DOCKETED

Docket Number:	15-AFC-01
Project Title:	Puente Power Project
TN #:	215438-3
Document Title:	Testimony of Jim Caldwell Exhibit Appendix D Board Approved 2015-2016 Transmission Plan
Description:	N/A
Filer:	PATRICIA LARKIN
Organization:	SHUTE, MIHALY & WEINBERGER LLP
Submitter Role:	Intervenor Representative
Submission Date:	1/18/2017 4:10:35 PM
Docketed Date:	1/18/2017

APPENDIX D: 2025 Local Capacity Technical Analysis for the Los Angeles Basin (LA Basin), Big Creek/Ventura and San Diego Local Capacity Requirement Areas

Intentionally left blank

California Independent System Operator

2025
LOCAL CAPACITY TECHNICAL ANALYSIS

DRAFT REPORT
AND STUDY RESULTS

March 28, 2016

Local Capacity Technical Analysis
Overview and Study Results

I. Executive Summary

This Report documents the results and recommendations of the 2025 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 2025 LCR need for the overall LA Basin remains fairly constant compared to the 2024 LCR need (8,319 MW vs. 8,350 MW). However, the Eastern LA Basin sub-area LCR need, due to the same critical contingency, in the sub-area reduces by about 650 MW due to lower net peak demand in the LA Basin (320 MW). For the Western LA Basin sub-area, however, the LCR need increases by about 620 MW, which can be met by either additional local capacity procurement (up to maximum authorized amount of 2,500 MW), or by implementing one of the potential transmission solutions as evaluated further in the Western LA Basin sub-area. The reason for the increase in the Western LA Basin sub-area LCR need for the 2025 time frame is due to updated level that reflects higher dispatch of renewable resources that are based on the CPUC-provided technology factors (for Net Qualifying Capacity), for modeled renewable generation north and east of the LA Basin LCR area. This higher level of renewable generation dispatch (about 2,000 MW higher) reflects updated modeling for generation NQC outputs for centralized photovoltaic solar farms located outside north and east of the LA Basin LCR area. In addition, the updated models also include NQC level of generation dispatch for wind generation resources located north of the LA Basin LCR area. The increase in renewable generation dispatch level to reflect NQC-level outputs contributes to further thermal loading concerns for the 230kV lines south of newly upgraded Mesa Substation under contingency conditions. This reflects the ability of the upgraded Mesa Substation to facilitate delivering more renewable generation into the LA Basin load centers when it’s upgraded to 500kV voltage level and having additional 230kV lines in the Western LA Basin looped into it. In the Western LA Basin Sub-area LCR need discussion section, the ISO evaluated thirteen different options, which include either additional resource procurement and/or small-scale transmission upgrades[1], for mitigating the identified overloading concerns.

The overall San Diego-Imperial Valley LCR need increases by about 720 MW, mainly due to the need to dispatch resources to mitigate thermal loading concerns on the 230kV lines south of new upgraded Mesa Substation as discussed above. Although it is more effective to have additional resources in the Western LA Basin to mitigate this thermal loading concern, existing resources in the San Diego-Imperial Valley LCR area were dispatched after additional resource additions reach maximum procurement authorized for the Western LA Basin (i.e., 2500 MW).

Alternatively to the above, the following are several potential small-scale transmission upgrades studied for the Western LA Basin sub-area. These could effectively address this loading concern while maintaining the long-term power procurement at the current level that was approved by the CPUC for SCE's Western LA Basin and incremental procurement[2] of preferred resources and energy storage for the San Diego sub-area.

- opening Mesa 500/230kV Bank #2 under contingency conditions;
- re-arranging Mesa-Laguna Bell 230kV Lines and Opening Laguna Bell – La Fresa 230kV line under contingency; and
- Installing 10-Ohm series reactors[3] on the Mesa-Laguna Bell #1 230kV Line and potentially the Mesa-Redondo 230kV line in the future (beyond ten-year horizon for this line)

[1] Small-scale transmission upgrades include upgrades that are anticipated to be confined within the substation boundaries and do not require new Rights-of-Way for implementation.
[2] Incremental procurement of preferred resources and energy storage in San Diego area amounts to 250 MW, which is less than the 300 MW ceiling for preferred resources and energy storage authorized by the CPUC.
[3] Variation of this option includes thyristor-controlled series reactor to be inserted upon occurrence of the second N-1 contingency under peak load conditions. This option would have higher cost than the permanently installed series reactor, but its advantage is to preserve the original line impedance for lower losses in the pre-contingency condition.

Of the above three options, installing 10-Ohm series reactors[4] on the Mesa-Laguna Bell #1 230kV Line and potentially the Mesa-Redondo 230kV line in the future (i.e., the third option listed above) appears to have the least impact to the system under contingency condition and potentially have the lowest cost. This transmission upgrade option also would appear to be less costly and more effective in mitigating the potential loading concern than the option that calls for additional local capacity preferred resource procurement in the western LA Basin.

The following table summarizes the range of alternatives that were studied to address the 2025 LCR need under various resource procurement scenarios, including the above options and other alternatives that were found not to be sufficient and would leave a resource deficiency in the area.

Table D1: Summary of Alternatives for Meeting Long-Term (2025) LCR Needs for the LA Basin / San Diego Areas

No	Scenarios	Results
Alternatives that do meet the identified need		
1	• This is the same as option 1 described above • Fully procure LTPP Tracks 1 and 4 resources up to maximum authorizations for SCE (i.e., 2500 MW) and SDG&E (i.e., 1100 MW); and • Repurpose a total of 476 MW of existing demand response (i.e., this amount is approximately 286 MW beyond the baseline assumption of 189 MW in the LTPP Track 4 scoping ruling) with adequate operational characteristics[5], ***OR***	Then there is no resource deficiency

[4] Variation of this option includes thyristor-controlled series reactor to be inserted upon occurrence of the second N-1 contingency under peak load conditions. This option would have higher cost than the permanently installed series reactor, but its advantage is to preserve the original line impedance for lower losses in the pre-contingency condition.
[5] Implementable within 20 minutes time frame

No	Scenarios	Results
2	Alternatively to the above additional resource procurement scenario, • implement the CPUC recent decisions for SCE's procurement (i.e., 1813 MW) for the western LA Basin sub-area, and • procure additional 250 MW[6] of preferred resources for local capacity in the San Diego sub-area (part of the CPUC maximum authorizations of 300 MW of preferred resources for San Diego), and • implement small transmission upgrades[7] in the western LA Basin	Then there is no resource deficiency; system is more robust than Scenario #1
Alternatives that do NOT meet the identified need		
3A	• LTPP Tracks 1 and 4 are not fully procured up to maximum authorizations (i.e., 687 MW less than maximum authorized amount of 2500 MW) for the western LA Basin; • however, fully procure 300 MW preferred resources in San Diego to complete the San Diego local capacity procurement; • utilize LTPP Track 4 baseline assumptions for existing demand response (i.e., 190 MW for both western LA Basin and San Diego sub-areas) • but there are no further transmission upgrades in the western LA Basin, ***OR***	Then there would be resource deficiency
3B	Alternately • same Scenario as #2 but AAEE does not materialize as forecast (i.e., 962 MW in the western LA Basin and 401 MW in San Diego sub-area) , ***OR***	Then there would be resource deficiency

[6] Potential preferred resources for procurement under consideration by SDG&E
[7] For further information on potential small-scale transmission upgrades in the western LA Basin, please see discussion and summary table under the "Western LA Basin Sub-area" in this report.

No	Scenarios	Results
3C	• same as Option 3A, but the existing demand response is fully repurposed and used (i.e., 894 MW in the western LA Basin and 17 MW in the San Diego sub-area)	Then there would still be resource deficiency

For the Big Creek/Ventura LCR area, the demand forecast decreased by 285 MW and the Big Creek/Ventura overall LCR need has decreased by 94 MW. The AAEE remains critical for the Santa Clara and Moorpark sub-areas. The Moorpark sub-area LCR need is determined to be 516 MW, which exceeds its available local resources by 234 MW after Ormond Beach and Mandalay retirement by the end of 2020. The Moorpark sub-area is projected to be resource deficient by 234 MW if there is no approval decision from the CPUC for local capacity procurement to replace Ormond Beach and Mandalay generation after their retirement by the end of 2020 to comply with the SWRCB's Policy on OTC generating facilities. However, with the CPUC approval for long-term local capacity procurement selection in the Moorpark sub-area, it is expected that there is no resource deficiency.

The load forecast used in this study is based on the final adopted California Energy Demand 2015 - 2025 final forecast developed and adopted by the CEC, namely the mid-demand baseline with low-mid additional achievable energy efficiency (AAEE), which is posted at:
http://www.energy.ca.gov/2014_energypolicy/documents/index.html#adoptedforecast.

The following table provides a summary of the local capacity requirements for the Big Creek/Ventura, LA Basin and San Diego/Imperial Valley LCR areas for the 2025 study year.

2025 Local Capacity Needs

Table D2: Summary of Long-Term LCR Needs (2025) for Local Reliability Areas in Southern California

	Qualifying Capacity (MW)			2025 LCR Need Based on Single-Element Contingency (MW)			2025 LCR Need Based on Multiple-Element Contingency (MW)		
Local Area Name	Existing Resources	CPUC-approved procurement contracts	Total	Available Capacity Needed	Deficiency	Total	Available Capacity Needed	Deficiency	Total
Western LA Basin	2,728	1,813	4,541	4,541	(695)	5,236	4,541	(973)[8]	5,514
Eastern LA Basin	3,531	N/A	3,531	2,132	0	2,132	2,805	0	2,805
Big Creek/Ventura	3,667	Pending review and decision from the CPUC for the Moorpark sub-area procurement selection	3,667	2,111	0	2,111	2,455	234	2,689
San Diego/ Imperial Valley	4,618	800	4,618[9]	3,151	0	3,151	4,618	(250)[10]	4,868

The following are write-ups for each Local Capacity Area, which lists relevant new projects that were approved by the ISO Board, and which were modeled in the study cases, as well as reasons for changes between the 2024 Long-Term LCR study and the 2025 Long-Term LCR study results.

[8] This can be met with: (a) 687 MW of potential further procurement; and (c) 286 MW of additional repurposing for existing demand response (beyond the baseline 173 MW assumptions for the Western LA Basin sub-area and 17 MW for San Diego sub-area), or by minor transmission upgrades in the area.

[9] This also includes 133 MW of wind resources, 67 MW (NQC value) of new RPS distributed generation (PV), 17 MW of existing demand response and 800 MW of conventional resources that were approved by the CPUC as part of the long-term procurement plan for Tracks 1 and 4.

[10] This can be met with additional procurement (250 MW) of preferred resources and energy storage as previously authorized by the CPUC for long-term procurement plan (Tracks 1 and 4) for San Diego area.

Table of Contents

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

A. Objectives

As was the objective of all previous LCT Studies, the intent of the 2025 Long-Term LCT Study is to identify specific local areas within the CAISO Balancing Authority Area (BAA)'s southern California that have limited import capability and determine the minimum resource capacity (MW) necessary to mitigate the local reliability problems in those areas.

B. Key Study Assumptions

Inputs and Methodology

The ISO used the same Inputs and Methodology as agreed upon by interested parties previously incorporated into the 2025 LCR Study, as well as ISO Final Study Plan for the 2015 – 2016 Transmission Planning Process and the "CPUC Assigned Commissioner's Ruling on Updates to the Planning Assumptions and Scenarios for Use in the 2014 Long Term Procurement Plan and the California Independent System Operator's 2015-16 Transmission Planning Process" (the CPUC ACR Planning Study Assumptions). The following table sets forth a summary of the approved inputs and methodology that have been used in the previous 2024 LCR Study and this 2025 LCR Study:

Table D3: Summary 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[11], 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 previous 2024 as well as 2025 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

[11] TPL 002 Category B is generally equivalent to TPL 001-4 Category P1. TPL 003 Category C is generally equivalent to TPL 001-4 P2 through P7.

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.[12] 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., 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

[12] Pub. Utilities Code § 345

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. Performance Criteria- Category B

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.[13] 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.

[13] 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.

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)**.

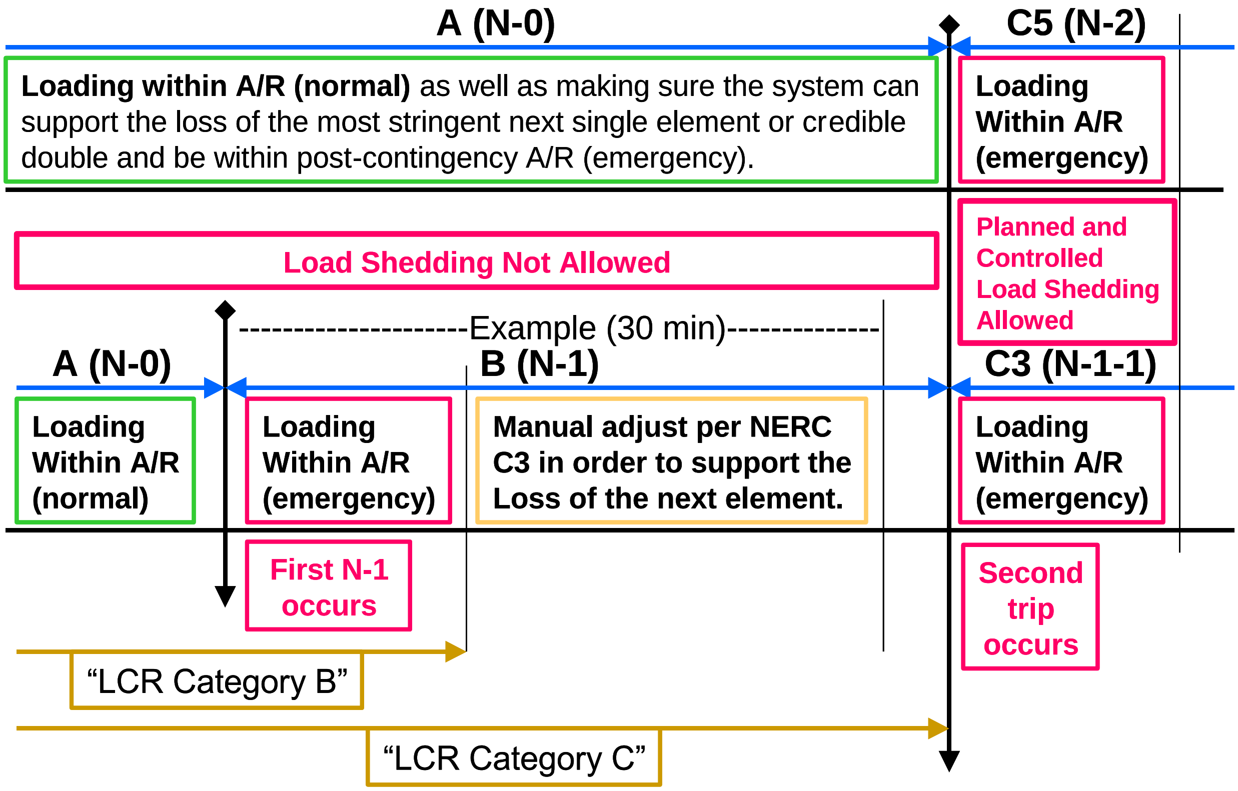

Figure D1: Summary of LCR Reliability Criteria

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.

<u>System Readjustment:</u>

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.

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

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

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

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

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:

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

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

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

(1) make an informed assessment of system conditions after a contingency has occurred;
(2) identify available resources and make prudent decisions about the most effective system redispatch;
(3) manually readjust the system within safe operating limits after a first contingency to be prepared for the next contingency; and
(4) allow sufficient time for resources to ramp and respond according to the operator's redispatch instructions. This all must be accomplished within 30 minutes.

Local capacity resources can meet this requirement by either (1) responding with sufficient speed, allowing the operator the necessary time to assess and redispatch resources to effectively reposition the system within 30 minutes after the first contingency, or (2) have sufficient energy available for frequent dispatch on a pre-contingency basis to ensure the operator can meet minimum online commitment constraints or reposition the system within 30 minutes after the first contingency occurs. Accordingly, when evaluating resources that satisfy the requirements of the CAISO Local Capacity Technical Study, the CAISO assumes that local capacity resources need to be available in no longer than 20 minutes so the CAISO and demand response providers have a reasonable opportunity to perform their respective and necessary tasks and enable the CAISO to reposition the system within the 30 minutes in accordance with applicable reliability criteria.

F. The Two Options Presented In This LCT Report

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

1. Option 1- Meet Performance Criteria Category B

Option 1 is a service reliability level that reflects generation capacity that must be available to comply with reliability standards immediately after a NERC Category B given that load cannot be removed to meet this performance standard under Reliability Criteria. However, this capacity amount implicitly relies on load interruption as the **only means** of meeting any Reliability Criteria that is beyond the loss of a single transmission element (N-1). These situations will likely require substantial load interruptions in order to maintain system continuity and alleviate equipment overloads prior to the actual occurrence of the second contingency.[14]

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

[14] 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.

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

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

III. Assumption Details: How the Study was Conducted

A. System Planning Criteria

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

Table D4: Reliability 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 over-lapping outage is considered a single contingency within the ISO Grid Planning Criteria. Therefore, load dropping for an overlapping G-1, L-1 scenario is not permitted.
[3] Applicable Rating – Based on CAISO Transmission Register or facility upgrade plans including established Path ratings.
[4] Applicable Rating – CAISO Grid Planning Criteria or facility owner criteria as appropriate including established Path ratings.
[5] A thermal or voltage criterion violation resulting from a transformer outage may not be cause for a local area reliability requirement if the violation is considered

marginal (e.g. acceptable loss of facility life or low voltage), otherwise, such a violation will necessitate creation of a requirement.

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

[7] During normal operation or following the first contingency (N-1), the generation must be sufficient to allow the operators to prepare for the next worst N-1 or common mode N-2 without pre-contingency interruptible or firm load shedding. SPS/RAS/Safety Nets may be utilized to satisfy the criteria after the second N-1 or common mode N-2 except if the problem is of a thermal nature such that short-term ratings could be utilized to provide the operators time to shed either interruptible or firm load. T-2s (two transformer bank outages) would be excluded from the criteria.

2. Post Transient Load Flow Assessment:

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

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

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

3. Stability Assessment:

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

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

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

B. Load Forecast

1. System Forecast

The California Energy Commission (CEC) derives the load forecast at the system and Participating Transmission Owner (PTO) levels. This relevant CEC forecast is then distributed across the entire system, down to the local area, division and substation level. The PTOs use an econometric equation to forecast the system load. The predominant parameters affecting the system load are (1) number of households, (2) economic activity (gross metropolitan products or 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[15] 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

[15] 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.

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.

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 D5: 2025 Local Capacity Needs vs. Peak Load and Local Area Resources

	2025 Total LCR (MW)	Peak Load (1 in10) (MW)	2025 LCR as % of Peak Load	Total Available Local Area Resources to Meet LCR Needs (MW)	2025 LCR as % of Total Area Resources
LA Basin	8,319	22,376	37%	7,346	113%** $
Big Creek/Ventura	2,689	4,794	56%	3,667	73%**
San Diego/Imperial Valley	4,868	5,394	90%	4,618	105% $

* 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, or further local capacity resource procurement is needed.

$ These are calculated with existing resources and future resources that already have approved PPTAs.

Table 3 shows how much of the Local Capacity Area load is dependent on local resources and how much local resources must be available in order to serve the load in those Local Capacity Areas in a manner consistent with the Reliability Criteria.

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 2025 have been included in this 2025 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 5), the 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 or single-element contingencies. The 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 as applicable, for multiple element contingencies (two or more elements, for more details, please see Table 1).

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.

3. LA Basin Area

<u>Area Definition</u>

The transmission tie lines into the LA Basin Area are:

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

3) San Onofre is in Capistrano is out
4) Mira Loma is in Lugo is out
5) Rancho Vista is in Lugo is out
6) Eagle Rock is in Sylmar is out
7) Gould is in Sylmar is out
8) 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 2025 demand for the LA Basin is 22,376 MW (includes 23,718 MW of forecasted substation demands, with 1,288 MW of AAEE, 125 MW of LTPP EE and 38 MW LTPP solar DG), with 109 MW of losses and 24 MW pump loads resulting in total load + losses + pump loads of 22,400 MW.

Table D6: 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 Metro	Not modeled	MUNI
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 Metro	Energy Only	Market
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[16]	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

[16] 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 (mid-level retirement assumptions) from the CPUC's "Assigned Commissioner's Ruling On Updates to the Planning Assumptions and Scenarios for Use in the 2014 Long-term Procurement Plan and the California Independent System Operator's 2015-16 Transmission Planning Process" (Rulemaking 13-12-010)".

Major new projects modeled:

1. Vincent-Mira Loma 500 kV (part of Tehachapi Upgrade)
2. East County 500kV Substation (ECO)
3. Mesa Loop-In Project and South of Mesa 230 kV line upgrades
4. Imperial Valley Phase Shifting Transformers (2x400 MVA)
5. Delaney – Colorado River 500 kV Line
6. Hassayampa – North Gila #2 500 kV Line (APS)
7. Bay Blvd. Substation Project
8. Sycamore – Penasquitos 230 kV Line
9. Talega Synchronous Condensers (2x225 MVAR)
10. San Luis Rey Synchronous Condensers (2x225 MVAR)
11. San Onofre Synchronous 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
15. Imperial Valley – Dixieland 230 kV tie with IID
16. Bypass series capacitors on the 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 is 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 Mesa – Redondo 230kV line, system re-adjusted, followed by the loss of Mesa – Lighthipe 230kV line. This N-1-1 (P6) contingency causes an overloading concern (114.5%) on the Mesa – Laguna Bell No. 1 230kV line. All resources in the western LA Basin, as well as in San Diego, have been utilized. However, the overloading concern still persists and to mitigate identified loading concern, the following mitigating options, summarized in the following Table XX, including transmission upgrades, are proposed. The overloading concerns are correlated to an additional 2,000 MW of renewable generation dispatch north of Mesa 500/230kV Substation. For the LCR analyses, the ISO dispatches generation based on the recommended Net Qualifying Capacity (NQC) values as evaluated by the CPUC as opposed to lower capacity values obtained from Gridview production cost simulation that were utilized for the reliability study cases. NQC values are recommended to be used for Resource Adequacy assessment such as Local Capacity Requirement studies for annual and Long Term Procurement Plan purposes.

The potential mitigation options that appear to be feasible to implement and mitigate identified overloading concerns are the following:

- Option 6 (opening Mesa 500/230kV Bank #2 under contingency conditions)
- Option Option 7B (Re-arranging Mesa-Laguna Bell 230kV Lines and Opening Laguna Bell – La Fresa 230kV line under contingency);
- Option 9 (Installing 10-Ohm Thyristor Controlled Series Reactors) on the Mesa-Laguna Bell #1 230kV Line

Other evaluated options either are uncertain in terms of being environmentally feasible options or appear to fall short of mitigating identified overloading concerns or cause new overloading concerns.

Table D7: Compare Mitigation Alternatives for South of Mesa 230 kV Loading Concerns

Scenario	Mitigation Options	Contingency	Category	Overloaded Facilities	Post-Mitigation Facility's Loading (%)	Emergency Rating (MVA)	Mitigating Loading Concern?	Comments / Is mitigation option feasible to Implement?
1	No mitigation	Mesa - Redondo 230kV, followed by Mesa - Lighthipe 230kV	P6 (N-1-1)	Mesa-Laguna Bell #1 230kV Line	116.2	1335	N/A	Identified loading concerns
2	Repurpose all utilize all existing DR (876 MW) in the western LA Basin and San Diego area (17 MW)	Mesa - Redondo 230kV, followed by Mesa - Lighthipe 230kV	P6 (N-1-1)	Mesa-Laguna Bell #1 230kV Line	109.9	1335	No	Not adequate
3	Close Mesa 230kV bus tie breaker	Mesa - Redondo 230kV, followed by Mesa - Lighthipe 230kV	P6 (N-1-1)	Mesa-Laguna Bell #1 230kV Line	75.2	1335	Yes	Adequate, but mitigation option is **not feasible** due to short circuit duty concerns exceeding circuit breakers' rating
4	Curtail generation north of Mesa 500/230kV Substation	Mesa - Redondo 230kV, followed by Mesa - Lighthipe 230kV	P6 (N-1-1)	Mesa-Laguna Bell #1 230kV Line	100.0	1335	Yes, marginally	Will need to curtail approximately 1,700 MW of generation (from 60 different resources), and dispatch another 1,600 MW of resources to maintain Path 26 within limits --> Burdensome to Operations and may not be feasible within 30 minutes time frame.
5	De-loop Vincent - Mira Loma 500kV line from Mesa after the first N-1 contingency	Mesa - Redondo 230kV, followed by Mesa - Lighthipe 230kV	P6 (N-1-1)	Mesa-Laguna Bell #1 230kV Line	143.0	1335	No	Not adequate
6A	Open Mesa 500/230kV Bank #2 After the first	Mesa - Redondo 230kV, followed	P6 (N-1-1)	Mesa-Laguna Bell #1 230kV Line	94.1	1335	Yes	The mitigation option is feasible. However, there are concerns on having too many SPS and potential mistrip of

Scenario	Mitigation Options	Contingency	Category	Overloaded Facilities	Post-Mitigation Facility's Loading (%)	Emergency Rating (MVA)	Mitigating Loading Concern?	Comments / Is mitigation option feasible to Implement?
	N-1 to prepare for the second N-1 contingency (Alternatively, install an SPS to monitor the outages and open the 500/230kV bank only after the second N-1 contingency)	by Mesa - Lighthipe 230kV						the SPS (for the alternative mitigation option where the SPS opens the 500/230kV bank after the N-1-1 contingency).
6B	Open Mesa 500/230kV Bank #2 upon an N-2 contingency (N-2 SPS)	Simultaneous N-2 of Mesa-Laguna Bell #2 and Mesa-Lighthipe 230kV lines	P7 (N-2)	Mesa-Laguna Bell #1 230kV Line	Pre-mitigation(%): 108Post-mitigation(%): 90.2	1335	Yes	Mitigation option is feasible to implement. However, there's concern regarding proliferation of SPS that could mistrip.
7A	Rearrange 230kV lines: relocate Mesa - Laguna Bell #2 230kV line from Mesa Cal South bus to Mesa Cal North bus --> Two Mesa - Laguna Bell 230kV lines to terminate at the same Mesa Cal N. 230kV bus	Mesa - Redondo 230kV, followed by Mesa - Lighthipe 230kV	P6 (N-1-1)	Mesa-Laguna Bell #1 230kV Line	74.2	1335	Yes, it mitigates this specific overloadin g concern, but causes another overloads under a different N-1-1 condition	The mitigatation option is feasible. However, with this configuration, it causes another overloading concern on the Mesa Cal - Laguna Bell #1 (or 2) under an N-1-1 of Mesa Cal - Laguna Bell #2 (or 1), followed by Mesa Cal - Lighthipe 230kV line.
7B	Same as above, but with opening of the Laguna Bell - La Fresa 230kV	Simultaneous N-2 of Mesa-Laguna Bell #2 and Mesa-	P7 (N-2)	Mesa-Laguna Bell #1 230kV Line	Pre-mitigation(%): 107.5 Post-	1335	Yes	Yes, mitigation option is feasible. This also mitigates the overloads on the Mesa - Laguna Bell # 1 under an N-1-1 contingency of Mesa - Laguna Bell #2,

Scenario	Mitigation Options	Contingency	Category	Overloaded Facilities	Post-Mitigation Facility's Loading (%)	Emergency Rating (MVA)	Mitigating Loading Concern?	Comments / Is mitigation option feasible to Implement?
	line upon the N-2 contingency	Lighthipe 230kV lines			mitigation(%): 84.4			followed by Mesa - Lighthipe 230kV line. However, this mitigation option would require installation of an SPS to open Laguna Bell-Mesa 230kV line upon the second N-1 contingency.
8	Reconductor Mesa-Laguna Bell 230kV and Mesa-Redondo 230kV lines with conductors having higher rating	Mesa - Redondo 230kV, followed by Mesa - Lighthipe 230kV, or Simultaneous N-2 of Mesa-Laguna Bell #2 and Mesa-Lighthipe 230kV lines	P6 (N-1-1) / P7 (N-2)	Mesa-Laguna Bell #1 230kV Line	TBD	TBD	Yes	This option would likely require environmental review from the CPUC (CPCN process due to voltage being 200kV or higher). It is uncertain if this option is feasible if there exists a potential need for additional Rights-of-Way for replacing existing towers to install higher rated conductors.
9	Install Thyristor Controlled Series Reactor (TCSR) with 10-ohm reactor on Mesa-Laguna Bell #1 230kV line; this is to be switched in upon the second N-1 or under N-2 contingency	Mesa - Redondo 230kV, followed by Mesa - Lighthipe 230kV, or Simultaneous N-2 of Mesa-Laguna Bell #2 and Mesa-Lighthipe 230kV lines	P6 (N-1-1) /P7 (N-2)	Mesa-Laguna Bell #1 230kV Line	59.4	1335	Yes	This option appears to be effective in mitigating loading concerns. This still requires SCE Substation Engineering evaluation to determine if there's adequate real estate at Mesa or Laguna Bell substations to install TCSR equipment.
10A	De-loop Laguna Bell - Rio Hondo 230kV line and Goodrich - Laguna Bell 230kV lines from Mesa Substation	Mesa-Lighthipe 230kV, followed by Alamitos-Lighthipe 230kV line	P6 (N-1-1)	Mesa-Redondo 230kV Line	102.2	876	No	Option is feasible to implement. However, this causes new overloading concerns under overlapping N-1-1 contingencies (see loading results at left for information)

Scenario	Mitigation Options	Contingency	Category	Overloaded Facilities	Post-Mitigation Facility's Loading (%)	Emergency Rating (MVA)	Mitigating Loading Concern?	Comments / Is mitigation option feasible to Implement?
10B	Same as above, but with a different contingency	Mesa-Lighthipe 230kV, followed by Rio Hondo-Laguna Bell 230kV line	P6 (N-1-1)	Mesa-Redondo 230kV Line	103.7	876	No	See above
11	Install Thyristor Controlled Series Reactor (TCSR) with 10-ohm reactor on Mesa-Redondo #1 230kV line; this is to be switched in upon the second N-1 contingency, OR alternatively, Install Permanently A 10-Ohm Series Reactor	Mesa – Laguna Bell #1 230kV, followed by Mesa - Lighthipe 230kV	P6 (N-1-1)	Mesa-Redondo #1 230kV Line*	Pre-mitigation: 98.8	1335	Yes	Although the Mesa-Redondo #1 230kV line is not yet overloaded for the 2025 condition, it's loading is projected to be near its emergency rating under an N-1-1 contingency. To prevent overloading beyond 10-year time frame horizon, a 10-ohm series reactor may be considered in the future.
12	Additional Resource Procurement Option: Implement 692 MW (this amount would bring the total procurement in line with the maximum authorization for the LA Basin) of	Mesa – Redondo 230kV, followed by Mesa - Lighthipe 230kV	P6 (N-1-1)	Mesa-Laguna Bell #1 230kV Line	99.4	1335	Yes	This option does **not** appear to be robust enough to accommodate future load growth. In addition, additional procurement of 692 MW of capacity in the western LA Basin may be more costly than some of the above considered transmission upgrade options.

Scenario	Mitigation Options	Contingency	Category	Overloaded Facilities	Post-Mitigation Facility's Loading (%)	Emergency Rating (MVA)	Mitigating Loading Concern?	Comments / Is mitigation option feasible to Implement?
	energy storage at El Segundo and Redondo switch yards (can split evenly between the two substations), and Repurpose an additional 286 MW of demand response (beyond the baseline assumptions) in the western LA Basin							
13	Connect Alamitos new CCGT to west bus?	Mesa – Redondo 230kV, followed by Mesa - Lighthipe 230kV	P6 (N-1-1)	Mesa-Laguna Bell #1 230kV Line	115.7	1335	No	This option does **not** mitigate identified loading concerns. It only reduces loading by about 0.5%.

With the potential transmission mitigation options considered and implemented, the local capacity requirements can be met with SCE-selected and CPUC-proposed decisions on long-term procurement plan resources and the existing resources, including baseline demand response assumptions (i.e., 190 MW for both western LA Basin and San Diego areas per the CPUC LTPP Track 4 Scoping Ruling). However, if transmission upgrades are not considered or are found to be infeasible or not cost effective as additional preferred resources or energy storage procurement option, then it would require approximately an additional 692 MW[17] of preferred resources, or energy storage, located at the most effective locations, and repurposing of an additional 286 MW of existing demand response in the western LA Basin beyond the LTPP Track 4 baseline assumptions of 173 MW of demand response located in the same sub-area.

This limiting contingency (overlapping N-1-1 contingency), as discussed further in the above section on page 28, establishes a local capacity need of about 5,514 MW in the Western LA Basin in 2025 (includes 517 MW of QF, 8 MW of wind, 582 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 Mesa – Lighthipe 230kV line with the new Alamitos repowered power plant (i.e., 640 MW combined cycle gas turbine) out of service, which could result in thermal loading concern for the Mesa – Laguna Bell #1 230kV line. This limiting contingency establishes a local capacity need of about 5,236 MW in the Western LA Basin in 2025 (includes 517 MW of QF, 8 MW of wind, 582 MW of MUNI generation).

Due to upcoming OTC compliance dates for the generating units in the LA Basin, the use of 920 MW of AAEE 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.

[17] For resource options, the ISO modeled the additional preferred resources or energy storage at the most effective locations to mitigate identified loading concerns at El Segundo and Redondo switchyards for this overlapping N-1-1 contingency. The residual 692 MW would fill up the maximum authorized amount of 2,500 MW from LTPP Tracks 1 and 4 for the western LA Basin.

Effectiveness factors:

Limiting factors that affect the LCR needs for the western LA Basin appear to trade places between previously identified post-transient voltage instability to thermal loading affecting the south of Mesa 230kV lines. As more dynamic reactive supports are added to the system, and the net peak load forecast (i.e., load including AAEE) is lower than previous forecast[18], the post-transient voltage instability concern is mitigated and is secondary to the thermal loading constraints on south of Mesa 230kV lines. The thermal loading constraints identified in the 2024 long-term LCR studies in the last planning cycle (2014-2015) that affected the Imperial Valley phase shifting transformers are mitigated with the updated design parameters for the phase shifters which reflect higher transformer impedance values. Future changes in the system (i.e., beyond 2025), such as higher loads, or selected mitigation option for relieving the south of Mesa 230kV loading concerns, may change the critical constraints that affect the western LA Basin LCR need identified in this planning cycle.

The following table has effectiveness factors (LEFs) that are higher than 5% to mitigate the most critical contingency (primary constraint) which caused thermal loading concerns on the Mesa – Laguna Bell 230kV line in the western LA Basin sub-area. It is noted that the overloading concern occurs with higher dispatch level of renewable generation outside of the LA Basin LCR area, based on the NQC values that are modeled using the technology factors provided by the CPUC staff. It is possible that the "minor" transmission upgrades, considered in Table XX, could turn out to be more cost effective than further preferred resource procurement.

[18] The difference between the 2014-2024 and 2015-2025 demand forecast for 2025 is estimated to be about 518 MW for the combined LA Basin and San Diego areas.

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

Please note that when a critical contingency and primary constraints in the local reliability areas are mitigated by potential transmission solutions, the next critical contingency would have caused a different transmission constraint that would trigger different effectiveness factors.

Western LA Basin Overall Requirements:

Table D8: LTPP Procurement Selection for the western LA Basin

2025 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)
CPUC Decisions on SCE-submitted procurement selection[19]	124	37.9	263.6	5	1,382	1,813

Table D9: Existing Resources[20] that Are Available for the Long-term Planning Horizon (2025)

2025	QF (MW)	Wind (MW)	Muni (MW)	Market (MW)	RPS DG[21] (MW)	DR[22] (MW)	Max. Qualifying Capacity (MW)
Available existing resources	517	8	588	1,285	157	173	2,728

[19] The CPUC approved SCE procurement selection, with exception, for the Western LA Basin local capacity needs per Decision D.15-11-041 at the November 19, 2015 CPUC Voting Meeting.

[20] These are existing resources minus retired OTC generation and aging generation facilities that are 40 years or older.

[21] RPS DG's are expressed in Net Qualifying Capacity (NQC) values

[22] Based on the CPUC LTPP Track 4 baseline assumptions for "fast" response DR. This includes 173 MW for the western LB Basin (at most effective locations) and 17 MW of DR in SDG&E system. There is approximately 90 MW currently is eligible to be characterized as being ready for contingency response in 20 minutes or less. The rest will need to be repurposed for response to the second contingency condition.

Table D10: Summary of LCR Needs for the Long-term Planning Horizon (2025)

2025	Total Local Capacity Requirements (MW)	Potential Resource Deficiency (MW)[23]	Break-downs of Projected 2025 Western LA Basin Sub-Area Resources		
			Available Existing Resources (MW)	CPUC-Proposed/Alternate Decisions on SCE Selected Procurement for LTPP Tracks 1 & 4 (MW)	Projected Total 2025 Local Resources (MW) (Sum of Two Columns at Left`)
Category B (Single)[24]	5,236	(695)	2,728	1,813	4,541
Category C (Multiple)[25]	5,514	(973)	2,728	1,813	4,541

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 2,805 MW in 2025 (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 available resources in the Eastern LA Basin sub-area are sufficient to meet this local capacity 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 could result in voltage instability. This limiting contingency establishes a local capacity need of about 2,132 MW in 2025 (includes 220 MW of QF, 60 MW of wind, and 581 MW of MUNI generation).

[23] To mitigate this potential resource deficiency concern, potential options include: (a) additional 687 MW of procurement of LTPP preferred resources (at effective locations) and repurposing of additional of 286 MW of existing DR; OR (b) implement cost effective and small-scale transmission upgrade options. Please see Table 1 for more details.
[24] 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.
[25] 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:

Table D11: Available Existing Resources for the Eastern LA Basin for the Long-Term Planning Horizon (2025)

2025	QF (MW)	Wind (MW)	Muni (MW)	Market (MW)	RPS DG (MW)	Max. Qualifying Capacity (MW)
Available resources	220	60	581	2,648	22	3,531

Table D12: Summary of LCR Needs for the Eastern LA Basin for the Long-Term Planning Horizon (2025)

2025	Local Capacity Requirements (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[26]	2,132	0	2,132
Category C (Multiple)[27]	2,805	0	2,805

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 two sub-areas of the Western and Eastern LA Basin sub-areas described above. The total need is determined to be 8,319 MW in 2025 (includes 737 MW of QF, 69 MW of wind, 1,163 MW of MUNI generation as well as 973 MW of potential deficiency[28]) as the minimum capacity necessary for reliable load serving capability within this sub-area.

---

[26] 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.

[27] 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.

[28] The “deficiency” is shown here if cost-effective transmission upgrades, shown in Table XX, are not considered and implemented, and the only solution is further procurement of resources and repurposing of existing demand response programs.

The overall single-element LA Basin local capacity need can also be best described as the sum of the Western and Eastern sub-area needs or 7,368 MW in 2025 (the LCR resource needs include resources from 737 MW of QF, 69 MW of wind, 1,163 MW of MUNI generation as well as potential 695 MW[29] of deficiency).

Due to upcoming OTC compliance dates the use of 1,288 MW of AAEE assumed for the overall LA Basin 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 actual locations of AAEE assumptions.

Changes compared to the 2024 results:

The one-in-ten mid demand with low-mid AAEE forecast, when compared to the 2014-2024 demand forecast, is reduced by 518 MW for 2025. Due to updated modeling of the capacity values at local area peak load from renewable generation facilities that are located outside of the LA Basin LCR area, there is approximately 2,000 MW of higher renewable generation dispatch, based on the NQC values calculated from the latest available CPUC-provided technology-based factors for wind and solar generation. With this higher level of renewable generation dispatch, the south of Mesa 230kV line loading remains a concern under an overlapping N-1-1 or simultaneous N-2 contingencies. The total LA Basin remains about the same (8,319 MW vs. 8,350 MW). However, the Western LA Basin sub-area's LCR need increases by 624 MW due to contingency overloading on the south of Mesa 230kV lines. This overloading concern can be mitigated either by additional procurement of preferred resources (up to the maximum authorized amount for the western LA Basin), ***or*** by implementing cost-effective and small-scale transmission upgrades that were evaluated and summarized in Table D7. The AAEE, LTPP EE and DR remain critical local resources for the LA Basin area.

[29] See above footnote (26)

LA Basin Overall Requirements:

Table D13: Summary of the Available Existing Resources[30] for the LA Basin for the Long-Term Planning Horizon (2025)

2025	QF (MW)	Wind (MW)	Muni (MW)	Market (MW)	RPS DG (MW)	DR (MW)	Max. Qualifying Capacity (MW)
Available resources	737	68	1,169	3,933	179	173[31]	6,259*

Notes:
*Due to large geographic area of the LA Basin, not all resources are effective at mitigating identified reliability concerns in the western LA Basin sub-area.

Table D14: Summary of the Total LCR Needs for the LA Basin for the Long-Term Planning Horizon (2025)

2025	Total LCR Requirements (MW)	Existing Resources Needed (MW)	CPUC Final Decisions for SCE Western LA Basin Procurement (MW)	Deficiency (MW)	Incremental Resource Needs	
					Additional Procurement of Preferred Resources (up to maximum authorized amount) (MW)	Additional Existing DR "Repurposed" Need[32] (MW)
Category B (Single)[33]	7,368	4,860	1,813	(695)**	687	8
Category C (Multiple)[34]	8,319	5,533	1,813	(973)**	687	286

Notes:
Deficiency is only for the Western LA Basin sub-area. This can be addressed by either additional procurement of preferred resources (up to maximum authorized amount of 2,500 MW) and repurposing of additional existing demand response, ***OR* by implementing cost-effective transmission solutions in the Western LA Basin (see discussion under this section).

2. Big Creek/Ventura Area

[30] Available existing resources minus OTC generation retirement and aging generation facilities (i.e., more than 40 years old)
[31] Baseline demand response in the LA Basin that was used in the LTPP Track 4 Scoping Ruling and studies
[32] These are existing demand response beyond the 173 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.
[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.

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

The total 2025 busload within the defined area is 4,542 MW (includes 4,824 MW of forecasted bus-level demand as well as 282 MW of AAEE) with 101 MW of losses and 151 MW pump loads resulting in total load + losses + pumps of 4,794 MW. This is based on the electrical representation of the area. The following information provides the total demand for the LCR area based on geographical representation of the Big Creek/Ventura, which more closely matches the demand forecast from the CEC for the area.

The geographical representation of this local area does not match the electrical representation above due to Saugus substation load being included in the LA Basin (geographical) representation. Saugus Substation is geographically located in Los Angeles County, thus being included as part of the LA Basin (geographical) total demand. The total load within the Big Creek/Ventura's geographical defined area is 3,579 MW of net bus-level load (includes 3,797 MW of forecasted bus-level demand as well as 218 MW of AAEE) with 101 MW of losses and 151 MW pump loads resulting in total load + losses + pumps of 3,831 MW.

Table D15: 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

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
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

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
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

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
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

<u>Critical Contingency Analysis Summary</u>

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 506 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 Factor (%)
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 728 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 246 MW (includes 68 MW QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Due to upcoming OTC compliance dates the use of 56 MW of AAEE and an assumption of 1 MW of solar DG and 1 MW of EE from long-term procurement plan RFO selection in this study is important, 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 516 MW. This local capacity requirement exceeds existing available resources by 234 MW, which in other words, meaning that the Moorpark sub-area is resource deficient by this amount.

Due to upcoming OTC compliance dates the use of 114 MW of AAEE 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 2,455 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 2,111 MW (includes 769 MW of QF and 392 MW of MUNI generation).

Due to upcoming OTC compliance dates the use of 282 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.

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 2024 results:

The load forecast decreased by 285 MW and the Big Creek/Ventura overall LCR need has decreased by 94 MW. The AAEE remains critical for the Santa Clara and Moorpark sub-areas. The Moorpark sub-area is projected to be deficient by 234 MW without the CPUC approval for long-term procurement for local capacity after Ormond Beach and Mandalay retirement to comply with the SWRCB's Policy on OTC generating units by the end of 2020 time frame. However, with the CPUC approval of SCE submitted procurement selection for local capacity in the Moorpark sub-area, it is expected that there is no deficiency.

Big Creek/Ventura Overall Requirements:

Table D16: Summary of SCE RFO Selection for Long-Term Local Capacity Procurement for the Moorpark Sub-Area

2025 LTPP Assumptions	LTPP EE (MW)	Solar PV (MW)	Storage 4h (MW)	Conventional resources (MW)	LTPP Total Capacity (MW)
SCE-submitted procurement selection for the Moorpark sub-area	6	5.66	0.5	262	274

Table D17: Available Existing Resources[35] for the Long-Term Planning Horizon (2025)

2025	QF (MW)	Muni (MW)	Market (MW)	New RPS DG (MW)	Max. Qualifying Capacity (MW)
Available resources for the larger Big Creek/Ventura LCR area	769	392	2258	248	3667

Table D18: Summary of LCR Needs for the Long-Term Planning Horizon (2025)

2025 LCR Requirements	Total MW Requirement	Existing Resource Need (MW)	Deficiency without LTPP T1 & T4 (MW)	Total SCE Selected Procurement for LTPP Tracks 1 & 4 for the Moorpark sub-area(MW)
Category B (Single)[36]	2,111	2,111	0	274
Category C (Multiple) [37]	2,689	2,455	234[38]	274

[35] Existing resources minus OTC generation (scheduled for retirement) and aging generation retirement assumptions (i.e., generating units that are more than 40 years old)

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

[38] Deficiency in the Moorpark sub-area. Resource deficiency values result from deficient sub-area; 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 curtailed immediately after the first contingency (to prepare for the next contingency) if there is no resource procurement to replace the retirement of Mandalay and Ormond Beach generation.

4. San Diego-Imperial Valley Area

Area Definition

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
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 2025 1-in-10 peak net demand for the area is 5,394 MW. The breakdown includes 5,700 MW of forecasted substation loads, 401 MW of AAEE and 40 MW of LTPP EE with 135 MW of losses, resulting in total load + losses of 5,394 MW.

Table D19: 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/Selfger
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/Selfger
MSSION_2_QF	22496	MISSION	69	0.70	1	San Diego	Aug NQC	QF/Selfger
NIMTG_6_NIQF	22576	NOISLMTR	69	36.43	1	San Diego	Aug NQC	QF/Selfger
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/Selfger
OTAY_7_UNITC1	22604	OTAY	69	2.57	3	San Diego, Border	Aug NQC	QF/Selfger
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	56.15	G1	None	NQC – Solar PV	Market
New Unit	23156	RPS	0.2	56.15	G2	None	NQC – Solar PV	Market
New Unit	23352	RPS	0.31	14.97	1	None	NQC – Solar PV	Market
New Unit	23487	RPS	0.31	14.97	1	None	NQC – Solar PV	Market
New Unit	23575	RPS	0.38	59.89	1	None	NQC – Solar PV	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. San Onofre 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 (300 MW)
25. Encina Repower (aka Carlsbad Energy Center) (500 MW)

Critical Contingency Analysis Summary

El Cajon Sub-area

The most critical contingency for the El Cajon sub-area is the loss of the El Cajon-Jamacha 69 kV line (TL624) followed by the loss of Garfield-Murray 69kV line (TL620), which would overload the El Cajon-Los Coches 69 kV line (TL620). This limiting contingency establishes an LCR of 6 MW (including 0 MW of QF generation) in 2025 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All resources 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-Kearny 69 kV line (TL600B and TL600C). This limiting contingency establishes a local capacity need of 40 MW (including 4 MW of QF generation and 36 MW of deficiency) in 2025 as the minimum generation capacity necessary for reliable load serving capability within this sub-area. It is also noted that there is an approximate 11 MW of AAEE modeled for substation loads located on the load side of the identified overloading concern. If this AAEE amount does not materialize, then the local capacity need is expected to increase by the same amount.

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

Effectiveness factors:

All Kearny Peakers have the same effectiveness factor.

Bernardo Sub-area

The Artesian 230 kV substation project (anticipated 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 Escondido-Esco-Warcyn Tap-Poway 69 kV line (TL6908-TL634D-TL634A). This limiting contingency establishes a local capacity need of 73 MW in 2025 (includes 38 MW of QF generation and 35 MW deficiency) as the minimum capacity necessary for reliable load serving capability within this sub-area.

The second Pomerado-Poway 69kV line project, approved by the ISO Board and Management in the 2014-2015 Transmission Plan, would eliminate the local capacity need in this sub-area. It was scheduled to be completed by June 2016 as reported in the 2014-2015 Transmission Plan, but could be delayed due to the need to obtain Permit to Construct (PTC) for obtaining new Rights-of-Way. This process could take up to 18 months to obtain the PTC from the CPUC, plus additional time for construction. If the project receives the PTC from the CPUC for construction, it will be placed in service for the ten-year planning horizon. However, there is uncertainty to when the project can be completed for the mid-term planning (i.e., up to five-year time frame).

Escondido Sub-area

The Bernardo – Rancho Carmel 69 kV line reconductoring project, with expected in-service date of June 2017, would 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 33 MW in 2025 (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 36 MW in 2025 (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 73 MW (including 0 MW of QF generation) in 2025 as the minimum generation 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 overlapping outage of the Mesa-Redondo 230kV line, followed by Mesa-Lighthipe 230kV line, which would result in thermal overload on the Mesa-Laguna Bell 230kV #1 line. As discussed in the Western LA Basin sub-area section, additional resources, up to maximum authorizations (i.e., 2500 MW) were modeled in the Western LA Basin as an option to determine if it can help mitigate identified loading concerns on the 230kV lines under contingency condition. Effective units, located in the San Diego sub-area, with effectiveness factors of 5% or more, were dispatched to help reducing loading concern. It is noted that if cost-effective transmission upgrades were implemented to mitigate identified potential loading concerns, as discussed in the Western LA Basin sub-area, the next limiting contingency for the San Diego sub-area would be the overlapping outage of the ECO-Miguel 500kV line, system readjusted, and followed by the Ocotillo-Suncrest 500kV line. This latter overlapping outage would cause post-transient voltage instability to the San Diego sub-area and the LA Basin. The LCR need associated with the latter contingency and reliability concern is about 100 MW less than the LCR need associated with the thermal loading concerns.

The following table under the “Effectiveness Factors” section below lists the resources located in SDG&E system that are effective by 5% or more in mitigating the identified overloading concern on the 230kV lines in the Western LA Basin sub-area. This limiting contingency establishes a local capacity need of 3,128 MW in 2025 (includes 164 MW of QF and 9 MW of wind generation as well as 250 MW of deficiency[39]). If an additional 50 MW of preferred resources are procured to meet maximum authorized amount (i.e., 300 MW), that would reduce the loading concerns by about 0.4%.

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

[39] The 250 MW deficiency is to be met by SDG&E procurement of preferred resources, which were authorized by the CPUC from the Long-Term Procurement Plan Tracks 1 and 4 proceedings. The 250 MW amount was provided by SDG&E as part of potential procurement for preferred resources.

instability. This limiting contingency establishes an overall local capacity need of 2,316 MW in 2025 (includes 164 MW of QF and 9 MW of wind generation).

Due to upcoming OTC compliance dates the use of 401 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 for the resources located in the San Diego sub-area to mitigate loading concerns caused by the most critical overlapping N-1-1 contingency.

RESOURCE LOCATIONS	EFFECTIVENESS FACTORS (%)
LAGNA NL 138.0 #DG	-7.6
MARGARTA 138.0 #DG	-7.59
CAPSTRNO 138.0 #DG	-7.57
PICO 138.0 #DG	-7.54
AVOCADO 69.0 #DG	-6.82
MELROSE 69.0 #DG	-6.81
MONSRATE 69.0 #DG	-6.76
COASTAL 1 13.8 #1	-6.56
SANMRCOS 69.0 #d1	-6.43
PA GEN1 13.8 #1	-6.4
VALCNTR 69.0 #1	-6.32
ESCNDIDO 69.0 #DG	-6.26
PEN_CT1 18.0 #1	-6.26
ES GEN 13.8 #1	-6.21
GOALLINE 69.0 #1	-6.2
CALPK_ES 13.8 #1	-6.19
LkHodG1 13.8 #1	-6.07
EASTGATE 69.0 #1	-6.02
BERNARDO 69.0 #DG	-6
ARTESN 69.0 #DG	-5.97
MEF MR1 13.8 #1	-5.93
MESAHGTS 69.0 #1	-5.93
CHCARITA 138.0 #1	-5.9
CABRILLO 69.0 #1	-5.89
POINTLMA 69.0 #1	-5.86
CREELMAN 69.0 #DG	-5.8
NOISLMTR 69.0 #1	-5.8

CARLTNHS 138.0 #1	-5.77
DIVISION 69.0 #1	-5.72
EC GEN1 13.8 #1	-5.72
KUMEYAAY 0.7 #1	-5.63
OTAY 69.0 #3	-5.6
OTAY 69.0 #1	-5.6
OY GEN 13.8 #1	-5.58
BORREGO 69.0 #DG	-5.52
SANIGEN 13.8 #D1	-5.42
CIMGEN 13.8 #D1	-5.4
SIMPSON 13.8 #D1	-5.39
CALPK_BD 13.8 #1	-5.3
LRKSPBD1 13.8 #1	-5.3
BULLMOOS 13.8 #1	-5.28
BR GEN1 0.2 #1	-5.12
OTAYMGT1 18.0 #1	-4.95

San Diego Sub-area Requirements:

Table D20: Summary of LTPP Local Capacity Procurement Assumptions for San Diego Area

Year 2025 - LTPP Tracks 1 & 4 Assumptions	Preferred Resources[40] (NQC) (MW)	Energy Storage (MW)	Conventional resources (MW)	Total Capacity (NQC) (MW)
SDG&E-procurement assumptions	100	150[41]	800[42]	1,050

Table D21: Available Existing Resources[43] for the Long-Term Planning Horizon (2025)

2025	QF (MW)	Wind (MW)	Market & LTPP Conventional Resources (MW)[44]	New RPS DG (MW)[45]	DR (MW)	Max. Qualifying Capacity (MW)
Available generation	164	9	2,621	67	17	2,878

[40] Preferred resource assumptions include 40 MW energy efficiency and 60 MW of demand response

[41] Potential energy storage assumptions

[42] Pio Pico (300 MW) and Carlsbad Energy Center (500 MW)

[43] Existing resources minus planned OTC generation retirement (i.e., Encina) and aging generation units/planned generation retirement (Cabrillo II)

[44] Including Pio Pico (300 MW) and Carlsbad Energy Center (500 MW)

[45] NQC values (assuming 0.47 peak load factor)

Table D22: Summary of LCR Needs for San Diego Sub-Area for the Long-Term Planning Horizon (2025)

2025	Total MW Requirement	Projected Available Resource Need[46] (MW)	Deficiency without further LTPP Preferred Resources Procurement (MW)	SDG&E Potential Additional LTPP Track 4 Procurement for Preferred Resources and Storage (MW)
Category B (Single)[47]	2,316	2,316	0	0
Category C (Multiple)[48]	3,128	2,878	250	250

San Diego-Imperial Valley overall:

The most limiting contingency is the same as the San Diego sub-area requirement, which is the overlapping outage of the Mesa-Redondo 230kV line, followed by Mesa-Lighthipe 230kV line that would result in thermal overload on the Mesa-Laguna Bell 230kV #1 line. This causes a local capacity requirement of 4,868 MW.[49] 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 3,151 MW in 2025 (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:

The following lists the effectiveness factors from lowest to highest in the San Diego-Imperial Valley area to mitigate identified loading concerns in the Western LA Basin sub-area.

[46] This amount includes approved 300 MW for Pio Pico and 500 MW for Carlsbad Energy Center

[47] 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.

[48] 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.

[49] As discussed in the Western LA Basin sub-area section, various transmission solutions were also evaluated as potential mitigation alternatives to identified loading concerns.

Resources kV/ID	Effectiveness Factor (%)
IV GEN2-U1 16.0 #1	-2.98
IV GEN1 CT 18.0 #1	-2.99
INTBCT 16.0 #1	-3
OCO GEN G1 0.7 #G1	-3.36
OTAYMGT1 18.0 #1	-5.03
BR GEN1 0.2 #1	-5.22
BULLMOOS 13.8 #1	-5.36
LRKSPBD1 13.8 #1	-5.38
CALPK_BD 13.8 #1	-5.39
BORREGO 69.0 #DG	-5.62
OY GEN 13.8 #1	-5.68
OTAY 69.0 #3	-5.69
OTAY 69.0 #1	-5.69
KUMEYAAY 0.7 #1	-5.72
DIVISION 69.0 #1	-5.77
EC GEN1 13.8 #1	-5.8
CREELMAN 69.0 #DG	-5.86
CARLTNHS 138.0 #1	-5.87
NOISLMTR 69.0 #1	-5.89
CABRILLO 69.0 #1	-5.94
POINTLMA 69.0 #1	-5.95
CHCARITA 138.0 #1	-6.01
MEF MR1 13.8 #1	-6.03
MESAHGTS 69.0 #1	-6.03
BERNARDO 69.0 #DG	-6.06
ARTESN 69.0 #DG	-6.07
EASTGATE 69.0 #1	-6.12
LkHodG1 13.8 #1	-6.17
CALPK_ES 13.8 #1	-6.27
GOALLINE 69.0 #1	-6.31
ES GEN 13.8 #1	-6.32
ESCNDIDO 69.0 #DG	-6.38
PEN_CT1 18.0 #1	-6.39
VALCNTR 69.0 #1	-6.43
PA GEN1 13.8 #1	-6.5
SANMRCOS 69.0 #d1	-6.55
COASTAL 1 13.8 #1	-6.68
MONSRATE 69.0 #DG	-6.85
AVOCADO 69.0 #DG	-6.86
MELROSE 69.0 #DG	-6.93
PICO 138.0 #DG	-7.72
CAPSTRNO 138.0 #DG	-7.75
MARGARTA 138.0 #DG	-7.76
LAGNA NL 138.0 #DG	-7.77

Changes compared to the 2024 results:

The overall load forecast decreased by 200 MW. The LCR need, however, for the Imperial Valley-San Diego LCR area was determined to increase by about 700 MW, of which 250 MW are assumed to be new preferred resources and energy storage and the rest are existing resources, to help mitigate identified loading concerns on the 230kV lines in the western LA Basin[50] due to higher level of renewable resource dispatch in the Tehachapi and east of LA Basin[51]. The AAEE and DR assumptions remain critical for the San Diego sub-area. Alternatively, cost-effective transmission solutions, as discussed in the Western LA Basin Sub-area section, can mitigate identified loading concerns effectively.

San Diego-Imperial Valley Overall Requirements:

Table D23: Summary of Available Existing Resources for the Long-Term Planning Horizon

2025	QF (MW)	Wind (MW)	Market (MW)	New RPS DG (MW)	DR (MW)	Max. Qualifying Capacity (MW)
Available resources[52]	164	133	4,237	67	17	4,618

Table D24: Summary of LCR Needs for the Long-Term Planning Horizon (2025)

2024	Total Local Capacity Requirement (MW)	Available Resources (MW)	Deficiency (MW)	Incremental Resource Needs
				SDG&E Preferred Resources from LTPP Track 4 (MW)
Category B (Single)[53]	3,151	4,618	0	0
Category C (Multiple)[54]	4,868	4,618	250	250

[50] Additional resources, up to maximum amount of 2500 MW authorized from the CPUC LTPP Tracks 1 and 4 are assumed for the western LA Basin sub-area.

[51] Higher level of renewable resource dispatch outside of the local capacity requirement areas based on qualifying capacity calculated from the CPUC-provided technology factors for determining capacity values at peak loads

[52] This includes 300 MW (Pio Pico) and 500 MW (Carlsbad Energy Center)

[53] 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.

[54] 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.