APPENDIX E: 2024 Local Capacity Technical Analysis

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California Independent System Operator

2024
LOCAL CAPACITY TECHNICAL ANALYSIS

FINAL REPORT
AND STUDY RESULTS

February 2, 2015

Local Capacity Technical Analysis
Overview and Study Results

I. Executive Summary

This Report documents the results and recommendations of the 2024 Long-Term Local Capacity Technical (LCT) Study. The LCT Study objectives, inputs, methodologies and assumptions are the same as those discussed in the 2015 LCT Study to be adopted by the CAISO and CPUC in their 2015 Local Resource Adequacy needs.

Overall, the LCR trend compared with 2019 is upward by about 1,100 MW mainly due to combination of higher load forecast and new transmission projects. It is worth mentioning the following areas: (1) Humboldt, North Coast/North Bay, Stockton, and Bay Area, LCR is steady due to a combination of load forecast and new transmission projects; (2) Sierra, Fresno and Big Creek/Ventura, where the LCR has increased mostly due to load forecast; (3) Kern and LA Basin, where the LCR has significantly decreased mostly due to new transmission projects; (4) San Diego-Imperial Valley where LCR has increased due to OTC retirement in the LA Basin and San Diego.

This Valley Electric Association (VEA) area is eliminated due to new transmission projects, the incorporation of the VEA UVLS model into the contingency analysis as well as the availability of ISO operating procedure 7910 that addresses some category C issues.

The load forecast used in this study is based on the final adopted California Energy Demand 2014 - 2024 Final Forecast developed by the CEC; namely the mid-demand baseline with low-mid additional achievable energy efficiency (AAEE), posted at: http://www.energy.ca.gov/2013_energypolicy/documents/.

For comparison below you will find the 2019 and 2024 total LCR needs.

2019 Local Capacity Needs

	Qualifying Capacity			2019 LCR Need Based on Category B			2019 LCR Need Based on Category C with operating procedure		
Local Area Name	**QF/ Muni (MW)**	**Market (MW)**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**Existing Capacity Needed****	**Deficiency**	**Total (MW)**
Humboldt	36	171	207	123	0	**123**	173	0	**173**
North Coast/ North Bay	130	771	901	310	0	**310**	516	0	**516**
Sierra	1299	771	2070	525	0	**525**	1102	0	**1102**
Stockton	295	392	687	163	0	**163**	308	43*	**351**
Greater Bay	1262	5589	6851	3198	0	**3198**	4224	0	**4224**
Greater Fresno	316	2532	2848	1463	0	**1463**	1545	44*	**1589**
Kern	225	87	312	156	32*	**188**	161	32*	**193**
LA Basin	2207	8985	11192	9059	0	**9059**	9119	0	**9119**
Big Creek/Ventura	1160	4203	5363	2499	0	**2499**	2619	0	**2619**
San Diego/ Imperial Valley	219	4004	4223	3160	3*	**3163**	3160	130*	**3290**
Total	7149	27505	34654	20656	35	**20691**	22927	249	**23176**

2024 Local Capacity Needs

	Qualifying Capacity			2024 LCR Need Based on Category B			2024 LCR Need Based on Category C with operating procedure		
Local Area Name	**QF/ Muni (MW)**	**Market (MW)**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**Existing Capacity Needed****	**Deficiency**	**Total (MW)**
Humboldt	36	171	207	127	0	**127**	178	0	**178**
North Coast/ North Bay	130	757	887	312	0	**312**	505	0	**505**
Sierra	1299	771	2070	907	0	**907**	1478	0	**1478**
Stockton	270	392	662	287	0	**287**	340	7*	**347**
Greater Bay	1290	5738	7028	4133	0	**4133**	4133	0	**4133**
Greater Fresno	316	3162	3478	1471	11*	**1482**	2182	31*	**2213**
Kern	179	83	262	150	0	**150**	154	0	**154**
LA Basin ***	1969	4293	6262	4620	1756*	**6376**	6190	2160*	**8350**
Big Creek/Ventura ***	1161	2506	3667	2603	0	**2603**	2553	230*	**2783**
San Diego/ Imperial Valley ***	297	3872	4169	3363	700*	**4063**	3363	784*	**4147**
Total	6947	21745	28692	17973	2467	**20440**	21076	3212	**24288**

* No local area is “overall deficient”. Resource deficiency values result from a few deficient sub-areas; and since there are no resources that can mitigate this deficiency the numbers are carried forward into the total area needs. Resource deficient sub-area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.
** Since “deficiency” cannot be mitigated by any available resource, the “Existing Capacity Needed” will be split among LSEs on a load share ratio during the assignment of local area resource responsibility.
*** More details are available in the LA Basin, Big Creek/Ventura and San Diego/Imperial Valley LCR study results sections on how LTPP Tracks 1 and 4 procurement, as well as repurposing demand response, can be used to mitigate resource deficiency.

The write-up for each Local Capacity Area lists important new projects included in the base cases as well as a description of reason for changes between the 2019 Long-Term LCR study and this 2024 Long-Term LCR study.

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

A. Objectives

As was the objective of all previous LCT Studies, the intent of the 2024 Long-Term LCT Study is to identify specific areas within the CAISO Balancing Authority Area that have limited import capability and determine the minimum generation capacity (MW) necessary to mitigate the local reliability problems in those areas.

B. Key Study Assumptions

Inputs and Methodology

The CAISO used the same Inputs and Methodology as does agreed upon by interested parties previously incorporated into the 2015 LCR Study. The following table sets forth a summary of the approved inputs and methodology that have been used in the previous 2015 LCR Study, 2019 LCR study and this 2024 LCR Study:

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

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

Further details regarding the 2019 as well as 2024 LCR Study methodology and assumptions are provided in Section III, below.

C. Grid Reliability

Service reliability builds from grid reliability because grid reliability is reflected in the planning standards of the Western Electricity Coordinating Council ("WECC") that incorporate standards set by the North American Electric Reliability Council ("NERC") (collectively "NERC Planning Standards"). The NERC Planning 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 NERC Planning Standards, the CAISO is under a statutory obligation to ensure efficient use and reliable operation of the transmission grid consistent with achievement of the NERC Planning Standards.[1] The CAISO is further under an obligation, pursuant to its FERC-approved Transmission Control Agreement, to secure compliance with all "Applicable Reliability Criteria." Applicable Reliability Criteria consists of the NERC Planning Standards as well as reliability criteria adopted by the CAISO, in consultation with the CAISO's Participating Transmission Owners ("PTOs"), which affect a PTO's individual system.

The NERC Planning 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 NERC Planning 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.,

[1] Pub. Utilities Code § 345

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.

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

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

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

E. Performance Criteria

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

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

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

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

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

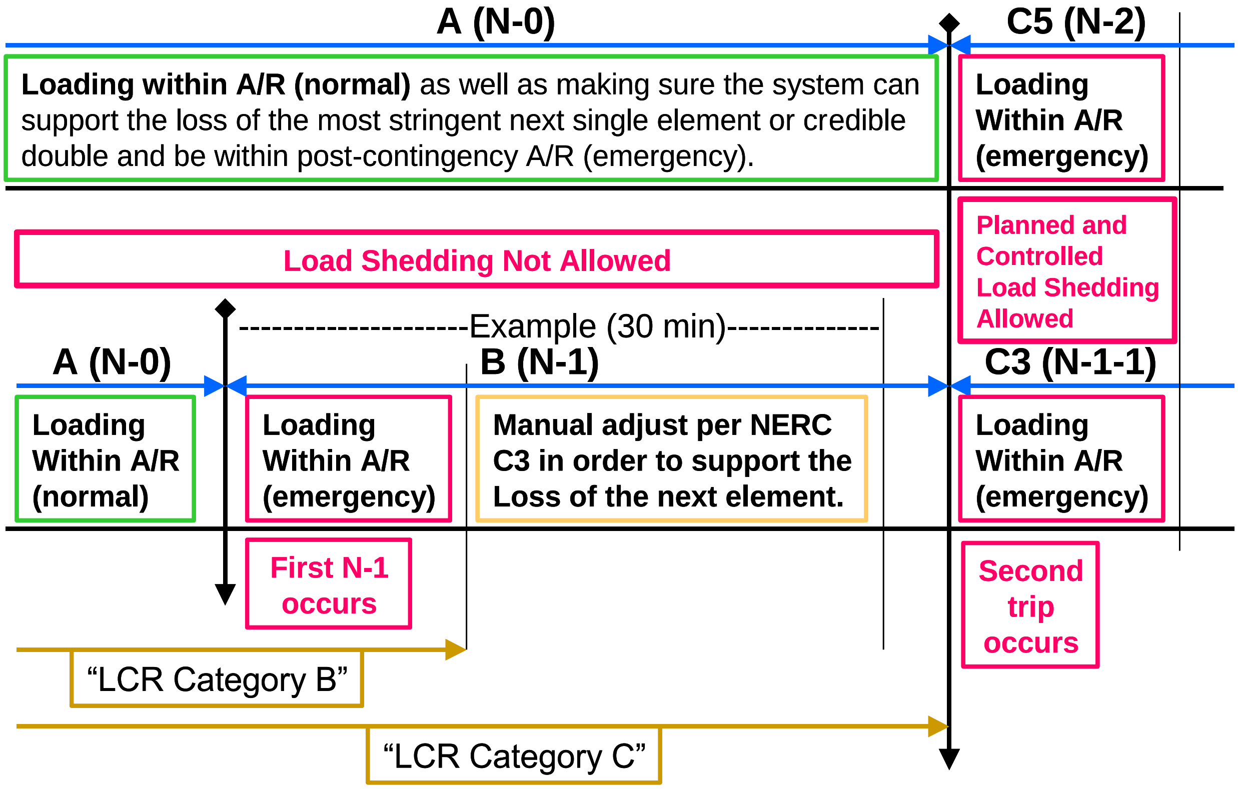
The NERC Planning Standards require system operators to "look forward" to make sure they safely prepare for the "next" N-1 following the loss of the "first" N-1 (stay within Applicable Ratings after the "next" N-1). This is commonly referred to as N-1-1. Because it is assumed that some time exists between the "first" and "next" element losses, operating personnel may make any reasonable and feasible adjustments to the system to prepare for the loss of the second element, including, operating procedures, dispatching generation, moving load from one substation to another to reduce equipment loading, dispatching operating personnel to specific station locations to manually adjust load from the substation site, or installing a "Special Protection Scheme" that would remove pre-identified load from service upon the loss of the "next " element.[2] All Category C requirements in this report refer to situations when in real time (N-0) or after the first contingency (N-1) the system requires additional readjustment in order to prepare for the next worst contingency. In this time frame, load drop is not allowed per existing planning criteria.

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

c. CAISO Statutory Obligation Regarding Safe Operation

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

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



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 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, as such the worst-case scenario must be covered. In case temperature-adjusted ratings are the only ratings available then the minimum rating (highest temperature) given the study conditions shall be used.

CAISO Transmission Register is the only official keeper of all existing ratings mentioned above.

Ratings for future projects provided by PTO and agree upon by the CAISO shall be used.

Other short-term ratings not included in the CAISO Transmission Register may be used as long as they are engineered, studied and enforced through clear operating procedures that can be followed by real-time operators.

Path Ratings need to be maintained in order for these studies to comply with the Minimum Operating Reliability Criteria and assure that proper capacity is available in order to operate the system in real-time.

Controlled load drop:

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

Planned load drop:

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

Special Protection Scheme:

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

System Readjustment:

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

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

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

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

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

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

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

Time allowed for manual readjustment:

This is the amount of time required for the operator to take all actions necessary to prepare the system for the next contingency. This time should be less than 30 minutes, based on existing CAISO Planning Standards.

This is a somewhat controversial aspect of the interpretation of existing criteria. This item is very specific in the CAISO Planning Standards. However, some will argue that 30 minutes only allows generation re-dispatch and automated switching where remote control is possible. If remote capability does not exist, a person must be dispatched in the field to do switching and 30 minutes may not allow sufficient time. If approved, an exemption from the existing time requirements may be given for small local areas with very limited exposure and impact, clearly described in operating procedures, and only until remote controlled switching equipment can be installed.

F. The Two Options Presented In This LCT Report

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

1. Option 1- Meet Performance Criteria Category B

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

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

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

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

III. Assumption Details: How the Study was Conducted

A. System Planning Criteria

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

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

Table 1: Criteria Comparison

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

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

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

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

4 Evaluate for risks and consequence, per NERC standards.

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

1. Power Flow Assessment:

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

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

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

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

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

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

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

[7] During normal operation or following the first contingency (N-1), the generation must be sufficient to allow the operators to prepare for the next worst N-1 or common mode N-2 without pre-contingency interruptible or firm load shedding.

SPS/RAS/Safety Nets may be utilized to satisfy the criteria after the second N-1 or common mode N-2 except if the problem is of a thermal nature such that short-term ratings could be utilized to provide the operators time to shed either interruptible or firm load. T-2s (two transformer bank outages) would be excluded from the criteria.

2. Post Transient Load Flow Assessment:

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

[1] If power flow results indicate significant low voltages for a given power flow contingency, simulate that outage using the post transient load flow program. The post-transient assessment will develop appropriate Q/V and/or P/V curves.

[2] Applicable Rating – positive margin based on the higher of imports or load increase by 5% for N-1 contingencies, and 2.5% for N-2 contingencies.

3. Stability Assessment:

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

[1] Base on historical information, engineering judgment and/or if power flow or post transient study results indicate significant low voltages or marginal reactive margin for a given contingency.

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

B. Load Forecast

1. System Forecast

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

2. Base Case Load Development Method

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

a. PTO Loads in Base Case

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

i. Determination of division loads

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

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

ii. Allocation of division load to transmission bus level

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

b. Municipal Loads in Base Case

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

C. Power Flow Program Used in the LCR analysis

The technical studies were conducted using General Electric's Power System Load Flow (GE PSLF) program version 18.1. This GE PSLF program is available directly from GE or through the Western System Electricity Council (WECC) to any member.

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. An CAISO created EPCL (a GE programming language contained within the GE PSLF package) routine was used to run the combination of contingencies; however, other routines are available from WECC with the GE PSFL package or can be developed by third parties to identify the most limiting combination of contingencies requiring the highest amount of generation within the local area to maintain power flows within applicable ratings.

IV. Locational Capacity Requirement Study Results

A. Summary of Study Results

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

Table 2: 2019 Local Capacity Needs vs. Peak Load and Local Area Resources

	2019 Total LCR (MW)	Peak Load (1 in10) (MW)	2019 LCR as % of Peak Load	Total Dependable Local Area Resources (MW)	2019 LCR as % of Total Area Resources
Humboldt	173	204	85%	207	84%
North Coast/North Bay	516	1484	35%	909	57%
Sierra	1102	2076	53%	2070	53%
Stockton	351	1136	31%	687	51%**
Greater Bay	4224	10330	41%	6851	62%
Greater Fresno	1589	3258	49%	2848	56%**
Kern	193	745	26%	312	47%**
LA Basin	9119	20506	44%	11192	81%
Big Creek/Ventura	2619	4889	54%	5363	49%
San Diego/Imperial Valley	3290	5538	59%	4223	78%**
Total	**23176**	**50166***	**46%***	**34662**	**67%**

Table 3: 2024 Local Capacity Needs vs. Peak Load and Local Area Resources

	2024 Total LCR (MW)	Peak Load (1 in10) (MW)	2024 LCR as % of Peak Load	Total Dependable Local Area Resources (MW)	2024 LCR as % of Total Area Resources
Humboldt	178	203	88%	207	86%
North Coast/North Bay	505	1550	33%	887	57%
Sierra	1478	2261	65%	2070	71%
Stockton	347	992	35%	662	52%**
Greater Bay	4133	10311	40%	7028	59%
Greater Fresno	2213	3806	58%	3478	64%**
Kern	154	255	60%	262	59%
LA Basin	8350	21127	40%	6262	133%**
Big Creek/Ventura	2783	4997	56%	3667	76%**
San Diego/Imperial Valley	4147	5513	75%	4169	99%**
Total	**24248**	**51015***	**48%***	**28692**	**85%**

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

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

Tables 2 and 3 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 2024 have been included in this 2024 Long-Term LCR Report and added to the total NQC values for those respective areas (see detail write-up for each area).

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

B. Summary of Results by Local Area

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

1. Humboldt Area

<u>Area Definition</u>

The transmission tie lines into the area include:

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

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

The substations that delineate the Humboldt Area are:

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

Total 2024 busload within the defined area: 196 MW with 7 MW of losses resulting in total load + losses of 203 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BLULKE_6_BLUELK	31156	BLUELKPP	12.5	8.49	1	None		Market
BRDGVL_7_BAKER				0.00		None	Not modeled Aug NQC	QF/Selfgen
FAIRHV_6_UNIT	31150	FAIRHAVN	13.8	16.05	1	None	Aug NQC	QF/Selfgen
FTSWRD_6_TRFORK				0.00		None	Energy Only	Market
FTSWRD_7_QFUNTS				0.50		None	Not modeled Aug NQC	QF/Selfgen
GRSCRK_6_BGCKWW				0.00		None	Energy Only	QF/Selfgen
HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.27	1	None		Market
HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.27	2	None		Market
HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.27	3	None		Market
HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.27	4	None		Market
HUMBPP_6_UNITS1	31181	HUMB_G2	13.8	16.27	5	None		Market
HUMBPP_6_UNITS1	31181	HUMB_G2	13.8	16.27	6	None		Market
HUMBPP_6_UNITS1	31181	HUMB_G2	13.8	16.27	7	None		Market
HUMBPP_6_UNITS2	31182	HUMB_G2	13.8	16.27	8	None		Market
HUMBPP_6_UNITS2	31182	HUMB_G2	13.8	16.27	9	None		Market
HUMBPP_6_UNITS2	31182	HUMB_G2	13.8	16.27	10	None		Market
HUMBSB_1_QF				0.00		None	Not modeled Aug NQC	QF/Selfgen
KEKAWK_6_UNIT	31166	KEKAWAK	9.1	0.00	1	None	Aug NQC	QF/Selfgen
PACLUM_6_UNIT	31152	PAC.LUMB	13.8	7.60	1	None	Aug NQC	QF/Selfgen
PACLUM_6_UNIT	31152	PAC.LUMB	13.8	7.60	2	None	Aug NQC	QF/Selfgen
PACLUM_6_UNIT	31153	PAC.LUMB	2.4	4.58	3	None	Aug NQC	QF/Selfgen
WLLWCR_6_CEDRFL				0.02		None	Not modeled Aug NQC	QF/Selfgen
LAPAC_6_UNIT	31158	LP SAMOA	12.5	0.00	1	None		QF/Selfgen

Projects modeled:

1. Laytonville 60 kV Circuit Breaker Installation Project (2016)
2. Maple Creek Reactive Support (2017)
3. Humboldt - Eureka 60 kV Line Capacity Increase (2017)
4. New Bridgeville - Garberville No.2 115 kV Line (2022)

<u>Critical Contingency Analysis Summary</u>

Humboldt Overall:

The most critical contingency for the Humboldt area is the outage of the Cottonwood-Bridgeville 115 kV line overlapping with an outage of the gen-tie from Humboldt Bay Power Plant to units 1-4. The local area limitation is potential overload on the Humboldt -Trinity 115 kV Line. This contingency establishes a local capacity need of 178 MW in 2024 (includes 36 MW of QF/Selfgen generation) as the minimum capacity necessary for reliable load serving capability within this area.

The single most critical contingency for the Humboldt area is the outage of the Cottonwood-Bridgeville 115 kV line with one of the Humboldt Bay Power Plant units already out of service, which could potentially overload the Humboldt -Trinity 115 kV line. This contingency establishes a local capacity need of 127 MW in 2024 (includes 36 MW of QF/Selfgen generation).

Effectiveness factors:

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

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

Changes compared to the 2019 results:

The load and losses have decreased by 1 MW from 2019 to 2024. This is due to the fact that there is a higher level of energy efficiency modeled into the 2024 case as compared to the 2019 case. The total LCR has increased slightly by 5 MW mainly due to the new transmission project.

Humboldt Overall Requirements:

	QF/Selfgen (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	36	171	207

2024	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[5]	127	0	127
Category C (Multiple)[6]	178	0	178

2. North Coast / North Bay Area

Area Definition

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

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

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

[5] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.
[6] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

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

Total 2024 busload within the defined area: 1511 MW with 39 MW of losses resulting in total load + losses of 1550 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ADLIN_1_UNITS	31435	GEO.ENGY	9.1	8.00	1	Eagle Rock, Fulton, Lakeville		Market
ADLIN_1_UNITS	31435	GEO.ENGY	9.1	8.00	2	Eagle Rock, Fulton, Lakeville		Market
BEARCN_2_UNITS	31402	BEAR CAN	13.8	6.50	1	Fulton, Lakeville		Market
BEARCN_2_UNITS	31402	BEAR CAN	13.8	6.50	2	Fulton, Lakeville		Market
FULTON_1_QF				0.08		Fulton, Lakeville	Not modeled Aug NQC	QF/Selfgen
GEYS11_7_UNIT11	31412	GEYSER11	13.8	65.00	1	Eagle Rock, Fulton, Lakeville		Market
GEYS12_7_UNIT12	31414	GEYSER12	13.8	50.00	1	Fulton, Lakeville		Market
GEYS13_7_UNIT13	31416	GEYSER13	13.8	56.00	1	Lakeville		Market
GEYS14_7_UNIT14	31418	GEYSER14	13.8	50.00	1	Fulton, Lakeville		Market
GEYS16_7_UNIT16	31420	GEYSER16	13.8	49.00	1	Fulton, Lakeville		Market
GEYS17_2_BOTRCK	31421	BOTTLERK	13.8	14.70	1	Fulton, Lakeville		Market
GEYS17_7_UNIT17	31422	GEYSER17	13.8	53.00	1	Fulton, Lakeville		Market
GEYS18_7_UNIT18	31424	GEYSER18	13.8	45.00	1	Lakeville		Market
GEYS20_7_UNIT20	31426	GEYSER20	13.8	40.00	1	Lakeville		Market
GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	40.00	1	Eagle Rock, Fulton, Lakeville		Market
GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	40.00	2	Eagle Rock, Fulton, Lakeville		Market
GYS7X8_7_UNITS	31408	GEYSER78	13.8	38.00	1	Eagle Rock, Fulton, Lakeville		Market
GYS7X8_7_UNITS	31408	GEYSER78	13.8	38.00	2	Eagle Rock, Fulton, Lakeville		Market
GYSRVL_7_WSPRNG				1.68		Fulton, Lakeville	Not modeled Aug NQC	QF/Selfgen
HILAND_7_YOLOWD				0.00		Eagle Rock, Fulton, Lakeville	Energy Only	Market
HIWAY_7_ACANYN				0.59		Lakeville	Not modeled Aug NQC	QF/Selfgen
IGNACO_1_QF				0.00		Lakeville	Not modeled Aug NQC	QF/Selfgen
INDVLY_1_UNITS	31436	INDIAN V	9.1	1.28	1	Eagle Rock, Fulton, Lakeville	Aug NQC	QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	3.96	1	Fulton, Lakeville	Aug NQC	QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	3.95	2	Fulton, Lakeville	Aug NQC	QF/Selfgen

MONTPH_7_UNITS	32700	MONTICLO	9.1	0.94	3	Fulton, Lakeville	Aug NQC	QF/Selfgen
NCPA_7_GP1UN1	38106	NCPA1GY1	13.8	31.00	1	Lakeville	Aug NQC	MUNI
NCPA_7_GP1UN2	38108	NCPA1GY2	13.8	28.00	1	Lakeville	Aug NQC	MUNI
NCPA_7_GP2UN3	38110	NCPA2GY1	13.8	0.00	1	Fulton, Lakeville	Aug NQC	MUNI
NCPA_7_GP2UN4	38112	NCPA2GY2	13.8	52.73	1	Fulton, Lakeville	Aug NQC	MUNI
POTTER_6_UNITS	31433	POTTRVLY	2.4	4.70	1	Eagle Rock, Fulton, Lakeville	Aug NQC	Market
POTTER_6_UNITS	31433	POTTRVLY	2.4	2.25	3	Eagle Rock, Fulton, Lakeville	Aug NQC	Market
POTTER_6_UNITS	31433	POTTRVLY	2.4	2.25	4	Eagle Rock, Fulton, Lakeville	Aug NQC	Market
POTTER_7_VECINO				0.03		Eagle Rock, Fulton, Lakeville	Not modeled Aug NQC	QF/Selfgen
SANTFG_7_UNITS	31400	SANTA FE	13.8	30.00	1	Lakeville		Market
SANTFG_7_UNITS	31400	SANTA FE	13.8	30.00	2	Lakeville		Market
SMUDGO_7_UNIT 1	31430	SMUDGEO1	13.8	37.00	1	Lakeville		Market
SNMALF_6_UNITS	31446	SONMA LF	9.1	4.14	1	Fulton, Lakeville	Aug NQC	QF/Selfgen
UKIAH_7_LAKEMN				1.70		Eagle Rock, Fulton, Lakeville	Not modeled	MUNI
WDFRDF_2_UNITS	31404	WEST FOR	13.8	12.51	1	Fulton, Lakeville		Market
WDFRDF_2_UNITS	31404	WEST FOR	13.8	12.49	2	Fulton, Lakeville		Market
New Unit	31405	RpsCA_07	13.8	7.5	1	Eagle Rock, Fulton, Lakeville	No NQC - Pmax	Market
New Unit	31447	RpsCA_13	13.8	10.5	1	Lakeville		Market

Projects modeled:

1. Mendocino Coast Reactive Support (2015)
2. Laytonville 60 kV Circuit Breaker Installation Project (2016)
3. Fulton - Fitch Mountain 60 kV Line Reconductor (2016)
4. Tulucay 230/60 kV Transformer No. 1 Capacity Increase (2016)
5. Napa - Tulucay No. 1 60 kV Line Upgrades (2017)
6. Vaca Dixon - Lakeville 230 kV Reconductoring (2018)
7. Clear Lake 60 kV System Reinforcement (2020)
8. Mare Island - Ignacio 115 kV Reconductoring Project (2020)
9. Fulton 230/115 kV Transformer (2021)
10. Ignacio - Alto 60 kV Line Voltage Conversion (2021)
11. Two new small renewable resources

Critical Contingency Analysis Summary

Eagle Rock Sub-area

The most critical single contingency is an outage of the Cortina-Mendocino 115 kV transmission line with Geysers 11 unit out of service. The sub-area limitation is thermal overloading of the parallel Eagle Rock-Cortina 115 kV line. This limiting contingency establishes a local capacity need of 219 MW in 2024 (includes 3 MW of QF/Muni generation).

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31406	GEYSR5-6	1	36
31406	GEYSR5-6	2	36
31405	RPSP1014	1	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

Fulton Sub-area

The most critical overlapping contingency is the outage of the Fulton-Ignacio 230 kV line #1 and the Fulton-Lakeville 230 kV line #1. The sub-area area limitation is thermal overloading of Santa Rosa - Corona 115 kV line #1. This limiting contingency establishes a local capacity need of 312 MW in 2024 (includes 16 MW of QF and 54 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area. All of the units required to meet the Eagle Rock pocket count towards the Fulton total requirement.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
38112	NCPA2GY2	1	57
38110	NCPA2GY1	1	57

31422	GEYSER17	1	57
31421	BOTTLERK	1	57
31420	GEYSER16	1	57
31418	GEYSER14	1	57
31414	GEYSER12	1	57
31404	WEST FOR	2	57
31404	WEST FOR	1	57
31402	BEAR CAN	1	57
31402	BEAR CAN	2	57
31406	GEYSR5-6	1	31
31406	GEYSR5-6	2	31
31405	RPSP1014	1	31
31408	GEYSER78	1	31
31408	GEYSER78	2	31
31412	GEYSER11	1	31
31435	GEO.ENGY	1	31
31435	GEO.ENGY	2	31
31433	POTTRVLY	1	29
31433	POTTRVLY	3	29
31433	POTTRVLY	4	29

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

The most limiting contingency for the North Coast/North Bay Area is a common mode outage of the Vaca Dixon-Lakeville and Vaca Dixon-Tulucay 230 kV lines. The area limitation is thermal overloading of the Eagle Rock-Cortina and Eagle Rock-Fulton 115 kV lines. This limiting contingency establishes a local capacity need of 505 MW in 2024 (includes 17 MW of QF and 113 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

The following units have at least 5% effectiveness to the Eagle Rock-Cortina constraint:

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31406	GEYSR5-6	1	33
31406	GEYSR5-6	2	33
31405	RPSP1014	1	34
31408	GEYSER78	1	34
31408	GEYSER78	2	34
31412	GEYSER11	1	34
31435	GEO.ENGY	1	33
31435	GEO.ENGY	2	33
31433	POTTRVLY	1	23

31433	POTTRVLY	3	23
31433	POTTRVLY	4	23
31400	SANTA FE	2	8
31400	SANTA FE	1	8
31430	SMUDGEO1	1	8
31402	BEAR CAN	1	10
31402	BEAR CAN	1	10
31404	WEST FOR	1	10
31404	WEST FOR	2	10
31414	GEYSER12	1	10
31416	GEYSER13	1	8
31418	GEYSER14	1	10
31421	BOTTLERK	1	10
31420	GEYSER16	1	10
31422	GEYSER17	1	10
31424	GEYSER18	1	8
31426	GEYSER20	1	8
31446	SONMA LF	1	11
32700	MONTICLO	1	15
32700	MONTICLO	2	15
32700	MONTICLO	3	15
38106	NCPA1GY1	1	8
38108	NCPA1GY2	1	8
38110	NCPA2GY1	1	10
38112	NCPA2GY2	1	10

The following units have at least 5% effectiveness to the Eagle Rock-Fulton constraint:

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31400	SANTA FE	2	9
31400	SANTA FE	1	9
31430	SMUDGEO1	1	9
31402	BEAR CAN	1	11
31402	BEAR CAN	1	11
31404	WEST FOR	1	11
31404	WEST FOR	2	11
31414	GEYSER12	1	11
31416	GEYSER13	1	9
31418	GEYSER14	1	11
31421	BOTTLERK	1	11
31420	GEYSER16	1	11
31422	GEYSER17	1	11
31424	GEYSER18	1	9
31426	GEYSER20	1	9
31446	SONMA LF	1	12
32700	MONTICLO	1	21
32700	MONTICLO	2	21

32700	MONTICLO	3	21
38106	NCPA1GY1	1	9
38108	NCPA1GY2	1	9
38110	NCPA2GY1	1	11
38112	NCPA2GY2	1	11

The most limiting single contingency is the outage of Vaca Dixon-Lakeville 230 kV line with Delta Energy Center combined cycle plant out of service. The sub-area limitation is thermal overloading of the Vaca Dixon-Tulucay 230 kV line. However, if the LCR requirements for the Fulton and Eagle Rock sub-areas are satisfied, no overload is expected. The Vaca Dixon-Tulucay 230 kV line loading under these conditions was 95%. Therefore, the minimum capacity necessary for reliable load serving capability within this sub-area in 2024 is the same as for the Fulton sub-area which is 312 MW (includes 16 MW of QF and 54 MW of Muni generation). The local capacity need for Eagle Rock and Fulton sub-areas can be counted toward fulfilling the need of Lakeville sub-area.

Effectiveness factors:

The following table has units at least 5% effectiveness to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
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
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

Changes compared to the 2019 results:

Overall the load and losses forecast went up by 66 MW compared to 2019 and the overall LCR requirement went down by 11 MW due mainly to different resource dispatch in the Bay Area.

North Coast/North Bay Overall Requirements:

2024	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	17	113	757	887

2024	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[7]	312	0	312
Category C (Multiple)[8]	505	0	505

3. Sierra Area

[7] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.
[8] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

Area Definition

The transmission tie lines into the Sierra Area are:

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

The substations that delineate the Sierra Area are:

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

Total 2024 busload within the defined area: 2187 MW with 84 MW of losses resulting in total load + losses of 2261 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
APLHIL_1_SLABCK				0.00	1	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Energy Only	Market
BANGOR_6_HYDRO				0.00		South of Table Mountain	Energy Only	Market
BELDEN_7_UNIT 1	31784	BELDEN	13.8	115.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market

BIOMAS_1_UNIT 1	32156	WOODLAND	9.1	24.70	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
BNNIEN_7_ALTAPH	32376	BONNIE N	60	0.46		Weimer, Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
BOGUE_1_UNITA1	32451	FREC	13.8	45.00	1	Bogue, Drum-Rio Oso, South of Table Mountain	Aug NQC	Market
BOWMN_6_UNIT	32480	BOWMAN	9.1	2.95	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
BUCKCK_7_OAKFLT				1.12		South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
BUCKCK_7_PL1X2	31820	BCKS CRK	11	29.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
BUCKCK_7_PL1X2	31820	BCKS CRK	11	29.00	2	South of Palermo, South of Table Mountain	Aug NQC	Market
CAMPFW_7_FARWST	32470	CMP.FARW	9.1	3.80	1	South of Table Mountain	Aug NQC	MUNI
CHICPK_7_UNIT 1	32462	CHI.PARK	11.5	38.00	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
COLGAT_7_UNIT 1	32450	COLGATE1	13.8	161.65	1	South of Table Mountain	Aug NQC	MUNI
COLGAT_7_UNIT 2	32452	COLGATE2	13.8	161.68	1	South of Table Mountain	Aug NQC	MUNI
CRESTA_7_PL1X2	31812	CRESTA	11.5	35.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
CRESTA_7_PL1X2	31812	CRESTA	11.5	35.00	2	South of Palermo, South of Table Mountain	Aug NQC	Market
DAVIS_7_MNMETH				1.95		Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
DEADCK_1_UNIT	31862	DEADWOOD	9.1	0.00	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
DEERCR_6_UNIT 1	32474	DEER CRK	9.1	3.48	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DRUM_7_PL1X2	32504	DRUM 1-2	6.6	13.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DRUM_7_PL1X2	32504	DRUM 1-2	6.6	13.00	2	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DRUM_7_PL3X4	32506	DRUM 3-4	6.6	13.70	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DRUM_7_PL3X4	32506	DRUM 3-4	6.6	13.70	2	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DRUM_7_UNIT 5	32454	DRUM 5	13.8	49.50	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DUTCH1_7_UNIT 1	32464	DTCHFLT1	11	22.00	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DUTCH2_7_UNIT 1	32502	DTCHFLT2	6.9	26.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
ELDORO_7_UNIT 1	32513	ELDRADO1	21.6	11.00	1	Placerville, South of Rio Oso, South of Palermo,		Market

						South of Table Mountain		
ELDORO_7_UNIT 2	32514	ELDRADO2	21.6	11.00	1	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain		Market
FMEADO_6_HELLHL	32486	HELLHOLE	9.1	0.38	1	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
FMEADO_7_UNIT	32508	FRNCH MD	4.2	16.01	1	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
FORBST_7_UNIT 1	31814	FORBSTWN	11.5	37.50	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
GOLDHL_1_QF				0.00		Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled	QF/Selfgen
GRIDLY_6_SOLAR				0.00		South of Table Mountain	Not modeled Energy Only	Market
GRNLF1_1_UNITS	32490	GRNLEAF1	13.8	6.31	1	Bogue, Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
GRNLF1_1_UNITS	32490	GRNLEAF1	13.8	32.25	2	Bogue, Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
GRNLF2_1_UNIT	32492	GRNLEAF2	13.8	40.63	1	Pease, Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
HALSEY_6_UNIT	32478	HALSEY F	9.1	7.03	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
HAYPRS_6_QFUNTS	32488	HAYPRES+	9.1	0.14	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
HAYPRS_6_QFUNTS	32488	HAYPRES+	9.1	0.15	2	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
HIGGNS_1_COMBIE				0.00		Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Energy Only	Market
HIGGNS_7_QFUNTS				0.25		Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	QF/Selfgen
KANAKA_1_UNIT				0.00		Drum-Rio Oso, South of Table Mountain	Not modeled Aug NQC	MUNI
KELYRG_6_UNIT	31834	KELLYRDG	9.1	10.00	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
LODIEC_2_PL1X2	38123	LODI CT1	18	166.00	1	South of Rio Oso, South of Palermo, South of Table Mountain		MUNI
LODIEC_2_PL1X2	38124	LODI ST1	18	114.00	1	South of Rio Oso, South of Palermo, South of Table Mountain		MUNI
MDFKRL_2_PROJCT	32456	MIDLFORK	13.8	62.18	1	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
MDFKRL_2_PROJCT	32456	MIDLFORK	13.8	62.18	2	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
MDFKRL_2_PROJCT	32458	RALSTON	13.8	84.32	1	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
NAROW1_2_UNIT	32466	NARROWS1	9.1	9.99	1	South of Table Mountain	Aug NQC	Market

NAROW2_2_UNIT	32468	NARROWS2	9.1	28.51	1	South of Table Mountain	Aug NQC	MUNI
NWCSTL_7_UNIT 1	32460	NEWCSTLE	13.2	0.03	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
OROVIL_6_UNIT	31888	OROVLLE	9.1	7.50	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
OXBOW_6_DRUM	32484	OXBOW F	9.1	6.00	1	Weimer, Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
PACORO_6_UNIT	31890	PO POWER	9.1	7.07	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
PACORO_6_UNIT	31890	PO POWER	9.1	7.07	2	Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
PLACVL_1_CHILIB	32510	CHILIBAR	4.2	3.46	1	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PLACVL_1_RCKCRE				0.00		Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
PLSNTG_7_LNCLND	32408	PLSNT GR	60	1.86		Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
POEPH_7_UNIT 1	31790	POE 1	13.8	60.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
POEPH_7_UNIT 2	31792	POE 2	13.8	60.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
RCKCRK_7_UNIT 1	31786	ROCK CK1	13.8	56.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
RCKCRK_7_UNIT 2	31788	ROCK CK2	13.8	56.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
RIOOSO_1_QF				1.37		Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	QF/Selfgen
ROLLIN_6_UNIT	32476	ROLLINSF	9.1	11.09	1	Weimer, Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
SLYCRK_1_UNIT 1	31832	SLY.CR.	9.1	10.36	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
SPAULD_6_UNIT 3	32472	SPAULDG	9.1	6.12	3	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
SPAULD_6_UNIT12	32472	SPAULDG	9.1	4.96	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
SPAULD_6_UNIT12	32472	SPAULDG	9.1	4.96	2	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
SPI LI_2_UNIT 1	32498	SPILINCF	12.5	9.34	1	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
STIGCT_2_LODI	38114	Stig CC	13.8	49.50	1	South of Rio Oso, South of Palermo, South of Table Mountain		MUNI
ULTRCK_2_UNIT	32500	ULTR RCK	9.1	21.71	1	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen

WDLEAF_7_UNIT 1	31794	WOODLEAF	13.8	55.00	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
WHEATL_6_LNDFIL	32350	WHEATLND	60	1.14		South of Table Mountain	Not modeled Aug NQC	Market
WISE_1_UNIT 1	32512	WISE	12	11.44	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
WISE_1_UNIT 2	32512	WISE	12	0.11	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
YUBACT_1_SUNSWT	32494	YUBA CTY	9.1	29.78	1	Pease, Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
YUBACT_6_UNITA1	32496	YCEC	13.8	46.00	1	Pease, Drum-Rio Oso, South of Table Mountain		Market
NA	32162	RIV.DLTA	9.11	0.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	No NQC - hist. data	QF/Selfgen
UCDAVS_1_UNIT	32166	UC DAVIS	9.1	3.50	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	No NQC - hist. data	QF/Selfgen

Projects modeled:

1. East Nicolaus 115 kV Area Reinforcement (2016)
2. Gold Hill-Missouri Flat #1 and #2 115 kV line Reconductoring (2018)
3. Pease 115/60 kV Transformer Addition (2018)
4. Pease-Marysville #2 60 kV line (2019)
5. Rio Oso #1 and #2 230/115 kV Transformer Replacement (2019)
6. Rio Oso Area 230 kV Voltage Support (2019)
7. South of Palermo 115 kV Reinforcement (2019)
8. New Atlantic-Placer 115 kV Line (2019)
9. New Rio Oso-Atlantic 230 kV line (2020)
10. Vaca Dixon-Davis Voltage Conversion (2021)

Critical Contingency Analysis Summary

Placerville Sub-area

The most critical contingency is the loss of the Gold Hill-Clarksville 115 kV line followed by loss of the Gold Hill-Missouri Flat #2 115 kV line. The area limitation is thermal overloading of the Gold Hill-Missouri Flat #1 115 kV line. This limiting contingency establishes a LCR of 16 MW (includes 0 MW of QF and MUNI generation) in 2024 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the loss of the Gold Hill-Missouri Flat #2 115 kV line with one of the El Dorado units out of service. The area limitation is low voltage at Placerville 115 kV bus. This limiting contingency establishes a local capacity need of 13 MW (includes 0 MW of QF generation) in 2024.

Effectiveness factors:

All units within this area have the same effectiveness factor.

Placer Sub-area

The most critical contingency is the loss of the New Atlantic-Placer 115 kV line with Chicago Park unit out of service. The area limitation is thermal overloading of the Drum-Higgins 115 kV line. This limiting contingency establishes a local capacity need of 62 MW (includes 38 MW of QF and MUNI generation) in 2024 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Gen Bus #	Gen Name	Gen ID	Eff Fctr (%)
32464	DTCHFLT1	1	57%
32462	CHI.PARK	1	49%
32478	HALSEY F	1	22%
32512	WISE	1	22%
32460	NEWCSTLE	1	18%

Pease Sub-area

The most critical contingency is the loss of the Palermo-Pease 115 kV line followed by Pease-Rio Oso 115 kV line. The area limitation is thermal overloading of the Table Mountain-Pease 60 kV line and low voltage at Pease 115 kV bus. This limiting contingency establishes a LCR of 127 MW (includes 70 MW of QF generation) in 2024 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the loss of the Palermo-Pease 115 kV line with YCEC unit out of service. The area limitation is thermal overloading of the Table Mountain-Pease 60 kV line. This limiting contingency establishes a local capacity need of 82 MW (includes 70 MW of QF generation) in 2024.

Effectiveness factors:

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

Bogue Sub-area

No requirements due to the Palermo-Rio Oso 115 kV reconductoring project.

Drum-Rio Oso Sub-area

No requirements due to the Rio Oso 230/115 kV transformers replacement project.

South of Palermo Sub-area

No requirements due to the South of Palermo reinforcement project.

South of Rio Oso Sub-area

The most critical contingency is the loss of the Rio Oso-Gold Hill 230 line followed by loss of the Rio Oso-Atlantic #1 or #2 230 kV line or vice versa. The area limitation is thermal overloading of the remaining Rio Oso-Atlantic 230 kV line. This limiting contingency establishes a LCR of 362 MW (includes 31 MW of QF and 593 MW of MUNI generation) in 2024 as the minimum capacity necessary for reliable load serving capability within this sub-area.

There is no single most critical contingency due to the installation of the new Rio Oso-Atlantic 230 kV.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr. (%)
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

South of Table Mountain Sub-area

The most critical contingency is the loss of the Table Mountain-Rio Oso and Table Mountain-Palermo 230 kV double circuit tower line outage. The area limitation is thermal overloading of the Caribou-Palermo 115 kV line and Table Mountain-Pease 60 kV line. This limitation establishes a local capacity need of 1478 MW in 2024 (includes 192 MW of QF and 1107 MW of MUNI generation) as the minimum capacity necessary for reliable load serving capability within this area.

The most critical single contingency is the loss of the Table Mountain-Rio Oso line with Belden unit out of service. The area limitation is thermal overloading of the Table Mountain-Palermo 230 kV line. This limiting contingency establishes a local capacity need of 907 MW (includes 192 MW of QF and 1107 MW of MUNI generation) in 2024.

Effectiveness factors:

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

Gen Bus #	Gen Name	Gen ID	Eff Fctr (%)
31814	FORBSTWN	1	7
31794	WOODLEAF	1	7

31832	SLY.CR.	1	7
31862	DEADWOOD	1	7
31890	PO POWER	1	6
31890	PO POWER	2	6
31888	OROVLLE	1	6
31834	KELLYRDG	1	6
32450	COLGATE1	1	4
32466	NARROWS1	1	4
32468	NARROWS2	1	4
32452	COLGATE2	1	4
32470	CMP.FARW	1	4
32451	FREC	1	4
32490	GRNLEAF1	1	4
32490	GRNLEAF1	2	4
32496	YCEC	1	4
32494	YUBA CTY	1	4
32492	GRNLEAF2	1	4
32498	SPILINCF	1	2
31788	ROCK CK2	1	2
31812	CRESTA	1	2
31812	CRESTA	2	2
31820	BCKS CRK	1	2
31820	BCKS CRK	2	2
31786	ROCK CK1	1	2
31790	POE 1	1	2
31792	POE 2	1	2
31784	BELDEN	1	2
32500	ULTR RCK	1	2
32156	WOODLAND	1	2
32510	CHILIBAR	1	2
32513	ELDRADO1	1	2
32514	ELDRADO2	1	2
32478	HALSEY F	1	2
32460	NEWCSTLE	1	1
32458	RALSTON	1	1
32512	WISE	1	1
32456	MIDLFORK	1	1
32456	MIDLFORK	2	1
32486	HELLHOLE	1	1
32508	FRNCH MD	1	1
32162	RIV.DLTA	1	1
32502	DTCHFLT2	1	1
32462	CHI.PARK	1	1

32464	DTCHFLT1	1	1
32454	DRUM 5	1	1
32476	ROLLINSF	1	1
32484	OXBOW F	1	1
32474	DEER CRK	1	1
32504	DRUM 1-2	1	1
32504	DRUM 1-2	2	1
32506	DRUM 3-4	1	1
32506	DRUM 3-4	2	1
32166	UC DAVIS	1	1
32472	SPAULDG	1	1
32472	SPAULDG	2	1
32472	SPAULDG	3	1
32480	BOWMAN	1	1
32488	HAYPRES+	1	1
32488	HAYPRES+	2	1
38124	LODI ST1	1	1
38123	LODI CT1	1	1
38114	STIG CC	1	1

Changes compared to the 2019 results:

The load forecast went up by 185 MW as compared to 2019 and that results in overall LCR increase of 376 MW.

Sierra Overall Requirements:

2024	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	192	1107	771	2070

2024	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[9]	907	0	907
Category C (Multiple)[10]	1478	0	1478

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

[10] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

4. Stockton Area

Area Definition

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

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

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

1) Bellota 230 kV is out Bellota 115 kV is in
2) Bellota 230 kV is out Bellota 115 kV is in
3) Tesla is out Tracy is in
4) Tesla is out Salado is in
5) Tesla is out Salado and Manteca are in
6) Tesla is out Schulte is in
7) Tesla is out Schulte is in
8) Tesla is out Thermal Energy is in

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

1) Stockton “A” - Weber #1 60 kV line
2) Stockton “A” - Weber #2 60 kV line
3) Stockton “A” – Weber #3 60 kV line

The substations that delineate the Weber Sub-area are:

1) Santa Fee switches are in Weber 60 kV is out
2) Santa Fee switches are in Weber 60 kV is out
3) Hazelton junction is in Weber 60 kV is out

Total 2024 busload within the defined area: 975 MW with 17 MW of losses resulting in total load + losses of 992 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BEARDS_7_UNIT 1	34074	BEARDSLY	6.9	8.36	1	Tesla-Bellota, Stanislaus	Aug NQC	MUNI

CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	1.44	1	Tesla-Bellota	Aug NQC	MUNI
CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	1.44	2	Tesla-Bellota	Aug NQC	MUNI
CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	1.45	3	Tesla-Bellota	Aug NQC	MUNI
COGNAT_1_UNIT	33818	COG.NTNL	12	25.46	1	Weber	Aug NQC	QF/Selfgen
CURIS_1_QF				0.94		Tesla-Bellota	Not modeled Aug NQC	QF/Selfgen
DONNLS_7_UNIT	34058	DONNELLS	13.8	72.00	1	Tesla-Bellota, Stanislaus	Aug NQC	MUNI
FROGTN_7_UTICA				0.00		Tesla-Bellota, Stanislaus	Energy Only	Market
PHOENX_1_UNIT				1.33		Tesla-Bellota, Stanislaus	Not modeled Aug NQC	Market
SCHLTE_1_PL1X3	33805	GWFTRCY1	13.8	83.56	1	Tesla-Bellota		Market
SCHLTE_1_PL1X3	33807	GWFTRCY2	13.8	82.88	1	Tesla-Bellota		Market
SCHLTE_1_PL1X3	33811	GWFTRCY3	13.8	132.96	1	Tesla-Bellota		Market
SNDBAR_7_UNIT 1	34060	SANDBAR	13.8	13.11	1	Tesla-Bellota, Stanislaus	Aug NQC	MUNI
SPIFBD_1_PL1X2	33917	FBERBORD	115	0.63	1	Tesla-Bellota, Stanislaus	Aug NQC	QF/Selfgen
SPRGAP_1_UNIT 1	34078	SPRNG GP	6	0.08	1	Tesla-Bellota, Stanislaus	Aug NQC	Market
STANIS_7_UNIT 1	34062	STANISLS	13.8	91.00	1	Tesla-Bellota, Stanislaus	Aug NQC	Market
STNRES_1_UNIT	34056	STNSLSRP	13.8	10.10	1	Tesla-Bellota	Aug NQC	QF/Selfgen
TULLCK_7_UNITS	34076	TULLOCH	6.9	8.23	1	Tesla-Bellota	Aug NQC	MUNI
TULLCK_7_UNITS	34076	TULLOCH	6.9	8.24	2	Tesla-Bellota	Aug NQC	MUNI
ULTPCH_1_UNIT 1	34050	CH.STN.	13.8	17.15	1	Tesla-Bellota, Stanislaus	Aug NQC	QF/Selfgen
VLYHOM_7_SSJID				1.40		Tesla-Bellota, Stanislaus	Not modeled Aug NQC	QF/Selfgen
NA	33687	STKTN WW	60	1.50	1	Weber	No NQC - hist. data	QF/Selfgen
STOKCG_1_UNIT 1	33814	CPC STCN	12.5	0.00	1	Tesla-Bellota		QF/Selfgen
SANJOA_1_UNIT 1	33808	SJ COGEN	13.8	48	1	Tesla-Bellota		QF/Selfgen
SMPRIP_1_SMPSON	33810	SP CMPNY	13.8	33.02	1	Tesla-Bellota	Aug NQC	QF/Selfgen
THMENG_1_UNIT 1	33806	TH.E.DV.	13.8	17.87	1	Tesla-Bellota	Aug NQC	QF/Selfgen

Projects modeled:

1. Tesla 115 kV Capacity Increase (2016)
2. Weber 230/60 kV Transformer Nos. 2 and 2A Replacement (2016)
3. Ripon 115 kV New Line Reconfiguration (2016)
4. Stockton 'A' - Weber 60 kV Line Nos. 1 and 2 Reconductor (2017)
5. Mosher Transmission Project (2017)
6. Weber - French Camp 60 kV Line Reconfiguration (2018)
7. West Point - Valley Springs 60 kV Line (Reconductor) (2019)
8. West Point - Valley Springs 60 kV Line Project (Second Line) (2019)
9. Vierra 115 kV Looping (2019)
10. Lockeford - Lodi Area 230 kV Development (2020)

<u>Critical Contingency Analysis Summary</u>

Stanislaus Sub-area

The critical contingency for the Stanislaus area is the loss of Bellota-Riverbank-Melones 115 kV circuit with Stanislaus PH out of service. The area limitation is thermal overloading of the River Bank Jct.-Manteca 115 kV line. This limiting contingency establishes a local capacity need of 133 MW (including 19 MW of QF and 93 MW of MUNI generation) in 2024 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Tesla-Bellota Sub-area

The most critical contingency for the Tesla-Bellota pocket is the loss of Tesla-Vierra 115 kV and the new Tesla-Schulte #2 115 kV lines. The area limitation is thermal overload of the Tesla-Schulte #1 115 kV line above its emergency rating. This limiting contingency establishes a local capacity need of 313 MW (includes 129 MW of QF and 114 MW of MUNI generation) in 2024 as the minimum capacity necessary for reliable load serving capability within this sub-area

The most critical single contingency for the Tesla-Bellota pocket is the loss of the Tesla-Schulte #2 115 kV line and the loss of the GWF Tracy unit #3. The area limitation is the thermal overload of the Tesla-Schulte #1 115 kV line. This single contingency establishes a local capacity need of 287 MW (includes 129 MW of QF and 114 MW of MUNI generation) in 2024.

Effectiveness factors:

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

Gen Bus#	Gen Name	Gen ID	Eff Fctr (%)
33805	GWFTRCY1	1	71.23
33807	GWFTRCY2	1	71.23

33811	Q268ST1	1	71.22
33808	SJ COGEN	1	34.59
33810	SP CMPNY	1	30.68
34062	STANISLS	1	27.95
34050	CH.STN.	1	22.61
33917	FBERBORD	1	22.28
34078	SPRNG GP	1	20.29
34060	SANDBAR	1	20.09
34074	BEARDSLY	1	19.93
34058	DONNELLS	1	19.75
34076	TULLOCH	1	17.66
34076	TULLOCH	2	17.66
33806	TH.E.DV.	1	8.72
34056	STNSLSRP	1	8.14
33814	CPC STCN	1	3.37
33850	CAMANCHE	1	3.35
33850	CAMANCHE	2	3.35
33850	CAMANCHE	3	3.35
33804	BELLTA T	1	0.49

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

Lockeford Sub-area

No requirements due to the Lockeford-Lodi area 230 kV development project.

Weber Sub-area

The critical contingency for the Weber sub-area is the loss of Stockton A-Weber #1 & #2 60 kV lines. The area limitation is thermal overloading of the Stockton A-Weber #3 60 kV line. This limiting contingency establishes a local capacity need of 34 MW (including 27 MW of QF generation as well as 7 MW of deficiency) in 2024 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Stockton Overall

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

Changes compared to the 2019 results:

There is overall load growth in this area however compared with 2019 the 2024 load forecast went down by 144 MW mainly due to the elimination of the Lockeford sub-area; as a result the overall LCR has decreased by 4 MW as compared to the 2019.

Stockton Overall Requirements:

2024	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	156	114	392	662

2024	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[11]	287	0	287
Category C (Multiple)[12]	340	7	347

5. Greater Bay Area

<u>Area Definition</u>

The transmission tie lines into the Greater Bay Area are:

1) Lakeville-Sobrante 230 kV

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

[12] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

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

The substations that delineate the Greater Bay Area are:

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

Total 2024 busload within the defined area: 9853 MW with 194 MW of losses and 264 MW of pumps resulting in total load + losses + pumps of 10311 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ALMEGT_1_UNIT 1	38118	ALMDACT1	13.8	23.80	1	Oakland		MUNI
ALMEGT_1_UNIT 2	38119	ALMDACT2	13.8	24.40	1	Oakland		MUNI
BANKPP_2_NSPIN	38760	DELTA E	13.2	28.00	10	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38760	DELTA E	13.2	28.00	11	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38765	DELTA D	13.2	28.00	8	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38765	DELTA D	13.2	28.00	9	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38770	DELTA C	13.2	28.00	6	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38770	DELTA C	13.2	28.00	7	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38815	DELTA B	13.2	28.00	4	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38815	DELTA B	13.2	28.00	5	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38820	DELTA A	13.2	7.00	1	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38820	DELTA A	13.2	7.00	2	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38820	DELTA A	13.2	26.00	3	Contra Costa	Pumps	MUNI
BLHVN_7_MENLOP				0.88		None	Not modeled Aug NQC	QF/Selfgen
BRDSLD_2_HIWIND	32172	HIGHWINDS	34.5	38.96	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_MTZUM2	32179	MNTZUMA2	0.69	13.02	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_MTZUMA	32171	HIGHWND3	34.5	7.12	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_SHILO1	32176	SHILOH	34.5	35.34	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_SHILO2	32177	SHILOH 2	34.5	36.13	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_SHLO3A	32191	SHLH3AC2	0.58	17.45	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_SHLO3B	32194	SHLH3BC2	0.58	17.45	1	Contra Costa	Aug NQC	Wind
CALPIN_1_AGNEW	35860	OLS-AGNE	9.11	28.00	1	San Jose	Aug NQC	QF/Selfgen
CARDCG_1_UNITS	33463	CARDINAL	12.5	10.49	1	None	Aug NQC	QF/Selfgen
CARDCG_1_UNITS	33463	CARDINAL	12.5	10.49	2	None	Aug NQC	QF/Selfgen
CLRMTK_1_QF				0.00		Oakland	Not modeled	QF/Selfgen
COCOPP_2_CTG1	33188	MARSHBS1	16.4	191.35	1	Contra Costa	Aug NQC	Market
COCOPP_2_CTG2	33188	MARSHBS1	16.4	189.30	2	Contra Costa	Aug NQC	Market
COCOPP_2_CTG3	33189	MARSHBS2	16.4	191.45	3	Contra Costa	Aug NQC	Market
COCOPP_2_CTG4	33189	MARSHBS2	16.4	191.44	4	Contra Costa	Aug NQC	Market
CONTAN_1_UNIT	36856	CCA100	13.8	27.70	1	San Jose	Aug NQC	QF/Selfgen
CROKET_7_UNIT	32900	CRCKTCOG	18	225.24	1	Pittsburg	Aug NQC	QF/Selfgen
CSCCOG_1_UNIT 1	36854	Cogen	12	3.00	1	San Jose		MUNI
CSCCOG_1_UNIT 1	36854	Cogen	12	3.00	2	San Jose		MUNI
CSCGNR_1_UNIT 1	36858	Gia100	13.8	24.00	1	San Jose		MUNI
CSCGNR_1_UNIT 2	36895	Gia200	13.8	24.00	2	San Jose		MUNI
DELTA_2_PL1X4	33107	DEC STG1	24	269.61	1	Pittsburg	Aug NQC	Market
DELTA_2_PL1X4	33108	DEC CTG1	18	181.13	1	Pittsburg	Aug NQC	Market
DELTA_2_PL1X4	33109	DEC CTG2	18	181.13	1	Pittsburg	Aug NQC	Market
DELTA_2_PL1X4	33110	DEC CTG3	18	181.13	1	Pittsburg	Aug NQC	Market
DUANE_1_PL1X3	36863	DVRaGT1	13.8	49.27	1	San Jose		MUNI
DUANE_1_PL1X3	36864	DVRbGT2	13.8	49.27	1	San Jose		MUNI
DUANE_1_PL1X3	36865	DVRaST3	13.8	49.26	1	San Jose		MUNI
FLOWD1_6_ALTPP1	35318	FLOWDPTR	9.11	0.00	1	Contra Costa	Aug NQC	Wind
GATWAY_2_PL1X3	33118	GATEWAY1	18	189.27	1	Contra Costa	Aug NQC	Market
GATWAY_2_PL1X3	33119	GATEWAY2	18	185.36	1	Contra Costa	Aug NQC	Market
GATWAY_2_PL1X3	33120	GATEWAY3	18	185.36	1	Contra Costa	Aug NQC	Market
GILROY_1_UNIT	35850	GLRY COG	13.8	69.30	1	Llagas	Aug NQC	Market
GILROY_1_UNIT	35850	GLRY COG	13.8	35.70	2	Llagas	Aug NQC	Market
GILRPP_1_PL1X2	35851	GROYPKR1	13.8	45.50	1	Llagas	Aug NQC	Market
GILRPP_1_PL1X2	35852	GROYPKR2	13.8	45.50	1	Llagas	Aug NQC	Market
GILRPP_1_PL3X4	35853	GROYPKR3	13.8	46.00	1	Llagas	Aug NQC	Market

GRZZLY_1_BERKLY	32740	HILLSIDE	115	24.92	1	None	Aug NQC	QF/Selfgen
HICKS_7_GUADLP				1.74		None	Not modeled Aug NQC	QF/Selfgen
KELSO_2_UNITS	33813	MARIPCT1	13.8	45.95	1	Contra Costa	Aug NQC	Market
KELSO_2_UNITS	33815	MARIPCT2	13.8	45.95	2	Contra Costa	Aug NQC	Market
KELSO_2_UNITS	33817	MARIPCT3	13.8	45.95	3	Contra Costa	Aug NQC	Market
KELSO_2_UNITS	33819	MARIPCT4	13.8	45.96	4	Contra Costa	Aug NQC	Market
KIRKER_7_KELCYN				3.21		Pittsburg	Not modeled	Market
LAWRNC_7_SUNYVL				0.11		None	Not modeled Aug NQC	Market
LECEF_1_UNITS	35854	LECEFGT1	13.8	46.50	1	San Jose	Aug NQC	Market
LECEF_1_UNITS	35855	LECEFGT2	13.8	46.50	1	San Jose	Aug NQC	Market
LECEF_1_UNITS	35856	LECEFGT3	13.8	46.50	1	San Jose	Aug NQC	Market
LECEF_1_UNITS	35857	LECEFGT4	13.8	46.50	1	San Jose	Aug NQC	Market
LECEF_1_UNITS	35858	LECEFST1	13.8	107.88	1	San Jose		Market
LFC 51_2_UNIT 1	35310	LFC FIN+	9.11	2.03	1	None	Aug NQC	Wind
LMBEPK_2_UNITA1	32173	LAMBGT1	13.8	47.00	1	Contra Costa	Aug NQC	Market
LMBEPK_2_UNITA2	32174	GOOSEHGT	13.8	46.00	2	Contra Costa	Aug NQC	Market
LMBEPK_2_UNITA3	32175	CREEDGT1	13.8	47.00	3	Contra Costa	Aug NQC	Market
LMEC_1_PL1X3	33111	LMECCT2	18	163.20	1	Pittsburg	Aug NQC	Market
LMEC_1_PL1X3	33112	LMECCT1	18	163.20	1	Pittsburg	Aug NQC	Market
LMEC_1_PL1X3	33113	LMECST1	18	229.60	1	Pittsburg	Aug NQC	Market
MARTIN_1_SUNSET				1.18		None	Not modeled Aug NQC	QF/Selfgen
METCLF_1_QF				0.13		None	Not modeled Aug NQC	QF/Selfgen
METEC_2_PL1X3	35881	MEC CTG1	18	178.43	1	None	Aug NQC	Market
METEC_2_PL1X3	35882	MEC CTG2	18	178.43	1	None	Aug NQC	Market
METEC_2_PL1X3	35883	MEC STG1	18	213.14	1	None	Aug NQC	Market
MILBRA_1_QF				0.00		None	Not modeled	QF/Selfgen
MISSIX_1_QF				0.31		None	Not modeled Aug NQC	QF/Selfgen
MLPTAS_7_QFUNTS				0.01		San Jose	Not modeled Aug NQC	QF/Selfgen
MNTAGU_7_NEWBYI				1.34		None	Not modeled Aug NQC	QF/Selfgen
NEWARK_1_QF				0.02		None	Not modeled Aug NQC	QF/Selfgen
OAK C_1_EBMUD				0.73		Oakland	Not modeled Aug NQC	MUNI
OAK C_7_UNIT 1	32901	OAKLND 1	13.8	55.00	1	Oakland		Market
OAK C_7_UNIT 2	32902	OAKLND 2	13.8	55.00	1	Oakland		Market
OAK C_7_UNIT 3	32903	OAKLND 3	13.8	55.00	1	Oakland		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	1	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	2	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	3	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	4	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	5	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	6	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	7	None		Market
PALALT_7_COBUG				4.50		None	Not modeled	MUNI
PITTSP_7_UNIT 5	33105	PTSB 5	18	0.00	1	Pittsburg	Retired	Market
PITTSP_7_UNIT 6	33106	PTSB 6	18	0.00	1	Pittsburg	Retired	Market
PITTSP_7_UNIT 7	30000	PTSB 7	20	0.00	1	Pittsburg	Retired	Market
RICHMN_7_BAYENV				2.00		None	Not modeled Aug NQC	QF/Selfgen

RUSCTY_2_UNITS	35304	RUSELCT1	15	172.35	1	None	No NQC - Pmax	Market
RUSCTY_2_UNITS	35305	RUSELCT2	15	172.35	1	None	No NQC - Pmax	Market
RUSCTY_2_UNITS	35306	RUSELST1	15	241.00	1	None	No NQC - Pmax	Market
RVRVEW_1_UNITA1	33178	RVEC_GEN	13.8	46.00	1	Contra Costa	Aug NQC	Market
SEAWST_6_LAPOS	35312	SEAWESTF	9.11	0.24	1	Contra Costa	Aug NQC	Wind
SRINTL_6_UNIT	33468	SRI INTL	9.11	1.23	1	None	Aug NQC	QF/Selfgen
STAUFF_1_UNIT	33139	STAUFER	9.11	0.03	1	None	Aug NQC	QF/Selfgen
STOILS_1_UNITS	32921	CHEVGEN1	13.8	0.86	1	Pittsburg	Aug NQC	QF/Selfgen
STOILS_1_UNITS	32922	CHEVGEN2	13.8	0.86	1	Pittsburg	Aug NQC	QF/Selfgen
TIDWTR_2_UNITS	33151	FOSTER W	12.5	7.05	1	Pittsburg	Aug NQC	QF/Selfgen
TIDWTR_2_UNITS	33151	FOSTER W	12.5	7.05	2	Pittsburg	Aug NQC	QF/Selfgen
TIDWTR_2_UNITS	33151	FOSTER W	12.5	7.05	3	Pittsburg	Aug NQC	QF/Selfgen
UNCHEM_1_UNIT	32920	UNION CH	9.11	16.42	1	Pittsburg	Aug NQC	QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.14	1	Pittsburg	Aug NQC	QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.14	2	Pittsburg	Aug NQC	QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.13	3	Pittsburg	Aug NQC	QF/Selfgen
USWNDR_2_SMUD	32169	SOLANOWP	21	21.05	1	Contra Costa	Aug NQC	Wind
USWNDR_2_SMUD2	32186	SOLANO	34.5	20.92	1	Contra Costa	Aug NQC	Wind
USWNDR_2_UNITS	32168	EXNCO	9.11	15.97	1	Contra Costa	Aug NQC	Wind
USWPFK_6_FRICK	35320	USW FRIC	12	0.60	1	Contra Costa	Aug NQC	Wind
USWPFK_6_FRICK	35320	USW FRIC	12	0.61	2	Contra Costa	Aug NQC	Wind
USWPJR_2_UNITS	39233	GRNRDG	0.69	14.37	1	Contra Costa	Aug NQC	Wind
WNDMAS_2_UNIT 1	33170	WINDMSTR	9.11	3.28	1	Contra Costa	Aug NQC	Wind
ZOND_6_UNIT	35316	ZOND SYS	9.11	3.60	1	Contra Costa	Aug NQC	Wind
IBMCTL_1_UNIT 1	35637	IBM-CTLE	115	0.00	1	San Jose	No NQC - hist. data	Market
IMHOFF_1_UNIT 1	33136	CCCSD	12.5	4.40	1	Pittsburg	No NQC - hist. data	QF/Selfgen
MARKHM_1_CATLST	35863	CATALYST	9.11	0.00	1	San Jose		QF/Selfgen
SHELRF_1_UNITS	33141	SHELL 1	12.5	20.00	1	Pittsburg	No NQC - hist. data	QF/Selfgen
SHELRF_1_UNITS	33142	SHELL 2	12.5	40.00	1	Pittsburg	No NQC - hist. data	QF/Selfgen
SHELRF_1_UNITS	33143	SHELL 3	12.5	40.00	1	Pittsburg	No NQC - hist. data	QF/Selfgen
ZANKER_1_UNIT 1	35861	SJ-SCL W	9.11	5.00	1	San Jose	No NQC - hist. data	QF/Selfgen
New Unit	32188	COLNSVLE	34.5	9.80	1	Contra Costa	No NQC - est. data	Wind
New Unit	30531	RpsCA_02	230	4.30	FW	Contra Costa	No NQC - Pmax	Market
New Unit	30524	RpsCA_04	230	1.80	EW	Contra Costa	No NQC - Pmax	Market
New Unit	33181	OAKLYCT1	18	221.00	1	Contra Costa	No NQC - Pmax	Market
New Unit	33182	OAKLYCT2	18	215.00	2	Contra Costa	No NQC - Pmax	Market
New Unit	33183	OAKLYST1	18	215.00	3	Contra Costa	No NQC - Pmax	Market
COCOPP_7_UNIT 6	33116	C.COS 6	18	0.00	1	Contra Costa	Retired	Market
COCOPP_7_UNIT 7	33117	C.COS 7	18	0.00	1	Contra Costa	Retired	Market
GWFPW1_6_UNIT	33131	GWF #1	9.11	0.00	1	Pittsburg, Contra Costa	Retired	QF/Selfgen
GWFPW2_1_UNIT 1	33132	GWF #2	13.8	0.00	1	Pittsburg	Retired	QF/Selfgen
GWFPW3_1_UNIT 1	33133	GWF #3	13.8	0.00	1	Pittsburg, Contra Costa	Retired	QF/Selfgen
GWFPW4_6_UNIT 1	33134	GWF #4	13.8	0.00	1	Pittsburg, Contra Costa	Retired	QF/Selfgen
GWFPW5_6_UNIT 1	33135	GWF #5	13.8	0.00	1	Pittsburg	Retired	QF/Selfgen
UNTDQF_7_UNITS	33466	UNTED CO	9.11	0.00	1	None	Retired	QF/Selfgen
New Unit	33102	RpsCA_86	0.32	20.00	1	Pittsburg	No NQC - Pmax	Market

New Unit	36859	Laf300	12	3.90	1	San Jose	No NQC - Pmax	MUNI
New Unit	36859	Laf300	12	3.90	2	San Jose	No NQC - Pmax	MUNI

Projects modeled:

1. Pittsburg - Tesla 230 kV Reconductoring (2016)
2. Pittsburg - Lakewood SPS Project (2016)
3. Monta Vista - Wolfe 115 kV Substation Equipment Upgrade (2016)
4. NRS - Scott No. 1 115 kV Line Reconductor (2016)
5. Almaden 60 kV Shunt Capacitor (2017)
6. Bay Meadows 115 kV Reconductoring (2017)
7. Newark - Ravenswood 230 kV Line (2017)
8. Contra Costa - Moraga 230 kV Line Reconductoring (2017)
9. Moraga Transformer Capacity Increase (2017)
10. Christie 115/60 kV Transformer Addition (2017)
11. Contra Costa Sub 230 kV Switch Replacement (2017)
12. Embarcadero - Potrero 230 kV Transmission Project (2017)
13. Cooley Landing - Los Altos 60 kV Line Reconductor (2017)
14. Moraga - Oakland "J" SPS Project (2017)
15. Cooley Landing 115/60 kV Transformer Capacity Upgrade (2017)
16. Evergreen - Mabury 60 to 115 kV Conversion (2017)
17. Monta Vista - Los Gatos - Evergreen 60 kV Project (2017)
18. Moraga - Castro Valley 230 kV Line Capacity Increase Project (2017)
19. Pittsburg 230/115 kV Transformer Capacity Increase (2018)
20. Tesla - Newark 230 kV Path Upgrade (2018)
21. Metcalf - Evergreen 115 kV line Reconductoring (2018)
22. Vaca Dixon - Lakeville 230 kV Reconductoring (2018)
23. Stone 115 kV Back-tie Reconductor (2018)
24. Newark - Applied Materials 115 kV Substation Equipment Upgrade (2018)
25. Monta Vista - Los Altos 60 kV Reconductoring (2019)
26. Jefferson - Stanford #2 60 kV Line (2019)

27. North Tower 115 kV Looping Project (2019)
28. Potrero 115 kV Bus Upgrade (2019)
29. Ravenswood - Cooley Landing 115 kV Line Reconductor (2019)
30. South of San Mateo Capacity Increase (2019)
31. Monta Vista 230 kV Bus Upgrade (2019)
32. Metcalf - Piercy & Swift and Newark - Dixon Landing 115 kV Upgrade (2019)
33. East Shore - Oakland J 115 kV Reconductoring Project (2019)
34. San Mateo - Bair 60 kV Line Reconductor (2021)
35. Morgan Hill Area Reinforcement (2021)
36. Mountain View/Whisman - Monta Vista 115 kV Reconductoring (2024)
37. Del Monte - Fort Ord 60 kV Reinforcement Project – Phase 2 (2025)

Critical Contingency Analysis Summary

Oakland Sub-area

The critical contingency for the Oakland pocket is the loss of C-X #2 115 kV cable followed by the C-X #3 115 kV cable or vice versa. The area limitation is thermal overloading of the Moraga-Claremont #1 or #2 115 kV lines above their emergency rating. This limiting contingency establishes a local capacity need of 155 MW in 2024 (includes 49 MW of MUNI generation) as minimum capacity necessary for reliable load serving capability within this sub-area.

The critical single contingency for the Oakland pocket is the loss of either Moraga-Claremont #1 or #2 115 kV line with one of the Oakland CTs out of service. The area limitation is thermal overloading of the remaining Moraga-Claremont 115 kV lines above their emergency rating. This limiting contingency establishes a local capacity need of 151 MW in 2024 (includes 49 MW of MUNI generation).

The starting base case had the Oakland power plant off-line due to its over 40 years old status; however these studies prove the it will continue to be needed until a replacement power plant, additional resources or new transmission projects not approved at this time are in-service.

Effectiveness factors:

All units within this sub-area have the same effectiveness factor. Units outside of this sub-area are not effective.

Llagas Sub-area

The most critical contingency is an outage of Metcalf D-Morgan Hill 115 kV line followed by Spring 230/115 kV transformer or vice versa. The area limitation is thermal overload on the Morgan Hill-Llagas 115 kV Line. This limiting contingency establishes a local capacity need of 23 MW in 2024 (includes 0 MW of QF and MUNI generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area have the same effectiveness factor. Units outside of this sub-area are not effective.

San Jose Sub-area

The most critical contingency in the San Jose area is the Metcalf El Patio #1 or #2 overlapped with the outage of Metcalf-Evergreen #2 115 kV lines. The limiting element is the Metcalf - Piercy 115 kV line and establishes a local capacity 170 MW in 2024 (includes 271 MW of QF/MUNI generation) as minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The following table has units within the Bay Area that are at least 5% effective.

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
35863	CATALYST	1	20
36856	CCCA100	1	6
36854	Cogen	1	6
36854	Cogen	2	6
36863	DVRaGT1	1	6
36864	DVRbGT2	1	6
36865	DVRaST3	1	6
35860	OLS-AGNE	1	5

36858	Gia100	1	5
36859	Gia200	2	5
35854	LECEFGT1	1	5
35855	LECEFGT2	2	5
35856	LECEFGT3	3	5
35857	LECEFGT4	4	5

Pittsburg Sub-area

This sub-area is eliminated after the following projects are operational: Tesla-Pittsburg 230 kV Reconductoring, Moraga 230/115 kV Banks Replacement, Contra Costa-Moraga 230 kV Reconductoring and the Vaca Dixon-Lakeville 230 kV Reconductoring.

Contra Costa Sub-area

The most critical contingency is an outage of Kelso-Tesla 230 kV with Gateway out of service. The area limitation is thermal overloading of the Delta Switching Yard-Tesla 230 kV line. This limiting contingency establishes a LCR of 1509 MW in 2024 (includes 264 MW of MUNI pumps and 256 MW of wind generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

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

33178	RVEC_GEN	1	23
33131	GWF #1	1	22
32179	T222	1	18
32188	P0611G	1	18
32190	Q039	1	18
32186	P0609	1	18
32171	HIGHWND3	1	18
32177	Q0024	1	18
32168	ENXCO	2	18
32169	SOLANOWP	1	18
32172	HIGHWNDS	1	18
32176	SHILOH	1	18
33838	USWP_#3	1	18
32173	LAMBGT1	1	14
32174	GOOSEHGT	2	14
32175	CREEDGT1	3	14
35312	SEAWESTF	1	11
35316	ZOND SYS	1	11
35320	USW FRIC	1	11

Bay Area overall

The most critical contingency is the loss of the Tesla-Metcalf 500 kV with Delta Energy Center out of service. The area limitation is reactive margin. This limiting contingency establishes a local capacity need of 4133 MW in 2024 (includes 485 MW of QF, 278 MW of wind and 527 MW of MUNI generation) as the minimum capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

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

Changes compared to the 2019 results:

The load forecast went down by 19 MW and the LCR has decreased by 91 MW. Morgan Hill area reinforcement project significantly decreases the LCR need in the Llagas sub-area.

Bay Area Overall Requirements:

2024	Wind	QF/Selfgen	Muni	Market	New DG	Max. Qualifying

	(MW)	(MW)	(MW)	(MW)	(MW)	Capacity (MW)
Available generation	278	485	527	5589	149	7028

2024	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[13]	4133	0	4133
Category C (Multiple)[14]	4133	0	4133

6. Greater Fresno Area

<u>Area Definition</u>

The transmission facilities coming into the Greater Fresno area are:

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

The substations that delineate the Greater Fresno area are:

1) Gates is out Henrietta is in
2) Gates is out Henrietta is in
3) Gates is out Gregg is in
4) Gates 230 is out Gates 70 is in

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

[14] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

5) Mercy Spring 230 is out Mercy Spring 70 is in
6) Los Banos 230 is out Los Banos 70 is in
7) Los Banos 230 is out Los Banos 70 is in
8) Warnerville is out Wilson is in
9) Melones is out North Merced is in
10) Panoche is out Kearney is in
11) Panoche is out Helm is in
12) Panoche 230 is out Panoche 115 is in
13) Panoche 230 is out Panoche 115 is in
14) Corcoran is in Smyrna is out
15) Coalinga is in San Miguel is out

Total 2024 busload within the defined area: 3714 MW with 92 MW of losses resulting in total load + losses of 3806 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
AGRICO_6_PL3N5	34608	AGRICO	13.8	20.00	3	Wilson, Herndon		Market
AGRICO_7_UNIT	34608	AGRICO	13.8	43.05	2	Wilson, Herndon		Market
AGRICO_7_UNIT	34608	AGRICO	13.8	7.45	4	Wilson, Herndon		Market
AVENAL_6_AVPARK	34265	AVENAL P	12	0.00	1	Wilson	Energy Only	Market
AVENAL_6_SANDDG	34263	SANDDRAG	12	0.00	1	Wilson	Energy Only	Market
AVENAL_6_SUNCTY	34257	SUNCTY D	12	0.00	1	Wilson	Energy Only	Market
BALCHS_7_UNIT 1	34624	BALCH	13.2	33.00	1	Wilson, Herndon	Aug NQC	Market
BALCHS_7_UNIT 2	34612	BLCH	13.8	52.50	1	Wilson, Herndon	Aug NQC	Market
BALCHS_7_UNIT 3	34614	BLCH	13.8	52.50	1	Wilson, Herndon	Aug NQC	Market
BORDEN_2_QF	34253	BORDEN D	12.5	1.13	QF	Wilson	Aug NQC	QF/Selfgen
BULLRD_7_SAGNES	34213	BULLD 12	12.5	0.03	1	Wilson	Aug NQC	QF/Selfgen
CANTUA_1_SOLAR	34349	CANTUA_D	12.5	0.00	1	Wilson	Energy Only	Market
CANTUA_1_SOLAR	34349	CANTUA_D	12.5	0.00	2	Wilson	Energy Only	Market
CAPMAD_1_UNIT 1	34179	MADERA_G	13.8	17.00	1	Wilson		Market
CHEVCO_6_UNIT 1	34652	CHV.COAL	9.11	2.96	1	Wilson	Aug NQC	QF/Selfgen
CHEVCO_6_UNIT 2	34652	CHV.COAL	9.11	1.13	2	Wilson	Aug NQC	QF/Selfgen
CHWCHL_1_BIOMAS	34305	CHWCHLA2	13.8	8.87	1	Wilson, Herndon	Aug NQC	Market
CHWCHL_1_UNIT	34301	CHOWCOGN	13.8	48.00	1	Wilson, Herndon		Market
COLGA1_6_SHELLW	34654	COLNGAGN	9.11	35.25	1	Wilson	Aug NQC	QF/Selfgen
CRESSY_1_PARKER	34140	CRESSEY	115	1.60		Wilson	Not modeled Aug NQC	MUNI
CRNEVL_6_CRNVA	34634	CRANEVLY	12	0.71	1	Wilson, Borden	Aug NQC	Market
CRNEVL_6_SJQN 2	34631	SJ2GEN	9.11	3.20	1	Wilson, Borden	Aug NQC	Market
CRNEVL_6_SJQN 3	34633	SJ3GEN	9.11	4.20	1	Wilson, Borden	Aug NQC	Market
DINUBA_6_UNIT	34648	DINUBA E	13.8	9.87	1	Wilson, Herndon, Reedley		Market
ELNIDP_6_BIOMAS	34330	ELNIDO	13.8	6.09	1	Wilson	Aug NQC	Market
EXCHEC_7_UNIT 1	34306	EXCHQUER	13.8	61.77	1	Wilson	Aug NQC	MUNI
FRIANT_6_UNITS	34636	FRIANTDM	6.6	11.66	2	Wilson, Borden	Aug NQC	QF/Selfgen
FRIANT_6_UNITS	34636	FRIANTDM	6.6	6.23	3	Wilson, Borden	Aug NQC	QF/Selfgen
FRIANT_6_UNITS	34636	FRIANTDM	6.6	1.65	4	Wilson, Borden	Aug NQC	QF/Selfgen
GATES_6_PL1X2	34553	WHD_GAT2	13.8	0.00	1	Wilson		Market
GUERNS_6_SOLAR	34461	GUERNSEY	12.5	8.14	1	Wilson	Aug NQC	Market

GUERNS_6_SOLAR	34461	GUERNSEY	12.5	8.14	2	Wilson	Aug NQC	Market
GWFPWR_1_UNITS	34431	GWF_HEP1	13.8	42.20	1	Wilson, Herndon, Hanford		Market
GWFPWR_1_UNITS	34433	GWF_HEP2	13.8	42.20	1	Wilson, Herndon, Hanford		Market
HAASPH_7_PL1X2	34610	HAAS	13.8	68.15	1	Wilson, Herndon	Aug NQC	Market
HAASPH_7_PL1X2	34610	HAAS	13.8	68.15	2	Wilson, Herndon	Aug NQC	Market
HELMPG_7_UNIT 1	34600	HELMS	18	404.00	1	Wilson	Aug NQC	Market
HELMPG_7_UNIT 2	34602	HELMS	18	404.00	2	Wilson	Aug NQC	Market
HELMPG_7_UNIT 3	34604	HELMS	18	404.00	3	Wilson	Aug NQC	Market
HENRTA_6_UNITA1	34539	GWF_GT1	13.8	45.33	1	Wilson		Market
HENRTA_6_UNITA2	34541	GWF_GT2	13.8	45.23	1	Wilson		Market
HURON_6_SOLAR	34557	HURON_DI	12.5	0.00	1	Wilson	Energy Only	Market
HURON_6_SOLAR	34557	HURON_DI	12.5	0.00	2	Wilson	Energy Only	Market
INTTRB_6_UNIT	34342	INT.TURB	9.11	3.20	1	Wilson	Aug NQC	QF/Selfgen
KERKH1_7_UNIT 1	34344	KERCK1-1	6.6	13.00	1	Wilson, Herndon	Aug NQC	Market
KERKH1_7_UNIT 3	34345	KERCK1-3	6.6	12.80	3	Wilson, Herndon	Aug NQC	Market
KERKH2_7_UNIT 1	34308	KERCKHOF	13.8	153.90	1	Wilson, Herndon	Aug NQC	Market
KINGCO_1_KINGBR	34642	KINGSBUR	9.11	28.35	1	Wilson, Herndon, Hanford	Aug NQC	QF/Selfgen
KINGRV_7_UNIT 1	34616	KINGSRIV	13.8	51.20	1	Wilson, Herndon	Aug NQC	Market
MALAGA_1_PL1X2	34671	KRCDPCT1	13.8	48.00	1	Wilson, Herndon		Market
MALAGA_1_PL1X2	34672	KRCDPCT2	13.8	48.00	1	Wilson, Herndon		Market
MCCALL_1_QF	34219	MCCALL 4	12.5	0.52	QF	Wilson, Herndon	Aug NQC	QF/Selfgen
MCSWAN_6_UNITS	34320	MCSWAIN	9.11	6.72	1	Wilson	Aug NQC	MUNI
MENBIO_6_RENEW1	34339	CALRENEW	12.5	0.00	1	Wilson	Energy Only	Market
MENBIO_6_UNIT	34334	BIO PWR	9.11	20.24	1	Wilson	Aug NQC	QF/Selfgen
MERCFL_6_UNIT	34322	MERCEDFL	9.11	2.82	1	Wilson	Aug NQC	Market
PINFLT_7_UNITS	38720	PINEFLAT	13.8	21.75	1	Wilson, Herndon	Aug NQC	MUNI
PINFLT_7_UNITS	38720	PINEFLAT	13.8	21.75	2	Wilson, Herndon	Aug NQC	MUNI
PINFLT_7_UNITS	38720	PINEFLAT	13.8	21.75	3	Wilson, Herndon	Aug NQC	MUNI
PNCHPP_1_PL1X2	34328	STARGT1	13.8	55.58	1	Wilson		Market
PNCHPP_1_PL1X2	34329	STARGT2	13.8	55.58	1	Wilson		Market
PNOCHE_1_PL1X2	34142	WHD_PAN2	13.8	49.97	1	Wilson, Herndon		Market
PNOCHE_1_UNITA1	34186	DG_PAN1	13.8	48.00	1	Wilson		Market
SCHNDR_1_FIVPTS	34353	SCHINDLE	12.5	0.00	1	Wilson	Energy Only	Market
SCHNDR_1_FIVPTS	34353	SCHINDLE	12.5	0.00	2	Wilson	Energy Only	Market
SCHNDR_1_WSTSDE	34353	SCHINDLE	12.5	0.00	3	Wilson	Energy Only	Market
SCHNDR_1_WSTSDE	34353	SCHINDLE	12.5	0.00	4	Wilson	Energy Only	Market
SGREGY_6_SANGER	34646	SANGERCO	13.8	28.13	1	Wilson	Aug NQC	QF/Selfgen
STOREY_7_MDRCHW	34209	STOREY D	12.5	0.91	1	Wilson	Aug NQC	QF/Selfgen
STROUD_6_SOLAR	34563	STROUD_D	12.5	0.00	1	Wilson	Energy Only	Market
STROUD_6_SOLAR	34563	STROUD_D	12.5	0.00	2	Wilson	Energy Only	Market
ULTPFR_1_UNIT 1	34640	ULTR.PWR	9.11	21.79	1	Wilson, Herndon	Aug NQC	QF/Selfgen
WAUKNA_1_SOLAR				0.00		Wilson, Herndon, Hanford	Energy Only	Market
WFRESN_1_SOLAR				0.00		Wilson	Energy Only	Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	1	Wilson, Borden	Aug NQC	Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	2	Wilson, Borden	Aug NQC	Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	3	Wilson, Borden	Aug NQC	Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	4	Wilson, Borden	Aug NQC	Market
WISHON_6_UNITS	34658	WISHON	2.3	0.36	5	Wilson, Borden	Aug NQC	Market
WRGHTP_7_AMENGY	24207	WRIGHT D	12.5	0.46	QF	Wilson	Aug NQC	QF/Selfgen
JRWOOD_1_UNIT 1	34332	JRWCOGEN	9.11	7.80	1	Wilson		QF/Selfgen
KERKH1_7_UNIT 2	34343	KERCK1-2	6.6	8.50	2	Wilson, Herndon	Aug NQC	Market
NA	34485	FRESNOWW	12.5	4.00	1	Wilson	No NQC - hist. data	QF/Selfgen
NA	34485	FRESNOWW	12.5	4.00	2	Wilson	No NQC - hist. data	QF/Selfgen
NA	34485	FRESNOWW	12.5	1.00	3	Wilson	No NQC - hist. data	QF/Selfgen

ONLLPP_6_UNIT 1	34316	ONEILPMP	9.11	0.50	1	Wilson	No NQC - hist. data	MUNI
New Unit	34603	JGBSWLT	12.5	0.00	ST	Wilson	Energy Only	Market
New Unit	34675	RpsCA_34	21	19.75	1	Wilson, Herndon, Hanford	No NQC - Pmax	Market
New Unit	34677	RpsCA_05	21	19.75	1	Wilson, Herndon, Hanford	No NQC - Pmax	Market
New Unit	34696	CORCORAN	21	20.00	1	Wilson, Herndon, Hanford	No NQC - Pmax	Market
New Unit	34311	RpsCA_47	0.48	60.00	1	Wilson	No NQC - Pmax	Market
New Unit	34646	SANGERCO	13.8	12.50	2	Wilson	No NQC - Pmax	Market
New Unit	34666	KANSAS	12.5	20.00	F	Wilson	No NQC - Pmax	Market
New Unit	34679	RpsCA_44	0.34	101.70	1	Wilson, Herndon, Hanford	No NQC - Pmax	Market

Projects modeled:

1. Fresno Reliability (stages: 2014, 2015, 2016, 2016)
2. Shepherd Substation Interconnection (2015)
3. Cressey - Gallo 115 kV Line (2016)
4. Lemoore 70 kV Disconnect Switches Replacement (2016)
5. Kearney 230/70 kV Transformer Addition (2017)
6. Kearney - Caruthers 70 kV Line Reconductor (2017)
7. Caruthers - Kingsburg 70 kV Line Reconductor (2017)
8. Reedley-Dinuba 70 kV Line Reconductor (2017)
9. Reedley-Orosi 70 kV Line Reconductor (2017)
10. Helm - Kerman 70 kV Line Reconductor (2017)
11. Ashlan - Gregg and Ashlan - Herndon 230 kV Line Reconductor (2017)
12. Oakhurst/Coarsegold UVLS (2017)
13. Gregg - Herndon #2 230 kV Line Circuit Breaker Upgrade (2017)
14. Los Banos - Livingston Jct - Canal 70 kV Switch Replacement (2017)
15. Warnerville - Bellota 230 kV Line Reconductoring (2017)
16. Gates No. 2 500/230 kV Transformer (2018)
17. Series Reactor on Warnerville-Wilson 230 kV Line (2018)
18. Reedley 70 kV Reinforcement (2018)
19. Reedley 115/70 kV Transformer Capacity Increase (2018)
20. Cressey - North Merced 115 kV Line Addition (2018)
21. Kearney - Kerman 70 kV Line Reconductor (2018)
22. Kearney - Herndon 230kV Line Reconductor (2019)

23. McCall - Reedley #2 115 kV Line (2019)
24. Oro Loma - Mendota 115 kV Conversion Project (2019)
25. Wilson 115 kV Area Reinforcement (2019)
26. Borden 230 kV Voltage Support (2019)
27. Northern Fresno 115 kV Area Reinforcement (2020)
28. Kerchhoff PH #2 - Oakhurst 115 kV Line (2020)
29. Oro Loma 70 kV Area Reinforcement (2020)
30. Wilson - Le Grand 115 kV line reconductoring (2021)
31. New Gates - Gregg 230 kV Line (2023)
32. Woodward 115 kV Reinforcement (2024)

Critical Contingency Analysis Summary

Hanford Sub-area

The most critical contingency for the Hanford sub-area is the loss of the McCall-Kingsburg #2 115 kV line followed by Henrietta-GWF 115 kV line or vice versa, which would thermally overload the McCall-Kingsburg #1115 kV line. This limiting contingency establishes a local capacity need of 63 MW (including 28 MW of QF generation) in 2024 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Reedley Sub-area

No requirements due to the McCall-Reedley # 2 115 kV line project.

Herndon Sub-area

This sub-area has been eliminated due to the new E2 substation that loops the Helms-Gregg #1 & #2 230kV lines and now injects Helms generation into Sanger, eliminating the need for this sub-area.

Borden Sub-area

The most critical contingency for the Borden sub-area is the loss of the Friant-Coppermine 70 kV line followed by the loss of Borden # 4 230/70 kV transformer or vice versa, which would thermally overload the Borden #1 230/70 kV transformer. This limiting contingency establishes a local capacity need of 83 MW (including 20 MW of QF generation as well as 31 MW of deficiency) in 2024 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency for the Borden sub-area is the loss of the Borden #4 230/70 kV transformer, which would thermally overload the Borden #1 70 kV transformer. This limiting contingency establishes a local capacity need of 63 MW (including 20 MW of QF generation as well as 11 MW of deficiency) in 2024.

Effectiveness factors:

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

Wilson Sub-area

The most critical contingency for the Wilson sub-area is the loss of the Dairyland-Le Grand 115 kV line followed by Panoche-Mendota 115 kV line or vice versa, which would thermally overload the Panoche Junction-Hummons section of the Panoche-Oro Loma 115 kV line. This limiting contingency establishes a local capacity need of 2182 MW in 2024 (includes 180 MW of QF and 136 MW of Muni generation) as the generation capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency is the loss of Dairyland-Le Grand 115 kV line with Exchequer unit out of service. This limiting contingency establishes a local capacity need of 1471 MW in 2024 (includes 180 MW of QF and 136 MW of Muni generation).

Effectiveness factors:

The following table has units within Fresno that are at least 5% effective.

Gen No	Gen Name	ID	DFAX

34330	ELNIDO	1	15%
34322	MERCEDFL	1	13%
34301	CHOWCOGN	1	11%
34305	CHWCHLA2	1	11%
34602	HELMS 2	1	11%
34604	HELMS 3	1	11%
34658	WISHON	1	11%
34658	WISHON	2	11%
34658	WISHON	3	11%
34658	WISHON	4	11%
34658	WISHON	SJ	11%
34600	HELMS 1	1	11%
34631	SJ2GEN	1	11%
34308	KERCKHOF	1	11%
34344	KERCKHOF	1	11%
34344	KERCKHOF	2	11%
34344	KERCKHOF	3	11%
34634	CRANEVLY	1	11%
34633	SJ3GEN	1	11%
34624	BALCH 1	1	8%
34616	KINGSRIV	1	8%
34648	DINUBA E	1	7%
34671	KRCDPCT1	1	7%
34672	KRCDPCT2	1	7%
34612	BLCH 2-2	1	5%
34614	BLCH 2-3	1	5%
34610	HAAS	1	5%
34610	HAAS	2	5%

Additional helpful effectiveness factors for Fresno area:

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

Changes compared to the 2019 results:

Overall the load forecast went up by 548 MW and the LCR need has increased by 624 MW. A few new transmission projects have been modeled including the new Gates-Gregg 230 kV line. One sub-area has been eliminated and a new sub-area has been created. 41 new DG resources have been modeled along with a few new transmission connected resources for a total increase of 630 MW of potential additional capacity.

Fresno Area Overall Requirements:

2024	QF/Selfgen (MW)	Muni (MW)	Market (MW)	New DG (MW)	Max. Qualifying Capacity (MW)
Available generation	180	136	2666	496	3478

2024	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single) [15]	1471	11	1482
Category C (Multiple) [16]	2182	31	2213

7. Kern Area

Area Definition

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

1) Kern-7th Standard 115 kV line
2) Kern-Live Oak 115 kV line
3) Kern-Magunden-Witco 115 kV line
4) Charca-Famoso 115kV (Normal Open)

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

1) Kern is out 7th Standard is in
2) Kern is out Live Oak is in
3) Kern and Magunden are out Witco is in
4) Charca is out Famoso is in

Total 2024 busload within the defined area: 254 MW with 1 MW of losses resulting in total load + losses of 255 MW.

Total units and qualifying capacity available in this Kern PP sub-area:

[15] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.
[16] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
DEXZEL_1_UNIT	35024	DEXEL +	9.11	27.89	1	South Kern PP	Aug NQC	QF/Selfgen
DISCOV_1_CHEVRN	35062	DISCOVRY	9.11	3.01	1	South Kern PP	Aug NQC	QF/Selfgen
LIVOAK_1_UNIT 1	35058	PSE-LVOK	9.11	44.18	1	South Kern PP	Aug NQC	QF/Selfgen
MTNPOS_1_UNIT	35036	MT POSO	9.11	18.61	1	South Kern PP	Aug NQC	QF/Selfgen
OILDAL_1_UNIT 1	35028	OILDALE	9.11	38.34	1	South Kern PP	Aug NQC	QF/Selfgen
ULTOGL_1_POSO	35035	ULTR PWR	9.11	33.37	1	South Kern PP	Aug NQC	QF/Selfgen
VEDDER_1_SEKERN	35046	SEKR	9.11	13.86	1	South Kern PP	Aug NQC	QF/Selfgen

Projects modeled:

1. Kern - Old River 70 kV No.2 Reconductoring (2016)
2. San Bernard - Tejon 70 kV Line Reconductor (2017)
3. Kern PP 115 kV Area Reinforcement (2018)
4. Taft - Maricopa 70 kV Line Reconductor (2018)
5. Semitropic - Midway 115 kV Line Reconductor (2018)
6. Taft 115/70 kV Transformer #2 Replacement (2018)
7. Wheeler Ridge Voltage Support (2018)
8. Wheeler Ridge - Weedpatch 70 kV Line Reconductor (2018)
9. Kern PP 230 kV Area Reinforcement (2019)
10. Wheeler Ridge Junction Substation (2021)

<u>Critical Contingency Analysis Summary</u>

West Park Sub-area

No requirements due to the Wheeler Ridge Junction substation and reconductoring of Kern PP - West Park 115 kV lines.

South Kern PP Sub-area

The most critical contingency is the outage of Kern-Magunden-Witco 115 kV line overlapping with Kern-7th Standard 115 kV line, which could thermally overload the Kern-Live Oak 115 kV line. This limiting contingency establishes a LCR of 154 MW in 2024 (includes 179 MW of QF generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency is the loss of Kern-Magunden-Witco 115 kV line with PSE Live Oak generation out of service. This limiting contingency establishes a local capacity requirement of 150 MW in 2024 (includes 179 MW of QF generation).

Effectiveness factors:

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

Changes compared to the 2019 results:

Overall the load went down by 490 MW, the maximum qualifying capacity went down by 50 MW and the LCR requirement have gone down by 39 MW mostly due to area redefinition caused by a new transmission projects in the area.

Kern Area Overall Requirements:

2024	QF/Selfgen (MW)	Market (MW)	New DG (MW)	Max. Qualifying Capacity (MW)
Available generation	179	0	83	262

2024	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single) [17]	150	0	150
Category C (Multiple) [18]	154	0	154

8. LA Basin Area

<u>Area Definition</u>

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

[18] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

The transmission tie lines into the LA Basin Area are:

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

The substations that delineate the LA Basin Area are:

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

Total 2024 busload within the defined area is 20,547 MW (includes 21,754 MW of forecasted demand as well as 1,077 MW of AAEE and 130 MW of LTPP EE), with 550 MW of losses and 30 MW pumps resulting in total load + losses + pumps of 21,127 MW.

The geographical representation of this local area does not match the electrical representation due to Saugus substation being included in the LA Basin geographical representation and not in Big Creek/Ventura. The geographical load is provided here to provide comparable comparison to the CEC demand forecast, which is based on the geographical representation of the LA Basin. The total load within the geographical defined area is 21,444 MW (includes 22,721 MW of forecasted demand as well as 1,147 MW of AAEE and 130 MW of LTPP EE) with 550 MW of losses and 30 MW pumps resulting in total load + losses + pumps of 22,024 MW.

Total units and qualifying capacity available in the LA Basin area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ANAHM_2_CANYN1	25211	CanyonGT 1	13.8	49.40	1	Western		MUNI
ANAHM_2_CANYN2	25212	CanyonGT 2	13.8	48.00	2	Western		MUNI
ANAHM_2_CANYN3	25213	CanyonGT 3	13.8	48.00	3	Western		MUNI
ANAHM_2_CANYN4	25214	CanyonGT 4	13.8	49.40	4	Western		MUNI
ANAHM_7_CT	25208	DowlingCTG	13.8	40.64	1	Western	Aug NQC	MUNI
ARCOGN_2_UNITS	24011	ARCO 1G	13.8	54.98	1	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24012	ARCO 2G	13.8	54.98	2	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24013	ARCO 3G	13.8	54.98	3	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24014	ARCO 4G	13.8	54.98	4	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24163	ARCO 5G	13.8	27.49	5	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24164	ARCO 6G	13.8	27.50	6	Western	Aug NQC	QF/Selfgen
BARRE_2_QF	24016	BARRE	230	0.00		Western	Not modeled	QF/Selfgen
BARRE_6_PEAKER	29309	BARPKGEN	13.8	47.00	1	Western		Market
BLAST_1_WIND	24839	BLAST	115	8.55	1	Eastern, Valley-Devers	Aug NQC	Wind
BRDWAY_7_UNIT 3	29007	BRODWYSC	13.8	65.00	1	Western		MUNI
BUCKWD_1_NPALM1	25634	BUCKWIND	115	1.95		Eastern, Valley-Devers	Not modeled Aug NQC	Wind
BUCKWD_1_QF	25634	BUCKWIND	115	2.53	QF	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
BUCKWD_7_WINTCV	25634	BUCKWIND	115	0.15	W5	Eastern, Valley-Devers	Aug NQC	Wind
CABZON_1_WINDA1	29290	CABAZON	33	11.34	1	Eastern, Valley-Devers	Aug NQC	Wind
CENTER_2_QF	24203	CENTER S	66	18.97		Western	Not modeled Aug NQC	QF/Selfgen
CENTER_2_RHONDO	24203	CENTER S	66	1.91		Western	Not modeled	QF/Selfgen
CENTER_6_PEAKER	29308	CTRPKGEN	13.8	47.00	1	Western		Market
CENTRY_6_PL1X4	25302	CLTNCTRY	13.8	36.00	1	Eastern, Eastern Metro	Aug NQC	MUNI
CHEVMN_2_UNITS	24022	CHEVGEN1	13.8	0.00	1	Western, El Nido	Aug NQC	QF/Selfgen
CHEVMN_2_UNITS	24023	CHEVGEN2	13.8	0.00	2	Western, El Nido	Aug NQC	QF/Selfgen
CHINO_2_QF	24024	CHINO	66	5.99		Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
CHINO_2_SOLAR	24024	CHINO	66	0.00		Eastern, Eastern Metro	Not modeled Energy Only	Market
CHINO_6_CIMGEN	24026	CIMGEN	13.8	26.10	D1	Eastern, Eastern Metro	Aug NQC	QF/Selfgen
CHINO_6_SMPPAP	24140	SIMPSON	13.8	29.34	D1	Eastern, Eastern Metro	Aug NQC	QF/Selfgen
CHINO_7_MILIKN	24024	CHINO	66	1.41		Eastern, Eastern Metro	Not modeled Aug NQC	Market
COLTON_6_AGUAM1	25303	CLTNAGUA	13.8	43.00	1	Eastern, Eastern Metro	Aug NQC	MUNI
CORONS_2_SOLAR				0.00		Eastern, Eastern Metro	Not modeled Energy Only	Market
CORONS_6_CLRWTR	24210	MIRALOMA	66	14.00		Eastern, Eastern	Not modeled	MUNI

						Metro		
CORONS_6_CLRWTR	24210	MIRALOMA	66	14.00		Eastern, Eastern Metro	Not modeled	MUNI
DELAMO_2_SOLRC1				0.00		Western	Not modeled Energy Only	Market
DELAMO_2_SOLRD				0.00		Western	Not modeled Energy Only	Market
DEVERS_1_QF	24815	GARNET	115	2.08	QF	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25632	TERAWND	115	4.05	QF	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25633	CAPWIND	115	0.77	QF	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25635	ALTWIND	115	1.86	Q1	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25635	ALTWIND	115	3.45	Q2	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	0.81	Q1	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	0.37	W1	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25637	TRANWIND	115	9.19	QF	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25639	SEAWIND	115	2.77	QF	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25645	VENWIND	115	2.11	EU	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25645	VENWIND	115	4.93	Q1	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25645	VENWIND	115	3.32	Q2	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25646	SANWIND	115	1.11	Q1	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_SEPV05				0.00		Eastern, Valley-Devers	Energy Only	Market
DMDVLY_1_UNITS	25425	ESRP P2	6.9	7.25		Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
DREWS_6_PL1X4	25301	CLTNDREW	13.8	36.00	1	Eastern, Eastern Metro	Aug NQC	MUNI
DVLCYN_1_UNITS	25603	DVLCYN3G	13.8	67.15	3	Eastern, Eastern Metro	Aug NQC	MUNI
DVLCYN_1_UNITS	25604	DVLCYN4G	13.8	67.14	4	Eastern, Eastern Metro	Aug NQC	MUNI
DVLCYN_1_UNITS	25648	DVLCYN1G	13.8	50.34	1	Eastern, Eastern Metro	Aug NQC	MUNI
DVLCYN_1_UNITS	25649	DVLCYN2G	13.8	50.34	2	Eastern, Eastern Metro	Aug NQC	MUNI
ELLIS_2_QF	24197	ELLIS	66	0.00		Western	Not modeled Aug NQC	QF/Selfgen
ELSEGN_2_UN1011	28903	ELSEG6ST	18	68	6	Western, El Nido	Aug NQC	Market
ELSEGN_2_UN1011	28904	ELSEG5ST	18	195	5	Western, El Nido	Aug NQC	Market
ELSEGN_2_UN2021	28901	ELSEG8ST	18	68.68	8	Western, El Nido	Aug NQC	Market
ELSEGN_2_UN2021	28902	ELSEG7GT	18	195	7	Western, El Nido	Aug NQC	Market
ETIWND_2_FONTNA	24055	ETIWANDA	66	1.03		Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
ETIWND_2_QF	24055	ETIWANDA	66	15.24		Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
ETIWND_6_GRPLND	29305	ETWPKGEN	13.8	46.00	1	Eastern, Eastern Metro		Market

ETIWND_6_MWDETI	25422	ETI MWDG	13.8	9.13	1	Eastern, Eastern Metro	Aug NQC	Market
ETIWND_7_MIDVLY	24055	ETIWANDA	66	1.55		Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
GARNET_1_SOLAR	24815	GARNET	115	0.00		Eastern, Valley-Devers	Not modeled Energy Only	Market
GARNET_1_UNITS	24815	GARNET	115	1.29	G1	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
GARNET_1_UNITS	24815	GARNET	115	0.45	G2	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
GARNET_1_UNITS	24815	GARNET	115	0.93	G3	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
GARNET_1_WIND	24815	GARNET	115	0.38	PC	Eastern, Valley-Devers	Aug NQC	Wind
GARNET_1_WINDS	24815	GARNET	115	1.80	W2	Eastern, Valley-Devers	Aug NQC	Wind
GARNET_1_WINDS	24815	GARNET	115	1.80	W3	Eastern, Valley-Devers	Aug NQC	Wind
GARNET_1_WT3WND	24815	GARNET	115	0.00		Eastern, Valley-Devers	Not modeled Energy Only	Market
GLNARM_7_UNIT 1	29005	PASADNA1	13.8	22.07	1	Western		MUNI
GLNARM_7_UNIT 2	29006	PASADNA2	13.8	22.30	1	Western		MUNI
GLNARM_7_UNIT 3	29005	PASADNA1	13.8	44.83		Western	Not modeled	MUNI
GLNARM_7_UNIT 4	29006	PASADNA2	13.8	42.42		Western	Not modeled	MUNI
HARBGN_7_UNITS	24062	HARBOR G	13.8	76.28	1	Western		Market
HARBGN_7_UNITS	24062	HARBOR G	13.8	11.86	HP	Western		Market
HARBGN_7_UNITS	25510	HARBORG4	4.16	11.86	LP	Western		Market
HINSON_6_CARBGN	24020	CARBOGEN	13.8	29.00	1	Western	Aug NQC	Market
HINSON_6_SERRGN	24139	SERRFGEN	13.8	28.26	D1	Western	Aug NQC	QF/Selfgen
INDIGO_1_UNIT 1	29190	WINTECX2	13.8	42.00	1	Eastern, Valley-Devers		Market
INDIGO_1_UNIT 2	29191	WINTECX1	13.8	42.00	1	Eastern, Valley-Devers		Market
INDIGO_1_UNIT 3	29180	WINTEC8	13.8	42.00	1	Eastern, Valley-Devers		Market
INLDEM_5_UNIT 1	29041	IEEC-G1	19.5	335.00	1	Eastern, Valley, Valley-Devers	Aug NQC	Market
INLDEM_5_UNIT 2	29042	IEEC-G2	19.5	335.00	1	Eastern, Valley, Valley-Devers	Aug NQC	Market
JOHANN_6_QFA1	24072	JOHANNA	230	0.01		Western	Not modeled Aug NQC	QF/Selfgen
LACIEN_2_VENICE	24337	VENICE	13.8	4.54	1	Western, El Nido	Aug NQC	MUNI
LAFRES_6_QF	24073	LA FRESA	66	1.44		Western, El Nido	Not modeled Aug NQC	QF/Selfgen
LAGBEL_6_QF	24075	LAGUBELL	66	9.82		Western	Not modeled Aug NQC	QF/Selfgen
LGHTHP_6_ICEGEN	24070	ICEGEN	13.8	47.61	1	Western	Aug NQC	QF/Selfgen
LGHTHP_6_QF	24083	LITEHIPE	66	0.78		Western	Not modeled Aug NQC	QF/Selfgen
MESAS_2_QF	24209	MESA CAL	66	0.70		Western	Not modeled Aug NQC	QF/Selfgen
MIRLOM_2_CORONA				2.49		Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
MIRLOM_2_ONTARO				0.00		Eastern, Eastern Metro	Energy Only	Market
MIRLOM_2_TEMESC				2.60		Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
MIRLOM_6_DELGEN	24030	DELGEN	13.8	30.83	1	Eastern, Eastern Metro	Aug NQC	QF/Selfgen

MIRLOM_6_PEAKER	29307	MRLPKGEN	13.8	46.00	1	Eastern, Eastern Metro		Market
MIRLOM_7_MWDLKM	24210	MIRALOMA	66	5.00		Eastern, Eastern Metro	Not modeled Aug NQC	MUNI
MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	4.66	1	Eastern, Eastern Metro	Aug NQC	Market
MOJAVE_1_SIPHON	25658	MJVSPHN1	13.8	4.67	2	Eastern, Eastern Metro	Aug NQC	Market
MOJAVE_1_SIPHON	25659	MJVSPHN1	13.8	4.67	3	Eastern, Eastern Metro	Aug NQC	Market
MTWIND_1_UNIT 1	29060	MOUNTWND	115	8.29	S1	Eastern, Valley-Devers	Aug NQC	Wind
MTWIND_1_UNIT 2	29060	MOUNTWND	115	3.10	S2	Eastern, Valley-Devers	Aug NQC	Wind
MTWIND_1_UNIT 3	29060	MOUNTWND	115	4.23	S3	Eastern, Valley-Devers	Aug NQC	Wind
OLINDA_2_COYCRK	24211	OLINDA	66	3.13		Western	Not modeled	QF/Selfgen
OLINDA_2_LNDFL2	24211	OLINDA	66	27.19		Western	Not modeled	Market
OLINDA_2_QF	24211	OLINDA	66	0.16	1	Western	Aug NQC	QF/Selfgen
OLINDA_7_LNDFIL	24211	OLINDA	66	4.09		Western	Not modeled Aug NQC	QF/Selfgen
PADUA_2_ONTARO	24111	PADUA	66	0.89		Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
PADUA_6_MWDSDM	24111	PADUA	66	4.13		Eastern, Eastern Metro	Not modeled Aug NQC	MUNI
PADUA_6_QF	24111	PADUA	66	0.68		Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
PADUA_7_SDIMAS	24111	PADUA	66	1.05		Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
PANSEA_1_PANARO	25640	PANAERO	115	4.21	QF	Eastern, Valley-Devers	Aug NQC	Wind
PWEST_1_UNIT				0.06		Western	Not modeled Aug NQC	Market
RENWD_1_QF	25636	RENWIND	115	1.74	Q2	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
RHONDO_2_QF	24213	RIOHONDO	66	2.51		Western	Not modeled Aug NQC	QF/Selfgen
RHONDO_6_PUENTE	24213	RIOHONDO	66	0.00		Western	Not modeled Aug NQC	Market
RVSIDE_2_RERCU3	24299	RERC2G3	13.8	48.50	1	Eastern, Eastern Metro		MUNI
RVSIDE_2_RERCU4	24300	RERC2G4	13.8	48.50	1	Eastern, Eastern Metro		MUNI
RVSIDE_6_RERCU1	24242	RERC1G	13.8	48.35	1	Eastern, Eastern Metro		MUNI
RVSIDE_6_RERCU2	24243	RERC2G	13.8	48.50	1	Eastern, Eastern Metro		MUNI
RVSIDE_6_SPRING	24244	SPRINGEN	13.8	36.00	1	Eastern, Eastern Metro		Market
SANTGO_6_COYOTE	24133	SANTIAGO	66	6.26	1	Western	Aug NQC	Market
SANWD_1_QF	25646	SANWIND	115	4.48	Q2	Eastern, Valley-Devers	Aug NQC	Wind
SBERDO_2_PSP3	24921	MNTV-CT1	18	129.71	1	Eastern, West of Devers, Eastern Metro		Market
SBERDO_2_PSP3	24922	MNTV-CT2	18	129.71	1	Eastern, West of Devers, Eastern Metro		Market

SBERDO_2_PSP3	24923	MNTV-ST1	18	225.08	1	Eastern, West of Devers, Eastern Metro		Market
SBERDO_2_PSP4	24924	MNTV-CT3	18	129.71	1	Eastern, West of Devers, Eastern Metro		Market
SBERDO_2_PSP4	24925	MNTV-CT4	18	129.71	1	Eastern, West of Devers, Eastern Metro		Market
SBERDO_2_PSP4	24926	MNTV-ST2	18	225.08	1	Eastern, West of Devers, Eastern Metro		Market
SBERDO_2_QF	24214	SANBRDNO	66	0.09		Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
SBERDO_2_REDLND	24214	SANBRDNO	66	0.00		Eastern, West of Devers, Eastern Metro	Energy Only	Market
SBERDO_2_SNTANA	24214	SANBRDNO	66	0.61		Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
SBERDO_6_MILLCK	24214	SANBRDNO	66	2.27		Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
SENTNL_2_CTG1	29101	TOT032G1	13.8	91	1	Eastern, Valley-Devers		Market
SENTNL_2_CTG2	29102	TOT032G2	13.8	91	1	Eastern, Valley-Devers		Market
SENTNL_2_CTG3	29103	TOT032G3	13.8	91	1	Eastern, Valley-Devers		Market
SENTNL_2_CTG4	29104	TOT032G4	13.8	91	1	Eastern, Valley-Devers		Market
SENTNL_2_CTG5	29105	TOT032G5	13.8	91	1	Eastern, Valley-Devers		Market
SENTNL_2_CTG6	29106	TOT032G6	13.8	91	1	Eastern, Valley-Devers		Market
SENTNL_2_CTG7	29107	TOT032G7	13.8	91	1	Eastern, Valley-Devers		Market
SENTNL_2_CTG8	29108	TOT032G8	13.8	91	1	Eastern, Valley-Devers		Market
TIFFNY_1_DILLON				8.48		Western	Not modeled Aug NQC	Wind
VALLEY_5_PERRIS	24160	VALLEYSC	115	7.94		Eastern, Valley, Valley-Devers	Not modeled Aug NQC	QF/Selfgen
VALLEY_5_REDMTN	24160	VALLEYSC	115	3.22		Eastern, Valley, Valley-Devers	Not modeled Aug NQC	QF/Selfgen
VALLEY_7_BADLND	24160	VALLEYSC	115	0.76		Eastern, Valley, Valley-Devers	Not modeled Aug NQC	Market
VALLEY_7_UNITA1	24160	VALLEYSC	115	1.45		Eastern, Valley, Valley-Devers	Not modeled Aug NQC	Market
VERNON_6_GONZL1				5.75		Western	Not modeled	MUNI
VERNON_6_GONZL2				5.75		Western	Not modeled	MUNI
VERNON_6_MALBRG	24239	MALBRG1G	13.8	42.37	C1	Western		MUNI
VERNON_6_MALBRG	24240	MALBRG2G	13.8	42.37	C2	Western		MUNI
VERNON_6_MALBRG	24241	MALBRG3G	13.8	49.26	S3	Western		MUNI
VILLPK_2_VALLYV	24216	VILLA PK	66	4.10		Western	Not modeled Aug NQC	QF/Selfgen
VILLPK_6_MWDYOR	24216	VILLA PK	66	0.00		Western	Not modeled Aug NQC	MUNI
VISTA_2_RIALTO	24901	VSTA	230	0.00		Eastern, Eastern	Energy Only	Market

						Metro		
VISTA_6_QF	24902	VSTA	66	0.18	1	Eastern, Eastern Metro	Aug NQC	QF/Selfgen
WALCRK_2_CTG1	29201	EME WCG1	13.8	96	1	Western		Market
WALCRK_2_CTG2	29202	EME WCG2	13.8	96	1	Western		Market
WALCRK_2_CTG3	29203	EME WCG3	13.8	96	1	Western		Market
WALCRK_2_CTG4	29204	EME WCG4	13.8	96	1	Western		Market
WALCRK_2_CTG5	29205	EME WCG5	13.8	96	1	Western		Market
WALNUT_7_WCOVCT	24157	WALNUT	66	2.16		Western	Not modeled Aug NQC	Market
WALNUT_7_WCOVST	24157	WALNUT	66	4.42		Western	Not modeled Aug NQC	Market
WHTWTR_1_WINDA1	29061	WHITEWTR	33	9.83	1	Eastern, Valley-Devers	Aug NQC	Wind
ARCOGN_2_UNITS	24018	BRIGEN	13.8	0.00	1	Western	No NQC - hist. data	Market
HINSON_6_QF	24064	HINSON	66	0.00	1	Western	No NQC - hist. data	QF/Selfgen
INLAND_6_UNIT	24071	INLAND	13.8	30.30	1	Eastern, Eastern Metro	No NQC - hist. data	QF/Selfgen
MOBGEN_6_UNIT 1	24094	MOBGEN	13.8	20.20	1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24063	HILLGEN	13.8	0.00	D1	Western	No NQC - hist. data	QF/Selfgen
NA	24324	SANIGEN	13.8	6.80	D1	Eastern, Eastern Metro	No NQC - hist. data	QF/Selfgen
NA	24325	ORCOGEN	13.8	0.00	1	Western	No NQC - hist. data	QF/Selfgen
NA	24327	THUMSGEN	13.8	40.00	1	Western	No NQC - hist. data	QF/Selfgen
NA	24328	CARBGEN2	13.8	15.2	1	Western	No NQC - hist. data	Market
NA	24329	MOBGEN2	13.8	20.2	1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24330	OUTFALL1	13.8	0.00	1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24331	OUTFALL2	13.8	0.00	1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24332	PALOGEN	13.8	3.60	D1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24341	COYGEN	13.8	0.00	1	Western	No NQC - hist. data	QF/Selfgen
NA	24342	FEDGEN	13.8	0.00	1	Western	No NQC - hist. data	QF/Selfgen
NA	29021	WINTEC6	115	0.00	1	Eastern, Valley-Devers	No NQC - hist. data	Wind
NA	29023	WINTEC4	12	0.00	1	Eastern, Valley-Devers	No NQC - hist. data	Wind
NA	29260	ALTAMSA4	115	0.00	1	Eastern, Valley-Devers	No NQC - hist. data	Wind
NA	29338	CLRWTRCT	13.8	0.00	G1	Eastern, Eastern Metro	No NQC - hist. data	QF/Selfgen
NA	29339	DELGEN	13.8	0.00	1	Eastern, Eastern Metro	No NQC - hist. data	QF/Selfgen
NA	29340	CLRWTRST	13.8	0.00	S1	Eastern, Eastern Metro	No NQC - hist. data	QF/Selfgen
NA	29951	REFUSE	13.8	9.90	D1	Western	No NQC - Pmax	QF/Selfgen
NA	29953	SIGGEN	13.8	24.90	D1	Western	No NQC - Pmax	QF/Selfgen
HNTGBH_7_UNIT 3	24167	HUNT3 G	13.8	0.00	3	Western	Retired	Market
HNTGBH_7_UNIT 4	24168	HUNT4 G	13.8	0.00	4	Western	Retired	Market
SONGS_7_UNIT 2	24129	S.ONOFR2	22	0.00	2	None	Retired	Nuclear
SONGS_7_UNIT 3	24130	S.ONOFR3	22	0.00	3	None	Retired	Nuclear
ALAMIT_7_UNIT 1	24001	ALAMT1 G	18	0.00	1	Western	Retired	Market
ALAMIT_7_UNIT 2	24002	ALAMT2 G	18	0.00	2	Western	Retired	Market
ALAMIT_7_UNIT 3	24003	ALAMT3 G	18	0.00	3	Western	Retired	Market
ALAMIT_7_UNIT 4	24004	ALAMT4 G	18	0.00	4	Western	Retired	Market
ALAMIT_7_UNIT 5	24005	ALAMT5 G	20	0.00	5	Western	Retired	Market
ALAMIT_7_UNIT 6	24161	ALAMT6 G	20	0.00	6	Western	Retired	Market
ELSEGN_7_UNIT 4	24048	ELSEG4 G	18	0.00	4	Western, El Nido	Retired	Market

ETIWND_7_UNIT 3	24052	MTNVIST3	18	0.00	3	Eastern, Eastern Metro	Retired[19]	Market
ETIWND_7_UNIT 4	24053	MTNVIST4	18	0.00	4	Eastern, Eastern Metro	Retired[19]	Market
HINSON_6_LBECH1	24170	LBEACH12	13.8	0.00	1	Western	Retired[19]	Market
HINSON_6_LBECH2	24170	LBEACH12	13.8	0.00	2	Western	Retired[19]	Market
HINSON_6_LBECH3	24171	LBEACH34	13.8	0.00	3	Western	Retired[19]	Market
HINSON_6_LBECH4	24171	LBEACH34	13.8	0.00	4	Western	Retired[19]	Market
HNTGBH_7_UNIT 1	24066	HUNT1 G	13.8	0.00	1	Western	Retired	Market
HNTGBH_7_UNIT 2	24067	HUNT2 G	13.8	0.00	2	Western	Retired	Market
NA	29060	SEAWEST	115	0.00	S1	Eastern, Eastern Metro	Retired	Wind
NA	29060	SEAWEST	115	0.00	S2	Eastern, Eastern Metro	Retired	Wind
NA	29060	SEAWEST	115	0.00	S3	Eastern, Eastern Metro	Retired	Wind
REDOND_7_UNIT 5	24121	REDON5 G	18	0.00	5	Western	Retired	Market
REDOND_7_UNIT 6	24122	REDON6 G	18	0.00	6	Western	Retired	Market
REDOND_7_UNIT 7	24123	REDON7 G	20	0.00	7	Western	Retired	Market
REDOND_7_UNIT 8	24124	REDON8 G	20	0.00	8	Western	Retired	Market
WALNUT_6_HILLGEN	24063	HILLGEN	13.8	0.00	1	Western	Retired	QF/Selfgen

Major new projects modeled:

1. Vincent-Mira Loma 500 kV (part of Tehachapi Upgrade)
2. East County 500kV Substation (ECO)
3. Mesa Loop-In Project and South of Mesa 230 kV line upgrades
4. Imperial Valley Phase Shifting Transformers (2x400 MVA)
5. Delany – Colorado River 500 kV Line
6. Hassayampa – North Gila #2 500 kV Line (APS)
7. Bay Blvd. Substation Project
8. Sycamore – Penasquitos 230 kV Line
9. Talega Synchronous Condensers (2x225 MVAR)
10. San Luis Rey Synchronous Condensers (2x225 MVAR)
11. SONGS Synchronous Condenser (225 MVAR)
12. Santiago Synchronous Condenser (225 MVAR)
13. Miguel-Otay Mesa-South Bay-Sycamore 230 kV re-configuration
14. Artesian 230/69 kV Substation and loop-in project

[19] Assumed retired based on aging criteria to be consistent with the CPUC Long Term Procurement Plan (LTPP) Track 4 Scoping Memo (Rulemaking 12-03-014) and “Mid-Level” assumptions for retirement based on resource age of 40 years or more from the CPUC’s “Assigned Commissioner’s Ruling Technical Updates to Planning Assumptions and Scenarios for Use in the 2014 Long-term Procurement Plan and 2014-2015 CAISO TPP” (Rulemaking 13-12-010).

15. Imperial Valley – Dixieland 230 kV tie with IID
16. Bypass series capacitors on the Imperial Valley-N.Gila, ECO-Miguel, and Ocotillo-Suncrest 500kV lines
17. West of Devers 230 kV line upgrades

<u>Critical Contingency Analysis Summary</u>

El Nido Sub-area:

The most critical contingency could be the loss of La Fresa - Redondo #1 and #2 230 kV lines followed by the loss of Hinson - La Fresa 230 kV line or vice versa, which would result in voltage collapse. This limiting contingency establishes a local capacity need of 110 MW (includes 45 MW of QF and 5 MW of MUNI generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area have the same effectiveness factor.

Western LA Basin Sub-area:

The most limiting contingency is the loss of the Ocotillo - Suncrest 500 kV line followed by the loss of ECO - Miguel 500 kV line, which would result in thermal overload on the Imperial Valley phase shifters and/or Otay Mesa – Tijuana 230 kV line. This limiting contingency establishes a local capacity need of about 6,780 MW of which Western LA Basin requirement is 4,890 MW in 2024 (includes 517 MW of QF, 8 MW of wind, 582 MW of MUNI generation as well as 2,160 MW of deficiency) as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the loss of the Imperial Valley – North Gila 500 kV line with Otay Mesa power plant out of service, which would result in voltage instability. This limiting contingency establishes a local capacity need of about 6,376 MW of which Western LA Basin requirement is 4,486 MW in 2024 (includes 517 MW of QF, 8 MW of wind, 582 MW of MUNI generation as well as 1,756 MW of deficiency).

Due to upcoming OTC compliance dates the use of 865 MW of AAEE and LTPP EE assumed in this study is critical, without it the LCR need will be higher by approximately similar amount. The more precise estimate will depend on the locations of additional resources.

Effectiveness factors:

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

Western LA Basin Overall Requirements:

2024 LTPP Tracks 1 & 4 Assumptions	LTPP EE (MW)	Behind the Meter Solar PV (MW)	Storage 4-hr (MW)	Demand Response (MW)	Conventional resources (MW)	Total Capacity (MW)
SCE-submitted procurement selection[20]	130	44	261	75	1,382	1,892

2024	QF (MW)	Wind (MW)	Muni (MW)	Market (MW)	RPS DG (MW)	DR[21] (MW)	Max. Qualifying Capacity (MW)
Available existing resources	517	8	582	1,285	157	181	2,730

2024	Local Resource Capacity Needed	Deficiency without LTPP T1 & T4 and before "repurposing" DR	Incremental Resource Needs	
			Total SCE Selected Procurement for	Additional Existing DR

[20] SCE submitted filing of selected procurement to the CPUC for meeting LTPP Tracks 1 & 4 authorizations on November 21, 2014 https://www.sce.com/wps/portal/home/procurement/solicitation/lcr/!ut/p/b1/hc7BDoIwEATQb_ELOlhT6HGRpiwhIpZE7IX0RJooejB-v5jgUdzbJG8mK7zohZ_CK47hGe9TuH6yV0PFBSV2t-UmTwzIcVaY0sA1agaXGeDHEf71z8KvkX2tFpBklkp2YKS1BufHk9GdllkqF6AtTFk1YNu1EixbHByRBL4LK08-bj0ij5s3_aA9eQ!!/dl4/d5/L2dBISEvZ0FBIS9nQSEh/

[21] "Fast" DR assumptions from LTPP Track 4 studies (most effective locations in Western LA Basin); total maximum DR for the Western LA Basin is 449 MW of which 268 MW may need "repurposing" for use under contingency conditions. The remaining (181 MW) was assumed to be baseline "fast" demand response in effective locations that was used in the LTPP Track 4 studies.

	(MW)	(MW)	LTPP Tracks 1 & 4 (MW)	"Repurposed" Need[22] (MW)
Category B (Single)[23]	4,486	-1,756	1,892	0
Category C (Multiple)[24]	4,890	-2,160	1,892	268

Note:

The 2160 MW deficiency is the amount of local capacity needed beyond the available existing capacity prior to the addition of SCE's selected procurement (1,892 MW) for LTPP Tracks 1 and 4, and additional existing demand response to be repurposed (268 MW) beyond the base-line assumptions (181 MW for Western LA Basin, or 198 MW for both Western LA Basin and San Diego sub-areas) that were used for LTPP Track 4 studies.

Eastern Metro LA Basin Sub-area:

This new sub-area is fully contained within the Eastern LA Basin sub-area. The resources within this sub-area are effective in mitigating both the N-1-1 contingency in southern San Diego (of course less effective than San Diego or Western LA Basin resources) as well as the Eastern LA Basin sub-area main constraint (less effective than the remaining Eastern LA Basin resources). The most critical contingency is the overlapping N-1-1 contingency of the loss of Ocotillo – Suncrest 500 kV line, system readjusted, followed by the loss of ECO-Miguel 500 kV line, which would result in thermal overload on the Imperial Valley phase shifters and/or Otay Mesa – Tijuana 230 kV line. This limiting contingency establishes a local capacity need of about 6,780 MW of which Eastern Metro LA Basin requirement is 1,890 MW in 2024 (includes 165 MW of

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[22] These are existing demand response beyond the 181 MW "fast" DR (located in the most effective locations in Southwestern LA Basin) that is needed to be "repurposed" for use to respond to contingency conditions. Because these are spread out at many locations, they do not correspond 1-for-1 MW need.

[23] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[24] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

QF and 581 MW of MUNI generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the loss of the Imperial Valley – North Gila 500 kV line with Otay Mesa power plant out of service, which would result in voltage instability. This limiting contingency establishes a local capacity need of about 6,376 MW of which Eastern Metro LA Basin requirement is 1,890 MW in 2024 (includes 165 MW of QF and 581 MW of MUNI generation).

Eastern Metro LA Basin Overall Requirements:

2024	QF (MW)	Muni (MW)	Market (MW)	Wind (MW)	RPS DG (MW)	Max. Qualifying Capacity (MW)
Available generation	165	581	1,122	0	22	1,890

2024	Existing Resource Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[25]	1,890	0	1,890
Category C (Multiple)[26]	1,890	0	1,890

Eastern Sub-area:

The most critical contingency is the loss of the Alberhill - Serrano 500 kV line, followed by an N-2 of Red Bluff-Devers #1 and #2 500 kV lines, which would result in voltage instability. This limiting contingency establishes a local capacity need of about 3,460 MW in 2024 (includes 220 MW of QF, 60 MW of wind and 581 MW of MUNI generation) as the minimum capacity necessary for reliable load serving capability within this sub-area. The resources needed for the Eastern Metro LA Basin sub-area fully count towards meeting the Eastern sub-area requirement.

[25] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[26] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

Eastern Overall Requirements:

2024	QF (MW)	Wind (MW)	Muni (MW)	Market (MW)	RPS DG (MW)	Max. Qualifying Capacity (MW)
Available generation	220	60	581	2,648	22	3,531

2024	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[27]	1,890	0	1,890
Category C (Multiple)[28]	3,460	0	3,460

West of Devers Sub-area:

No requirements due to the Mesa Loop-in as well as West of Devers reconductoring projects.

Valley-Devers Sub-area:

No requirements due to the Mesa Loop-in as well as Colorado River-Delany 500 kV line projects.

LA Basin Overall:

The overall LA Basin local capacity need is the combination of the overlapping need of the sub-areas described above. The total need, however, does not equal to the sum of all sub-area needs, but rather the sum of the resources that were used but counted once to avoid double counting, and it can be best described as the sum of the Western and Eastern sub-area needs or 8,350 MW in 2024 (includes 737 MW of QF, 69 MW of wind, 1,163 MW of MUNI generation as well as 2,160 MW of deficiency) as the minimum capacity necessary for reliable load serving capability within this sub-area.

[27] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[28] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

The overall single LA Basin local capacity need can also be best described as the sum of the Western and Eastern sub-area needs or 6,376 MW in 2024 (includes 737 MW of QF, 69 MW of wind, 1,163 MW of MUNI generation as well as 1,756 MW of deficiency).

Due to upcoming OTC compliance dates the use of 1,202 MW of AAEE and LTPP EE assumed in this study is critical, without it the LCR need will be higher by approximately the same amount. The more precise estimate will be dependent on the locations of additional resources.

Effectiveness factors:

The following table has effectiveness factors (LEFs) to the most critical contingency (primary constraint) which caused thermal loading concerns on the Imperial Valley phase shifting transformers. The LEFs that are 5% or higher are listed here.

RESOURCE NAME / kV / ID	LEFs
SANTIAGO 66.0 #l8	-18.7
JOHANNA 66.0 #l5	-17.1
ELLIS 66.0 #l7	-14.74
BARRE 66.0 #m3	-11.9
HUNT1 G 13.8 #X	-11.46
VILLA PK 66.0 #l2	-11.34
BARPKGEN 13.8 #1	-11.32
DowlingC 13.8 #1	-11.18
CanyonGT 13.8 #1	-10.72
BARRE G 13.8 #X2	-9.84
SANIGEN 13.8 #D1	-9.52
ALMITOSW 66.0 #l3	-9.48
CIMGEN 13.8 #D1	-9.48
PADUA 66.0 #l8	-9.48
SIMPSON 13.8 #D1	-9.46
VENICE 13.8 #1	-9.1
WALNUT 66.0 #l3	-9.04
PALOGEN 13.8 #D1	-8.78
MOBGEN1 13.8 #1	-8.76
CTRPKGEN 13.8 #1	-8.72
OLINDA 66.0 #1	-8.7
SIGGEN 13.8 #D1	-8.68
ALAMT4 G 18.0 #4	-8.58

RESOURCE NAME / kV / ID	LEFs
ICEGEN 13.8 #D1	-8.54
MRLPKGEN 13.8 #1	-8.52
CENTER G 18.0 #1	-8.28
BREAPWR2 13.8 #C4	-8.12
CARBGEN1 13.8 #1	-8.12
SERRFGEN 13.8 #D1	-8.12
THUMSGEN 13.8 #1	-8.12
RIOHONDO 66.0 #I8	-7.68
ARCO 1G 13.8 #1	-7.5
EAGLROCK 66.0 #I4	-7.44
ELSEG6ST 13.8 #6	-7.42
INLAND 13.8 #1	-7.32
ELSEG5GT 16.5 #5	-7.18
ETI MWDG 13.8 #1	-7.18
HARBOR G 13.8 #1	-7.18
ETWPKGEN 13.8 #1	-7.06
BRODWYSC 13.8 #1	-6.82
MALBRG1G 13.8 #C1	-6.72
REFUSE 13.8 #D1	-6.72
PASADNA1 13.8 #1	-6.54
EME WCG1 13.8 #1	-6.12
SPRINGEN 13.8 #1	-6.02
RERC1G 13.8 #1	-5.96
CLTNCTRY 13.8 #1	-5.82
CLTNDREW 13.8 #1	-5.82
CLTNAGUA 13.8 #1	-5.66
CHARMIN 13.8 #1	-5.1
WDT273 66.0 #EQ	-5

The following are the LEFs based on the post-transient voltage instability concerns (secondary constraint):

Summary of LEFs Based on Post-Transient Voltage Instability Concerns

Areas		**Calculated LEFs (in %)**
San Diego Area	South & Southwest*	100
	North & Northwest**	100
LA Basin Area	Northwest^{+}	59
	Western Central^{++}	71
	Southwest^{+++}	94

Notes:

* South and Southwest San Diego sub-area includes the area having major bulk 230kV substations and sub-transmission substations starting from Penasquitos to its southern area, south of Sycamore Canyon Substation, south of San Luis 230kV Substation, Miguel 230kV and its northern area. Due to numerous sub-transmission substations located in this sub-area, only major 230kV substations are listed here: Penasquitos, Old Town, Mission, Miguel, Silvergate, and Otay Mesa.
**North and Northwest San Diego sub-area includes the area having major bulk 230kV substations and sub-transmission substations (138kV and lower transmission voltage) south of the SCE-SDG&E border, north of Penasquitos and Mission 230kV Substations and north of Sycamore Canyon 230kV Substation. Due to numerous sub-transmission substations located in this sub-area, only major 230kV substations are listed here: Talega, San Onofre, San Luis Rey, Encina, Escondido and Palomar Energy.
+Northwest LA Basin sub-area includes these substations: El Segundo, Chevmain, El Nido, La Cienega, La Fresa, Redondo, La Fresa, La Cienega, Hinson, Arcogen, Harborgen, Long Beach, Lighthipe, Rio Hondo, Mesa and Laguna Bell.
++Western Central LA Basin sub-area includes these substations: Center, Del Amo, Walnut, and Olinda.
+++Southwest LA Basin sub-area includes these substations: Alamitos, Barre, Lewis, Villa Park, Ellis, Huntington Beach, Johanna, Santiago, and Viejo.
Please note that the above serves as a guide with the understanding that these LEF values are subject to change over time due to load growth (or reduction), additional transmission upgrades from future transmission plans, AAEE assumptions or preferred resource assumptions that are modified based on nodal levels.

Changes compared to the 2019 results:

The load forecast went up by 621 MW. The LA Basin LCR need has decreased by 769 MW mainly due to new transmission projects such as Mesa Loop-in, West of Devers upgrade, Imperial Valley phase-shifting transformers, dynamic reactive supports at Santiago, San Onofre, Talega and San Luis Rey substations, as well as the Colorado-Delany 500 kV line after resource retirements in the area. The AAEE, LTPP EE and DR remain critical for the LA Basin area.

LA Basin Overall Requirements:

2024	QF (MW)	Wind (MW)	Muni (MW)	Market (MW)	RPS DG (MW)	DR (MW)	Max. Qualifying Capacity (MW)
Available resources	737	69	1,163	3,933	179	181[29]	6,262

2024	Total	Existing	Deficiency	Incremental Resource Needs

[29] Baseline demand response in the LA Basin that was used in the LTPP Track 4 Scoping Ruling and studies

	(MW) Requirement	Resources Needed (MW)	(MW)	Total SCE Selected Procurement for LTPP Tracks 1 & 4 (MW)	Additional Existing DR "Repurposed" Need[30] (MW)
Category B (Single)[31]	6,376	4,620	1,756	1,892	0
Category C (Multiple)[32]	8,350	6,190	2,160	1,892	268

9. Big Creek/Ventura Area

Area Definition

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

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

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

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

Total 2024 busload within the defined area is 4,564 MW (includes 4,881 MW of forecasted demand as well as 311 MW of AAEE and 6 MW of LTPP EE) with 71 MW of losses and 362 MW pumps resulting in total load + losses + pumps of 4,997 MW.

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[30] These are existing demand response beyond the 181 MW "fast" DR (located in the most effective locations in Southwestern LA Basin) that is needed to be "repurposed" for use to respond to contingency conditions. Because these are spread out at many locations, they do not correspond 1-for-1 MW need.

[31] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[32] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

The geographical representation of this local area does not match the electrical representation due to Saugas substation being included in the LA Basin geographical representation and not in Big Creek/Ventura. The total load within the geographical defined area is 3,673 MW (includes 3,915 MW of forecasted demand as well as 236 MW of AAEE and 6 MW of LTPP EE) with 71 MW of losses and 362 MW pumps resulting in total load + losses + pumps of 4,106 MW.

Total units and qualifying capacity available in the Big Creek/Ventura area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ALAMO_6_UNIT	25653	ALAMO SC	13.8	14.58	1	Big Creek	Aug NQC	Market
BIGCRK_2_EXESWD	24306	B CRK1-1	7.2	19.38	1	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24306	B CRK1-1	7.2	21.03	2	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24307	B CRK1-2	13.8	21.03	3	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24307	B CRK1-2	13.8	30.39	4	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24308	B CRK2-1	13.8	49.48	1	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24308	B CRK2-1	13.8	50.64	2	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24309	B CRK2-2	7.2	18.22	3	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24309	B CRK2-2	7.2	19.19	4	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24310	B CRK2-3	7.2	16.55	5	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24310	B CRK2-3	7.2	18.02	6	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24311	B CRK3-1	13.8	34.09	1	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24311	B CRK3-1	13.8	34.09	2	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24312	B CRK3-2	13.8	34.09	3	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24312	B CRK3-2	13.8	39.93	4	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24313	B CRK3-3	13.8	37.99	5	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24314	B CRK 4	11.5	49.09	41	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24314	B CRK 4	11.5	49.28	42	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24315	B CRK 8	13.8	23.76	81	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24315	B CRK 8	13.8	42.85	82	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24317	MAMOTH1G	13.8	91.07	1	Big Creek, Rector, Vestal	Aug NQC	Market

BIGCRK_2_EXESWD	24318	MAMOTH2G	13.8	91.07	2	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24323	PORTAL	4.8	9.35	1	Big Creek, Rector, Vestal	Aug NQC	Market
EASTWD_7_UNIT	24319	EASTWOOD	13.8	199.00	1	Big Creek, Rector, Vestal		Market
EDMONS_2_NSPIN	25605	EDMON1AP	14.4	25.00	1	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25606	EDMON2AP	14.4	25.00	2	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25607	EDMON3AP	14.4	25.00	3	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25607	EDMON3AP	14.4	25.00	4	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25608	EDMON4AP	14.4	25.00	5	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25608	EDMON4AP	14.4	25.00	6	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25609	EDMON5AP	14.4	25.00	7	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25609	EDMON5AP	14.4	25.00	8	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25610	EDMON6AP	14.4	25.00	9	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25610	EDMON6AP	14.4	25.00	10	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25611	EDMON7AP	14.4	25.00	11	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25611	EDMON7AP	14.4	25.00	12	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25612	EDMON8AP	14.4	25.00	13	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25612	EDMON8AP	14.4	25.00	14	Big Creek	Pumps	MUNI
GLOW_6_SOLAR	29896	APPINV	0.42	0.00	EQ	Big Creek	Energy Only	Market
GOLETA_2_QF	24057	GOLETA	66	0.09		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	QF/Selfgen
GOLETA_6_ELLWOD	29004	ELLWOOD	13.8	54.00	1	Ventura, S.Clara, Moorpark		Market
GOLETA_6_EXGEN	24057	GOLETA	66	1.37		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	QF/Selfgen
GOLETA_6_GAVOTA	24057	GOLETA	66	0.82		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	QF/Selfgen
GOLETA_6_TAJIGS	24057	GOLETA	66	2.89		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	Market
LEBECS_2_UNITS	29051	PSTRIAG1	18	157.90	G1	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	29052	PSTRIAG2	18	157.90	G2	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	29053	PSTRIAS1	18	162.40	S1	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	29054	PSTRIAG3	18	157.90	G3	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	29055	PSTRIAS2	18	78.90	S2	Big Creek	Aug NQC	Market
LITLRK_6_SEPV01				0.00		Big Creek	Not modeled Energy Only	Market
MNDALY_6_MCGRTH	29306	MCGPKGEN	13.8	47.20	1	Ventura, S.Clara, Moorpark		Market
MNDALY_7_UNIT 3	24222	MANDLY3G	16	0.00	3	Ventura, S.Clara, Moorpark	Retired over 40 year	Market
MOORPK_2_CALABS	24099	MOORPARK	230	6.96		Ventura, Moorpark	Not modeled	Market
MOORPK_6_QF	24098	MOORPARK	66	26.56		Ventura, Moorpark	Not modeled Aug NQC	QF/Selfgen
MOORPK_7_UNITA1	24098	MOORPARK	66	2.03		Ventura, Moorpark	Not modeled Aug NQC	QF/Selfgen
NEENCH_6_SOLAR	29900	ALPINE_G	0.48	53.75	EQ	Big Creek	Aug NQC	Market
OMAR_2_UNIT 1	24102	OMAR 1G	13.8	77.25	1	Big Creek		QF/Selfgen
OMAR_2_UNIT 2	24103	OMAR 2G	13.8	77.25	2	Big Creek		QF/Selfgen
OMAR_2_UNIT 3	24104	OMAR 3G	13.8	77.25	3	Big Creek		QF/Selfgen
OMAR_2_UNIT 4	24105	OMAR 4G	13.8	77.25	4	Big Creek		QF/Selfgen
OSO_6_NSPIN	25614	OSO A P	13.2	2.38	1	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25614	OSO A P	13.2	2.38	2	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25614	OSO A P	13.2	2.38	3	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25614	OSO A P	13.2	2.38	4	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	2.38	5	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	2.38	6	Big Creek	Pumps	MUNI

OSO_6_NSPIN	25615	OSO B P	13.2	2.38	7	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	2.38	8	Big Creek	Pumps	MUNI
PANDOL_6_UNIT	24113	PANDOL	13.8	25.70	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
PANDOL_6_UNIT	24113	PANDOL	13.8	20.94	2	Big Creek, Vestal	Aug NQC	QF/Selfgen
RECTOR_2_KAWEAH	24212	RECTOR	66	2.76		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
RECTOR_2_KAWH 1	24212	RECTOR	66	1.29		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
RECTOR_2_QF	24212	RECTOR	66	9.48		Big Creek, Rector, Vestal	Not modeled Aug NQC	QF/Selfgen
RECTOR_7_TULARE	24212	RECTOR	66	0.17		Big Creek, Rector, Vestal	Not modeled	QF/Selfgen
SAUGUS_2_TOLAND	24135	SAUGUS	66	0.00		Big Creek	Not modeled Energy Only	Market
SAUGUS_6_MWDFTH	24135	SAUGUS	66	4.08		Big Creek	Not modeled Aug NQC	MUNI
SAUGUS_6_PTCHGN	24118	PITCHGEN	13.8	18.95	D1	Big Creek	Aug NQC	MUNI
SAUGUS_6_QF	24135	SAUGUS	66	0.92		Big Creek	Not modeled Aug NQC	QF/Selfgen
SAUGUS_7_CHIQCN	24135	SAUGUS	66	2.02		Big Creek	Not modeled Aug NQC	Market
SAUGUS_7_LOPEZ	24135	SAUGUS	66	5.42		Big Creek	Not modeled Aug NQC	QF/Selfgen
SNCLRA_6_OXGEN	24110	OXGEN	13.8	35.70	D1	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SNCLRA_6_PROCGN	24119	PROCGEN	13.8	46.26	D1	Ventura, S.Clara, Moorpark	Aug NQC	Market
SNCLRA_6_QF	24127	S.CLARA	66	0.00	1	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SNCLRA_6_WILLMT	24159	WILLAMET	13.8	13.94	D1	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SPRGVL_2_QF	24215	SPRINGVL	66	0.23		Big Creek, Rector, Vestal	Not modeled Aug NQC	QF/Selfgen
SPRGVL_2_TULE	24215	SPRINGVL	66	0.59		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
SPRGVL_2_TULESC	24215	SPRINGVL	66	0.41		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
SYCAMR_2_UNITS	24143	SYCCYN1G	13.8	56.53	1	Big Creek	Aug NQC	QF/Selfgen
SYCAMR_2_UNITS	24144	SYCCYN2G	13.8	56.54	2	Big Creek	Aug NQC	QF/Selfgen
SYCAMR_2_UNITS	24145	SYCCYN3G	13.8	56.53	3	Big Creek	Aug NQC	QF/Selfgen
SYCAMR_2_UNITS	24146	SYCCYN4G	13.8	56.53	4	Big Creek	Aug NQC	QF/Selfgen
TENGEN_2_PL1X2	24148	TENNGEN1	13.8	17.49	D1	Big Creek	Aug NQC	Market
TENGEN_2_PL1X2	24149	TENNGEN2	13.8	17.50	D2	Big Creek	Aug NQC	Market
VESTAL_2_WELLHD	24116	VESTAL	13.8	49.00	1	Big Creek, Vestal		Market
VESTAL_6_QF	24152	VESTAL	66	6.91		Big Creek, Vestal	Not modeled Aug NQC	QF/Selfgen
VESTAL_6_ULTRGN	24150	ULTRAGEN	13.8	34.13	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
VESTAL_6_WDFIRE	29008	LAKEGEN	13.8	6.60	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
WARNE_2_UNIT	25651	WARNE1	13.8	38.00	1	Big Creek	Aug NQC	Market
WARNE_2_UNIT	25652	WARNE2	13.8	38.00	1	Big Creek	Aug NQC	Market
APPGEN_6_UNIT 1	24009	APPGEN1G	13.8	0.00	1	Big Creek	No NQC - hist. data	Market
APPGEN_6_UNIT 1	24010	APPGEN2G	13.8	0.00	2	Big Creek	No NQC - hist. data	Market
APPGEN_6_UNIT 1	24361	APPGEN3G	13.8	0.00	3	Big Creek	No NQC - hist. data	Market
NA	24326	EXGEN1	13.8	0.60	S1	Ventura, S.Clara, Moorpark	No NQC - hist. data	QF/Selfgen
NA	24340	CHARMIN	13.8	15.00	1	Ventura, S.Clara, Moorpark	No NQC - hist. data	QF/Selfgen

NA	24362	EXGEN2	13.8	0.80	G1	Ventura, S.Clara, Moorpark	No NQC - hist. data	QF/Selfgen
NA	24370	KAWGEN	13.8	2.80	1	Big Creek, Rector, Vestal	No NQC - hist. data	Market
NA	24372	KR 3-1	13.8	13.70	1	Big Creek, Vestal	No NQC - hist. data	QF/Selfgen
NA	24373	KR 3-2	13.8	12.90	1	Big Creek, Vestal	No NQC - hist. data	QF/Selfgen
NA	24422	PALMDALE	66	0.00	1	Big Creek	No NQC - hist. data	Market
New Unit	28019	RPS	13.8	50.00	1	Big Creek, Vestal	No NQC - Pmax	Market
New Unit	29884	DAWNGEN	0.82	20.00	EQ	Big Creek	No NQC - Pmax	Market
New Unit	29888	TWILGHTG	0.82	20.00	EQ	Big Creek	No NQC - Pmax	Market
New Unit	29918	VLYFLR_G	0.2	20.00	EQ	Big Creek	No NQC - Pmax	Market
New Unit	29952	CAMGEN	14.2	28.00	D1	Ventura, S.Clara, Moorpark	No NQC - Pmax	Market
New Unit	29954	RPS	66	10.00	EQ	Big Creek	No NQC - Pmax	Market
KERRGN_1_UNIT 1	24437	KERNRVR	66	0.00	1	Big Creek	Retired	Market
MNDALY_7_UNIT 1	24089	MANDLY1G	13.8	0.00	1	Ventura, Moorpark	Retired	Market
MNDALY_7_UNIT 2	24090	MANDLY2G	13.8	0.00	2	Ventura, Moorpark	Retired	Market
ORMOND_7_UNIT 1	24107	ORMOND1G	26	0.00	1	Ventura, Moorpark	Retired	Market
ORMOND_7_UNIT 2	24108	ORMOND2G	26	0.00	2	Ventura, Moorpark	Retired	Market
VESTAL_2_KERN	24152	VESTAL	66	0.00	1	Big Creek, Vestal	Retired	QF/Selfgen

Major new projects modeled: None

Critical Contingency Analysis Summary

Rector Sub-area:

The most critical contingency is the loss of the Rector - Vestal 230 kV line with the Eastwood unit out of service, which could thermally overload the remaining Rector - Vestal 230 kV line. This limiting contingency establishes a local capacity need of 560 MW (includes 10 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
24370	KAWGEN	1	45
24319	EASTWOOD	1	41
24306	B CRK1-1	1	41
24306	B CRK1-1	2	41
24307	B CRK1-2	3	41
24307	B CRK1-2	4	41
24323	PORTAL	1	41
24308	B CRK2-1	1	40

24308	B CRK2-1	2	40
24309	B CRK2-2	3	40
24309	B CRK2-2	4	40
24315	B CRK 8	81	40
24315	B CRK 8	82	40
24310	B CRK2-3	5	39
24310	B CRK2-3	6	39
24311	B CRK3-1	1	39
24311	B CRK3-1	2	39
24312	B CRK3-2	3	39
24312	B CRK3-2	4	39
24313	B CRK3-3	5	39
24317	MAMOTH1G	1	39
24318	MAMOTH2G	2	39
24314	B CRK 4	41	38
24314	B CRK 4	42	38

Vestal Sub-area:

The most critical contingency is the loss of the Magunden - Vestal 230 kV line with the Eastwood unit out of service, which could thermally overload the remaining Magunden - Vestal 230 kV line. This limiting contingency establishes a local capacity need of 693 MW (includes 131 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
28008	LAKEGEN	1	46
24113	PANDOL	1	45
24113	PANDOL	2	45
24150	ULTRAGEN	1	45
24372	KR 3-1	1	45
24373	KR 3-2	2	45
24152	VESTAL	1	45
24370	KAWGEN	1	45
24319	EASTWOOD	1	24
24306	B CRK1-1	1	24
24306	B CRK1-1	2	24
24307	B CRK1-2	3	24
24307	B CRK1-2	4	24
24308	B CRK2-1	1	24
24308	B CRK2-1	2	24
24309	B CRK2-2	3	24

24309	B CRK2-2	4	24
24310	B CRK2-3	5	24
24310	B CRK2-3	6	24
24315	B CRK 8	81	24
24315	B CRK 8	82	24
24323	PORTAL	1	24
24311	B CRK3-1	1	23
24311	B CRK3-1	2	23
24312	B CRK3-2	3	23
24312	B CRK3-2	4	23
24313	B CRK3-3	5	23
24317	MAMOTH1G	1	23
24318	MAMOTH2G	2	23
24314	B CRK 4	41	22
24314	B CRK 4	42	22

Santa Clara Sub-area:

The most critical contingency is the loss of the Pardee - Santa Clara 230 kV line followed by the loss of Moorpark - Santa Clara 230 kV #1 and #2 lines, which would cause voltage collapse. This limiting contingency establishes a local capacity need of 277 MW (includes 68 MW QF generation as well as 30 MW of deficiency) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Due to upcoming OTC compliance dates the use of 29 MW of AAEE and LTPP EE assumed in this study is critical, without it the LCR need will be higher by about the same amount.

Effectiveness factors:

All units within this area have the same effectiveness factor.

Moorpark Sub-area:

The most critical contingency is the loss of the Moorpark - Pardee 230 kV #3 line followed by the loss of the Moorpark - Pardee 230 kV #1 and #2 lines, which will cause voltage collapse. This limiting contingency establishes a local capacity need of 512 MW (includes 97 MW QF generation as well as 230 MW of deficiency) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Due to upcoming OTC compliance dates the use of 93 MW of AAEE and LTPP EE assumed in this study is critical, without it the LCR need will be higher by about the same amount.

Effectiveness factors:

All units within this area have the same effectiveness factor.

Big Creek/Ventura overall:

The most critical contingency is the loss of the Lugo - Victorville 500 kV line followed by loss of one of the Sylmar - Pardee 230 kV line, which would thermally overload the remaining Sylmar - Pardee 230 kV line. This limiting contingency establishes a local capacity need of 2,783 MW (includes 769 MW of QF and 392 MW of MUNI generation) as the minimum capacity necessary for reliable load serving capability within this area.

The single most critical contingency is the loss of Sylmar - Pardee #1 (or # 2) line with Pastoria power plant (CCGT) out of service, which could thermally overload the remaining Sylmar - Pardee #1 or #2 230 kV line. This limiting contingency establishes a Local Capacity Need of 2,603 MW (includes 769 MW of QF and 392 MW of MUNI generation).

Due to upcoming OTC compliance dates the use of 317 MW of AAEE and LTPP EE assumed in this study is critical, without it the LCR need will be higher by about the same amount.

Effectiveness factors:

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

Gen Bus	Gen Name	Ck	Eff Factor (%)
24108	ORMOND2G	1	40
24010	APPGEN2G	1	39
24148	TENNGEN1	1	39

24149	TENNGEN2	1	39
24009	APPGEN1G	1	38
24107	ORMOND1G	1	38
24118	PITCHGEN	1	38
24361	APPGEN3G	1	38
25651	WARNE1	1	37
25652	WARNE2	1	37
24089	MANDLY1G	1	36
24090	MANDLY2G	1	36
24127	S.CLARA	1	36
29004	ELLWOOD	1	36
24110	OXGEN	1	36
24119	PROCGEN	1	36
24159	WILLAMET	1	36
24340	CHARMIN	1	36
29952	CAMGEN	1	36
24362	EXGEN2	1	36
24326	EXGEN1	1	36
24362	EXGEN2	1	36
24222	MANDLY3G	1	35
25614	OSO A P	1	35
25614	OSO A P	1	35
25615	OSO B P	1	35
25615	OSO B P	1	35
29306	MCGPKGEN	1	35
29055	PSTRIAS2	1	34
29054	PSTRIAG3	1	34
29053	PSTRIAS1	1	34
29052	PSTRIAG2	1	34
29051	PSTRIAG1	1	34
25605	EDMON1AP	1	34
25606	EDMON2AP	1	34
25607	EDMON3AP	1	34
25607	EDMON3AP	1	34
25608	EDMON4AP	1	34
25608	EDMON4AP	1	34
25609	EDMON5AP	1	34
25609	EDMON5AP	1	34
25610	EDMON6AP	1	34
25610	EDMON6AP	1	34
25611	EDMON7AP	1	34
25611	EDMON7AP	1	34
25612	EDMON8AP	1	34

25612	EDMON8AP	1	34
25653	ALAMO SC	1	34
24370	KAWGEN	1	32
24113	PANDOL	1	31
24113	PANDOL	1	31
29008	LAKEGEN	1	31
24150	ULTRAGEN	1	31
24152	VESTAL	1	31
24307	B CRK1-2	1	31
24307	B CRK1-2	1	31
24308	B CRK2-1	1	31
24308	B CRK2-1	1	31
24309	B CRK2-2	1	31
24309	B CRK2-2	1	31
24310	B CRK2-3	1	31
24310	B CRK2-3	1	31
24311	B CRK3-1	1	31
24311	B CRK3-1	1	31
24312	B CRK3-2	1	31
24312	B CRK3-2	1	31
24313	B CRK3-3	1	31
24314	B CRK 4	1	31
24314	B CRK 4	1	31
24315	B CRK 8	1	31
24315	B CRK 8	1	31
24317	MAMOTH1G	1	31
24318	MAMOTH2G	1	31
24372	KR 3-1	1	31
24373	KR 3-2	1	31
24102	OMAR 1G	1	30
24103	OMAR 2G	1	30
24104	OMAR 3G	1	30
24105	OMAR 4G	1	30
24143	SYCCYN1G	1	30
24144	SYCCYN2G	1	30
24145	SYCCYN3G	1	30
24146	SYCCYN4G	1	30
24319	EASTWOOD	1	30
24306	B CRK1-1	1	30
24306	B CRK1-1	1	30
24136	SEAWEST	1	9
24437	KERNRVR	1	8

Changes compared to the 2019 results:

The load forecast went up by 108 MW and the LCR need has increased by 164 MW.

The AAEE and LTPP EE remain critical for the Santa Clara and Moorpark sub-areas.

Big Creek/Ventura Overall Requirements:

2024 LTPP Assumptions	LTPP EE (MW)	Solar PV (MW)	Storage 4h (MW)	Conventional resources (MW)	LTPP Total Capacity (MW)
SCE-submitted procurement selection	6	6	1	262	275

2024	QF (MW)	Muni (MW)	Market (MW)	New DG (MW)	Max. Qualifying Capacity (MW)
Available generation	769	392	2258	248	3667

2024	Total MW Requirement	Existing Resource Need (MW)	Deficiency without LTPP T1 & T4 (MW)	Total SCE Selected Procurement for LTPP Tracks 1 & 4 (MW)
Category B (Single)[33]	2,603	2,603	0	275
Category C (Multiple)[34]	2,783	2,553	230	275

10. San Diego-Imperial Valley Area

<u>Area Definition</u>

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

1) Imperial Valley – North Gila 500 kV Line
2) Otay Mesa – Tijuana 230 kV Line
3) San Onofre - San Luis Rey #1 230 kV Line
4) San Onofre - San Luis Rey #2 230 kV Line

[33] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[34] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

5) San Onofre - San Luis Rey #3 230 kV Line
6) San Onofre – Talega 230 kV Line
7) San Onofre – Capistrano 230 kV Line
8) Imperial Valley – Fern 230 kV Line
9) Imperial Valley – Liebert 230 kV Line
10) Imperial Valley – Dixieland 230 kV Line
11) Imperial Valley – La Rosita 230 kV Line

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

1) Imperial Valley is in North Gila is out
2) Otay Mesa is in Tijuana is out
3) San Onofre is out San Luis Rey is in
4) San Onofre is out San Luis Rey is in
5) San Onofre is out San Luis Rey is in
6) San Onofre is out Talega is in
7) San Onofre is out Talega is in
8) Imperial Valley is in Fern is out
9) Imperial Valley is in Liebert is out
10) Imperial Valley is in Dixieland is out
11) Imperial Valley is in La Rosita is out

Total 2024 busload within the defined area: 5,344 MW (includes 5,682 MW of forecasted demand as well as 338 MW of AAEE) with 169 MW of losses resulting in total load + losses of 5,513 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BORDER_6_UNITA1	22149	CALPK_BD	13.8	48.00	1	San Diego, Border		Market
BREGGO_6_SOLAR	22082	BR GEN1	0.21	21.17	1	San Diego	Aug NQC	Market
CBRLLO_6_PLSTP1	22092	CABRILLO	69	3.05	1	San Diego	Aug NQC	QF/Selfger
CCRITA_7_RPPCHF	22124	CHCARITA	138	3.66	1	San Diego	Aug NQC	QF/Selfger
CHILLS_1_SYCENG	22120	CARLTNHS	138	0.34	1	San Diego	Aug NQC	QF/Selfger
CHILLS_7_UNITA1	22120	CARLTNHS	138	1.59	2	San Diego	Aug NQC	QF/Selfger
CNTNLA_2_SOLAR1	23463	DW GEN3&4	0.33	41.92	1	None	Aug NQC	Market
CNTNLA_2_SOLAR1	23463	DW GEN3&4	0.33	0.00	2	None	Aug NQC	Market
CPSTNO_7_PRMADS	22112	CAPSTRNO	138	5.26	1	San Diego	Aug NQC	QF/Selfger
CPVERD_2_SOLAR	23301	IV GEN3 G2	0.32	56.61	G2	None	Aug NQC	Market
CPVERD_2_SOLAR	23309	IV GEN3 G1	0.32	56.60	G1	None	Aug NQC	Market
CRSTWD_6_KUMYAY	22915	KUMEYAAY	34.5	8.72	1	San Diego	Aug NQC	Wind
CSLR4S_2_SOLAR	23298	DW GEN1 G1	0.32	52.94	G1	None	Aug NQC	Market
CSLR4S_2_SOLAR	23299	DW GEN1 G2	0.32	52.94	G2	None	Aug NQC	Market
DIVSON_6_NSQF	22172	DIVISION	69	41.73	1	San Diego	Aug NQC	QF/Selfger
EGATE_7_NOCITY	22204	EASTGATE	69	0.26	1	San Diego	Aug NQC	QF/Selfger
ELCAJN_6_LM6K	23320	EC GEN2	13.8	48.10	1	San Diego, El Cajon		Market
ELCAJN_6_UNITA1	22150	EC GEN1	13.8	45.42	1	San Diego, El Cajon		Market

ESCNDO_6_PL1X2	22257	ESGEN	13.8	35.50	1	San Diego, Escondido		Market
ESCNDO_6_UNITB1	22153	CALPK_ES	13.8	48.00	1	San Diego, Escondido		Market
ESCO_6_GLMQF	22332	GOALLINE	69	38.37	1	San Diego, Esco, Escondido	Aug NQC	QF/Selfgen
IVSLRP_2_SOLAR1	23440	DW GEN2 G1	0.36	18.77	1	None	Aug NQC	Market
IVSLRP_2_SOLAR1	23441	DW GEN2 G2	0.36	18.78	1	None	Aug NQC	Market
IVSLRP_2_SOLAR1	23442	DW GEN2 G3	0.36	18.78	1	None	Aug NQC	Market
LAKHDG_6_UNIT 1	22625	LKHODG1	13.8	20.00	1	San Diego, Bernardo, Encinitas		Market
LAKHDG_6_UNIT 2	22626	LKHODG2	13.8	20.00	2	San Diego, Bernardo, Encinitas		Market
LARKSP_6_UNIT 1	22074	LRKSPBD1	13.8	46.00	1	San Diego, Border		Market
LARKSP_6_UNIT 2	22075	LRKSPBD2	13.8	46.00	1	San Diego, Border		Market
LAROA1_2_UNITA1	20187	LRP-U1	16	165	1	None		Market
LAROA2_2_UNITA1	22996	INTBST	18	157	1	None		Market
LAROA2_2_UNITA1	22997	INTBCT	16	165	1	None		Market
MRGT_6_MEF2	22487	MEF_MR2	13.8	47.90	1	San Diego, Mission, Miramar		Market
MRGT_6_MMAREF	22486	MEF_MR1	13.8	48.00	1	San Diego, Mission, Miramar		Market
MSHGTS_6_MMARLF	22448	MESAHGTS	69	3.64	1	San Diego, Mission	Aug NQC	QF/Selfgen
MSSION_2_QF	22496	MISSION	69	0.70	1	San Diego	Aug NQC	QF/Selfgen
NIMTG_6_NIQF	22576	NOISLMTR	69	36.43	1	San Diego	Aug NQC	QF/Selfgen
OCTILO_5_WIND	23314	OCO GEN G1	0.69	23.13	G1	None	Aug NQC	Wind
OCTILO_5_WIND	23318	OCO GEN G2	0.69	23.13	G2	None	Aug NQC	Wind
OGROVE_6_PL1X2	22628	PA GEN1	13.8	49.95	1	San Diego, Pala		Market
OGROVE_6_PL1X2	22629	PA GEN2	13.8	49.95	2	San Diego, Pala		Market
OTAY_6_PL1X2	22617	OYGEN	13.8	35.50	1	San Diego, Border		Market
OTAY_6_UNITB1	22604	OTAY	69	2.83	1	San Diego, Border	Aug NQC	QF/Selfgen
OTAY_7_UNITC1	22604	OTAY	69	2.57	3	San Diego, Border	Aug NQC	QF/Selfgen
OTMESA_2_PL1X3	22605	OTAYMGT1	18	185.06	1	San Diego		Market
OTMESA_2_PL1X3	22606	OTAYMGT2	18	185.06	1	San Diego		Market
OTMESA_2_PL1X3	22607	OTAYMST1	16	233.48	1	San Diego		Market
PALOMR_2_PL1X3	22262	PEN_CT1	18	162.39	1	San Diego		Market
PALOMR_2_PL1X3	22263	PEN_CT2	18	162.39	1	San Diego		Market
PALOMR_2_PL1X3	22265	PEN_ST	18	240.83	1	San Diego		Market
PTLOMA_6_NTCCGN	22660	POINTLMA	69	1.98	2	San Diego	Aug NQC	QF/Selfgen
PTLOMA_6_NTCQF	22660	POINTLMA	69	19.44	1	San Diego	Aug NQC	QF/Selfgen
SAMPSN_6_KELCO1	22704	SAMPSON	12.5	1.00	1	San Diego	Aug NQC	QF/Selfgen
SMRCOS_6_UNIT 1	22724	SANMRCOS	69	0.65	1	San Diego	Aug NQC	QF/Selfgen
TERMEX_2_PL1X3	22981	TDM STG	18	281	1	None		Market
TERMEX_2_PL1X3	22982	TDM CTG2	18	156	1	None		Market
TERMEX_2_PL1X3	22983	TDM CTG3	18	156	1	None		Market
NA	22916	PFC-AVC	0.6	0.00	1	San Diego	No NQC - hist. data	QF/Selfgen
New unit	22245	COSTAL 2	13.8	70.00	1	San Diego	No NQC - Pmax	Market
New unit	22246	COSTAL 2	16.5	230.00	0	San Diego	No NQC - Pmax	Market
New unit	22928	COSTAL 1	16.5	230.00	1	San Diego	No NQC - Pmax	Market
New unit	22929	COSTAL 1	13.8	70.00	1	San Diego	No NQC - Pmax	Market
New unit	23162	C574CT1	13.8	100.00	1	San Diego	No NQC - Pmax	Market
New unit	23163	C574CT2	13.8	100.00	1	San Diego	No NQC - Pmax	Market
New unit	23164	C574CT3	13.8	100.00	1	San Diego	No NQC - Pmax	Market
ELCAJN_7_GT1	22212	ELCAJNGT	12.5	0.00	1	San Diego, El Cajon	Retired	Market
ENCINA_7_EA1	22233	ENCINA 1	14.4	0.00	1	San Diego, Encina	Retired	Market
ENCINA_7_EA2	22234	ENCINA 2	14.4	0.00	1	San Diego, Encina	Retired	Market

ENCINA_7_EA3	22236	ENCINA 3	14.4	0.00	1	San Diego, Encina	Retired	Market
ENCINA_7_EA4	22240	ENCINA 4	22	0.00	1	San Diego, Encina	Retired	Market
ENCINA_7_EA5	22244	ENCINA 5	24	0.00	1	San Diego, Encina	Retired	Market
ENCINA_7_GT1	22248	ENCINAGT	12.5	0.00	1	San Diego, Encina	Retired	Market
KEARNY_7_KY1	22377	KEARNGT1	12.5	0.00	1	San Diego, Mission	Retired	Market
KEARNY_7_KY2	22373	KEARN2AB	12.5	0.00	1	San Diego, Mission	Retired	Market
KEARNY_7_KY2	22373	KEARN2AB	12.5	0.00	2	San Diego, Mission	Retired	Market
KEARNY_7_KY2	22374	KEARN2CD	12.5	0.00	1	San Diego, Mission	Retired	Market
KEARNY_7_KY2	22374	KEARN2CD	12.5	0.00	2	San Diego, Mission	Retired	Market
KEARNY_7_KY3	22375	KEARN3AB	12.5	0.00	1	San Diego, Mission	Retired	Market
KEARNY_7_KY3	22375	KEARN3AB	12.5	0.00	2	San Diego, Mission	Retired	Market
KEARNY_7_KY3	22376	KEARN3CD	12.5	0.00	1	San Diego, Mission	Retired	Market
KEARNY_7_KY3	22376	KEARN3CD	12.5	0.00	2	San Diego, Mission	Retired	Market
MRGT_7_UNITS	22488	MIRAMRGT	12.5	0.00	1	San Diego, Mission, Miramar	Retired	Market
MRGT_7_UNITS	22488	MIRAMRGT	12.5	0.00	2	San Diego, Mission, Miramar	Retired	Market
New Unit	22914	RPS	0.48	0.00	1	None	Energy Only	Market
New Unit	22942	RPS	0.69	15.40	G1	None	No NQC - est. data	Wind
New Unit	22945	RPS	0.69	15.40	G2	None	No NQC - est. data	Wind
New Unit	23100	RPS	0.69	7.70	G1	None	No NQC - est. data	Wind
New Unit	23105	RPS	0.69	7.70	G2	None	No NQC - est. data	Wind
New Unit	23131	RPS	0.69	0.00	G1	None	Energy Only	Market
New Unit	23134	RPS	0.69	0.00	G2	None	Energy Only	Market
New Unit	23155	RPS	0.2	75.00	G1	None	No NQC - P max	Market
New Unit	23156	RPS	0.2	75.00	G2	None	No NQC - P max	Market
New Unit	23352	RPS	0.31	20.00	1	None	No NQC - P max	Market
New Unit	23487	RPS	0.31	20.00	1	None	No NQC - P max	Market
New Unit	23575	RPS	0.38	80.00	1	None	No NQC - P max	Market
OCTILO_5_WIND	23318	OCO GEN G2	0.69	32.00	G3	None	No NQC - est. data	Wind
New Unit	22152	CREELMAN	69	7.50	1	San Diego	No NQC - P max	Market
New Unit	22870	VALCNTR	69	7.50	1	San Diego, Pala	No NQC - P max	Market
New Unit	23120	BULLMOOS	13.8	27.00	1	San Diego, Border	No NQC - P max	Market

Major new projects modeled:

1. Vincent-Mira Loma 500 kV (part of Tehachapi Upgrade)
2. Talega SVC
3. East County 500 kV Substation (ECO)
4. Mesa Loop-In Project and South of Mesa 230 kV line upgrades
5. Imperial Valley Phase Shifting Transformers (2x400 MVA)
6. Delany – Colorado River 500 kV Line
7. Hassayampa – North Gila #2 500 kV Line (APS)
8. Bay Blvd. Substation Project
9. Sycamore – Penasquitos 230 kV Line
10. Talega Synchronous Condensers (2x225 MVAR)
11. San Luis Rey Synchronous Condensers (2x225 MVAR)

12. SONGS Synchronous Condenser (225 MVAR)
13. Santiago Synchronous Condenser (225 MVAR)
14. Miguel-Otay Mesa-South Bay-Sycamore 230 kV re-configuration
15. Artesian 230/69 kV Substation and loop-in project
16. Imperial Valley – Dixieland 230 kV tie with IID
17. Bypass series capacitors on the Imperial Valley-N.Gila, ECO-Miguel, and Ocotillo-Suncrest 500kV lines
18. Reconductor of El Cajon – Los Coches 69 kV line
19. Reconductor of Mission – Clairmont 69 kV line
20. Reconductor of Mission – Kearny 69 kV line
21. Reconductor of Mission – Mesa Heights 69 kV line
22. Reconductor Bernardo-Rancho Carmel 69 kV line
23. Reconductor of Sycamore – Chicarita 138 kV line
24. Pio Pico Power Plant (308 MW)
25. Encina Repower (600 MW)

Critical Contingency Analysis Summary

El Cajon Sub-area

The most critical contingency for the El Cajon sub-area is the loss of the El Cajon-Jamacha 69 kV line (TL624) followed by the loss of Miguel-Granite-Los Coches 69 kV line (TL632) or vice versa, which could thermally overload the Garfield-Murray 69 kV line (TL620). This limiting contingency establishes a LCR of 8 MW (including 0 MW of QF generation) in 2024 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area (El Cajon CalPeak, El Cajon GT and El Cajon Energy Center) have the same effectiveness factor.

Mission Sub-area

The most critical contingency for the Mission sub-area is the loss of Mission - Kearny 69 kV line (TL663) followed by the loss of Mission – Mesa Heights 69 kV line (TL676), which could thermally overload the Clairmont-Clairmont Tap 69 kV line (TL600). This limiting contingency establishes a local capacity need of 51 MW (including 4 MW of QF generation and 47 MW of deficiency) in 2024 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

It is recommended to retain the Kearny peakers, generating facilities until the limiting component is eliminated. This requirement is not driven by OTC retirement.

Effectiveness factors:
All Kearny Peakers have the same effectiveness factor.

Bernardo Sub-area
Artesian 230 kV substation project (expected to be in-service in 2016) will eliminate the local capacity need in this sub-area.

Esco Sub-area
The most critical contingency for the Esco sub-area is the loss of Poway-Pomerado 69 kV line (TL6913) followed by the loss of Bernardo – Rancho Carmel 69 kV line, which could thermally overload the Esco-Escondido 69 kV line (TL6908). This limiting contingency establishes a local capacity need of 75 MW in 2024 (includes 38 MW of QF generation and 37 MW deficiency) as the minimum capacity necessary for reliable load serving capability within this sub-area.

This requirement is not driven by OTC retirement and could be mitigated by a second Pomerado-Poway 69 kV line project. This project is being presented to ISO Management for consideration and approval.

Effectiveness factors:

The only unit within this area (Goal line) is needed therefore no effectiveness factor is required.

Escondido Sub-area

Bernardo – Rancho Carmel 69 kV line reconductoring project (expected in-service date – 2016) will eliminate the local capacity need in this sub-area.

Pala Sub-area

The most critical contingency for the Pala sub-area is the loss of Pendleton – San Luis Rey 69 kV line (TL6912) followed by the loss of Lilac - Pala 69 kV line (TL6932), which could thermally overload the Melrose – Morro Hill Tap 69 kV line (TL694). This limiting contingency establishes a local capacity need of 37 MW in 2024 (includes 0 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Border Sub-area

The most critical contingency for the Border sub-area is the loss of Bay Boulevard – Otay 69 kV line #1 (TL645) followed by Bay Boulevard Otay – 69 kV line #2 (TL646) or vice versa, which could thermally overload the Imperial Beach – Bay Boulevard 69 kV line (TL647). This limiting contingency establishes a local capacity need of 41 MW in 2024 (includes 5 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area have the same effectiveness factor.

Miramar Sub-area

The most critical contingency for the Miramar sub-area is the loss of Miguel-Bay Blvd. 230 kV line (TL23042A) followed by the loss of Sycamore-Penasquitos 230 kV line or vice versa, which could thermally overload the Sycamore - Scripps 69 kV line (TL6916). This limiting contingency establishes a LCR of 80 MW (including 0 MW of QF generation) in 2024 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency for the Miramar Sub-area is the loss of Miguel-Bay Blvd. 230 kV line (TL23042A) with Miramar Energy Facility #1 or #2 out of service, which could thermally overload the Sycamore-Scripps 69 kV line (TL6916). This limiting contingency establishes a local capacity need of 48 MW (including 0 MW of QF generation) in 2024 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:
All units within this area (Miramar Energy Facility #1 and #2) have the same effectiveness factor.

San Diego Sub-area:
The most limiting contingency is the loss of the Ocotillo - Suncrest 500 kV line followed by the loss of ECO - Miguel 500 kV line, which would result in thermal overload on the Imperial Valley phase shifters and/or Otay Mesa – Tijuana 230 kV line. This limiting contingency establishes a local capacity need of 3,078 MW in 2024 (includes 164 MW of QF and 9 MW of wind generation as well as 700 MW of deficiency) as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the loss of the Imperial Valley – North Gila 500 kV line with Otay Mesa power plant out of service, which would result in voltage instability. This limiting contingency establishes an overall local capacity need of about 4,063 MW of which San Diego sub-area requirement is 3,078 MW in 2024 (includes 164 MW of QF and 9 MW of wind generation as well as 700 MW of deficiency).

Due to upcoming OTC compliance dates the use of 338 MW of AAEE assumed in this study is critical, without it the LCR need will be higher by about the same amount.

Effectiveness factors:

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

RESOURCE NAME / kV / ID	LEFs
OTAYMGT1 18.0 #1	-33.84
C574CT1 13.8 #C1	-33.22
GRANITE 69.0 #d1	-31.96
EL CAJON 69.0 #d1	-31.74
MURRAY 69.0 #d1	-31.64
SAMPSON 12.5 #d1	-31.42
TELECYN 138.0 #d1	-31.42
EC GEN1 13.8 #1	-31.38
NOISLMTR 69.0 #1	-31.34
B 69.0 #d1	-31.3
DIVISION 69.0 #1	-31.26
OTAY 69.0 #1	-31.22
OTAY 69.0 #3	-31.18
CABRILLO 69.0 #1	-31.04
MESAHGTS 69.0 #1	-31
KUMEYAAY 0.7 #1	-30.96
OY GEN 13.8 #1	-30.96
CREELMAN 69.0 #DG	-30.9
POINTLMA 69.0 #1	-30.88
OLD TOWN 69.0 #d1	-30.7
MISSION 69.0 #d1	-30.64
CARLTNHS 138.0 #1	-30.34
CALPK_BD 13.8 #1	-30.08
LRKSPBD1 13.8 #1	-30.06
BULLMOOS 13.8 #1	-29.96
GENESEE 69.0 #d1	-29.94
EASTGATE 69.0 #1	-29.92
MESA RIM 69.0 #d1	-29.92
TOREYPNS 69.0 #d1	-29.82
MEF MR1 13.8 #1	-29.4
CHCARITA 138.0 #1	-29.32
BERNARDO 69.0 #DG	-28.82
ARTESN 69.0 #DG	-28.74
LkHodG1 13.8 #1	-27.82
VALCNTR 69.0 #1	-27.72

RESOURCE NAME / kV / ID	LEFs
GOALLINE 69.0 #1	-27.48
BORREGO 69.0 #DG	-27.42
ASH 69.0 #d1	-27.22
ESCNDIDO 69.0 #DG	-27.2
CANNON 138.0 #d1	-27.04
SANMRCOS 69.0 #d1	-27.04
AVOCADO 69.0 #DG	-26.98
MONSRATE 69.0 #DG	-26.74
ES GEN 13.8 #1	-26.62
CALPK_ES 13.8 #1	-26.56
MELROSE 69.0 #DG	-26.26
PEN_CT1 18.0 #1	-26.2
COASTAL 13.8 #1	-25.92
PA GEN1 13.8 #1	-25.84
SANLUSRY 69.0 #d1	-25.66
BR GEN1 0.2 #1	-25.28
MARGARTA 138.0 #DG	-22.78
LAGNA NL 138.0 #DG	-22.72
TRABUCO 138.0 #d1	-22.72
CAPSTRNO 138.0 #DG	-22.62
PICO 138.0 #DG	-22.58

San Diego Sub-area Requirements:

2024 LTPP Tracks 1 & 4 Assumptions	Preferred Resources[35] (NQC) (MW)	Energy Storage (MW)	Conventional resources (MW)	Total Capacity (NQC) (MW)
SDG&E-procurement selection	82	25	600	707

2024	QF (MW)	Wind (MW)	Market (MW)	New DG (MW)	DR (MW)	Max. Qualifying Capacity (MW)
Available generation	164	9	2,121	67	17	2,378

2024	Total MW Requirement	Existing Resource Need (MW)	Deficiency without LTPP T1 & T4 (MW)	Total SDG&E Selected Procurement for LTPP Tracks 1 & 4 (MW)
Category B (Single)[36]	3,078	2,378	700	707
Category C (Multiple)[37]	3,078	2,378	700	707

[35] The ISO assumed 175 MW of distributed solar DG with 47% NQC conversion factor.
[36] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.
[37] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system

San Diego-Imperial Valley overall:

The most limiting contingency is the same as LA Basin-San Diego-Imperial Valley overall requirement. The most critical single contingency is the loss of the Imperial Valley – North Gila 500 kV line with Otay Mesa power plant out of service, which would result in voltage instability. This limiting contingency establishes a local capacity need of about 4,063 MW in 2024 (includes 164 MW of QF and 133 MW of wind generation) as the minimum capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

All units within this area have about the same effectiveness factor.

Changes compared to the 2019 results:

The load forecast decreased by 44 MW and the LCR need increased by about 857 MW mainly due to OTC retirement in San Diego and LA Basin areas as well as new more effective resources available for dispatch. The AAEE and DR remain critical for the San Diego sub-area.

San Diego-Imperial Valley Overall Requirements:

2024	QF (MW)	Wind (MW)	Market (MW)	New DG (MW)	DR (MW)	Max. Qualifying Capacity (MW)
Available generation	164	133	3,788	67	17	4,169

2024	Total (MW) Requirement	Existing Resources Needed (MW)	Deficiency (MW)	Incremental Resource Needs
				Total SDG&E Selected Procurement for LTPP Tracks 1 & 4 (MW)
Category B (Single)[38]	4,063	3,363	700	707
Category C (Multiple)[39]	4,147	3,363	784	707

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

[38] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[39] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system

11. Valley Electric Area

Area Definition

The transmission tie lines into the area include:

1) Amargosa-Sandy 138 kV line
2) Jackass Flats-Mercury Switch 138 kV line
3) Mercury Switch – Mercury 138kV line
4) Mead-Bob Switchyard 230 kV line
5) Northwest-Desert View 230 kV line
6) Innovation-Mercury 138 kV line
7) Bob Switchyard-SCE Eldorado 230 kV line

The substations that delineate the area are:

1) Amargosa is out Sandy is in
2) Jackass Flats is a shared bus between CAISO and NVE
3) Mercury Switch is a shared bus between CAISO and NVE
4) Mead is out Bob Switchyard is in
5) Northwest is out Desert View is in
6) Mercury is out Innovation is in
7) SCE Eldorado is out Bob Switchyard is in

Total 2024 busload within the defined area was: 155 MW along with 3 MW of transmission losses resulting in total load + losses of 158 MW.

There is no generation and qualifying capacity available in this area.

Major new transmission projects modeled:

1. SCE Eldorado-Bob Switchyard 230 kV Line #1
2. Bob Tap 230 kV Switchyard
3. Innovation-Mercury 138 kV line

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

4. Innovation 230 kV Switchyard
5. Charleston-Vista 138 kV line

Critical Contingency Analysis Summary

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

- 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

Changes compared to last year's results:

This area is eliminated due to the reasons cited above. DOE load at Jackass Flat is now reflected at part of total VEA load. VEA UVLS model was incorporated in the contingency analysis. CAISO operating procedure 7910 is now in effect and addresses some category C issues.