagas, San Jose, South Bay-Moss Landing	Aug NQC	Market

Attachment A - List of physical resources by PTO, local area and market ID

PG&E	GILRPP_1_PL3X4	35853	GROYPKR3	13.8	46.20	1	Bay Area	Llagas, San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	GRZZLY_1_BERKLY	32741	HILLSIDE_12	12.5	7.91	1	Bay Area		Aug NQC	Net Seller
PG&E	KELSO_2_UNITS	33813	MARIPCT1	13.8	48.09	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	KELSO_2_UNITS	33815	MARIPCT2	13.8	48.09	2	Bay Area	Contra Costa	Aug NQC	Market
PG&E	KELSO_2_UNITS	33817	MARIPCT3	13.8	48.09	3	Bay Area	Contra Costa	Aug NQC	Market
PG&E	KELSO_2_UNITS	33819	MARIPCT4	13.8	48.09	4	Bay Area	Contra Costa	Aug NQC	Market
PG&E	KIRKER_7_KELCYN				3.22		Bay Area	Pittsburg	Not modeled	Market
PG&E	LAWRNC_7_SUNYVL				0.09		Bay Area		Not modeled Aug NQC	Market
PG&E	LECEF_1_UNITS	35858	LECEFST1	13.8	111.58	1	Bay Area	San Jose, South Bay-Moss Landing		Market
PG&E	LECEF_1_UNITS	35854	LECEFGT1	13.8	46.49	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	LECEF_1_UNITS	35855	LECEFGT2	13.8	46.49	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	LECEF_1_UNITS	35856	LECEFGT3	13.8	46.49	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	LECEF_1_UNITS	35857	LECEFGT4	13.8	46.49	1	Bay Area	San Jose, South Bay-Moss Landing	Aug NQC	Market
PG&E	LMBEPK_2_UNITA1	32173	LAMBGT1	13.8	47.50	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	LMBEPK_2_UNITA2	32174	GOOSEHGT	13.8	47.60	2	Bay Area	Contra Costa	Aug NQC	Market
PG&E	LMBEPK_2_UNITA3	32175	CREEDGT1	13.8	47.40	3	Bay Area	Contra Costa	Aug NQC	Market
PG&E	LMEC_1_PL1X3	33113	LMECST1	18	243.71	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	LMEC_1_PL1X3	33111	LMECCT2	18	165.41	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	LMEC_1_PL1X3	33112	LMECCT1	18	165.41	1	Bay Area	Pittsburg	Aug NQC	Market
PG&E	MARTIN_1_SUNSET				1.22		Bay Area		Not modeled Aug NQC	QF/Selfgen
PG&E	METEC_2_PL1X3	35883	MEC STG1	18	213.13	1	Bay Area	South Bay-Moss Landing	Aug NQC	Market
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	MISSIX_1_QF				0.01		Bay Area		Not modeled Aug NQC	QF/Selfgen
PG&E	MLPTAS_7_QFUNTS				0.00		Bay Area	San Jose, South Bay-Moss Landing	Not modeled Aug NQC	QF/Selfgen

Attachment A - List of physical resources by PTO, local area and market ID

PG&E	MOSSLD_1_QF				0.00		Bay Area		Not modeled Aug NQC	Market
PG&E	MOSSLD_2_PSP1	36223	DUKMOSS3	18	183.60	1	Bay Area	South Bay-Moss Landing		Market
PG&E	MOSSLD_2_PSP1	36221	DUKMOSS1	18	163.20	1	Bay Area	South Bay-Moss Landing		Market
PG&E	MOSSLD_2_PSP1	36222	DUKMOSS2	18	163.20	1	Bay Area	South Bay-Moss Landing		Market
PG&E	MOSSLD_2_PSP2	36226	DUKMOSS6	18	183.60	1	Bay Area	South Bay-Moss Landing		Market
PG&E	MOSSLD_2_PSP2	36224	DUKMOSS4	18	163.20	1	Bay Area	South Bay-Moss Landing		Market
PG&E	MOSSLD_2_PSP2	36225	DUKMOSS5	18	163.20	1	Bay Area	South Bay-Moss Landing		Market
PG&E	NEWARK_1_QF				0.04		Bay Area		Not modeled Aug NQC	QF/Selfgen
PG&E	OAK C_1_EBMUD				1.65		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	Retired by 2026	Market
PG&E	OAK C_7_UNIT 3	32903	OAKLND 3	13.8	55.00	1	Bay Area	Oakland	Retired by 2026	Market
PG&E	OAK L_1_GTG1				0.00		Bay Area	Oakland	Not modeled Energy Only	Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.50	1	Bay Area	Ames		Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.50	2	Bay Area	Ames		Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.50	3	Bay Area	Ames		Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.50	4	Bay Area	Ames		Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.50	5	Bay Area	Ames		Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.50	6	Bay Area	Ames		Market
PG&E	OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.50	7	Bay Area	Ames		Market
PG&E	PALALT_7_COBUG				0.00		Bay Area		Not modeled	MUNI
PG&E	RICHMN_1_CHVSR2				2.30		Bay Area		Not modeled Aug NQC	Solar
PG&E	RICHMN_1_SOLAR				0.54		Bay Area		Not modeled Aug NQC	Solar
PG&E	RICHMN_7_BAYENV				0.04		Bay Area		Not modeled Aug NQC	Market
PG&E	RUSCTY_2_UNITS	35306	RUSELST1	15	237.09	3	Bay Area	Ames	No NQC - Pmax	Market

Attachment A - List of physical resources by PTO, local area and market ID

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	RVRVEW_1_UNITA1	33178	RVEC_GEN	13.8	47.60	1	Bay Area	Contra Costa	Aug NQC	Market
PG&E	SHELRF_1_UNITS	33142	SHELL 2	12.5	11.41	1	Bay Area	Pittsburg	Aug NQC	Net Seller
PG&E	SHELRF_1_UNITS	33143	SHELL 3	12.5	11.41	1	Bay Area	Pittsburg	Aug NQC	Net Seller
PG&E	SHELRF_1_UNITS	33141	SHELL 1	12.5	6.15	1	Bay Area	Pittsburg	Aug NQC	Net Seller
PG&E	SRINTL_6_UNIT	33468	SRI INTL	9.11	0.76	1	Bay Area		Aug NQC	QF/Selfgen
PG&E	STAUFF_1_UNIT	33139	STAUFER	9.11	0.04	1	Bay Area		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	SWIFT_1_NAS	35623	SWIFT	21	3.00	BT	Bay Area	San Jose, South Bay-Moss Landing		Battery
PG&E	TIDWTR_2_UNITS	33151	FOSTER W	12.5	4.97	1	Bay Area	Pittsburg	Aug NQC	Net Seller
PG&E	TIDWTR_2_UNITS	33151	FOSTER W	12.5	4.97	2	Bay Area	Pittsburg	Aug NQC	Net Seller
PG&E	TIDWTR_2_UNITS	33151	FOSTER W	12.5	3.78	3	Bay Area	Pittsburg	Aug NQC	Net Seller
PG&E	UNCHEM_1_UNIT	32920	UNION CH	9.11	15.37	1	Bay Area	Pittsburg	Aug NQC	QF/Selfgen
PG&E	UNOCAL_1_UNITS	32910	UNOCAL	12	0.01	1	Bay Area	Pittsburg	Aug NQC	QF/Selfgen
PG&E	UNOCAL_1_UNITS	32910	UNOCAL	12	0.01	2	Bay Area	Pittsburg	Aug NQC	QF/Selfgen
PG&E	UNOCAL_1_UNITS	32910	UNOCAL	12	0.01	3	Bay Area	Pittsburg	Aug NQC	QF/Selfgen
PG&E	USWNDR_2_LABWD1				1.89		Bay Area	Contra Costa	Aug NQC	Wind
PG&E	USWNDR_2_SMUD	36557 4	SOLANO2W	1	18.24	2	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	USWNDR_2_SMUD	36556 6	SOLANO1W	0.69	3.22	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	USWNDR_2_SMUD2	36560 0	SOLANO3W	1	26.84	3	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	USWPJR_2_UNITS	39233	GRNRDG	0.69	16.42	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	WNDMAS_2_UNIT 1	33170	WINDMSTR	21.6	7.98	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	ZOND_6_UNIT	35316	ZOND SYS	12.5	3.59	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_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	0.00	1	Bay Area	San Jose, South Bay-Moss Landing	No NQC - hist. data	QF/Selfgen

Attachment A - List of physical resources by PTO, local area and market ID

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	0.00	1	Bay Area	Contra Costa	No NQC - est. data	Wind
PG&E	ZZ_USWPFK_6_FRICK	35320	FRICKWND	12	1.90	1	Bay Area	Contra Costa	Aug NQC	Wind
PG&E	ZZ_USWPFK_6_FRICK	35320	FRICKWND	12	0.00	2	Bay Area	Contra Costa	Aug NQC	Wind
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	36577 3	Q1111BES	0.69	208.00	1	Bay Area	Pittsburg	No NQC - Pmax	Battery
PG&E	ZZZ_New Unit	36610 3	Q1374BES	0.55	182.50	1	Bay Area	South Bay-Moss Landing	E-4949	Battery
PG&E	ZZZ_New Unit	36671 1	Q1472BES	34.5	100.00	1	Bay Area	South Bay-Moss Landing	E-4949	Battery
PG&E	ZZZ_New Unit	36671 2	Q1472BES	34.5	100.00	2	Bay Area	South Bay-Moss Landing	E-4949	Battery
PG&E	ZZZ_New Unit	36671 3	Q1472BES	34.5	100.00	3	Bay Area	South Bay-Moss Landing	E-4949	Battery
PG&E	ZZZ_New Unit	36671 4	Q1472BES	34.5	100.00	4	Bay Area	South Bay-Moss Landing		Battery
PG&E	ZZZ_New Unit	36639 4	Q1454B	0.69	75.00	1	Bay Area	San Jose, South Bay-Moss Landing	E-4949	Battery
PG&E	ZZZ_New Unit	30522	0354-WD	21	1.83	EW	Bay Area	Contra Costa	No NQC - Pmax	Market
PG&E	ZZZ_New Unit	36554 0	Q1016	12.5	0.00	1	Bay Area		Energy Only	Market
PG&E	ZZZ_New Unit	32741	HILLSIDE	12.5	0.00	1	Bay Area		Energy Only	Market
PG&E	ZZZ_New Unit	36671 5	Q1472BES	34.5	0.00	5	Bay Area	South Bay-Moss Landing		Battery
PG&E	ZZZ_New Unit	32741	HILLSIDE	12.5	0.00	RN	Bay Area		Energy Only	Market
PG&E	ZZZ_New Unit	36555 9	STANFORD	12.5	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	35859	HGST-LV	12.4	0.00	RN	Bay Area		Energy Only	Market
PG&E	ZZZ_New Unit	35307	A100US-L	12.6	0.00	RN	Bay Area		Energy Only	Market
PG&E	ZZZZZ_METCLF_1_QF				0.00		Bay Area		Retired	QF/Selfgen
PG&E	ZZZZZ_OAK C_7_UNIT 2	32902	OAKLND 2	13.8	0.00	1	Bay Area	Oakland	Retired	Market
PG&E	ZZZZZ_USWNDR_2_UNITS	32168	EXNCO	9.11	0.00	1	Bay Area	Contra Costa	Retired	Wind

Attachment A - List of physical resources by PTO, local area and market ID

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_CONTAN_1_UNIT	36856	CCA100	13.8	0.00	1	Bay Area	San Jose, South Bay-Moss Landing	Retired	MUNI
PG&E	ZZZZZZ_FLOWD1_6_ALTPP1	35318	FLOWDPTR	9.11	0.00	1	Bay Area	Contra Costa	Retired	Wind
PG&E	ZZZZZZ_LFC 51_2_UNIT 1	35310	PPASSWND	21	0.00	1	Bay Area		Retired	Wind
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	RT	Bay Area	Pittsburg	Retired	Market
PG&E	ZZZZZZ_PITTSP_7_UNIT 6	33106	PTSB 6	18	0.00	RT	Bay Area	Pittsburg	Retired	Market
PG&E	ZZZZZZ_PITTSP_7_UNIT 7	30000	PTSB 7	20	0.00	RT	Bay Area	Pittsburg	Retired	Market
PG&E	ZZZZZZ_UNTDQF_7_UNITS	33466	UNTED CO	9.11	0.00	1	Bay Area		Retired	QF/Selfgen
PG&E	ADERA_1_SOLAR1	34319	CHWCHLAS	0.48	0.00	1	Fresno	Herndon, Panoche 115 kV, Wilson 115 kV	Energy Only	Solar
PG&E	ADMEST_6_SOLAR	34315	ADAMS_E	12.5	0.00	1	Fresno	Herndon	Energy Only	Solar
PG&E	AGRICO_6_PL3N5	34608	AGRICO	13.8	22.69	3	Fresno	Herndon		Market
PG&E	AGRICO_7_UNIT	34608	AGRICO	13.8	43.13	4	Fresno	Herndon		Market
PG&E	AGRICO_7_UNIT	34608	AGRICO	13.8	7.47	2	Fresno	Herndon		Market
PG&E	AKINGS_6_AMESR1	34688	Q272	0.36	33.21	1	Fresno	Hanford	Aug NQC	Solar
PG&E	AVENAL_6_AVPARK	34265	AVENAL P	12	0.00	1	Fresno	Coalinga	Aug NQC	Solar
PG&E	AVENAL_6_AVSLR1	34691	AVENAL_1	21	0.00	EW	Fresno	Coalinga	Energy Only	Solar
PG&E	AVENAL_6_AVSLR2	34691	AVENAL_1	21	0.00	EW	Fresno	Coalinga	Energy Only	Solar
PG&E	AVENAL_6_SANDDG	34263	SANDDRAG	12	4.29	1	Fresno	Coalinga	Aug NQC	Solar
PG&E	AVENAL_6_SUNCTY	34257	SUNCTY D	12	0.00	1	Fresno	Coalinga	Aug NQC	Solar
PG&E	BALCHS_7_UNIT 1	34624	BALCH	13.2	31.00	1	Fresno	Herndon	Aug NQC	Market
PG&E	BALCHS_7_UNIT 2	34612	BLCH	13.8	52.50	1	Fresno	Herndon	Aug NQC	Market
PG&E	BALCHS_7_UNIT 3	34614	BLCH	13.8	54.60	1	Fresno	Herndon	Aug NQC	Market
PG&E	CABALO_2_M2WSR2	365524	Q1036SPV	0.36	27.00	1	Fresno		Aug NQC	Solar

Attachment A - List of physical resources by PTO, local area and market ID

PG&E	CANTUA_1_SOLAR	34349	CANTUA_D	12.5	2.70	1	Fresno	Panoche 115 kV	Aug NQC	Solar
PG&E	CANTUA_1_SOLAR	34349	CANTUA_D	12.5	2.70	2	Fresno	Panoche 115 kV	Aug NQC	Solar
PG&E	CHEVCO_6_UNIT 1	34652	CHV.COAL	9.11	1.98	1	Fresno	Coalinga, Panoche 115 kV	Aug NQC	QF/Selfgen
PG&E	CHEVCO_6_UNIT 2	34652	CHV.COAL	9.11	0.60	2	Fresno	Coalinga, Panoche 115 kV	Aug NQC	QF/Selfgen
PG&E	CHWCHL_1_BIOMAS	34305	CHWCHLA2	13.8	9.33	1	Fresno	Herndon, Panoche 115 kV, Wilson 115 kV	Aug NQC	Market
PG&E	CHWCHL_1_UNIT	34301	CHOWCOGN	13.8	48.00	1	Fresno	Herndon, Panoche 115 kV, Wilson 115 kV		Market
PG&E	CORCAN_1_SOLAR1	34690	CORCORAN	12.5	5.40	FW	Fresno	Herndon, Hanford	Aug NQC	Solar
PG&E	CORCAN_1_SOLAR2	34692	CORCORAN	12.5	2.97	FW	Fresno	Herndon, Hanford	Aug NQC	Solar
PG&E	CRESSY_1_PARKER	34140	CRESSEY	115	0.99		Fresno		Not modeled Aug NQC	MUNI
PG&E	CRNEVL_6_CRNVA	34634	CRANEVLY	12	0.00	1	Fresno	Borden	Aug NQC	Market
PG&E	CRNEVL_6_SJQN 2	34631	SJ2GEN	9.11	0.01	1	Fresno	Borden	Aug NQC	Market
PG&E	CRNEVL_6_SJQN 3	34633	SJ3GEN	9.11	0.00	1	Fresno	Borden	Aug NQC	Market
PG&E	CURTIS_1_CANLCK				0.00		Fresno		Not modeled Aug NQC	Market
PG&E	CURTIS_1_FARFLD				0.53		Fresno		Not modeled Aug NQC	Market
PG&E	DAIRLD_1_MD1SL1				0.00		Fresno		Energy Only	Solar
PG&E	DAIRLD_1_MD2BM1				0.00		Fresno		Energy Only	Market
PG&E	DINUBA_6_UNIT	34648	DINUBA E	13.8	0.00	1	Fresno	Herndon, Reedley	Mothballed	Market
PG&E	EEKTMN_6_SOLAR1	34629	KETTLEMN	0.8	0.00	1	Fresno		Energy Only	Solar
PG&E	ELCAP_1_SOLAR				0.00		Fresno		Not Modeled Aug NQC	Solar
PG&E	ELNIDP_6_BIOMAS	34330	ELNIDO	13.8	10.05	1	Fresno	Panoche 115 kV, Wilson 115 kV	Aug NQC	Market
PG&E	EXCHEC_7_UNIT 1	34306	EXCHQUER	13.8	75.60	1	Fresno	Panoche 115 kV, Wilson 115 kV	Aug NQC	MUNI
PG&E	EXCLSG_1_SOLAR	34623	Q678	0.5	16.20	1	Fresno	Panoche 115 kV	Aug NQC	Solar
PG&E	FRESHW_1_SOLAR1	34699	Q529	0.39	0.00	1	Fresno	Herndon	Energy Only	Solar
PG&E	FRIANT_6_UNITS	34636	FRIANTDM	6.6	11.83	2	Fresno	Borden	Aug NQC	Net Seller
PG&E	FRIANT_6_UNITS	34636	FRIANTDM	6.6	6.32	3	Fresno	Borden	Aug NQC	Net Seller
PG&E	FRIANT_6_UNITS	34636	FRIANTDM	6.6	1.67	4	Fresno	Borden	Aug NQC	Net Seller
PG&E	GIFENS_6_BUGSL1	34644	Q679	0.55	5.40	1	Fresno		Aug NQC	Solar

PG&E	GIFFEN_6_SOLAR	34467	GIFFEN_DIST	12.5	2.70	1	Fresno	Herndon	Aug NQC	Solar
PG&E	GIFFEN_6_SOLAR1				0.00		Fresno	Herndon	Not modeled Energy Only	Solar
PG&E	GUERNS_6_HD3BM3				0.00		Fresno		Not modeled Energy Only	Market
PG&E	GUERNS_6_SOLAR	34463	GUERNSEY_ D2	12.5	2.70	5	Fresno		Aug NQC	Solar
PG&E	GUERNS_6_SOLAR	34461	GUERNSEY_ D1	12.5	2.70	8	Fresno		Aug NQC	Solar
PG&E	GUERNS_6_VH2BM1				0.00		Fresno		Not modeled Energy Only	Market
PG&E	GWFPWR_1_UNITS	34431	GWF_HEP1	13.8	45.30	1	Fresno	Herndon, Hanford		Market
PG&E	GWFPWR_1_UNITS	34433	GWF_HEP2	13.8	45.30	1	Fresno	Herndon, Hanford		Market
PG&E	HAASPH_7_PL1X2	34610	HAAS	13.8	72.00	1	Fresno	Herndon	Aug NQC	Market
PG&E	HAASPH_7_PL1X2	34610	HAAS	13.8	72.00	2	Fresno	Herndon	Aug NQC	Market
PG&E	HARDWK_6_STWBM1				0.00		Fresno		Not modeled Energy Only	Market
PG&E	HELMPG_7_UNIT 1	34600	HELMS	18	407.00	1	Fresno		Aug NQC	Market
PG&E	HELMPG_7_UNIT 2	34602	HELMS	18	407.00	2	Fresno		Aug NQC	Market
PG&E	HELMPG_7_UNIT 3	34604	HELMS	18	404.00	3	Fresno		Aug NQC	Market
PG&E	HENRTA_6_SOLAR1				0.41		Fresno		Not modeled Aug NQC	Solar
PG&E	HENRTA_6_SOLAR2				0.00		Fresno		Not modeled Energy Only	Solar
PG&E	HENRTA_6_UNITA1	34539	GWF_GT1	13.8	44.99	1	Fresno			Market
PG&E	HENRTA_6_UNITA2	34541	GWF_GT2	13.8	44.68	1	Fresno			Market
PG&E	HENRTS_1_SOLAR	34617	Q581	0.38	27.00	1	Fresno	Herndon	Aug NQC	Solar
PG&E	HURON_6_SOLAR	34557	HURON_DI	12.5	2.70	1	Fresno	Coalinga, Panoche 115 kV	Aug NQC	Solar
PG&E	HURON_6_SOLAR	34557	HURON_DI	12.5	2.70	2	Fresno	Coalinga, Panoche 115 kV	Aug NQC	Solar
PG&E	JAYNE_6_WLSLR	34639	WESTLNDS	0.48	0.00	1	Fresno	Coalinga	Energy Only	Solar
PG&E	KANSAS_6_SOLAR	34666	KANSASS_S	12.5	0.00	F	Fresno		Energy Only	Solar
PG&E	KERKH1_7_UNIT 1	34344	KERCK1-1	6.6	13.00	1	Fresno	Herndon, Wilson 115 kV	Aug NQC	Market
PG&E	KERKH1_7_UNIT 3	34345	KERCK1-3	6.6	12.80	3	Fresno	Herndon, Wilson 115 kV	Aug NQC	Market
PG&E	KERKH2_7_UNIT 1	34308	KERCKHOF	13.8	153.90	1	Fresno	Herndon, Wilson 115 kV	Aug NQC	Market

PG&E	KERMAN_6_SOLAR1				0.00		Fresno		Not modeled Energy Only	Solar
PG&E	KERMAN_6_SOLAR2				0.00		Fresno		Not modeled Energy Only	Solar
PG&E	KINGCO_1_KINGBR	34642	KINGSBUR	9.11	34.50	1	Fresno	Herndon, Hanford	Aug NQC	Net Seller
PG&E	KINGRV_7_UNIT 1	34616	KINGSRIV	13.8	51.20	1	Fresno	Herndon, Reedley	Aug NQC	Market
PG&E	KNGBRG_1_KBSLR1				0.00		Fresno		Not modeled Energy Only	Solar
PG&E	KNGBRG_1_KBSLR2				0.00		Fresno		Not modeled Energy Only	Solar
PG&E	KNTSTH_6_SOLAR	34694	KENT_S	0.8	0.00	1	Fresno		Energy Only	Solar
PG&E	LEPRFD_1_KANSAS	34680	KANSAS	12.5	5.40	1	Fresno	Herndon, Hanford	Aug NQC	Solar
PG&E	LOTUS_6_LSFSR1	34335	Q723	0.32	13.50	1	Fresno	Borden	Aug NQC	Solar
PG&E	LTBEAR_1_LB3SR3	365663	Q1127SPV	0.36	5.40	1	Fresno	Panoche 115 kV, Wilson 115 kV	Aug NQC	Solar
PG&E	LTBEAR_1_LB4SR4	365673	Q1128-4S	0.36	13.50	1	Fresno	Panoche 115 kV, Wilson 115 kV	Aug NQC	Solar
PG&E	LTBEAR_1_LB4SR5	365675	Q1128-5S	0.36	13.50	1	Fresno	Panoche 115 kV, Wilson 115 kV	Aug NQC	Solar
PG&E	LTBERA_1_LB1SR1	365604	Q1028Q10	0.36	10.80	1	Fresno	Panoche 115 kV, Wilson 115 kV	Aug NQC	Solar
PG&E	MALAGA_1_PL1X2	34671	KRCDPCT1	13.8	48.00	1	Fresno	Herndon		Market
PG&E	MALAGA_1_PL1X2	34672	KRCDPCT2	13.8	48.00	1	Fresno	Herndon		Market
PG&E	MCCALL_1_QF	34219	MCCALL 4	12.5	0.57	QF	Fresno	Herndon	Aug NQC	QF/Selfgen
PG&E	MCSWAN_6_UNITS	34320	MCSWAIN	9.11	9.60	1	Fresno	Panoche 115 kV, Wilson 115 kV	Aug NQC	MUNI
PG&E	MENBIO_6_RENEW1	34339	CALRENEW	12.5	1.35	1	Fresno	Herndon, Panoche 115 kV, Wilson 115 kV	Aug NQC	Net Seller
PG&E	MERCED_1_SOLAR1				0.00		Fresno		Not modeled Energy Only	Solar
PG&E	MERCED_1_SOLAR2				0.00		Fresno		Not modeled Energy Only	Solar
PG&E	MERCFL_6_UNIT	34322	MERCEDFL	9.11	3.36	1	Fresno	Panoche 115 kV, Wilson 115 kV	Aug NQC	Market
PG&E	MNDOTA_1_SOLAR1	34313	NORTHSTA	0.2	16.20	1	Fresno	Panoche 115 kV, Wilson 115 kV	Aug NQC	Solar
PG&E	MNDOTA_1_SOLAR2				0.00		Fresno		Not modeled Energy Only	Solar
PG&E	MSTANG_2_SOLAR	34683	Q643W	0.8	8.10	1	Fresno		Aug NQC	Solar

Attachment A - List of physical resources by PTO, local area and market ID

PG&E	MSTANG_2_SOLAR3	34683	Q643W	0.8	10.80	1	Fresno		Aug NQC	Solar
PG&E	MSTANG_2_SOLAR4	34683	Q643W	0.8	8.10	1	Fresno		Aug NQC	Solar
PG&E	ONLLPP_6_UNITS	34316	ONEILPMP	9.11	6.04	1	Fresno		Aug NQC	MUNI
PG&E	OROLOM_1_SOLAR1	34689	ORO LOMA_3	12.5	0.00	EW	Fresno	Panoche 115 kV	Energy Only	Solar
PG&E	OROLOM_1_SOLAR2	34689	ORO LOMA_3	12.5	0.00	EW	Fresno	Panoche 115 kV	Energy Only	Solar
PG&E	ORTGA_6_ME1SL1				0.00		Fresno		Not modeled Energy Only	Solar
PG&E	PAIGES_6_SOLAR	34653	Q526	0.55	0.00	1	Fresno	Coalinga, Panoche 115 kV	Energy Only	Solar
PG&E	PINFLT_7_UNITS	38720	PINEFLAT	13.8	32.63	1	Fresno	Herndon	Aug NQC	MUNI
PG&E	PINFLT_7_UNITS	38720	PINEFLAT	13.8	32.63	2	Fresno	Herndon	Aug NQC	MUNI
PG&E	PINFLT_7_UNITS	38720	PINEFLAT	13.8	32.63	3	Fresno	Herndon	Aug NQC	MUNI
PG&E	PNCHPP_1_PL1X2	34328	STARGT1	13.8	54.18	1	Fresno	Panoche 115 kV		Market
PG&E	PNCHPP_1_PL1X2	34329	STARGT2	13.8	54.18	2	Fresno	Panoche 115 kV		Market
PG&E	PNOCHE_1_PL1X2	34142	WHD_PAN2	13.8	49.97	1	Fresno	Herndon, Panoche 115 kV		Market
PG&E	PNOCHE_1_UNITA1	34186	DG_PAN1	13.8	52.01	1	Fresno	Panoche 115 kV		Market
PG&E	REEDLY_6_SOLAR				0.00		Fresno	Herndon, Reedley	Not modeled Energy Only	Solar
PG&E	S_RITA_6_SOLAR1				0.00		Fresno		Not modeled Energy Only	Solar
PG&E	SCHNDR_1_FIVPTS	34353	SCHINDLER_D	12.5	2.70	1	Fresno	Coalinga, Panoche 115 kV	Aug NQC	Solar
PG&E	SCHNDR_1_FIVPTS	34353	SCHINDLER_D	12.5	1.35	2	Fresno	Coalinga, Panoche 115 kV	Aug NQC	Solar
PG&E	SCHNDR_1_OS2BM2				0.00		Fresno	Coalinga	Energy Only	Market
PG&E	SCHNDR_1_WSTSDE	34353	SCHINDLER_D	12.5	2.70	3	Fresno	Coalinga, Panoche 115 kV	Aug NQC	Solar
PG&E	SCHNDR_1_WSTSDE	34353	SCHINDLER_D	12.5	1.35	4	Fresno	Coalinga, Panoche 115 kV	Aug NQC	Solar
PG&E	SGREGY_6_SANGER	34646	SANGERCO	13.8	38.77	1	Fresno	Herndon	Aug NQC	Market
PG&E	SGREGY_6_SANGER	34646	SANGERCO	13.8	9.31	2	Fresno	Herndon	Aug NQC	Market
PG&E	STOREY_2_MDRCH2				0.38		Fresno		Not modeled Aug NQC	Market
PG&E	STOREY_2_MDRCH3				0.22		Fresno		Not modeled Aug NQC	Market
PG&E	STOREY_2_MDRCH4				0.36		Fresno		Not modeled Aug NQC	Market
PG&E	STOREY_7_MDRCHW	34209	STOREY D	12.5	0.61	1	Fresno		Aug NQC	Net Seller

Attachment A - List of physical resources by PTO, local area and market ID

PG&E	STROUD_6_SOLAR	34563	STROUD_D	12.5	2.70	1	Fresno	Herndon	Aug NQC	Solar
PG&E	STROUD_6_SOLAR	34563	STROUD_D	12.5	2.70	2	Fresno	Herndon	Aug NQC	Solar
PG&E	STROUD_6_WWHSR1				0.00		Fresno	Herndon	Energy Only	Solar
PG&E	SUMWHT_6_SWSSR1				5.00		Fresno		Aug NQC	Solar
PG&E	TRNQL8_2_AMASR1	365514	Q1032G1	0.55	5.40	1	Fresno		Aug NQC	Solar
PG&E	TRNQL8_2_AZUSR1	365517	Q1032G2	0.55	5.40	2	Fresno		Aug NQC	Solar
PG&E	TRNQL8_2_ROJSR1	365520	Q1032G3	0.55	8.10	3	Fresno		Aug NQC	Solar
PG&E	TRNQL8_2_VERSR1	365520	Q1032G3	0.55	0.00	3	Fresno		Aug NQC	Solar
PG&E	TRNQLT_2_SOLAR	34340	Q643X	0.8	54.00	1	Fresno		Aug NQC	Solar
PG&E	ULTPFR_1_UNIT 1	34640	ULTR.PWR	9.11	23.76	1	Fresno	Herndon	Aug NQC	Market
PG&E	VEGA_6_SOLAR1	34314	VEGA	34.5	0.00	1	Fresno		Energy Only	Solar
PG&E	WAUKNA_1_SOLAR	34696	CORCORANPV_S	21	5.40	1	Fresno	Herndon, Hanford	Aug NQC	Solar
PG&E	WAUKNA_1_SOLAR2	34677	Q558	21	5.33	1	Fresno	Herndon, Hanford	No NQC - Pmax	Solar
PG&E	WFRESN_1_SOLAR				0.00		Fresno		Not modeled Energy Only	Solar
PG&E	WHITNY_6_SOLAR	34673	Q532	0.55	0.00	1	Fresno	Coalinga, Panoche 115 kV	Energy Only	Solar
PG&E	WISHON_6_UNITS	34658	WISHON	2.3	4.51	1	Fresno	Borden	Aug NQC	Market
PG&E	WISHON_6_UNITS	34658	WISHON	2.3	4.51	2	Fresno	Borden	Aug NQC	Market
PG&E	WISHON_6_UNITS	34658	WISHON	2.3	4.51	3	Fresno	Borden	Aug NQC	Market
PG&E	WISHON_6_UNITS	34658	WISHON	2.3	4.51	4	Fresno	Borden	Aug NQC	Market
PG&E	WISHON_6_UNITS	34658	WISHON	2.3	0.36	SJ	Fresno	Borden	Aug NQC	Market
PG&E	WOODWR_1_HYDRO				0.00		Fresno	Herndon	Not modeled Energy Only	Market
PG&E	WRGHTP_7_AMENGY	34207	WRIGHT D	12.5	0.78	QF	Fresno		Aug NQC	QF/Selfgen
PG&E	ZZ_BORDEN_2_QF	34253	BORDEN D	12.5	1.30	QF	Fresno		No NQC - hist. data	Net Seller
PG&E	ZZ_BULLRD_7_SAGNES	34213	BULLD 12	12.5	0.06	1	Fresno	Herndon	Aug NQC	QF/Selfgen
PG&E	ZZ_JRWOOD_1_UNIT 1	34332	JRWCOGEN	9.11	0.00	1	Fresno			QF/Selfgen
PG&E	ZZ_KERKH1_7_UNIT 2	34343	KERCK1-2	6.6	8.50	2	Fresno	Herndon, Wilson 115 kV	No NQC - hist. data	Market
PG&E	ZZ_NA	34485	FRESNOWW	12.5	0.10	2	Fresno		No NQC - hist. data	QF/Selfgen

PG&E	ZZ_NA	34485	FRESNOWW	12.5	0.00	1	Fresno		No NQC - hist. data	QF/Selfgen
PG&E	ZZ_NA	34485	FRESNOWW	12.5	0.00	3	Fresno		No NQC - hist. data	QF/Selfgen
PG&E	ZZ_NA	34651	JACALITO-LV	0.55	0.00	RN	Fresno	Coalinga	No NQC - hist. data	Market
PG&E	ZZZ_New Unit	365697	Q1158B	0.27	300.00	2	Fresno		No NQC - est. data	Battery
PG&E	ZZZ_New Unit	365504	Q632BSPV	0.55	5.00	1	Fresno		No NQC - est. data	Solar
PG&E	ZZZ_New Unit	34649	Q965SPV	0.36	3.65	1	Fresno	Herndon	No NQC - est. data	Solar
PG&E	ZZZ_New Unit	365694	Q1158S	0.42	0.00	1	Fresno		No NQC - est. data	Solar
PG&E	ZZZ_New Unit	92007	2007-RD	70	0.00	ER	Fresno	Borden	Energy Only	Market
PG&E	ZZZ_New Unit	91317	1317-RD	12	0.00	ER	Fresno		Energy Only	Market
PG&E	ZZZ_New Unit	91318	1318-RD	115	0.00	ER	Fresno	Panoche 115 kV, Wilson 115 kV	Energy Only	Market
PG&E	ZZZ_New Unit	91316	1316-RD	115	0.00	ER	Fresno	Panoche 115 kV	Energy Only	Market
PG&E	ZZZ_New Unit	34603	JGBSWLT	12.5	0.00	ST	Fresno	Herndon	Energy Only	Market
PG&E	ZZZZZ_CAPMAD_1_UNIT 1	34179	MADERA_G	13.8	0.00	RT	Fresno		Retired	Market
PG&E	ZZZZZ_COLGA1_6_SHELLW	34654	COLNGAGN	9.11	0.00	1	Fresno	Coalinga	Retired	Net Seller
PG&E	ZZZZZ_GATES_6_PL1X2	34553	WHD_GAT2	13.8	0.00	RT	Fresno	Coalinga	Retired	Market
PG&E	ZZZZZ_INTTRB_6_UNIT	34342	INT.TURB	9.11	0.00	1	Fresno		Retired	Market
PG&E	ZZZZZ_MENBIO_6_UNIT	34334	BIO PWR	9.11	0.00	1	Fresno	Panoche 115 kV, Wilson 115 kV	Retired	QF/Selfgen
PG&E	BRDGVL_7_BAKER				0.00		Humboldt		Not modeled Aug NQC	Net Seller
PG&E	FAIRHV_6_UNIT	31150	FAIRHAVN	13.8	5.70	1	Humboldt		Aug NQC	Net Seller
PG&E	FTSWRD_6_TRFORK				0.18		Humboldt		Not modeled Aug NQC	Market
PG&E	FTSWRD_7_QFUNTS				0.00		Humboldt		Not modeled Aug NQC	QF/Selfgen
PG&E	GRSCRK_6_BGCKWW				0.00		Humboldt		Not modeled Aug NQC	Market
PG&E	HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.69	3	Humboldt			Market
PG&E	HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.32	1	Humboldt			Market

Attachment A - List of physical resources by PTO, local area and market ID

PG&E	HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.22	4	Humboldt			Market
PG&E	HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	15.85	2	Humboldt			Market
PG&E	HUMBPP_6_UNITS	31182	HUMB_G3	13.8	16.62	8	Humboldt			Market
PG&E	HUMBPP_6_UNITS	31181	HUMB_G2	13.8	16.33	6	Humboldt			Market
PG&E	HUMBPP_6_UNITS	31182	HUMB_G3	13.8	16.33	9	Humboldt			Market
PG&E	HUMBPP_6_UNITS	31181	HUMB_G2	13.8	16.24	7	Humboldt			Market
PG&E	HUMBPP_6_UNITS	31181	HUMB_G2	13.8	16.14	5	Humboldt			Market
PG&E	HUMBPP_6_UNITS	31182	HUMB_G3	13.8	15.95	10	Humboldt			Market
PG&E	HUMBSB_1_QF				0.00		Humboldt		Not modeled Aug NQC	QF/Selfgen
PG&E	KEKAWK_6_UNIT	31166	KEKAWAK	9.1	0.00	1	Humboldt		Aug NQC	Net Seller
PG&E	LAPAC_6_UNIT	31158	LP SAMOA	12.5	0.00	1	Humboldt			Market
PG&E	LOWGAP_1_SUPHR				0.00		Humboldt		Not modeled Aug NQC	Market
PG&E	PACLUM_6_UNIT	31152	PAC.LUMB	13.8	4.83	1	Humboldt		Aug NQC	Net Seller
PG&E	PACLUM_6_UNIT	31152	PAC.LUMB	13.8	4.83	2	Humboldt		Aug NQC	Net Seller
PG&E	PACLUM_6_UNIT	31153	PAC.LUMB	2.4	2.90	3	Humboldt		Aug NQC	Net Seller
PG&E	ZZZZZ_BLULKE_6_BLUELK	31156	BLUELKPP	12.5	0.00	1	Humboldt		Retired	Market
PG&E	7STDRD_1_SOLAR1	35065	7STNDRD_1	21	5.40	FW	Kern	South Kern PP, Kern Oil	Aug NQC	Solar
PG&E	ADOBEE_1_SOLAR	35021	Q622B	34.5	5.40	1	Kern	South Kern PP	Aug NQC	Solar
PG&E	BDGRCK_1_UNITS	35029	BADGERCK	13.8	40.20	1	Kern	South Kern PP	Aug NQC	Net Seller
PG&E	BEARMT_1_UNIT	35066	PSE-BEAR	13.8	44.00	1	Kern	South Kern PP, Westpark	Aug NQC	Net Seller
PG&E	BKRFLD_2_SOLAR1				0.37		Kern	South Kern PP	Not modeled Aug NQC	Solar
PG&E	DEXZEL_1_UNIT	35024	DEXEL +	13.8	16.95	1	Kern	South Kern PP, Kern Oil	Aug NQC	Net Seller
PG&E	DISCOV_1_CHEVRN	35062	DISCOVRY	13.8	3.72	1	Kern	South Kern PP, Kern Oil	Aug NQC	QF/Selfgen
PG&E	DOUBLC_1_UNITS	35023	DOUBLE C	13.8	24.75	1	Kern	South Kern PP	Aug NQC	Net Seller
PG&E	DOUBLC_1_UNITS	35023	DOUBLE C	13.8	24.75	2	Kern	South Kern PP	Aug NQC	Net Seller
PG&E	KERNFT_1_UNITS	35026	KERNFRNT	13.8	24.23	1	Kern	South Kern PP	Aug NQC	Net Seller
PG&E	KERNFT_1_UNITS	35026	KERNFRNT	13.8	24.23	2	Kern	South Kern PP	Aug NQC	Net Seller
PG&E	LAMONT_1_SOLAR1	35019	REGULUS	0.4	16.20	1	Kern	South Kern PP, Kern PWR-Tevis	Aug NQC	Solar
PG&E	LAMONT_1_SOLAR2	35092	Q744P4G4	0.38	5.40	1	Kern	South Kern PP, Kern PWR-Tevis	Aug NQC	Solar

PG&E	LAMONT_1_SOLAR3	35087	Q744P3G3	0.4	4.05	3	Kern	South Kern PP, Kern PWR-Tevis	Aug NQC	Solar
PG&E	LAMONT_1_SOLAR4	35059	Q744P2G2	0.4	21.53	2	Kern	South Kern PP, Kern PWR-Tevis	Aug NQC	Solar
PG&E	LAMONT_1_SOLAR5	35054	Q744P1G1	0.4	4.50	1	Kern	South Kern PP, Kern PWR-Tevis	Aug NQC	Solar
PG&E	LIVOAK_1_UNIT 1	35058	PSE-LVOK	9.1	42.50	1	Kern	South Kern PP, Kern Oil	Aug NQC	Net Seller
PG&E	MAGUND_1_BKISR1				0.27		Kern	South Kern PP, Kern Oil	Not modeled Aug NQC	Solar
PG&E	MAGUND_1_BKSSR2				1.42		Kern	South Kern PP, Kern Oil	Not modeled Aug NQC	Solar
PG&E	MTNPOS_1_UNIT	35036	MT POSO	13.8	38.13	1	Kern	South Kern PP, Kern Oil	Aug NQC	Net Seller
PG&E	OLDRIV_6_BIOGAS				1.69		Kern	South Kern PP, Kern 70 kV	Not modeled Aug NQC	Market
PG&E	OLDRIV_6_CESDBM				0.92		Kern	South Kern PP, Kern 70 kV	Not modeled Aug NQC	Market
PG&E	OLDRIV_6_LKVBM1				0.94		Kern	South Kern PP, Kern 70 kV	Not modeled Aug NQC	Market
PG&E	OLDRV1_6_SOLAR	35091	OLD_RVR1	12.5	5.40	1	Kern	South Kern PP, Kern 70 kV	Aug NQC	Solar
PG&E	SIERRA_1_UNITS	35027	HISIERRA	13.8	24.79	1	Kern	South Kern PP	Aug NQC	Market
PG&E	SIERRA_1_UNITS	35027	HISIERRA	13.8	24.79	2	Kern	South Kern PP	Aug NQC	Market
PG&E	SKERN_6_SOLAR1	35089	S_KERN	0.48	5.40	1	Kern	South Kern PP, Kern 70 kV	Aug NQC	Solar
PG&E	SKERN_6_SOLAR2	365563	Q885	0.36	2.70	1	Kern	South Kern PP, Kern 70 kV	Aug NQC	Solar
PG&E	VEDDER_1_SEKERN	35046	SEKR	9.11	0.06	1	Kern	South Kern PP, Kern Oil	Aug NQC	QF/Selfgen
PG&E	ZZZ_New Unit	365597	Q744P5G5	0.6	3.21	5	Kern	South Kern PP, Kern PWR-Tevis	No NQC - est. data	Solar
PG&E	ZZZZZ_KRNCNY_6_UNIT	35018	KERNCNYN	11	0.00	1	Kern	South Kern PP, Kern 70 kV	Retired	Market
PG&E	ZZZZZ_OILDAL_1_UNIT 1	35028	OILDALE	9.11	0.00	RT	Kern	South Kern PP, Kern Oil	Retired	Net Seller
PG&E	ZZZZZ_RIOBRV_6_UNIT 1	35020	RIOBRAVO	9.1	0.00	1	Kern	South Kern PP, Kern 70 kV	Retired	Market
PG&E	ZZZZZ_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		Market
PG&E	ADLIN_1_UNITS	31435	GEO.ENGY	9.1	8.00	2	NCNB	Eagle Rock, Fulton		Market
PG&E	CLOVDL_1_SOLAR				0.41		NCNB	Eagle Rock, Fulton	Not modeled Aug NQC	Solar
PG&E	CSTOGA_6_LNDFIL				0.00		NCNB	Fulton	Not modeled Energy Only	Market
PG&E	FULTON_1_QF				0.08		NCNB	Fulton	Not modeled Aug NQC	QF/Selfgen
PG&E	GEYS11_7_UNIT11	31412	GEYSER11	13.8	68.00	1	NCNB	Eagle Rock, Fulton		Market
PG&E	GEYS12_7_UNIT12	31414	GEYSER12	13.8	50.00	1	NCNB	Fulton		Market
PG&E	GEYS13_7_UNIT13	31416	GEYSER13	13.8	56.00	1	NCNB			Market
PG&E	GEYS14_7_UNIT14	31418	GEYSER14	13.8	50.00	1	NCNB	Fulton		Market
PG&E	GEYS16_7_UNIT16	31420	GEYSER16	13.8	49.00	1	NCNB	Fulton		Market
PG&E	GEYS17_2_BOTRCK	31421	BOTTLERK	13.8	0.00	1	NCNB	Fulton	Energy Only and Mothballed	Market
PG&E	GEYS17_7_UNIT17	31422	GEYSER17	13.8	56.00	1	NCNB	Fulton		Market
PG&E	GEYS18_7_UNIT18	31424	GEYSER18	13.8	45.00	1	NCNB			Market
PG&E	GEYS20_7_UNIT20	31426	GEYSER20	13.8	40.00	1	NCNB			Market
PG&E	GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	42.50	1	NCNB	Eagle Rock, Fulton		Market
PG&E	GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	42.50	2	NCNB	Eagle Rock, Fulton		Market
PG&E	GYS7X8_7_UNITS	31408	GEYSER78	13.8	38.00	1	NCNB	Eagle Rock, Fulton		Market
PG&E	GYS7X8_7_UNITS	31408	GEYSER78	13.8	38.00	2	NCNB	Eagle Rock, Fulton		Market
PG&E	GYSRVL_7_WSPRNG				1.48		NCNB	Fulton	Not modeled Aug NQC	QF/Selfgen
PG&E	HILAND_7_YOLOWD				0.00		NCNB	Eagle Rock, Fulton	Not Modeled. Energy Only	Market
PG&E	IGNACO_1_QF				0.00		NCNB		Not modeled Aug NQC	QF/Selfgen
PG&E	INDVLY_1_UNITS	31436	INDIAN V	9.1	1.57	1	NCNB	Eagle Rock, Fulton	Aug NQC	Net Seller
PG&E	MONTPH_7_UNITS	32700	MONTICLO	9.1	3.25	1	NCNB	Fulton	Aug NQC	Market
PG&E	MONTPH_7_UNITS	32700	MONTICLO	9.1	3.25	2	NCNB	Fulton	Aug NQC	Market
PG&E	MONTPH_7_UNITS	32700	MONTICLO	9.1	0.97	3	NCNB	Fulton	Aug NQC	Market
PG&E	NCPA_7_GP1UN1	38106	NCPA1GY1	13.8	31.00	1	NCNB		Aug NQC	MUNI
PG&E	NCPA_7_GP1UN2	38108	NCPA1GY2	13.8	28.00	1	NCNB		Aug NQC	MUNI
PG&E	NCPA_7_GP2UN3	38110	NCPA2GY1	13.8	0.00	1	NCNB	Fulton	Aug NQC	MUNI
PG&E	NCPA_7_GP2UN4	38112	NCPA2GY2	13.8	52.73	1	NCNB	Fulton	Aug NQC	MUNI
PG&E	NOVATO_6_LNDFL				2.40		NCNB		Not modeled Aug NQC	Market

PG&E	POTTER_6_UNITS	31433	POTTRVLY	2.4	1.42	1	NCNB	Eagle Rock, Fulton	Aug NQC	Market
PG&E	POTTER_6_UNITS	31433	POTTRVLY	2.4	0.65	3	NCNB	Eagle Rock, Fulton	Aug NQC	Market
PG&E	POTTER_6_UNITS	31433	POTTRVLY	2.4	0.65	4	NCNB	Eagle Rock, Fulton	Aug NQC	Market
PG&E	POTTER_7_VECINO				0.01		NCNB	Eagle Rock, Fulton	Not modeled Aug NQC	QF/Selfgen
PG&E	SANTFG_7_UNITS	31400	SANTA FE	13.8	31.50	1	NCNB			Market
PG&E	SANTFG_7_UNITS	31400	SANTA FE	13.8	31.50	2	NCNB			Market
PG&E	SMUDGO_7_UNIT 1	31430	SMUDGEO1	13.8	47.00	1	NCNB			Market
PG&E	SNMALF_6_UNITS	31446	SONMA LF	9.1	3.06	1	NCNB	Fulton	Aug NQC	QF/Selfgen
PG&E	UKIAH_7_LAKEMN	38020	CITY UKH	115	1.21	2	NCNB	Eagle Rock, Fulton	Aug NQC	MUNI
PG&E	UKIAH_7_LAKEMN	38020	CITY UKH	115	0.49	1	NCNB	Eagle Rock, Fulton	Aug NQC	MUNI
PG&E	ZZZ_New Unit	91991	1991-RD		0.00	ER	NCNB		Energy Only	Market
PG&E	ZZZZZ_BEARCN_2_UNITS	31402	BEAR CAN	13.8	0.00	1	NCNB	Fulton	Retired	Market
PG&E	ZZZZZ_BEARCN_2_UNITS	31402	BEAR CAN	13.8	0.00	2	NCNB	Fulton	Retired	Market
PG&E	ZZZZZ_WDFRDF_2_UNITS	31404	WEST FOR	13.8	0.00	1	NCNB	Fulton	Retired	Market
PG&E	ZZZZZ_WDFRDF_2_UNITS	31404	WEST FOR	13.8	0.00	2	NCNB	Fulton	Retired	Market
PG&E	ALLGNY_6_HYDRO1				0.06		Sierra		Not modeled Aug NQC	Market
PG&E	APLHIL_1_SLABCK				0.00	1	Sierra	South of Rio Oso, South of Palermo	Not modeled Energy Only	Market
PG&E	BANGOR_6_HYDRO				0.47		Sierra		Not modeled Aug NQC	Market
PG&E	BELDEN_7_UNIT 1	31784	BELDEN	13.8	119.00	1	Sierra	South of Palermo	Aug NQC	Market
PG&E	BIOMAS_1_UNIT 1	32156	WOODLANDB IOM	13.8	23.93	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	Net Seller
PG&E	BNNIEN_7_ALTAPH	32376	BONNIE N	60	0.70		Sierra	Placer, Gold Hill-Drum, Drum-Rio Oso, South of Rio Oso, South of Palermo	Not modeled Aug NQC	Market
PG&E	BOGUE_1_UNITA1	32451	FREC	13.8	47.60	1	Sierra	Bogue, Drum-Rio Oso	Aug NQC	Market
PG&E	BOWMN_6_HYDRO	32480	BOWMAN	9.11	2.52	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	MUNI
PG&E	BUCKCK_2_HYDRO				0.04		Sierra	South of Palermo	Not modeled Aug NQC	Market

Attachment A - List of physical resources by PTO, local area and market ID

PG&E	BUCKCK_7_OAKFLT				0.66		Sierra	South of Palermo	Not modeled Aug NQC	Market
PG&E	BUCKCK_7_PL1X2	31820	BCKS CRK	11	30.63	1	Sierra	South of Palermo	Aug NQC	Market
PG&E	BUCKCK_7_PL1X2	31820	BCKS CRK	11	26.62	2	Sierra	South of Palermo	Aug NQC	Market
PG&E	CAMPFW_7_FARWST	32470	CMP.FARW	9.11	2.90	1	Sierra		Aug NQC	MUNI
PG&E	CHICPK_7_UNIT 1	32462	CHI.PARK	11.5	42.00	1	Sierra	Placer, Gold Hill-Drum, Drum-Rio Oso, South of Rio Oso, South of Palermo	Aug NQC	MUNI
PG&E	COLGAT_7_UNIT 1	32450	COLGATE1	13.8	161.65	1	Sierra		Aug NQC	MUNI
PG&E	COLGAT_7_UNIT 2	32452	COLGATE2	13.8	161.68	1	Sierra		Aug NQC	MUNI
PG&E	CRESTA_7_PL1X2	31812	CRESTA	11.5	35.54	2	Sierra	South of Palermo	Aug NQC	Market
PG&E	CRESTA_7_PL1X2	31812	CRESTA	11.5	34.86	1	Sierra	South of Palermo	Aug NQC	Market
PG&E	DAVIS_1_SOLAR1				0.00		Sierra	Drum-Rio Oso, South of Palermo	Not modeled Energy Only	Solar
PG&E	DAVIS_1_SOLAR2				0.00		Sierra	Drum-Rio Oso, South of Palermo	Not modeled Aug NQC	Solar
PG&E	DAVIS_7_MNMETH				1.75		Sierra	Drum-Rio Oso, South of Palermo	Not modeled Aug NQC	Market
PG&E	DEADCK_1_UNIT	31862	DEADWOOD	9.11	0.02	1	Sierra	Drum-Rio Oso	Aug NQC	MUNI
PG&E	DEERCR_6_UNIT 1	32474	DEER CRK	2.4	3.18	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	Market
PG&E	DRUM_7_PL1X2	32504	DRUM 1-2	6.6	5.20	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	Market
PG&E	DRUM_7_PL1X2	32504	DRUM 1-2	6.6	5.20	2	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	Market
PG&E	DRUM_7_PL3X4	32506	DRUM 3-4	6.6	15.64	2	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	Market
PG&E	DRUM_7_PL3X4	32506	DRUM 3-4	6.6	13.26	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	Market
PG&E	DRUM_7_UNIT 5	32454	DRUM 5	13.8	47.74	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	Market
PG&E	DUTCH1_7_UNIT 1	32464	DTCHFLT1	11	22.00	1	Sierra	Placer, Gold Hill-Drum, Drum-Rio Oso, South of Rio Oso, South of Palermo	Aug NQC	Market
PG&E	DUTCH2_7_UNIT 1	32502	DTCHFLT2	6.9	15.21	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	MUNI

PG&E	ELDORO_7_UNIT 1	32513	ELDRADO1	21.6	3.32	1	Sierra	Gold Hill-Drum, South of Rio Oso, South of Palermo		Market
PG&E	ELDORO_7_UNIT 2	32514	ELDRADO2	21.6	11.00	1	Sierra	Gold Hill-Drum, South of Rio Oso, South of Palermo		Market
PG&E	FMEADO_6_HELLHL	32486	HELLHOLE	9.11	0.45	1	Sierra	South of Rio Oso, South of Palermo	Aug NQC	MUNI
PG&E	FMEADO_7_UNIT	32508	FRNCH MD	4.2	16.00	1	Sierra	South of Rio Oso, South of Palermo	Aug NQC	MUNI
PG&E	FORBST_7_UNIT 1	31814	FORBSTWN	11.5	37.50	1	Sierra	Drum-Rio Oso	Aug NQC	MUNI
PG&E	GRIDLY_6_SOLAR	38054	GRIDLEY	60	0.00	1	Sierra	Pease	Energy Only	Solar
PG&E	GRIZLY_1_UNIT 1	31900	GRIZLYG	6.9	20.00	1	Sierra	South of Palermo	Aug NQC	MUNI
PG&E	GRNLF2_1_UNIT	32492	GRNLEAF2	13.8	49.20	1	Sierra	Pease, Drum-Rio Oso	Aug NQC	QF/Selfgen
PG&E	HALSEY_6_UNIT	32478	HALSEY F	6.6	13.50	1	Sierra	Placer, Gold Hill-Drum, Drum-Rio Oso, South of Rio Oso, South of Palermo	Aug NQC	Market
PG&E	HAYPRS_6_QFUNTS	32488	HAYPRES+	9.11	0.05	2	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	QF/Selfgen
PG&E	HAYPRS_6_QFUNTS	32488	HAYPRES+	9.11	0.04	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	QF/Selfgen
PG&E	HIGGNS_1_COMBIE				0.35		Sierra	Drum-Rio Oso, South of Rio Oso, South of Palermo	Not modeled Aug NQC	Market
PG&E	HIGGNS_7_QFUNTS				0.25		Sierra	Drum-Rio Oso, South of Rio Oso, South of Palermo	Not modeled Aug NQC	QF/Selfgen
PG&E	KELYRG_6_UNIT	31834	KELLYRDG	4.16	11.00	1	Sierra	Drum-Rio Oso	Aug NQC	MUNI
PG&E	LIVEOK_6_SOLAR				0.14		Sierra	Pease	Not modeled Aug NQC	Solar
PG&E	LODIEC_2_PL1X2	38123	LODI CT1	18	199.03	1	Sierra	South of Rio Oso, South of Palermo		MUNI
PG&E	LODIEC_2_PL1X2	38124	LODI ST1	18	103.55	1	Sierra	South of Rio Oso, South of Palermo		MUNI
PG&E	MDFKRL_2_PROJCT	32458	RALSTON	13.8	81.66	1	Sierra	South of Rio Oso, South of Palermo	Aug NQC	MUNI

Attachment A - List of physical resources by PTO, local area and market ID

PG&E	MDFKRL_2_PROJCT	32456	MIDLFORK	13.8	63.57	1	Sierra	South of Rio Oso, South of Palermo	Aug NQC	MUNI
PG&E	MDFKRL_2_PROJCT	32456	MIDLFORK	13.8	63.57	2	Sierra	South of Rio Oso, South of Palermo	Aug NQC	MUNI
PG&E	NAROW1_2_UNIT	32466	NARROWS1	11	12.00	1	Sierra		Aug NQC	Market
PG&E	NAROW2_2_UNIT	32468	NARROWSPH 2	13.8	20.00	1	Sierra		Aug NQC	MUNI
PG&E	NWCSTL_7_UNIT 1	32460	NEWCSTLE	13.2	0.70	1	Sierra	Placer, Gold Hill-Drum, Drum-Rio Oso, South of Rio Oso, South of Palermo	Aug NQC	Market
PG&E	OROVIL_6_UNIT	31888	OROVLENRG	4.16	7.50	1	Sierra	Drum-Rio Oso	Aug NQC	Market
PG&E	OXBOW_6_DRUM	32484	OXBOW F	9.11	4.30	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	MUNI
PG&E	PLACVL_1_CHILIB	32510	CHILIBAR	4.2	8.40	1	Sierra	Gold Hill-Drum, South of Rio Oso, South of Palermo	Aug NQC	Market
PG&E	PLACVL_1_RCKCRE				0.00		Sierra	South of Rio Oso, South of Palermo	Not modeled Aug NQC	Market
PG&E	PLSNTG_7_LNCLND	32408	PLSNT GR	60	3.02		Sierra	Drum-Rio Oso, South of Rio Oso, South of Palermo	Not modeled Aug NQC	Market
PG&E	POEPH_7_UNIT 1	31790	POE 1	13.8	60.00	1	Sierra	South of Palermo	Aug NQC	Market
PG&E	POEPH_7_UNIT 2	31792	POE 2	13.8	60.00	1	Sierra	South of Palermo	Aug NQC	Market
PG&E	RCKCRK_7_UNIT 1	31786	ROCK CK1	13.8	57.00	1	Sierra	South of Palermo	Aug NQC	Market
PG&E	RCKCRK_7_UNIT 2	31788	ROCK CK2	13.8	56.90	1	Sierra	South of Palermo	Aug NQC	Market
PG&E	RIOOSO_1_QF				1.14		Sierra	Drum-Rio Oso, South of Palermo	Not modeled Aug NQC	QF/Selfgen
PG&E	ROLLIN_6_UNIT	32476	ROLLINSF	6.6	13.50	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	MUNI
PG&E	SLYCRK_1_UNIT 1	31832	SLY.CR.	6.6	13.00	1	Sierra	Drum-Rio Oso	Aug NQC	MUNI
PG&E	SPAULD_6_UNIT 3	32472	SPAULDG	9.11	3.48	3	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	Market
PG&E	SPAULD_6_UNIT12	32472	SPAULDG	9.11	7.00	1	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	Market
PG&E	SPAULD_6_UNIT12	32472	SPAULDG	9.11	4.40	2	Sierra	Drum-Rio Oso, South of Palermo	Aug NQC	Market

PG&E	SPI LI_2_UNIT 1	32498	SPILINCF	12.5	9.65	1	Sierra	Drum-Rio Oso, South of Rio Oso, South of Palermo	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		MUNI
PG&E	ULTRCK_2_UNIT	32500	ULTR RCK	12.5	23.24	1	Sierra	Drum-Rio Oso, South of Rio Oso, South of Palermo	Aug NQC	Market
PG&E	WDLEAF_7_UNIT 1	31794	WOODLEAF	13.8	60.00	1	Sierra	Drum-Rio Oso	Aug NQC	MUNI
PG&E	WHEATL_6_LNDFIL	32350	WHEATLND	60	3.16		Sierra		Not modeled Aug NQC	Market
PG&E	WISE_1_UNIT 1	32512	WISE	12	14.50	1	Sierra	Placer, Gold Hill-Drum, Drum-Rio Oso, South of Rio Oso, South of Palermo	Aug NQC	Market
PG&E	WISE_1_UNIT 2	32512	WISE	12	3.20	1	Sierra	Placer, Gold Hill-Drum, Drum-Rio Oso, South of Rio Oso, South of Palermo	Aug NQC	Market
PG&E	YUBACT_1_SUNSWT	32494	YUBA CTY	13.8	49.97	1	Sierra	Pease, Drum-Rio Oso	Aug NQC	Net Seller
PG&E	YUBACT_6_UNITA1	32496	YCEC	13.8	47.60	1	Sierra	Pease, Drum-Rio Oso		Market
PG&E	ZZ_NA	32162	RIV.DLTA	9.11	0.00	1	Sierra	Drum-Rio Oso, South of Palermo	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	No NQC - hist. data	QF/Selfgen
PG&E	ZZZ_New Unit	365936	Q653FSPV1	0.12	2.46	1	Sierra	Drum-Rio Oso, South of Palermo	No NQC - est. data	Solar
PG&E	ZZZ_New Unit	365940	Q653FSPV2	0.12	2.46	2	Sierra	Drum-Rio Oso, South of Palermo	No NQC - est. data	Solar
PG&E	ZZZ_New Unit	365938	Q653FC6BESS	0.48	0.00	3	Sierra	Drum-Rio Oso, South of Palermo	No NQC - est. data	Battery
PG&E	ZZZZZ_GOLDHL_1_QF				0.00		Sierra	South of Rio Oso, South of Palermo	Retired	QF/Selfgen
PG&E	ZZZZZ_GRNLF1_1_UNITS	32490	GRNLEAF1	13.8	0.00	1	Sierra	Bogue, Drum-Rio Oso	Retired	Market

Attachment A - List of physical resources by PTO, local area and market ID

PG&E	ZZZZZ_GRNLF1_1_UNITS	32491	GRNLEAF1	13.8	0.00	2	Sierra	Bogue, Drum-Rio Oso	Retired	Market
PG&E	ZZZZZ_KANAKA_1_UNIT				0.00		Sierra	Drum-Rio Oso	Retired	MUNI
PG&E	ZZZZZ_PACORO_6_UNIT	31890	PO POWER	9.11	0.00	1	Sierra	Drum-Rio Oso	Retired	QF/Selfgen
PG&E	ZZZZZ_PACORO_6_UNIT	31890	PO POWER	9.11	0.00	2	Sierra	Drum-Rio Oso	Retired	QF/Selfgen
PG&E	BEARDS_7_UNIT 1	34074	BEARDSLY	6.9	8.34	1	Stockton	Tesla-Bellota, Stanislaus	Aug NQC	MUNI
PG&E	CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	1.41	1	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	1.41	2	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	1.41	3	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	CENT40_1_C40SR1	36568 4	Q1103	0.32	10.80	1	Stockton	Tesla-Bellota	Aug NQC	Solar
PG&E	CRWCKS_1_SOLAR1	34051	Q539	34.5	0.00	1	Stockton	Tesla-Bellota	Energy Only	Solar
PG&E	DONNLS_7_UNIT	34058	DONNELLS	13.8	58.20	1	Stockton	Tesla-Bellota, Stanislaus	Aug NQC	MUNI
PG&E	FROGTN_1_UTICAA				0.79		Stockton	Tesla-Bellota, Stanislaus	Not Modeled Aug NQC	Market
PG&E	FROGTN_1_UTICAM				2.12		Stockton	Tesla-Bellota, Stanislaus	Not Modeled Aug NQC	Market
PG&E	LOCKFD_1_BEARCK				0.41		Stockton	Tesla-Bellota	Not Modeled Aug NQC	Solar
PG&E	LOCKFD_1_KSOLAR				0.27		Stockton	Tesla-Bellota	Not Modeled Aug NQC	Solar
PG&E	LODI25_2_UNIT 1	38120	LODI25CT	13.8	23.80	1	Stockton	Lockeford		MUNI
PG&E	MANTEC_1_ML1SR1				0.00		Stockton	Tesla-Bellota	Not modeled Energy Only	Solar
PG&E	PEORIA_1_SOLAR				0.41		Stockton	Tesla-Bellota, Stanislaus	Not modeled Aug NQC	Solar
PG&E	PHOENX_1_UNIT				0.90		Stockton	Tesla-Bellota, Stanislaus	Not modeled Aug NQC	Market
PG&E	SCHLTE_1_PL1X3	33811	GWFTRCY3	13.8	138.11	1	Stockton	Tesla-Bellota		Market
PG&E	SCHLTE_1_PL1X3	33805	GWFTRCY1	13.8	85.70	1	Stockton	Tesla-Bellota		Market
PG&E	SCHLTE_1_PL1X3	33807	GWFTRCY2	13.8	85.70	1	Stockton	Tesla-Bellota		Market
PG&E	SNDBAR_7_UNIT 1	34060	SANDBAR	13.8	13.64	1	Stockton	Tesla-Bellota, Stanislaus	Aug NQC	MUNI
PG&E	SPIFBD_1_PL1X2	34055	SPISONORA	13.8	4.69	1	Stockton	Tesla-Bellota, Stanislaus	Aug NQC	Market

PG&E	SPRGAP_1_UNIT 1	34078	SPRNG GP	6	0.09	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	18.01	1	Stockton	Tesla-Bellota	Aug NQC	Net Seller
PG&E	TULLCK_7_UNITS	34076	TULLOCH	6.9	7.95	2	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	TULLCK_7_UNITS	34076	TULLOCH	6.9	7.07	1	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	TULLCK_7_UNITS	34076	TULLOCH	6.9	5.22	3	Stockton	Tesla-Bellota	Aug NQC	MUNI
PG&E	ULTPCH_1_UNIT 1	34050	CH.STN.	13.8	17.95	1	Stockton	Tesla-Bellota, Stanislaus	Aug NQC	Market
PG&E	VLYHOM_7_SSJID				0.72		Stockton	Tesla-Bellota, Stanislaus	Not modeled Aug NQC	MUNI
PG&E	ZZZ_New Unit	36555 6	SAFEWAYB	12.5	0.00	RN	Stockton	Tesla-Bellota	Energy Only	Market
PG&E	ZZZZZ_FROGTN_7_UTICA				0.00		Stockton	Tesla-Bellota, Stanislaus	Retired	Market
PG&E	ZZZZZ_STOKCG_1_UNIT 1	33814	INGREDION	12.5	0.00	RN	Stockton	Tesla-Bellota	Retired	QF/Selfgen
PG&E	ZZZZZZ_NA	33830	GEN.MILL	9.11	0.00	1	Stockton	Lockeford	Retired	QF/Selfgen
SCE	ACACIA_6_SOLAR	29878	ACACIA_G	0.48	5.40	EQ	BC/Ventura		Aug NQC	Solar
SCE	ALAMO_6_UNIT	25653	ALAMO SC	13.8	13.87	1	BC/Ventura		Aug NQC	MUNI
SCE	BGSKYN_2_AS2SR1	29773	ANTLP2_P1_ G1	0.63	28.35	EQ	BC/Ventura		Aug NQC	Solar
SCE	BGSKYN_2_ASPSR2	29776	ANTLP2_P2_ G1	0.6	27.00	EQ	BC/Ventura		Aug NQC	Solar
SCE	BGSKYN_2_BS3SR3	29774	ANTLP2_P45_ G	0.44	5.40	EQ	BC/Ventura		Aug NQC	Solar
SCE	BIGCRK_2_EXESWD	24317	MAMOTH1G	13.8	92.02	1	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24318	MAMOTH2G	13.8	92.02	2	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24308	B CRK2-1	13.8	51.18	2	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24308	B CRK2-1	13.8	49.99	1	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24314	B CRK 4	11.5	49.80	42	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24314	B CRK 4	11.5	49.60	41	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24315	B CRK 8	13.8	43.30	82	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24313	B CRK3-3	13.8	35.92	5	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24312	B CRK3-2	13.8	35.43	4	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24311	B CRK3-1	13.8	34.44	1	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24312	B CRK3-2	13.8	34.44	3	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24311	B CRK3-1	13.8	33.46	2	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24307	B CRK1-2	13.8	30.71	4	BC/Ventura	Rector, Vestal	Aug NQC	Market

Attachment A - List of physical resources by PTO, local area and market ID

SCE	BIGCRK_2_EXESWD	24315	B CRK 8	13.8	24.01	81	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24306	B CRK1-1	7.2	21.26	2	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24307	B CRK1-2	13.8	21.26	3	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24306	B CRK1-1	7.2	19.58	1	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24309	B CRK2-2	7.2	19.39	4	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24309	B CRK2-2	7.2	18.40	3	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24310	B CRK2-3	7.2	18.21	6	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24310	B CRK2-3	7.2	16.73	5	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_2_EXESWD	24323	PORTAL	4.8	9.45	1	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	BIGCRK_7_DAM7				0.00		BC/Ventura	Rector, Vestal	Not modeled Energy Only	Market
SCE	BIGCRK_7_MAMRES				0.00		BC/Ventura	Rector, Vestal	Not modeled Energy Only	Market
SCE	BIGSKY_2_BSKSR6	29734	BSKY G BC	0.42	5.40	1	BC/Ventura		Aug NQC	Solar
SCE	BIGSKY_2_BSKSR7	29737	BSKY G WABS	0.42	5.40	1	BC/Ventura		Aug NQC	Solar
SCE	BIGSKY_2_BSKSR8	29740	BSKY G ABSR	0.38	5.40	1	BC/Ventura		Aug NQC	Solar
SCE	BIGSKY_2_SOLAR1	29704	BSKY G SMR	0.42	5.40	1	BC/Ventura		Aug NQC	Solar
SCE	BIGSKY_2_SOLAR2	29744	BSKY_G_ESC	0.42	34.81	1	BC/Ventura		Aug NQC	Solar
SCE	BIGSKY_2_SOLAR3	29725	BSKY_G_BD	0.42	5.40	1	BC/Ventura		Aug NQC	Solar
SCE	BIGSKY_2_SOLAR4	29701	BSKY_G_BA	0.42	17.26	1	BC/Ventura		Aug NQC	Solar
SCE	BIGSKY_2_SOLAR5	29731	BSKY_G_BB	0.42	1.35	1	BC/Ventura		Aug NQC	Solar
SCE	BIGSKY_2_SOLAR6	29728	BSKY_G_SOLV	0.42	22.95	1	BC/Ventura		Aug NQC	Solar
SCE	BIGSKY_2_SOLAR7	29731	BSKY_G_ADSR	0.42	13.50	1	BC/Ventura		Aug NQC	Solar
SCE	CEDUCR_2_SOLAR1	25049	DUCOR1	0.39	0.00	EQ	BC/Ventura	Vestal	Energy Only	Solar
SCE	CEDUCR_2_SOLAR2	25052	DUCOR2	0.39	0.00	EQ	BC/Ventura	Vestal	Energy Only	Solar
SCE	CEDUCR_2_SOLAR3	25055	DUCOR3	0.39	0.00	EQ	BC/Ventura	Vestal	Energy Only	Solar
SCE	CEDUCR_2_SOLAR4	25058	DUCOR4	0.39	0.00	EQ	BC/Ventura	Vestal	Energy Only	Solar
SCE	DELSUR_6_BSOLAR	24411	DELSUR_DIST	66	0.81	1	BC/Ventura		Aug NQC	Solar
SCE	DELSUR_6_CREST	24411	DELSUR_DIST	66	0.00		BC/Ventura		Not modeled Energy Only	Market
SCE	DELSUR_6_DRYFRB	24411	DELSUR_DIST	66	1.35	1	BC/Ventura		Aug NQC	Market
SCE	DELSUR_6_SOLAR1	24411	DELSUR_DIST	66	1.76	2	BC/Ventura		Aug NQC	Solar
SCE	DELSUR_6_SOLAR4	24411	DELSUR_DIST	66	0.00		BC/Ventura		Not modeled Energy Only	Solar

Attachment A - List of physical resources by PTO, local area and market ID

SCE	DELSUR_6_SOLAR5	24411	DELSUR_DIST	66	0.00		BC/Ventura		Not modeled Energy Only	Solar
SCE	EASTWD_7_UNIT	24319	EASTWOOD	13.8	199.00	1	BC/Ventura	Rector, Vestal		Market
SCE	EDMONS_2_NSPIN	25605	EDMON1AP	14.4	16.86	1	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25606	EDMON2AP	14.4	16.86	2	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25607	EDMON3AP	14.4	16.86	3	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25607	EDMON3AP	14.4	16.86	4	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25608	EDMON4AP	14.4	16.86	5	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25608	EDMON4AP	14.4	16.86	6	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25609	EDMON5AP	14.4	16.86	7	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25609	EDMON5AP	14.4	16.86	8	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25610	EDMON6AP	14.4	16.86	9	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25610	EDMON6AP	14.4	16.86	10	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25611	EDMON7AP	14.4	16.85	11	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25611	EDMON7AP	14.4	16.85	12	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25612	EDMON8AP	14.4	16.85	13	BC/Ventura		Pumps	MUNI
SCE	EDMONS_2_NSPIN	25612	EDMON8AP	14.4	16.85	14	BC/Ventura		Pumps	MUNI
SCE	GLDFGR_6_SOLAR1	25079	PRIDE B G	0.64	5.40	1	BC/Ventura		Aug NQC	Solar
SCE	GLDFGR_6_SOLAR2	25169	PRIDE C G	0.64	3.08	1	BC/Ventura		Aug NQC	Solar
SCE	GLOW_6_SOLAR	29896	APPINV	0.42	0.00	EQ	BC/Ventura		Energy Only	Solar
SCE	GOLETA_2_QF	25335	GOLETA_DIST	66	0.06	S1	BC/Ventura	S.Clara, Moorpark, Goleta	Aug NQC	QF/Selfgen
SCE	GOLETA_2_VALBT1	99739	GOLETA_DIST2	66	10.00	S2	BC/Ventura	S.Clara, Moorpark, Goleta		Battery
SCE	GOLETA_6_ELLWOD	29004	ELLWOOD	13.8	54.00	1	BC/Ventura	S.Clara, Moorpark, Goleta		Market
SCE	GOLETA_6_EXGEN	24362	EXGEN2	13.8	0.00	G1	BC/Ventura	S.Clara, Moorpark, Goleta	Aug NQC - Currently out of service	QF/Selfgen
SCE	GOLETA_6_EXGEN	24326	EXGEN1	13.8	0.00	S1	BC/Ventura	S.Clara, Moorpark, Goleta	Aug NQC - Currently out of service	QF/Selfgen
SCE	GOLETA_6_TAJIGS	25335	GOLETA_DIST	66	2.84	S1	BC/Ventura	S.Clara, Moorpark, Goleta	Aug NQC	Market
SCE	LEBECS_2_UNITS	29053	PSTRIAS1	18	176.14	S1	BC/Ventura		Aug NQC	Market
SCE	LEBECS_2_UNITS	29051	PSTRIAG1	18	171.10	G1	BC/Ventura		Aug NQC	Market
SCE	LEBECS_2_UNITS	29052	PSTRIAG2	18	171.10	G2	BC/Ventura		Aug NQC	Market
SCE	LEBECS_2_UNITS	29054	PSTRIAG3	18	171.10	G3	BC/Ventura		Aug NQC	Market
SCE	LEBECS_2_UNITS	29055	PSTRIAS2	18	85.55	S2	BC/Ventura		Aug NQC	Market

SCE	LITLRK_6_GBCSR1	25696	LTLRCK_DIST	66	0.81	EQ	BC/Ventura		Aug NQC	Solar
SCE	LITLRK_6_SEPV01	25696	LTLRCK_DIST	66	0.00	EQ	BC/Ventura		Energy Only	Market
SCE	LITLRK_6_SOLAR1	25696	LTLRCK_DIST	66	1.35	EQ	BC/Ventura		Aug NQC	Solar
SCE	LITLRK_6_SOLAR2	25696	LTLRCK_DIST	66	0.54	EQ	BC/Ventura		Aug NQC	Solar
SCE	LITLRK_6_SOLAR3	25696	LTLRCK_DIST	66	0.54	EQ	BC/Ventura		Aug NQC	Solar
SCE	LITLRK_6_SOLAR4	25696	LTLRCK_DIST	66	0.81	EQ	BC/Ventura		Aug NQC	Solar
SCE	LNCSTR_6_CREST				0.00		BC/Ventura		Not modeled Energy Only	Market
SCE	LNCSTR_6_SOLAR2	25695	LCANSTR_DIST	66	0.32	EQ	BC/Ventura		Aug NQC	Solar
SCE	MNDALY_6_MCGRTH	29306	MCGPKGEN	13.8	47.20	1	BC/Ventura	S.Clara, Moorpark		Market
SCE	MOORPK_2_CALABS	25081	WDT251	13.8	4.97	EQ	BC/Ventura	Moorpark	Aug NQC	Market
SCE	MOORPK_6_QF				0.62		BC/Ventura	Moorpark	Not modeled Aug NQC	Market
SCE	NEENCH_6_SOLAR	29900	ALPINE_G	0.48	17.82	EQ	BC/Ventura		Aug NQC	Solar
SCE	OASIS_6_CREST				0.00		BC/Ventura		Not modeled Energy Only	Market
SCE	OASIS_6_GBDSR4	25698	OASIS_DIST	66	0.81	EQ	BC/Ventura		Aug NQC	Solar
SCE	OASIS_6_SOLAR1	25095	SOLARISG2	0.2	0.00	EQ	BC/Ventura		Energy Only	Solar
SCE	OASIS_6_SOLAR2	25075	SOLARISG	0.2	5.40	EQ	BC/Ventura		Aug NQC	Solar
SCE	OASIS_6_SOLAR3				0.00		BC/Ventura		Not modeled Energy Only	Solar
SCE	OMAR_2_UNIT 1	24102	OMAR 1G	13.8	70.30	1	BC/Ventura			Net Seller
SCE	OMAR_2_UNIT 2	24103	OMAR 2G	13.8	71.24	2	BC/Ventura			Net Seller
SCE	OMAR_2_UNIT 3	24104	OMAR 3G	13.8	74.03	3	BC/Ventura			Net Seller
SCE	OMAR_2_UNIT 4	24105	OMAR 4G	13.8	81.44	4	BC/Ventura			Net Seller
SCE	ORMOND_7_UNIT 1	24107	ORMOND1G	26	741.27	1	BC/Ventura	Moorpark	Retired by 2026	Market
SCE	ORMOND_7_UNIT 2	24108	ORMOND2G	26	750.00	2	BC/Ventura	Moorpark	Retired by 2026	Market
SCE	OSO_6_NSPIN	25614	OSO A P	13.2	2.25	1	BC/Ventura		Pumps	MUNI
SCE	OSO_6_NSPIN	25614	OSO A P	13.2	2.25	2	BC/Ventura		Pumps	MUNI
SCE	OSO_6_NSPIN	25614	OSO A P	13.2	2.25	3	BC/Ventura		Pumps	MUNI
SCE	OSO_6_NSPIN	25614	OSO A P	13.2	2.25	4	BC/Ventura		Pumps	MUNI
SCE	OSO_6_NSPIN	25615	OSO B P	13.2	2.25	5	BC/Ventura		Pumps	MUNI
SCE	OSO_6_NSPIN	25615	OSO B P	13.2	2.25	6	BC/Ventura		Pumps	MUNI
SCE	OSO_6_NSPIN	25615	OSO B P	13.2	2.25	7	BC/Ventura		Pumps	MUNI
SCE	OSO_6_NSPIN	25615	OSO B P	13.2	2.25	8	BC/Ventura		Pumps	MUNI
SCE	PIUTE_6_GNBSR1	25699	PIUTE_DIST	66	0.81	EQ	BC/Ventura		Aug NQC	Solar

Attachment A - List of physical resources by PTO, local area and market ID

SCE	PLAINV_6_BSOLAR	29917	SSOLAR)GR WKS	0.8	0.00	1	BC/Ventura		Energy Only	Solar
SCE	PLAINV_6_DSOLAR	29914	WADR_PV	0.42	2.70	1	BC/Ventura		Aug NQC	Solar
SCE	PLAINV_6_NLRSR1	29921	NLR_INVTR	0.42	0.00	1	BC/Ventura		Energy Only	Solar
SCE	PLAINV_6_SOLAR3	25089	CNTRL ANT G	0.42	0.00	1	BC/Ventura		Energy Only	Solar
SCE	PLAINV_6_SOLARC	25086	SIRA SOLAR G	0.8	0.00	1	BC/Ventura		Energy Only	Solar
SCE	PMDLET_6_SOLAR1				2.70		BC/Ventura		Not modeled Aug NQC	Solar
SCE	RECTOR_2_CREST	25333	RECTOR_DIS T	66	0.00	S1	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	RECTOR_2_KAWEAH	25333	RECTOR_DIS T	66	3.40	S2	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	RECTOR_2_KAWH 1	24370	KAWGEN	13.8	0.46	1	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	RECTOR_2_QF	25333	RECTOR_DIS T	66	3.94	S1	BC/Ventura	Rector, Vestal	Aug NQC	Net Seller
SCE	RECTOR_2_TFDBM1				0.00		BC/Ventura	Rector, Vestal	Energy Only	Market
SCE	RECTOR_7_TULARE	25333	RECTOR_DIS T	66	0.00	S1	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	REDMAN_2_SOLAR	25700	REDMN_DIST	66	1.01	EQ	BC/Ventura		Aug NQC	Solar
SCE	REDMAN_6_AVSSR1	25700	REDMN_DIST	66	0.81	EQ	BC/Ventura		Aug NQC	Solar
SCE	ROSMND_6_SOLAR	25703	RSAMOND_DI S	66	0.81	EQ	BC/Ventura		Aug NQC	Solar
SCE	RSMSLR_6_SOLAR1	29984	DAWNGEN	0.8	5.40	EQ	BC/Ventura		Aug NQC	Solar
SCE	RSMSLR_6_SOLAR2	29888	TWILGHTG	0.8	5.40	EQ	BC/Ventura		Aug NQC	Solar
SCE	SAUGUS_6_CREST				0.00		BC/Ventura		Not modeled Energy Only	Market
SCE	SAUGUS_6_MWDFTH	25336	SAUGUS_MW D	66	5.40	S1	BC/Ventura		Aug NQC	MUNI
SCE	SAUGUS_6_QF	24135	SAUGUS	66	0.45		BC/Ventura		Not modeled Aug NQC	QF/Selfgen
SCE	SAUGUS_7_CHIQCN	24135	SAUGUS	66	5.22		BC/Ventura		Not modeled Aug NQC	Market
SCE	SAUGUS_7_LOPEZ	24135	SAUGUS	66	5.34		BC/Ventura		Not modeled Aug NQC	QF/Selfgen
SCE	SHUTLE_6_CREST	25701	SHTTLE_DIST	66	0.00	EQ	BC/Ventura		Energy Only	Market
SCE	SNCLRA_2_HOWLNG	25080	SANTACLR_D IS	13.8	5.45	EQ	BC/Ventura	S.Clara, Moorpark	Aug NQC	Market
SCE	SNCLRA_2_SPRHYD	25080	SANTACLR_D IS	13.8	0.14	EQ	BC/Ventura	S.Clara, Moorpark	Aug NQC	Market
SCE	SNCLRA_2_UNIT	29952	CAMGEN	13.8	27.50	D1	BC/Ventura	S.Clara, Moorpark	Aug NQC	Market

SCE	SNCLRA_2_UNIT1	24159	WILLAMET	3.8	15.67	D1	BC/Ventura	S.Clara, Moorpark	Aug NQC	Market
SCE	SNCLRA_6_OXGEN	24110	OXGEN	13.8	47.70	D1	BC/Ventura	S.Clara, Moorpark	Aug NQC	QF/Selfgen
SCE	SNCLRA_6_PROCGN	24119	PROCGEN	13.8	30.37	D1	BC/Ventura	S.Clara, Moorpark	Aug NQC	QF/Selfgen
SCE	SNCLRA_6_QF	25080	SANTACLR_DIS	13.8	0.00	EQ	BC/Ventura	S.Clara, Moorpark	Aug NQC	QF/Selfgen
SCE	SPRGVL_2_CREST	25334	SPRNGVL_DIST	66	0.00	S1	BC/Ventura	Rector, Vestal	Energy Only	Market
SCE	SPRGVL_2_QF	25334	SPRNGVL_DIST	66	0.18	S1	BC/Ventura	Rector, Vestal	Aug NQC	QF/Selfgen
SCE	SPRGVL_2_TULE	25334	SPRNGVL_DIST	66	0.00	S2	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	SPRGVL_2_TULESC	25334	SPRNGVL_DIST	66	0.44	S1	BC/Ventura	Rector, Vestal	Aug NQC	Market
SCE	SUNSHN_2_LNDFL	29954	WDT273	13.7	3.31	1	BC/Ventura		Aug NQC	Market
SCE	SUNSHN_2_LNDFL	29954	WDT273	13.7	3.31	2	BC/Ventura		Aug NQC	Market
SCE	SUNSHN_2_LNDFL	29954	WDT273	13.7	3.31	3	BC/Ventura		Aug NQC	Market
SCE	SUNSHN_2_LNDFL	29954	WDT273	13.7	3.31	4	BC/Ventura		Aug NQC	Market
SCE	SUNSHN_2_LNDFL	29954	WDT273	13.7	3.31	5	BC/Ventura		Aug NQC	Market
SCE	SYCAMR_2_UNIT 1	24143	SYCCYN1G	13.8	76.40	1	BC/Ventura		Aug NQC	Net Seller
SCE	SYCAMR_2_UNIT 2	24144	SYCCYN2G	13.8	78.00	2	BC/Ventura		Aug NQC	Net Seller
SCE	SYCAMR_2_UNIT 3	24145	SYCCYN3G	13.8	78.00	3	BC/Ventura		Aug NQC	Net Seller
SCE	SYCAMR_2_UNIT 4	24146	SYCCYN4G	13.8	78.00	4	BC/Ventura		Aug NQC	Net Seller
SCE	TENGEN_2_PL1X2	24148	TENNGEN1	13.8	17.57	D1	BC/Ventura		Aug NQC	Net Seller
SCE	TENGEN_2_PL1X2	24149	TENNGEN2	13.8	17.57	D2	BC/Ventura		Aug NQC	Net Seller
SCE	TULARE_2_TULBM1				0.00		BC/Ventura		Not modeled Energy Only	Market
SCE	VESTAL_2_KERN	24372	KR 3-1	11	11.45	1	BC/Ventura	Vestal	Aug NQC	QF/Selfgen
SCE	VESTAL_2_KERN	24373	KR 3-2	11	10.80	2	BC/Ventura	Vestal	Aug NQC	QF/Selfgen
SCE	VESTAL_2_RTS042				0.00		BC/Ventura	Vestal	Not modeled Energy Only	Market
SCE	VESTAL_2_SOLAR1	25064	TULRESLR	0.39	5.40	1	BC/Ventura	Vestal	Aug NQC	Solar
SCE	VESTAL_2_SOLAR2	25065	TULRESLR	0.39	3.78	1	BC/Ventura	Vestal	Aug NQC	Solar
SCE	VESTAL_2_UNIT1				3.52		BC/Ventura	Vestal	Not modeled Aug NQC	Market
SCE	VESTAL_2_WELLHD	24116	WELLGEN	13.8	49.00	1	BC/Ventura	Vestal		Market
SCE	VESTAL_6_QF	29008	LAKEGEN	13.8	8.65	1	BC/Ventura	Vestal	Aug NQC	Market
SCE	WARNE_2_UNIT	25651	WARNE1	13.8	20.79	1	BC/Ventura		Aug NQC	MUNI
SCE	WARNE_2_UNIT	25652	WARNE2	13.8	20.79	2	BC/Ventura		Aug NQC	MUNI
SCE	ZZ_CHARMN_2_PGONG1	24340	CHARMIN	13.8	2.80	1	BC/Ventura	S.Clara, Moorpark	No NQC - hist. data	QF/Selfgen

SCE	ZZZ_New Unit	29792	ANTLP2_BE_ B1	0.48	208.80	EQ	BC/Ventura		No NQC - est. data	Battery
SCE	ZZZ_New Unit	29528	TOT827_ES	0.48	120.00	1	BC/Ventura		No NQC - Pmax	Battery
SCE	ZZZ_New Unit	29824	WDT1519	66	100.00	1	BC/Ventura	S.Clara, Moorpark	No NQC - Pmax	Battery
SCE	ZZZ_New Unit	29782	ANTLP2_C2_ G1	0.44	68.53	EQ	BC/Ventura		No NQC - est. data	Solar
SCE	ZZZ_New Unit	69805 2	WDT1384_G_ ST	0.39	50.00	1	BC/Ventura	Vestal	No NQC - est. data	Battery
SCE	ZZZ_New Unit	29826	WDT1454	66	40.00	1	BC/Ventura	S.Clara, Moorpark	No NQC - Pmax	Battery
SCE	ZZZ_New Unit	29830	WDT1454	66	20.00	1	BC/Ventura	S.Clara, Moorpark	No NQC - Pmax	Battery
SCE	ZZZ_New Unit	99739	GOLETA-DIST2	66	20.00	S2	BC/Ventura	S.Clara, Moorpark, Goleta	No NQC - Pmax	Battery
SCE	ZZZ_New Unit	97386	PSTRSOL1	0.55	19.25	1	BC/Ventura		No NQC - est. data	Solar
SCE	ZZZ_New Unit	29971	ANTLP2_C3_ G1	0.6	13.15	EQ	BC/Ventura		No NQC - est. data	Solar
SCE	ZZZ_New Unit	99740	S.CLARA-DIST	66	11.00	S2	BC/Ventura	S.Clara, Moorpark	No NQC - Pmax	Battery
SCE	ZZZ_New Unit	97387	PSTRSOL2	0.55	9.61	1	BC/Ventura		No NQC - est. data	Solar
SCE	ZZZ_New Unit	24127	S.CLARA	66	9.27	X8	BC/Ventura	S.Clara, Moorpark	No NQC - Pmax	Battery
SCE	ZZZ_New Unit	97523	WDT1380	0.36	7.16	1	BC/Ventura		No NQC - est. data	Solar
SCE	ZZZ_New Unit	24057	GOLETA	66	4.73	X8	BC/Ventura	S.Clara, Moorpark	No NQC - Pmax	Battery
SCE	ZZZ_New Unit	97482	WDT1384_G	0.39	0.00	1	BC/Ventura	Vestal	No NQC - est. data	Solar
SCE	ZZZZZ_APPGEN_6_UNIT 1	24009	APPGEN1G	13.8	0.00	1	BC/Ventura		Retired	Market
SCE	ZZZZZ_APPGEN_6_UNIT 1	24010	APPGEN2G	13.8	0.00	2	BC/Ventura		Retired	Market
SCE	ZZZZZ_APPGEN_6_UNIT 1	24361	APPGEN3G	13.8	0.00	3	BC/Ventura		Retired	Market
SCE	ZZZZZ_GOLETA_6_GAVOTA	25335	GOLETA_DIS T	66	0.00	S1	BC/Ventura	S.Clara, Moorpark, Goleta	Retired	Market

Attachment A - List of physical resources by PTO, local area and market ID

SCE	ZZZZZ_MNDALY_7_UNIT 1	24089	MANDLY1G	13.8	0.00	1	BC/Ventura	S.Clara, Moorpark	Retired	Market
SCE	ZZZZZ_MNDALY_7_UNIT 2	24090	MANDLY2G	13.8	0.00	2	BC/Ventura	S.Clara, Moorpark	Retired	Market
SCE	ZZZZZ_MNDALY_7_UNIT 3	24222	MANDLY3G	16	0.00	3	BC/Ventura	S.Clara, Moorpark	Retired	Market
SCE	ZZZZZ_MOORPK_7_UNITA1	24098	MOORPARK	66	0.00		BC/Ventura	Moorpark	Retired	Market
SCE	ZZZZZ_PANDOL_6_UNIT	24113	PANDOL	13.8	0.00	1	BC/Ventura	Vestal	Retired	Market
SCE	ZZZZZ_PANDOL_6_UNIT	24113	PANDOL	13.8	0.00	2	BC/Ventura	Vestal	Retired	Market
SCE	ZZZZZ_SAUGUS_2_TOLAND	24135	SAUGUS	66	0.00		BC/Ventura		Retired	Market
SCE	ZZZZZ_SAUGUS_6_PTCHGN	24118	PITCHGEN	13.8	0.00	D1	BC/Ventura		Retired	MUNI
SCE	ZZZZZ_VESTAL_6_ULTRGN	24150	ULTRAGEN	13.8	0.00	1	BC/Ventura	Vestal	Retired	QF/Selfgen
SCE	ALAMIT_2_PL1X3	24577	ALMT STG	18	251.66	S1	LA Basin	Western		Market
SCE	ALAMIT_2_PL1X3	24575	ALMT CTG1	18	211.52	G1	LA Basin	Western		Market
SCE	ALAMIT_2_PL1X3	24576	ALMT CTG2	18	211.52	G2	LA Basin	Western		Market
SCE	ALAMIT_7_ES1	69808 2	ALMITOS B1A	0.42	50.00	1	LA Basin	Western		Battery
SCE	ALAMIT_7_ES1	69808 3	ALMITOS B12	0.42	50.00	1	LA Basin	Western		Battery
SCE	ALAMIT_7_UNIT 3	24003	ALAMT3 G	18	321.40	3	LA Basin	Western	Retired by 2026	Market
SCE	ALAMIT_7_UNIT 4	24004	ALAMT4 G	18	335.67	4	LA Basin	Western	Retired by 2026	Market
SCE	ALAMIT_7_UNIT 5	24005	ALAMT5 G	20	497.97	5	LA Basin	Western	Retired by 2026	Market
SCE	ALTWD_1_QF	25635	ALTWIND	115	3.03	Q1	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	ALTWD_1_QF	25635	ALTWIND	115	3.03	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	ARCOGN_2_UNITS	24011	ARCO 1G	13.8	51.43	1	LA Basin	Western	Aug NQC	Net Seller

Attachment A - List of physical resources by PTO, local area and market ID

SCE	ARCOGN_2_UNITS	24012	ARCO 2G	13.8	51.43	2	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24013	ARCO 3G	13.8	51.43	3	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24014	ARCO 4G	13.8	51.43	4	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24163	ARCO 5G	13.8	25.72	5	LA Basin	Western	Aug NQC	Net Seller
SCE	ARCOGN_2_UNITS	24164	ARCO 6G	13.8	25.72	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	10.29	1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	BUCKWD_1_NPALM1	25634	BUCKWIND	115	0.65		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind
SCE	BUCKWD_1_QF	25634	BUCKWIND	115	3.47	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	BUCKWD_7_WINTCV	25634	BUCKWIND	115	0.28	W5	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	CABZON_1_WINDA1	29290	CABAZON	33	8.61	1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	CAPWD_1_QF	25633	CAPWIND	115	4.11	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	CENTER_2_RHONDO	24203	CENTER S	66	0.00		LA Basin	Western	Not modeled	QF/Selfgen
SCE	CENTER_2_SOLAR1				0.00		LA Basin	Western	Not modeled Energy Only	Solar
SCE	CENTER_2_TECNG1				0.00		LA Basin	Western	Not modeled Energy Only	Market
SCE	CENTER_6_PEAKER	29308	CTRPKGEN	13.8	47.11	1	LA Basin	Western		Market
SCE	CENTRY_6_PL1X4	25302	CLTNCTRY	13.8	36.00	1	LA Basin	Eastern	Aug NQC	MUNI
SCE	CHEVMN_2_UNITS	24022	CHEVGEN1	13.8	2.01	1	LA Basin	Western, El Nido	Aug NQC	Net Seller
SCE	CHEVMN_2_UNITS	24023	CHEVGEN2	13.8	2.01	2	LA Basin	Western, El Nido	Aug NQC	Net Seller
SCE	CHINO_2_APEBT1	25180	WDT1250BES S_	0.48	20.00	1	LA Basin	Eastern	Aug NQC	Battery
SCE	CHINO_2_JURUPA				0.00		LA Basin	Eastern	Not modeled Energy Only	Market
SCE	CHINO_2_QF				0.00		LA Basin	Eastern	Not modeled Aug NQC	QF/Selfgen
SCE	CHINO_2_SASOLR				0.00		LA Basin	Eastern	Not modeled Energy Only	Solar
SCE	CHINO_2_SOLAR				0.27		LA Basin	Eastern	Not modeled	Solar
SCE	CHINO_2_SOLAR2				0.00		LA Basin	Eastern	Not modeled Energy Only	Solar
SCE	CHINO_6_CIMGEN	24026	CIMGEN	13.8	26.00	D1	LA Basin	Eastern	Aug NQC	QF/Selfgen

Attachment A - List of physical resources by PTO, local area and market ID

SCE	CHINO_7_MILIKN	24024	CHINO	66	1.19		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	COLTON_6_AGUAM1	25303	CLTNAGUA	13.8	43.00	1	LA Basin	Eastern	Aug NQC	MUNI
SCE	CORONS_2_SOLAR				0.00		LA Basin	Eastern	Not modeled Energy Only	Solar
SCE	CORONS_6_CLRWTR	29338	CLRWTRCT	13.8	20.72	G1	LA Basin	Eastern		MUNI
SCE	CORONS_6_CLRWTR	29340	CLRWTRST	13.8	7.28	S1	LA Basin	Eastern		MUNI
SCE	DELAMO_2_SOLAR1				0.41		LA Basin	Western	Not modeled Aug NQC	Solar
SCE	DELAMO_2_SOLAR2				0.47		LA Basin	Western	Not modeled Aug NQC	Solar
SCE	DELAMO_2_SOLAR3				0.34		LA Basin	Western	Not modeled Aug NQC	Solar
SCE	DELAMO_2_SOLAR4				0.35		LA Basin	Western	Not modeled Aug NQC	Solar
SCE	DELAMO_2_SOLAR5				0.27		LA Basin	Western	Not modeled Aug NQC	Solar
SCE	DELAMO_2_SOLAR6				0.54		LA Basin	Western	Not modeled Aug NQC	Solar
SCE	DELAMO_2_SOLRC1				0.00		LA Basin	Western	Not modeled Energy Only	Solar
SCE	DELAMO_2_SOLRD				0.00		LA Basin	Western	Not modeled Energy Only	Solar
SCE	DEVERS_1_QF	25632	TERAWND	115	0.00	QF	LA Basin	Eastern, Valley-Devers	Mothballed	QF/Selfgen
SCE	DEVERS_1_QF	25639	SEAWIND	115	0.00	QF	LA Basin	Eastern, Valley-Devers	Mothballed	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	Solar
SCE	DEVERS_1_SOLAR1				0.00		LA Basin	Eastern, Valley-Devers	Not modeled Energy Only	Solar
SCE	DEVERS_1_SOLAR2				0.00		LA Basin	Eastern, Valley-Devers	Not modeled Energy Only	Solar
SCE	DEVERS_2_CS2SR4				0.00		LA Basin	Eastern, Valley-Devers	Not modeled Energy Only	Solar
SCE	DEVERS_2_DHSPG2				0.00		LA Basin	Eastern, Valley-Devers	Not modeled Energy Only	Market
SCE	DMDVLY_1_UNITS	25425	ESRP P2	6.9	4.15	8	LA Basin	Eastern	Aug NQC	QF/Selfgen

Attachment A - List of physical resources by PTO, local area and market ID

SCE	DREWS_6_PL1X4	25301	CLTNDREW	13.8	36.00	1	LA Basin	Eastern	Aug NQC	MUNI
SCE	DVLCYN_1_UNITS	25603	DVLCYN3G	13.8	44.28	3	LA Basin	Eastern	Aug NQC	MUNI
SCE	DVLCYN_1_UNITS	25604	DVLCYN4G	13.8	44.28	4	LA Basin	Eastern	Aug NQC	MUNI
SCE	DVLCYN_1_UNITS	25648	DVLCYN1G	13.8	33.21	1	LA Basin	Eastern	Aug NQC	MUNI
SCE	DVLCYN_1_UNITS	25649	DVLCYN2G	13.8	33.21	2	LA Basin	Eastern	Aug NQC	MUNI
SCE	ELLIS_2_QF	24325	ORCOGEN	13.8	0.17	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	Not modeled Energy Only	Market
SCE	ETIWND_2_FONTNA	24055	ETIWANDA	66	0.48		LA Basin	Eastern	Not modeled Aug NQC	QF/Selfgen
SCE	ETIWND_2_RTS010	24055	ETIWANDA	66	0.41		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS015	24055	ETIWANDA	66	0.81		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS017	24055	ETIWANDA	66	0.95		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS018	24055	ETIWANDA	66	0.41		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS023	24055	ETIWANDA	66	0.68		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS026	24055	ETIWANDA	66	1.62		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	ETIWND_2_RTS027	24055	ETIWANDA	66	0.54		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	ETIWND_2_SOLAR1				0.00		LA Basin	Eastern	Not modeled Energy Only	Solar
SCE	ETIWND_2_SOLAR2				0.00		LA Basin	Eastern	Not modeled Energy Only	Solar
SCE	ETIWND_2_SOLAR5				0.00		LA Basin	Eastern	Not modeled Energy Only	Solar
SCE	ETIWND_2_UNIT1	24071	INLAND	13.8	5.05	1	LA Basin	Eastern	Aug NQC	QF/Selfgen
SCE	ETIWND_6_GRPLND	29305	ETWPKGEN	13.8	47.39	1	LA Basin	Eastern		Market
SCE	ETIWND_6_MWDETI	25422	ETI MWDG	13.8	10.74	1	LA Basin	Eastern	Aug NQC	Market
SCE	GARNET_1_SOLAR	24815	GARNET	115	0.00		LA Basin	Eastern, Valley-Devers	Not modeled Energy Only	Solar

SCE	GARNET_1_SOLAR2	24815	GARNET	115	1.08		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Solar
SCE	GARNET_1_UNITS	24815	GARNET	115	1.63	G1	LA Basin	Eastern, Valley-Devers	Aug NQC	Market
SCE	GARNET_1_UNITS	24815	GARNET	115	1.28	G3	LA Basin	Eastern, Valley-Devers	Aug NQC	Market
SCE	GARNET_1_UNITS	24815	GARNET	115	0.56	G2	LA Basin	Eastern, Valley-Devers	Aug NQC	Market
SCE	GARNET_1_WIND	24815	GARNET	115	1.37		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind
SCE	GARNET_1_WINDS	24815	GARNET	115	4.73	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_DIFWD1	24815	GARNET	115	1.65		LA Basin	Eastern, Valley-Devers	Aug NQC	Market
SCE	GARNET_2_HYDRO	24815	GARNET	115	0.81	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	Market
SCE	GARNET_2_WIND1	24815	GARNET	115	2.35		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind
SCE	GARNET_2_WIND2	24815	GARNET	115	2.46		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind
SCE	GARNET_2_WIND3	24815	GARNET	115	2.65		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind
SCE	GARNET_2_WIND4	24815	GARNET	115	2.06		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind
SCE	GARNET_2_WIND5	24815	GARNET	115	0.63		LA Basin	Eastern, Valley-Devers	Not modeled Aug NQC	Wind
SCE	GARNET_2_WPMWD6	24815	GARNET	115	1.25		LA Basin	Eastern, Valley-Devers	Not modeled 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		Market
SCE	HARBGN_7_UNITS	24062	HARBOR G	13.8	11.86	HP	LA Basin	Western		Market

Attachment A - List of physical resources by PTO, local area and market ID

SCE	HARBGN_7_UNITS	25510	HARBORG4	4.16	11.86	LP	LA Basin	Western		Market
SCE	HINSON_6_CARBGN	24020	CARBGEN1	13.8	14.82	1	LA Basin	Western	Aug NQC	Market
SCE	HINSON_6_CARBGN	24328	CARBGEN2	13.8	14.82	1	LA Basin	Western	Aug NQC	Market
SCE	HINSON_6_LBECH1	24170	LBEACH12	13.8	63.00	1	LA Basin	Western		Market
SCE	HINSON_6_LBECH2	24170	LBEACH12	13.8	63.00	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	63.00	4	LA Basin	Western		Market
SCE	HINSON_6_SERRGN	24139	SERRFGEN	13.8	34.00	D1	LA Basin	Western	Aug NQC	Market
SCE	HNTGBH_2_PL1X3	24582	HUNTBCH STG	18	251.34	S1	LA Basin	Western		Market
SCE	HNTGBH_2_PL1X3	24580	HUNTBCH CTG1	18	211.23	G1	LA Basin	Western		Market
SCE	HNTGBH_2_PL1X3	24581	HUNTBCH CTG2	18	211.23	G2	LA Basin	Western		Market
SCE	HNTGBH_7_UNIT 2	24067	HUNT2 G	13.8	225.80	2	LA Basin	Western	Retired by 2026	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	LACIEN_2_VENICE	24337	VENICE	13.8	0.00	1	LA Basin	Western, El Nido	Aug NQC	MUNI
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				0.92		LA Basin	Eastern	Not modeled Aug NQC	QF/Selfgen
SCE	MIRLOM_2_CREST				0.41		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	MIRLOM_2_LNDFL				0.81		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	MIRLOM_2_MLBBTA	25185	WDT1425_G1	0.48	10.00	1	LA Basin	Eastern	Aug NQC	Battery
SCE	MIRLOM_2_MLBBTB	25186	WDT1426_G2	0.48	10.00	1	LA Basin	Eastern	Aug NQC	Battery
SCE	MIRLOM_2_ONTARO				1.49		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	MIRLOM_2_RTS032				0.41		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	MIRLOM_2_RTS033				0.27		LA Basin	Eastern	Not modeled Aug NQC	Market

Attachment A - List of physical resources by PTO, local area and market ID

SCE	MIRLOM_2_TEMESC				0.00		LA Basin	Eastern	Not modeled Aug NQC	QF/Selfgen
SCE	MIRLOM_6_PEAKER	29307	MRLPKGEN	13.8	46.00	1	LA Basin	Eastern		Market
SCE	MIRLOM_7_MWDLKM	24210	MIRALOMA	66	2.40		LA Basin	Eastern	Not modeled Aug NQC	MUNI
SCE	MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	4.51	1	LA Basin	Eastern	Aug NQC	Market
SCE	MOJAVE_1_SIPHON	25658	MJVSPHN1	13.8	4.51	2	LA Basin	Eastern	Aug NQC	Market
SCE	MOJAVE_1_SIPHON	25659	MJVSPHN1	13.8	4.51	3	LA Basin	Eastern	Aug NQC	Market
SCE	MTWIND_1_UNIT 1	29060	MOUNTWND	115	9.32	S1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	MTWIND_1_UNIT 2	29060	MOUNTWND	115	4.66	S2	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	MTWIND_1_UNIT 3	29060	MOUNTWND	115	4.71	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	7.60	S1	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	4.25	C1	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	4.25	C2	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	4.25	C3	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	4.25	C4	LA Basin	Western	Aug NQC	Market
SCE	OLINDA_2_QF	24211	OLINDA	66	0.00		LA Basin	Western	Not modeled Aug NQC	QF/Selfgen
SCE	OLINDA_7_BLKSND	24211	OLINDA	66	0.08		LA Basin	Western	Not modeled Aug NQC	Market
SCE	PADUA_2_ONTARO	24111	PADUA	66	0.59		LA Basin	Eastern	Not modeled Aug NQC	QF/Selfgen
SCE	PADUA_2_SOLAR1	24111	PADUA	66	0.00		LA Basin	Eastern	Not modeled Energy Only	Solar
SCE	PADUA_6_MWDSDM	24111	PADUA	66	2.60		LA Basin	Eastern	Not modeled Aug NQC	MUNI
SCE	PADUA_6_QF	24111	PADUA	66	0.33		LA Basin	Eastern	Not modeled Aug NQC	QF/Selfgen
SCE	PADUA_7_SDIMAS	24111	PADUA	66	1.05		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	PANSEA_1_PANARO	25640	PANAERO	115	6.30	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	PWEST_1_UNIT	24815	GARNET	115	0.44	PC	LA Basin	Western	Aug NQC	Market
SCE	REDOND_7_UNIT 5	24121	REDON5 G	18	0.00	5	LA Basin	Western	Retired by 2022	Market

SCE	REDOND_7_UNIT 6	24122	REDON6 G	18	0.00	6	LA Basin	Western	Retired by 2022	Market
SCE	REDOND_7_UNIT 8	24124	REDON8 G	20	0.00	8	LA Basin	Western	Retired by 2022	Market
SCE	RENWD_1_QF	25636	RENWIND	115	1.05	Q1	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	RENWD_1_QF	25636	RENWIND	115	1.05	Q2	LA Basin	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
SCE	RVSIDE_2_RERCU3	24299	RERC2G3	13.8	49.00	1	LA Basin	Eastern		MUNI
SCE	RVSIDE_2_RERCU4	24300	RERC2G4	13.8	49.00	1	LA Basin	Eastern		MUNI
SCE	RVSIDE_6_RERCU1	24242	RERC1G	13.8	48.35	1	LA Basin	Eastern		MUNI
SCE	RVSIDE_6_RERCU2	24243	RERC2G	13.8	48.50	1	LA Basin	Eastern		MUNI
SCE	RVSIDE_6_SOLAR1	24244	SPRINGEN	13.8	2.03		LA Basin	Eastern	Not modeled Aug NQC	Solar
SCE	RVSIDE_6_SPRING	24244	SPRINGEN	13.8	36.00	1	LA Basin	Eastern		Market
SCE	SANITR_6_UNITS	24324	SANIGEN	13.8	0.79	D1	LA Basin	Eastern	Aug NQC	QF/Selfgen
SCE	SANTGO_2_LNDFL1	24341	COYGEN	13.8	18.73	1	LA Basin	Western	Aug NQC	Market
SCE	SANTGO_2_MABBT1	25192	WDT1406_G	0.48	2.00	1	LA Basin	Western	Aug NQC	Battery
SCE	SANWD_1_QF	25646	SANWIND	115	3.26	Q1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	SANWD_1_QF	25646	SANWIND	115	3.26	Q2	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	SBERDO_2_PSP3	24923	MNTV-ST1	18	257.82	1	LA Basin	Eastern, West of Devers		Market
SCE	SBERDO_2_PSP3	24921	MNTV-CT1	18	148.59	1	LA Basin	Eastern, West of Devers		Market
SCE	SBERDO_2_PSP3	24922	MNTV-CT2	18	148.59	1	LA Basin	Eastern, West of Devers		Market
SCE	SBERDO_2_PSP4	24926	MNTV-ST2	18	257.82	1	LA Basin	Eastern, West of Devers		Market
SCE	SBERDO_2_PSP4	24924	MNTV-CT3	18	148.59	1	LA Basin	Eastern, West of Devers		Market
SCE	SBERDO_2_PSP4	24925	MNTV-CT4	18	148.59	1	LA Basin	Eastern, West of Devers		Market
SCE	SBERDO_2_REDLND	24214	SANBRDNO	66	0.54		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS005	24214	SANBRDNO	66	0.68		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS007	24214	SANBRDNO	66	0.68		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	Market

SCE	SBERDO_2_RTS011	24214	SANBRDNO	66	0.95		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS013	24214	SANBRDNO	66	0.95		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS016	24214	SANBRDNO	66	0.41		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	Market
SCE	SBERDO_2_RTS048	24214	SANBRDNO	66	0.00		LA Basin	Eastern, West of Devers	Not modeled Energy Only	Market
SCE	SBERDO_2_SNTANA	24214	SANBRDNO	66	0.58		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	QF/Selfgen
SCE	SBERDO_6_MILLCK	24214	SANBRDNO	66	1.77		LA Basin	Eastern, West of Devers	Not modeled Aug NQC	QF/Selfgen
SCE	SENTNL_2_CTG1	29101	SENTINEL_G1	13.8	103.76	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG2	29102	SENTINEL_G2	13.8	95.34	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG3	29103	SENTINEL_G3	13.8	96.85	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG4	29104	SENTINEL_G4	13.8	102.47	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG5	29105	SENTINEL_G5	13.8	103.81	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG6	29106	SENTINEL_G6	13.8	100.99	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG7	29107	SENTINEL_G7	13.8	97.06	1	LA Basin	Eastern, Valley-Devers		Market
SCE	SENTNL_2_CTG8	29108	SENTINEL_G8	13.8	101.80	1	LA Basin	Eastern, Valley-Devers		Market
SCE	STANTN_2_STAGT1	97624	WH_STN_1	13.8	49.00	1	LA Basin	Western		Market
SCE	STANTN_2_STAGT2	97625	WH_STN_2	13.8	49.00	1	LA Basin	Western		Market
SCE	TIFFNY_1_DILLON	29021	WINTEC6	115	9.45	1	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	TRNSWD_1_QF	25637	TRANWIND	115	8.18	QF	LA Basin	Eastern, Valley-Devers	Aug NQC	Wind
SCE	TULEWD_1_TULWD1				27.41		LA Basin	Eastern, Valley-Devers	Not modeled 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	1.33		LA Basin	Eastern, Valley, Valley-Devers	Not modeled Aug NQC	QF/Selfgen

SCE	VALLEY_5_SOLAR1	24160	VALLEYSC	115	0.00		LA Basin	Eastern, Valley, Valley-Devers	Not modeled Energy Only	Solar
SCE	VALLEY_5_SOLAR2	25082	WDT786	34.5	5.40	EQ	LA Basin	Eastern, Valley, Valley-Devers	Aug NQC	Solar
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	24241	MALBRG3G	13.8	49.26	S3	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	VILLPK_2_VALLYV	24216	VILLA PK	66	4.10	DG	LA Basin	Western	Aug NQC	QF/Selfgen
SCE	VILLPK_6_MWDYOR	24216	VILLA PK	66	3.60		LA Basin	Western	Not modeled Aug NQC	MUNI
SCE	VISTA_2_RIALTO	24901	VSTA	230	0.27		LA Basin	Eastern	Not modeled	Market
SCE	VISTA_2_RTS028	24901	VSTA	230	0.95		LA Basin	Eastern	Not modeled Aug NQC	Market
SCE	VISTA_6_QF	24902	VSTA	66	0.12		LA Basin	Eastern	Not modeled Aug NQC	QF/Selfgen
SCE	WALCRK_2_CTG1	29201	WALCRKG1	13.8	96.43	1	LA Basin	Western		Market
SCE	WALCRK_2_CTG2	29202	WALCRKG2	13.8	96.91	1	LA Basin	Western		Market
SCE	WALCRK_2_CTG3	29203	WALCRKG3	13.8	96.65	1	LA Basin	Western		Market
SCE	WALCRK_2_CTG4	29204	WALCRKG4	13.8	96.49	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	Solar
SCE	WALNUT_6_HILLGEN	24063	HILLGEN	13.8	27.43	D1	LA Basin	Western	Aug NQC	Net Seller
SCE	WALNUT_7_WCOVST	24157	WALNUT	66	5.19		LA Basin	Western	Not modeled Aug NQC	Market
SCE	WHTWTR_1_WINDA1	29061	WHITEWTR	33	12.92	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	24327	THUMSGEN	13.8	0.00	1	LA Basin	Western	No NQC - hist. data	QF/Selfgen

Attachment A - List of physical resources by PTO, local area and market ID

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	29260	ALTAMSA4	115	0.00	1	LA Basin	Eastern, Valley-Devers	No NQC - hist. data	Wind
SCE	ZZ_VENWD_1_WIND1	25645	VENWIND	115	0.00	Q1	LA Basin	Eastern, Valley-Devers	Mothballed	QF/Selfgen
SCE	ZZ_VENWD_1_WIND2	25645	VENWIND	115	0.00	Q2	LA Basin	Eastern, Valley-Devers	Mothballed	QF/Selfgen
SCE	ZZ_VENWD_1_WIND3	25645	VENWIND	115	0.00	EU	LA Basin	Eastern, Valley-Devers	Mothballed	QF/Selfgen
SCE	ZZZZZ_ALAMIT_7_UNIT 1	24001	ALAMT1 G	18	0.00	1	LA Basin	Western	Retired	Market
SCE	ZZZZZ_ALAMIT_7_UNIT 2	24002	ALAMT2 G	18	0.00	2	LA Basin	Western	Retired	Market
SCE	ZZZZZ_ALAMIT_7_UNIT 6	24161	ALAMT6 G	20	0.00	6	LA Basin	Western	Retired	Market
SCE	ZZZZZ_ANAHM_7_CT	25208	Dow lingCTG	13.8	0.00	1	LA Basin	Western	Retired	MUNI
SCE	ZZZZZ_BRDWAY_7_UNIT 3	29007	BRODWYSC	13.8	0.00		LA Basin	Western	Retired	MUNI
SCE	ZZZZZ_CENTER_2_QF	29953	SIGGEN	13.8	0.00	D1	LA Basin	Western	Retired	QF/Selfgen
SCE	ZZZZZ_CHINO_6_SMPPAP	24140	SIMPSON	13.8	0.00	D1	LA Basin	Eastern	Retired	QF/Selfgen
SCE	ZZZZZ_ETIWND_7_MIDVLY	24055	ETIWANDA	66	0.00		LA Basin	Eastern	Retired	QF/Selfgen
SCE	ZZZZZ_ETIWND_7_UNIT 3	24052	MTNVIST3	18	0.00	3	LA Basin	Eastern	Retired	Market
SCE	ZZZZZ_ETIWND_7_UNIT 4	24053	MTNVIST4	18	0.00	4	LA Basin	Eastern	Retired	Market
SCE	ZZZZZ_HNTGBH_7_UNIT 1	24066	HUNT1 G	13.8	0.00	1	LA Basin	Western	Retired	Market
SCE	ZZZZZ_INLDEM_5_UNIT 1	29041	IEEC-G1	19.5	0.00	1	LA Basin	Eastern, Valley, Valley-Devers	Retired	Market
SCE	ZZZZZ_INLDEM_5_UNIT 2	29042	IEEC-G2	19.5	0.00	1	LA Basin	Eastern, Valley, Valley-Devers	Retired	Market
SCE	ZZZZZ_LAGBEL_2_STG1				0.00		LA Basin	Western	Retired	Market
SCE	ZZZZZ_LAGBEL_6_QF	29951	REFUSE	13.8	0.00	D1	LA Basin	Western	Retired	QF/Selfgen

Attachment A - List of physical resources by PTO, local area and market ID

SCE	ZZZZZ_MIRLOM_6_DELGEN	29339	DELGEN	13.8	0.00	1	LA Basin	Eastern	Retired	QF/Selfgen
SCE	ZZZZZ_OLINDA_7_LNDFIL	24211	OLINDA	66	0.00		LA Basin	Western	Retired	QF/Selfgen
SCE	ZZZZZ_REDOND_7_UNIT 7	24123	REDON7 G	20	0.00	7	LA Basin	Western	Retired	Market
SCE	ZZZZZ_RHONDO_2_QF	24213	RIOHONDO	66	0.00	DG	LA Basin	Western	Retired	QF/Selfgen
SCE	ZZZZZ_RHONDO_6_PUENTE	24213	RIOHONDO	66	0.00		LA Basin	Western	Retired	Net Seller
SCE	ZZZZZ_SBERDO_2_QF	24214	SANBRDNO	66	0.00		LA Basin	Eastern, West of Devers	Retired	QF/Selfgen
SCE	ZZZZZ_VALLEY_5_RTS044	24160	VALLEYSC	115	0.00		LA Basin	Eastern, Valley, Valley-Devers	Retired	Market
SCE	ZZZZZ_VALLEY_7_BADLND	24160	VALLEYSC	115	0.00		LA Basin	Eastern, Valley, Valley-Devers	Retired	Market
SCE	ZZZZZ_VALLEY_7_UNITA1	24160	VALLEYSC	115	0.00		LA Basin	Eastern, Valley, Valley-Devers	Retired	Market
SCE	ZZZZZ_WALNUT_7_WCOVCT	24157	WALNUT	66	0.00		LA Basin	Western	Retired	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	51.25	1	SD-IV	San Diego, Border		Market
SDG&E	BREGGO_6_DEGRSL	22085	BORREGO	12.5	1.70	DG	SD-IV	San Diego	Aug NQC	Solar
SDG&E	BREGGO_6_SOLAR	22082	BR GEN1	0.21	7.02	1	SD-IV	San Diego	Aug NQC	Solar
SDG&E	CARLS1_2_CARCT1	22783	EA5 REPOWER1	13.8	105.50	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CARLS1_2_CARCT1	22784	EA5 REPOWER2	13.8	105.50	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CARLS1_2_CARCT1	22786	EA5 REPOWER4	13.8	105.50	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CARLS1_2_CARCT1	22788	EA5 REPOWER3	13.8	105.50	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CARLS2_1_CARCT1	22787	EA5 REPOWER5	13.8	105.50	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CHILLS_1_SYCENG	22120	CARLTNHS	138	0.47	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	33.75	1	SD-IV		Aug NQC	Solar
SDG&E	CNTNLA_2_SOLAR2	23463	DW GEN3&4	0.33	12.31	2	SD-IV		Energy Only	Solar
SDG&E	CPSTNO_7_PRMADS	22112	CAPSTRNO	138	5.11	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	CPVERD_2_SOLAR	23309	IV GEN3 G1	0.31	20.85	G1	SD-IV		Aug NQC	Solar

SDG&E	CPVERD_2_SOLAR	23301	IV GEN3 G2	0.31	16.68	G2	SD-IV		Aug NQC	Solar
SDG&E	CRELMN_6_RAMON1	22152	CREELMAN	69	0.54	DG	SD-IV	San Diego	Aug NQC	Solar
SDG&E	CRELMN_6_RAMON2	22152	CREELMAN	69	1.35	DG	SD-IV	San Diego	Aug NQC	Solar
SDG&E	CRELMN_6_RAMSR3				0.94		SD-IV	San Diego	Not modeled Aug NQC	Solar
SDG&E	CRSTWD_6_KUMYAY	22915	KUMEYAAY	0.69	10.50	1	SD-IV	San Diego	Aug NQC	Wind
SDG&E	CSLR4S_2_SOLAR	23298	DW GEN1 G1	0.32	17.55	G1	SD-IV		Aug NQC	Solar
SDG&E	CSLR4S_2_SOLAR	23299	DW GEN1 G2	0.32	17.55	G2	SD-IV		Aug NQC	Solar
SDG&E	ELCAJN_6_EB1BT1	22208	EL CAJON	69	7.50	1	SD-IV	San Diego, El Cajon		Battery
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	ENERSJ_2_WIND	23100	ECO GEN1 G1	0.69	32.57	G1	SD-IV		Aug NQC	Wind
SDG&E	ESCNDO_6_EB1BT1	22256	ESCNDIDO	69	10.00	1	SD-IV	San Diego		Battery
SDG&E	ESCNDO_6_EB2BT2	22256	ESCNDIDO	69	10.00	1	SD-IV	San Diego		Battery
SDG&E	ESCNDO_6_EB3BT3	22256	ESCNDIDO	69	10.00	1	SD-IV	San Diego		Battery
SDG&E	ESCNDO_6_PL1X2	22257	ESGEN	13.8	48.71	1	SD-IV	San Diego		Market
SDG&E	ESCNDO_6_UNITB1	22153	CALPK_ES	13.8	48.04	1	SD-IV	San Diego		Market
SDG&E	ESCO_6_GLMQF	22332	GOALLINE	69	36.41	1	SD-IV	San Diego	Aug NQC	Net Seller
SDG&E	GATEWY_2_GESBT1	23710	Q1170_BESS	0.48	50.00	1	SD-IV	San Diego		Battery
SDG&E	IVSLR2_2_SM2SR1	23441	DW GEN6	0.42	40.50	1	SD-IV		Aug NQC	Solar
SDG&E	IVSLRP_2_SOLAR1	23440	DW GEN2 G1	0.36	54.00	1	SD-IV		Aug NQC	Solar
SDG&E	IVWEST_2_SOLAR1	23155	DU GEN1 G1	0.2	21.91	G1	SD-IV		Aug NQC	Solar
SDG&E	IVWEST_2_SOLAR1	23156	DU GEN1 G2	0.2	18.59	G2	SD-IV		Aug NQC	Solar
SDG&E	JACMSR_1_JACSR1	23352	ECO GEN2	0.55	5.40	1	SD-IV		Aug NQC	Solar
SDG&E	KYCORA_6_KMSBT1				0.00		SD-IV	San Diego	Not modeled Energy Only	Battery
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

Attachment A - List of physical resources by PTO, local area and market ID

SDG&E	LAROA1_2_UNITA1	20187	LRP-U1	16	0.00	1	SD-IV		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			Market
SDG&E	LAROA2_2_UNITA1	22996	INTBST	18	145.19	1	SD-IV			Market
SDG&E	LILIAC_6_SOLAR	22404	LILIAC	69	0.81	DG	SD-IV	San Diego		Solar
SDG&E	MRGT_6_MEF2	22487	MEF_MR2	13.8	44.00	1	SD-IV	San Diego		Market
SDG&E	MRGT_6_MMAREF	22486	MEF_MR1	13.8	45.00	1	SD-IV	San Diego		Market
SDG&E	MSHGTS_6_MMARLF	22448	MESAHGTS	69	3.80	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	MSSION_2_QF	22496	MISSION	69	0.41	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	MURRAY_6_UNIT	22532	MURRAY	69	0.00		SD-IV	San Diego	Not modeled Energy Only	Market
SDG&E	OCTILO_5_WIND	23314	OCO GEN G1	0.69	27.83	G1	SD-IV		Aug NQC	Wind
SDG&E	OCTILO_5_WIND	23318	OCO GEN G2	0.69	27.83	G2	SD-IV		Aug NQC	Wind
SDG&E	OGROVE_6_PL1X2	22628	PA GEN1	13.8	48.00	1	SD-IV	San Diego		Market
SDG&E	OGROVE_6_PL1X2	22629	PA GEN2	13.8	48.00	1	SD-IV	San Diego		Market
SDG&E	OTAY_6_PL1X2	22617	OYGEN	13.8	35.50	1	SD-IV	San Diego		Market
SDG&E	OTMESA_2_PL1X3	22607	OTAYMST1	16	272.27	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	22605	OTAYMGT1	18	165.16	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	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	PIOPIC_2_CTG1	23162	PIO PICO CT1	13.8	111.30	1	SD-IV	San Diego	No NQC - Pmax	Market
SDG&E	PIOPIC_2_CTG2	23163	PIO PICO CT2	13.8	112.70	1	SD-IV	San Diego	No NQC - Pmax	Market
SDG&E	PIOPIC_2_CTG3	23164	PIO PICO CT3	13.8	112.00	1	SD-IV	San Diego	No NQC - Pmax	Market
SDG&E	PRCTVY_1_MIGBT1				0.00		SD-IV	San Diego	Aug NQC	Battery
SDG&E	PTLOMA_6_NTCQF	22660	POINTLMA	69	6.39	1	SD-IV	San Diego	Aug NQC	QF/Selfgen
SDG&E	SAMPSN_6_KELCO1	22704	SAMPSON	12.5	0.90	1	SD-IV	San Diego	Aug NQC	Net Seller
SDG&E	SLRMS3_2_SRMSR1	23442	DW GEN2 G3A	0.6	40.50	1	SD-IV		Aug NQC	Solar
SDG&E	SLRMS3_2_SRMSR1	23443	DW GEN2 G3B	0.6	27.00	1	SD-IV		Aug NQC	Solar

SDG&E	SMRCOS_6_LNDFIL	22724	SANMRCOS	69	1.50	1	SD-IV	San Diego	Aug NQC	Market
SDG&E	TERMEX_2_PL1X3	22981	TDM STG	21	280.13	1	SD-IV			Market
SDG&E	TERMEX_2_PL1X3	22982	TDM CTG2	18	156.44	1	SD-IV			Market
SDG&E	TERMEX_2_PL1X3	22983	TDM CTG3	18	156.44	1	SD-IV			Market
SDG&E	VLCNTR_6_VCSLR	22870	VALCNTR	69	0.63	DG	SD-IV	San Diego	Aug NQC	Solar
SDG&E	VLCNTR_6_VCSLR1	22870	VALCNTR	69	0.68	DG	SD-IV	San Diego	Aug NQC	Solar
SDG&E	VLCNTR_6_VCSLR2	22870	VALCNTR	69	1.35	DG	SD-IV	San Diego	Aug NQC	Solar
SDG&E	VSTAES_6_VESBT1	23541	ME GEN 1_BS1	0.64	5.50	1	SD-IV	San Diego	No NQC - est. data	Battery
SDG&E	VSTAES_6_VESBT1	23216	ME GEN 1_BS2	0.48	5.50	1	SD-IV	San Diego	No NQC - est. data	Battery
SDG&E	WISTRA_2_WRSSR1	23287	Q429_G1	0.31	27.00	1	SD-IV		Aug NQC	Solar
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	22020	AVOCADO	69	40.00	S2	SD-IV	San Diego	No NQC - Pmax	Battery
SDG&E	ZZZ_New Unit	23544	Q1169_BESS1	0.4	35.00	C8	SD-IV	San Diego	No NQC - Pmax	Battery
SDG&E	ZZZ_New Unit	23519	Q1169_BESS2	0.4	35.00	C8	SD-IV	San Diego	No NQC - Pmax	Battery
SDG&E	ZZZ_New Unit	23412	Q1434_G	0.64	30.00	1	SD-IV	San Diego	No NQC - Pmax	Battery
SDG&E	ZZZ_New Unit	22942	BUE GEN 1_G1	0.69	11.60	G1	SD-IV		No NQC - est. data	Wind
SDG&E	ZZZ_New Unit	22945	BUE GEN 1_G2	0.69	11.60	G2	SD-IV		No NQC - est. data	Wind
SDG&E	ZZZ_New Unit	22947	BUE GEN 1_G3	0.69	11.60	G3	SD-IV		No NQC - est. data	Wind
SDG&E	ZZZ_New Unit	22256	ESCNDIDO	69	6.50	S2	SD-IV	San Diego	No NQC - Pmax	Battery
SDG&E	ZZZ_New Unit	22112	CAPSTRNO	138	5.90	1	SD-IV	San Diego	No NQC - Pmax	Battery
SDG&E	ZZZ_New Unit	22112	CAPSTRNO	138	4.00	S2	SD-IV	San Diego	No NQC - Pmax	Battery
SDG&E	ZZZ_New Unit	23597	Q1175_BESS	0.48	0.00	1	SD-IV		Energy Only	Battery
SDG&E	ZZZ_New Unit	22404	LILAC	69	0.00	S2	SD-IV	San Diego	Energy Only	Battery
SDG&E	ZZZ_New Unit	22512	MONSRATE	69	0.00	S2	SD-IV	San Diego	Energy Only	Battery
SDG&E	ZZZZZ_CBRLLO_6_PLSTP1	22092	CABRILLO	69	0.00	1	SD-IV	San Diego	Retired	Market

SDG&E	ZZZZZ_CCRITA_7_RPPCHF	22124	CHCARITA	138	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_DIVSON_6_NSQF	22172	DIVISION	69	0.00	1	SD-IV	San Diego	Retired	QF/Selfgen
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	Retired	Market
SDG&E	ZZZZZ_ENCINA_7_EA2	22234	ENCINA 2	14.4	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_ENCINA_7_EA3	22236	ENCINA 3	14.4	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_ENCINA_7_EA4	22240	ENCINA 4	22	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_ENCINA_7_EA5	22244	ENCINA 5	24	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_ENCINA_7_GT1	22248	ENCINAGT	12.5	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY2	22373	KEARN2AB	12.5	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY2	22374	KEARN2CD	12.5	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY2	22373	KEARN2AB	12.5	0.00	2	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY2	22374	KEARN2CD	12.5	0.00	2	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY3	22375	KEARN3AB	12.5	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY3	22376	KEARN3CD	12.5	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY3	22375	KEARN3AB	12.5	0.00	2	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_KEARNY_7_KY3	22376	KEARN3CD	12.5	0.00	2	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_MRGT_7_UNITS	22488	MIRAMRGT	12.5	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_MRGT_7_UNITS	22488	MIRAMRGT	12.5	0.00	2	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_NIMTG_6_NIQF	22576	NOISLMTR	69	0.00	1	SD-IV	San Diego	Retired	QF/Selfgen
SDG&E	ZZZZZ_OTAY_6_LNDFL5	22604	OTAY	69	0.00		SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_OTAY_6_LNDFL6	22604	OTAY	69	0.00		SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_OTAY_6_UNITB1	22604	OTAY	69	0.00	1	SD-IV	San Diego	Retired	Market
SDG&E	ZZZZZ_OTAY_7_UNITC1	22604	OTAY	69	0.00	3	SD-IV	San Diego	Retired	QF/Selfgen
SDG&E	ZZZZZ_PTLOMA_6_NTCCGN	22660	POINTLMA	69	0.00	2	SD-IV	San Diego	Retired	QF/Selfgen

Attachment B – Effectiveness factors for procurement guidance

Table - Eagle Rock.

Effectiveness factors to the Eagle Rock-Cortina 115 kV line:

Gen Bus	Gen Name	Gen ID	Eff Factor (%)
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

Table - Fulton

Effectiveness factors to the Lakeville-Petaluma-Cotati 60 kV line:

Gen Bus	Gen Name	Gen ID	Eff Factor (%)
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

Gen Bus	Gen Name	Gen ID	Eff Factor (%)
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

Table – North Coast and North Bay

Effectiveness factors to the Vaca Dixon-Lakeville 230 kV line:

Gen Bus	Gen Name	Gen ID	Eff Factor (%)
31400	SANTA FE	2	38
31430	SMUDGEO1	1	38
31400	SANTA FE	1	38
31416	GEYSER13	1	38
31424	GEYSER18	1	38
31426	GEYSER20	1	38
38106	NCPA1GY1	1	38
38108	NCPA1GY2	1	38
31421	BOTTLERK	1	36
31404	WEST FOR	2	36
31402	BEAR CAN	1	36
31402	BEAR CAN	2	36
31404	WEST FOR	1	36
31414	GEYSER12	1	36
31418	GEYSER14	1	36
31420	GEYSER16	1	36

Gen Bus	Gen Name	Gen ID	Eff Factor (%)
31422	GEYSER17	1	36
38110	NCPA2GY1	1	36
38112	NCPA2GY2	1	36
31446	SONMA LF	1	36
32700	MONTICLO	1	31
32700	MONTICLO	2	31
32700	MONTICLO	3	31
31406	GEYSR5-6	1	18
31406	GEYSR5-6	2	18
31405	RPSP1014	1	18
31408	GEYSER78	1	18
31408	GEYSER78	2	18
31412	GEYSER11	1	18
31435	GEO.ENGY	1	18
31435	GEO.ENGY	2	18
31433	POTTRVLY	1	15
31433	POTTRVLY	2	15
31433	POTTRVLY	3	15
38020	CITY UKH	1	15
38020	CITY UKH	2	15

Table – Rio Oso

Effectiveness factors to the Rio Oso-Atlantic 230 kV line:

Gen Bus	Gen Name	Gen ID	Eff Factor. (%)
32498	SPILINCF	1	49
32500	ULTR RCK	1	49
32456	MIDLFORK	1	33
32456	MIDLFORK	2	33
32458	RALSTON	1	33

32513	ELDRADO1	1	32
32514	ELDRADO2	1	32
32510	CHILIBAR	1	32
32486	HELLHOLE	1	31
32508	FRNCH MD	1	30
32460	NEWCSTLE	1	26
32478	HALSEY F	1	24
32512	WISE	1	24
38114	Stig CC	1	14
38123	Q267CT	1	14
38124	Q267ST	1	14
32462	CHI.PARK	1	8
32464	DTCHFLT1	1	4

Table – Sierra Overall

Effectiveness factors to the Table Mountain – Pease 60 kV line:

Gen Bus	Gen Name	Gen ID	Eff Factor. (%)
32492	GRNLEAF2	1	17
32494	YUBA CTY	1	17
32496	YCEC	1	17
31794	WOODLEAF	1	6
31814	FORBSTWN	1	6
31832	SLY.CR.	1	6
31834	KELLYRDG	1	6
31888	OROVLENRG	1	6

Attachment B – Effectiveness factors for procurement guidance

Gen Bus	Gen Name	Gen ID	Eff Factor. (%)
32451	FREC	1	5
32450	COLGATE1	1	5
32466	NARROWS1	1	5
32468	NARROWS2	1	5
32470	CMP.FARW	1	5
32452	COLGATE2	1	5
32156	WOODLAND	1	4
32498	SPILINCF	1	4
32502	DTCHFLT2	1	4
32454	DRUM 5	1	3
32474	DEER CRK	1	3
32476	ROLLINSF	1	3
32484	OXBOW F	1	3
32504	DRUM 1-2	1	3
32504	DRUM 1-2	2	3
32506	DRUM 3-4	1	3
32506	DRUM 3-4	2	3
32464	DTCHFLT1	1	3
32480	BOWMAN	1	3
32488	HAYPRES+	1	3
32488	HAYPRES+	2	3
32472	SPAULDG	1	3
32472	SPAULDG	2	3

Attachment B – Effectiveness factors for procurement guidance

Gen Bus	Gen Name	Gen ID	Eff Factor. (%)
32472	SPAULDG	3	3
32462	CHI.PARK	1	3
32500	ULTR RCK	1	3
31784	BELDEN	1	3
31786	ROCK CK1	1	3
31788	ROCK CK2	1	3
31790	POE 1	1	3
31792	POE 2	1	3
31812	CRESTA	1	3
31812	CRESTA	2	3
31820	BCKS CRK	1	3
31820	BCKS CRK	2	3
32478	HALSEY F	1	2
32512	WISE	1	2
32460	NEWCSTLE	1	2
32510	CHILIBAR	1	2
32513	ELDRADO1	1	2
32514	ELDRADO2	1	2
32456	MIDLFORK	1	2
32456	MIDLFORK	2	2
32458	RALSTON	1	2
32486	HELLHOLE	1	2
32508	FRNCH MD	1	2

Gen Bus	Gen Name	Gen ID	Eff Factor. (%)
38114	STIG CC	1	1
38123	LODI CT1	1	1
38124	LODI ST1	1	1

Table – San Jose

Effectiveness factors to the Metcalf 230/115 kV transformer #1:

Gen Bus	Gen Name	Gen ID	Eff Factor (%)
35850	GLRY COG	1	25
35850	GLRY COG	2	25
35851	GROYPKR1	1	25
35852	GROYPKR2	1	25
35853	GROYPKR3	1	25
35623	SWIFT	BT	21
35863	CATALYST	1	20
36863	DVRaGT1	1	9
36864	DVRbGt2	1	9
36865	DVRaST3	1	9
36859	Laf300	2	9
36859	Laf300	1	9
36858	Gia100	1	8
36895	Gia200	1	8
35861	SJ-SCL W	1	8
35854	LECEFGT1	1	7
35855	LECEFGT2	1	7
35856	LECEFGT3	1	7
35857	LECEFGT4	1	7
35858	LECEFST1	1	7
35860	OLS-AGNE	1	7

Table – South Bay-Moss Landing

Effectiveness factors to the Moss Landing-Las Aguillas 230 kV line:

Gen Bus	Gen Name	Gen ID	Eff Factor. (%)

36209	SLD ENRG	1	20
36221	DUKMOSS1	1	20
36222	DUKMOSS2	1	20
36223	DUKMOSS3	1	20
36224	DUKMOSS4	1	20
36225	DUKMOSS5	1	20
36226	DUKMOSS6	1	20
36405	MOSSLND6	1	17
36406	MOSSLND7	1	17
35881	MEC CTG1	1	13
35882	MEC CTG2	1	13
35883	MEC STG1	1	13
35850	GLRY COG	1	12
35850	GLRY COG	2	12
35851	GROYPKR1	1	12
35852	GROYPKR2	1	12
35853	GROYPKR3	1	12
35623	SWIFT	BT	10
35863	CATALYST	1	10
36863	DVRaGT1	1	8
36864	DVRbGt2	1	8
36865	DVRaST3	1	8
36859	Laf300	2	8
36859	Laf300	1	8
36858	Gia100	1	7

36895	Gia200	1	7
35854	LECEFGT1	1	7
35855	LECEFGT2	1	7
35856	LECEFGT3	1	7
35857	LECEFGT4	1	7
35858	LECEFST1	1	7
35860	OLS-AGNE	1	7

Table – Ames/Pittsburg/Oakland

Effectiveness factors to the Ames-Ravenswood #1 115 kV line:

Gen Bus	Gen Name	Gen ID	Eff Factor. (%)
35304	RUSELCT1	1	10
35305	RUSELCT2	2	10
35306	RUSELST1	3	10
33469	OX_MTN	1	10
33469	OX_MTN	2	10
33469	OX_MTN	3	10
33469	OX_MTN	4	10
33469	OX_MTN	5	10
33469	OX_MTN	6	10
33469	OX_MTN	7	10
33107	DEC STG1	1	3
33108	DEC CTG1	1	3
33109	DEC CTG2	1	3
33110	DEC CTG3	1	3

33102	COLUMBIA	1	3
33111	LMECCT2	1	3
33112	LMECCT1	1	3
33113	LMECST1	1	3
33151	FOSTER W	1	2
33151	FOSTER W	2	2
33151	FOSTER W	3	2
33136	CCCSD	1	2
33141	SHELL 1	1	2
33142	SHELL 2	1	2
33143	SHELL 3	1	2
32900	CRCKTCOG	1	2
32910	UNOCAL	1	2
32910	UNOCAL	2	2
32910	UNOCAL	3	2
32920	UNION CH	1	2
32921	ChevGen1	1	2
32922	ChevGen2	1	2
32923	ChevGen3	3	2
32741	HILLSIDE_12	1	2
32901	OAKLND 1	1	1
32902	OAKLND 2	2	1
32903	OAKLND 3	3	1
38118	ALMDACT1	1	1
38119	ALMDACT2	1	1

Effectiveness factors to the Moraga-Claremont #2 115 kV line:

Gen Bus	Gen Name	Gen ID	Eff Factor (%)
32921	ChevGen1	1	17
32922	ChevGen2	1	17
32923	ChevGen3	3	17
32901	OAKLND 1	1	16
32902	OAKLND 2	1	16
32903	OAKLND 3	1	16
38118	ALMDACT1	1	16
38119	ALMDACT2	1	16
32920	UNION CH	1	16
32910	UNOCAL	1	15
32910	UNOCAL	2	15
32910	UNOCAL	3	15
33141	SHELL 1	1	10
33142	SHELL 2	1	10
33143	SHELL 3	1	10
33136	CCCSD	1	9
32900	CRCKTCOG	1	8
33151	FOSTER W	1	6
33151	FOSTER W	2	6
33151	FOSTER W	3	6
33102	COLUMBIA	1	3
33111	LMECCT2	1	3
33112	LMECCT1	1	3
33113	LMECST1	1	3
33107	DEC STG1	1	3
33108	DEC CTG1	1	3
33109	DEC CTG2	1	3
33110	DEC CTG3	1	3

Table – Greater Bay Area

Effectiveness factors to the Metcalf 500/230 kV Transformer #13:

Gen Bus	Gen Name	Gen ID	Eff Factor (%)
35881	MEC CTG1	1	40
35882	MEC CTG2	1	40
35883	MEC STG1	1	40

35859	HGST-LV	RN	36
35850	GLRY COG	1	30
35850	GLRY COG	2	30
35851	GROYPKR1	1	30
35852	GROYPKR2	1	30
35853	GROYPKR3	1	30
35623	SWIFT	BT	29
35863	CATALYST	1	28
33469	OX_MTN	1	22
33469	OX_MTN	2	22
33469	OX_MTN	3	22
33469	OX_MTN	4	22
33469	OX_MTN	5	22
33469	OX_MTN	6	22
33469	OX_MTN	7	22
36863	DVRaGT1	1	21
36864	DVRbGt2	1	21
36865	DVRaST3	1	21
36859	Laf300	2	20
36859	Laf300	1	20
36858	Gia100	1	20
36895	Gia200	1	20
35861	SJ-SCL W	1	20
35854	LECEFGT1	1	20
35855	LECEFGT2	1	20
35856	LECEFGT3	1	20
35857	LECEFGT4	1	20
35858	LECEFST1	1	20
35860	OLS-AGNE	1	20
33468	SRI INTL	1	16
35304	RUSELCT1	1	12
35305	RUSELCT2	2	12
35306	RUSELST1	3	12
36209	SLD ENRG	1	9
36221	DUKMOSS1	1	7
36222	DUKMOSS2	1	7
36223	DUKMOSS3	1	7
36224	DUKMOSS4	1	7
36225	DUKMOSS5	1	7
36226	DUKMOSS6	1	7
30532	0162-WD	FW	7

39233	GRNRDG	1	6
33107	DEC STG1	1	6
33108	DEC CTG1	1	6
33109	DEC CTG2	1	6
33110	DEC CTG3	1	6
33102	COLUMBIA	1	6
33111	LMECCT2	1	6
33112	LMECCT1	1	6
33113	LMECST1	1	6
33136	CCCSD	1	6
33141	SHELL 1	1	6
33142	SHELL 2	1	6
33143	SHELL 3	1	6
33151	FOSTER W	1	6
33151	FOSTER W	2	6
33151	FOSTER W	3	6
32901	OAKLND 1	1	6
32902	OAKLND 2	1	6
32903	OAKLND 3	1	6
38118	ALMDACT1	1	6
38119	ALMDACT2	1	6
32910	UNOCAL	1	6
32910	UNOCAL	2	6
32910	UNOCAL	3	6
32920	UNION CH	1	5
33139	STAUFER	1	5
32741	HILLSIDE_12	1	5
32921	ChevGen1	1	5
32922	ChevGen2	1	5
32923	ChevGen3	3	5
32900	CRCKTCOG	1	5
33188	MARSHCT1	1	3
33189	MARSHCT2	2	3
33190	MARSHCT3	3	3
33191	MARSHCT4	4	3
33118	GATEWAY1	1	3
33119	GATEWAY2	1	3
33120	GATEWAY3	1	3
30522	0354-WD	EW	3
33178	RVEC_GEN	1	3
35310	PPASSWND	1	3

Table – Herndon

Effectiveness factors to the Herndon-Manchester 115 kV line:

Gen Bus	Gen Name	Gen ID	Eff Factor. (%)
34624	BALCH 1	1	22
34616	KINGSRIV	1	21
34648	DINUBA E	1	20
34671	KRCDPCT1	1	19
34672	KRCDPCT2	1	19
34308	KERCKHOF	1	18
34344	KERCK1-1	1	18
34345	KERCK1-3	3	18
34677	Q558	1	15
34690	CORCORAN_3	FW	15
34692	CORCORAN_4	FW	15
34696	CORCORANPV_S	1	15
34610	HAAS	1	13
34610	HAAS	2	13
34612	BLCH 2-2	1	13
34614	BLCH 2-3	1	13
34431	GWF_HEP1	1	8
34433	GWF_HEP2	1	8
34617	Q581	1	5
34680	KANSAS	1	5
34467	GIFFEN_DIST	1	4

34563	STROUD_DIST	2	4
34563	STROUD_DIST	1	4
34608	AGRICO	2	4
34608	AGRICO	3	4
34608	AGRICO	4	4
34644	Q679	1	4
365502	Q632BC1	1	4

Table – LA Basin

Effectiveness factors to the Mesa – Laguna Bell #1 230 kV line:

Gen Bus	Gen Name	Gen ID	Eff Factor. (%)
29951	REFUSE	D1	35
24239	MALBRG1G	C1	34
24240	MALBRG1G	C2	34
24241	MALBRG1G	S3	34
29903	ELSEG6ST	6	27
29904	ELSEG5GT	5	27
29902	ELSEG7ST	7	27
29901	ELSEG8GT	8	27
24337	VENICE	1	26
24094	MOBGEN1	1	26
24329	MOBGEN2	1	26
24332	PALOGEN	D1	26
24011	ARCO 1G	1	23
24012	ARCO 2G	2	23

24013	ARCO 3G	3	23
24014	ARCO 4G	4	23
24163	ARCO 5G	5	23
24164	ARCO 6G	6	23
24062	HARBOR G	1	23
24062	HARBOR G	HP	23
25510	HARBORG4	LP	23
24327	THUMSGEN	1	23
24020	CARBGEN1	1	23
24328	CARBGEN2	1	23
24139	SERRFGEN	D1	23
24070	ICEGEN	1	22
24001	ALAMT1 G	I	18
24002	ALAMT2 G	2	18
24003	ALAMT3 G	3	18
24004	ALAMT4 G	4	18
24005	ALAMT5 G	5	18
24161	ALAMT6 G	6	18
90000	ALMT-GT1	X1	18
90001	ALMT-GT2	X2	18
90002	ALMT-ST1	X3	18
29308	CTRPKGEN	1	18
29953	SIGGEN	D1	18
29309	BARPKGEN	1	13
29201	WALCRKG1	1	12

29202	WALCRKG2	1	12
29203	WALCRKG3	1	12
29204	WALCRKG4	1	12
29205	WALCRKG5	1	12
29011	BREAPWR2	C1	12
29011	BREAPWR2	C2	12
29011	BREAPWR2	C3	12
29011	BREAPWR2	C4	12
29011	BREAPWR2	S1	12
24325	ORCOGEN	I	12
24341	COYGEN	I	11
25192	WDT1406_G	I	11
25208	DowlingCTG	1	10
25211	CanyonGT 1	1	10
25212	CanyonGT 2	2	10
25213	CanyonGT 3	3	10
25214	CanyonGT 4	4	10
24216	VILLA PK	DG	9

Table – Rector

Effectiveness factors to the Rector-Vestal 230 kV line:

Gen Bus	Gen Name	Gen ID	MW Eff Factor (%)
24370	KAWGEN	1	51
24306	B CRK1-1	1	45
24306	B CRK1-1	2	45

24307	B CRK1-2	3	45
24307	B CRK1-2	4	45
24319	EASTWOOD	1	45
24323	PORTAL	1	45
24308	B CRK2-1	1	45
24308	B CRK2-1	2	45
24309	B CRK2-2	3	45
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

Table – San Diego

Effectiveness factors to the Imperial Valley – El Centro 230 kV line (i.e., the “S” line):

Gen Bus	Gen Name	Gen ID	Eff Factor. (%)
22982	TDM CTG2	1	25
22983	TDM CTG3	1	25

22981	TDM STG	1	25
22997	INTBCT	1	25
22996	INTBST	1	25
23440	DW GEN2 G1	1	25
23298	DW GEN1 G1	G1	25
23156	DU GEN1 G2	G2	25
23299	DW GEN1 G2	G2	25
23155	DU GEN1 G1	G1	25
23441	DW GEN2 G2	1	25
23442	DW GEN2 G3A	1	25
23443	DW GEN2 G3B	1	25
23314	OCO GEN G1	G1	23
23318	OCO GEN G2	G2	23
23100	ECO GEN1 G	G1	22
23352	ECO GEN2 G	1	21
22605	OTAYMGT1	1	18
22606	OTAYMGT2	1	18
22607	OTAYMST1	1	18
23162	PIO PICO CT1	1	18
23163	PIO PICO CT2	1	18
23164	PIO PICO CT3	1	18
22915	KUMEYAAY	1	17
23320	EC GEN2	1	17
22150	EC GEN1	1	17
22617	OY GEN	1	17

22604	OTAY	1	17
22604	OTAY	3	17
22172	DIVISION	1	17
22576	NOISLMTR	1	17
22704	SAMPSON	1	17
22092	CABRILLO	1	17
22074	LRKSPBD1	1	17
22075	LRKSPBD2	1	17
22660	POINTLMA	1	17
22660	POINTLMA	2	17
22149	CALPK_BD	1	17
22448	MESAHGTS	1	16
22120	CARLTNHS	1	16
22120	CARLTNHS	2	16
22496	MISSION	1	16
22486	MEF MR1	1	16
22124	CHCARITA	1	16
22487	MEF MR2	1	16
22625	LkHodG1	1	16
22626	LkHodG2	2	16
22332	GOALLINE	1	15
22262	PEN_CT1	1	15
22153	CALPK_ES	1	15
22786	EA GEN1 U6	1	15
22787	EA GEN1 U7	1	15

22783	EA GEN1 U8	1	15
22784	EA GEN1 U9	1	15
22789	EA GEN1 U10	1	15
22257	ES GEN	1	15
22263	PEN_CT2	1	15
22265	PEN_ST	1	15
22724	SANMRCOS	1	15
22628	PA GEN1	1	14
22629	PA GEN2	1	14
22082	BR GEN1	1	14
22112	CAPSTRNO	1	12