**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2016 and 2017 Compliance Years	Rulemaking 14-10-010 (Filed October 16, 2014)

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION FINAL LOCAL CAPACITY TECHNICAL ANALYSIS AND FINAL FLEXIBLE CAPACITY NEEDS ASSESSMENT FOR 2017

The California Independent System Operator Corporation (CAISO) has posted its Final Local Capacity Technical Analysis and Final Flexible Capacity Needs Assessment for 2017, and hereby submits these studies in this proceeding, consistent with the procedural schedule in the Assigned Commissioner and Administrative Law Judge's Phase 2 Scoping Memo and Ruling issued December 23, 2015.

Respectfully submitted,

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Dated: April 29, 2016

California Independent System Operator Corporation

Final Local Capacity Technical Analysis for 2017

California ISO

2017
LOCAL CAPACITY TECHNICAL ANALYSIS

FINAL REPORT
AND STUDY RESULTS

April 29, 2016

Local Capacity Technical Study
Overview and Results

I. Executive Summary

This Report documents the results and recommendations of the 2017 Local Capacity Technical (LCT) Study. The LCT Study assumptions, processes, and criteria were discussed and recommended through the 2017 Local Capacity Technical Study Criteria, Methodology and Assumptions Stakeholder Meeting held on October 29, 2015. On balance, the assumptions, processes, and criteria used for the 2017 LCT Study mirror those used in the 2007-2016 LCT Studies, which were previously discussed and recommended through the LCT Study Advisory Group ("LSAG")[1], an advisory group formed by the CAISO to assist the CAISO in its preparation for performing prior LCT Studies.

The 2017 LCT study results are provided to the CPUC for consideration in its 2017 resource adequacy requirements program. These results will also be used by the CAISO as "Local Capacity Requirements" or "LCR" (minimum quantity of local capacity necessary to meet the LCR criteria) and for assisting in the allocation of costs of any CAISO procurement of capacity needed to achieve the Reliability Standards notwithstanding the resource adequacy procurement of Load Serving Entities (LSEs).[2]

The load forecast used in this study is based on the final adopted California Energy Demand Updated Forecast, 2016-2026 developed by the CEC; namely the mid-demand baseline with low-mid additional achievable energy efficiency (AAEE), posted: http://www.energy.ca.gov/2015_energypolicy/documents/2016-01-27_load_serving_entity_and_Balencing_authority.php.

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[1] The LSAG consists of a representative cross-section of stakeholders, technically qualified to assess the issues related to the study assumptions, process and criteria of the existing LCT Study methodology and to recommend changes, where needed.

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

Below is a comparison of the 2017 vs. 2016 total LCR:

2017 Local Capacity Requirements

	Qualifying Capacity			2017 LCR Need Based on Category B***			2017 LCR Need Based on Category C*** with operating procedure		
Local Area Name	**QF/ Muni (MW)**	**Market (MW)**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**Existing Capacity Needed****	**Deficiency**	**Total (MW)**
Humboldt	20	198	218	110	0	**110**	157	0	**157**
North Coast / North Bay	128	722	850	721	0	**721**	721	0	**721**
Sierra	1176	890	2066	1247	0	**1247**	1731	312*	**2043**
Stockton	149	449	598	340	0	**340**	402	343*	**745**
Greater Bay	1070	8792	9862	4260	232*	**4492**	5385	232*	**5617**
Greater Fresno	231	3072	3303	1760	0	**1760**	1760	19*	**1779**
Kern	60	491	551	137	0	**137**	492	0	**492**
LA Basin	1615	8960	10575	6873	0	**6873**	7368	0	**7368**
Big Creek/ Ventura	543	4920	5463	1841	0	**1841**	2057	0	**2057**
San Diego/ Imperial Valley	239	5071	5310	3570	0	**3570**	3570	0	**3570**
Total	5231	33565	38796	20859	232	**21091**	23643	906	**24549**

2016 Local Capacity Requirements

	Qualifying Capacity			2016 LCR Need Based on Category B***			2016 LCR Need Based on Category C*** with operating procedure		
Local Area Name	**QF/ Muni (MW)**	**Market (MW)**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**Existing Capacity Needed****	**Deficiency**	**Total (MW)**
Humboldt	21	208	229	118	0	118	167	0	167
North Coast / North Bay	132	735	867	611	0	611	611	0	611
Sierra	1195	831	2026	1139	16*	1155	1765	253*	2018
Stockton	160	434	594	357	0	357	422	386*	808
Greater Bay	1104	6435	7539	3790	0	3790	4218	131*	4349
Greater Fresno	282	2647	2929	2445	0	2445	2445	74*	2519
Kern	99	430	529	214	0	214	400	0	400
LA Basin	1710	9259	10969	7576	0	7576	8887	0	8887
Big Creek/ Ventura	584	4951	5535	2141	0	2141	2398	0	2398
San Diego/ Imperial Valley	228	4687	4915	2850	0	2850	3112	72*	3184
Total	5515	30617	36132	21241	16	21257	24425	916	25341

* No local area is "overall deficient". Resource deficiency values result from a few deficient sub-areas; and since there are no resources that can mitigate this deficiency the numbers are carried forward into the total area needs. Resource deficient sub-area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.
** Since "deficiency" cannot be mitigated by any available resource, the "Existing Capacity Needed" will be split among LSEs on a load share ratio during the assignment of local area resource responsibility.
***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. Current LCR study report is compliant with existing language in the ISO Tariff section 40.3.1.1 Local Capacity Technical Study Criteria to be revised at a later date.

Overall, the LCR needs have decreased by about 790 MW or about 3.1% from 2016 to 2017. The LCR needs have decreased in the following areas: Humboldt, Stockton, Fresno and Big Creek/Ventura due to downward trend for load; La Basin due to downward trend for load and new transmission projects. The LCR needs have increased in North Coast/North Bay due to lower requirement in the Pittsburg sub-area of the Bay Area; Sierra due to increase in deficiency; Bay Area due to new South Bay-Moss Landing sub-area requirements and increase in San Jose sub-area deficiency; Kern due to additional load (about 280 MW) triggered by re-definition to account for the new 230 kV binding constraint and San Diego/Imperial Valley due to cancellation of previously planned upgrade projects connecting to the Imperial Valley 230 kV substation.

The write-up for each Local Capacity Area lists important new projects included in the base cases as well as a description of reason for changes between 2017 and 2016 LCRs.

Table of Contents

II. Study Overview: Inputs, Outputs and Options

A. Objectives

As was the objective of the previous annual LCT Studies, the intent of the 2017 LCT Study is to identify specific areas within the CAISO Balancing Authority Area that have limited import capability and determine the minimum generation capacity (MW) necessary to mitigate the local reliability problems in those areas.

B. Key Study Assumptions

1. Inputs and Methodology

The CAISO incorporated into its 2017 LCT study the same criteria, input assumptions and methodology that were incorporated into its previous years LCR studies. These inputs, assumptions and methodology were discussed and agreed to by stakeholders at the 2017 LCT Study Criteria, Methodology and Assumptions Stakeholder Meeting held on October 29, 2015.

The following table sets forth a summary of the approved inputs and methodology that have been used in the previous LCT studies as well as this 2017 LCT Study:

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

Issue:	How are they incorporated into this LCT study:
<u>Input Assumptions:</u>	
• 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
<u>Methodology:</u>	
• Maximize Import Capability	Import capability into the load pocket has been maximized, thus minimizing the generation required in the load pocket to meet applicable reliability requirements.
• QF/Nuclear/State/Federal Units	Regulatory Must-take and similarly situated units like QF/Nuclear/State/Federal resources have been modeled on-line at qualifying capacity output values for purposes of this LCT Study.
• Maintaining Path Flows	Path flows have been maintained below all established path ratings into the load pockets, including the 500 kV. For clarification, given the existing transmission system configuration, the only 500 kV path that flows directly into a load pocket and will, therefore, be considered in this LCR Study is the South of Lugo transfer path flowing into the LA Basin.
<u>Performance Criteria:</u>	
• Performance Level B & C, including incorporation of PTO operational solutions	This LCT 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 LCT Study.
<u>Load Pocket:</u>	
• Fixed Boundary, including limited reference to published effectiveness factors	This LCT Study has been produced based on load pockets defined by a fixed boundary. The CAISO only publishes effectiveness factors where they are useful in facilitating procurement where excess capacity exists within a load pocket.

Further details regarding the 2017 LCT Study methodology and assumptions are provided in Section III, below.

C. Grid Reliability

Service reliability builds from grid reliability because grid reliability is reflected in the Reliability Standards of the North American Electric Reliability Council (NERC) and the Western Electricity Coordinating Council ("WECC") Regional Criteria (collectively "Reliability Standards"). The Reliability Standards apply to the interconnected electric system in the United States and are intended to address the reality that within an integrated network, whatever one Balancing Authority Area does can affect the reliability of other Balancing Authority Areas. Consistent with the mandatory nature of the Reliability Standards, the CAISO is under a statutory obligation to ensure efficient use and reliable operation of the transmission grid consistent with achievement of the Reliability Standards.[3] The CAISO is further under an obligation, pursuant to its FERC-approved Transmission Control Agreement, to secure compliance with all "Applicable Reliability Criteria." Applicable Reliability Criteria consists of the Reliability Standards as well as reliability criteria adopted by the CAISO (Grid Planning Standards).

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

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[3] Pub. Utilities Code § 345

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

The CAISO will maintain the system in a safe operating mode at all times. This obligation translates into respecting the Reliability Criteria at all times, for example during normal operating conditions Category A (N-0) the CAISO must protect for all single contingencies Category B (N-1) and common mode Category C5 (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 requirement R1.1 of the WECC Regional Criteria[3] (“two adjacent circuits”) with no manual system adjustment between the two contingencies.

E. Performance Criteria

As set forth on the Summary Table of Inputs and Methodology, this LCT Report is based on NERC performance level B and performance level C standard. The NERC Standards refer mainly to system being stable and both thermal and voltage limits be within applicable ratings. However, the CAISO also tests the electric system in regards to the dynamic and reactive margin compliance with the existing WECC regional criteria that further specifies the dynamic and reactive margin requirements for the same NERC performance levels. These performance levels can be described as follows:

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

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

Category B system performance requires that system is stable and 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>LCR Performance Criteria- Category C</u>

The Reliability 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.[4] All Category

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[4] 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

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 Reliability Standards.

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 Standards at all times, for example during normal operating conditions Category **A (N-0)** the CAISO must protect for all single contingencies Category **B (N-1)** and common mode Category **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 Category **C3 (N-1-1)**.

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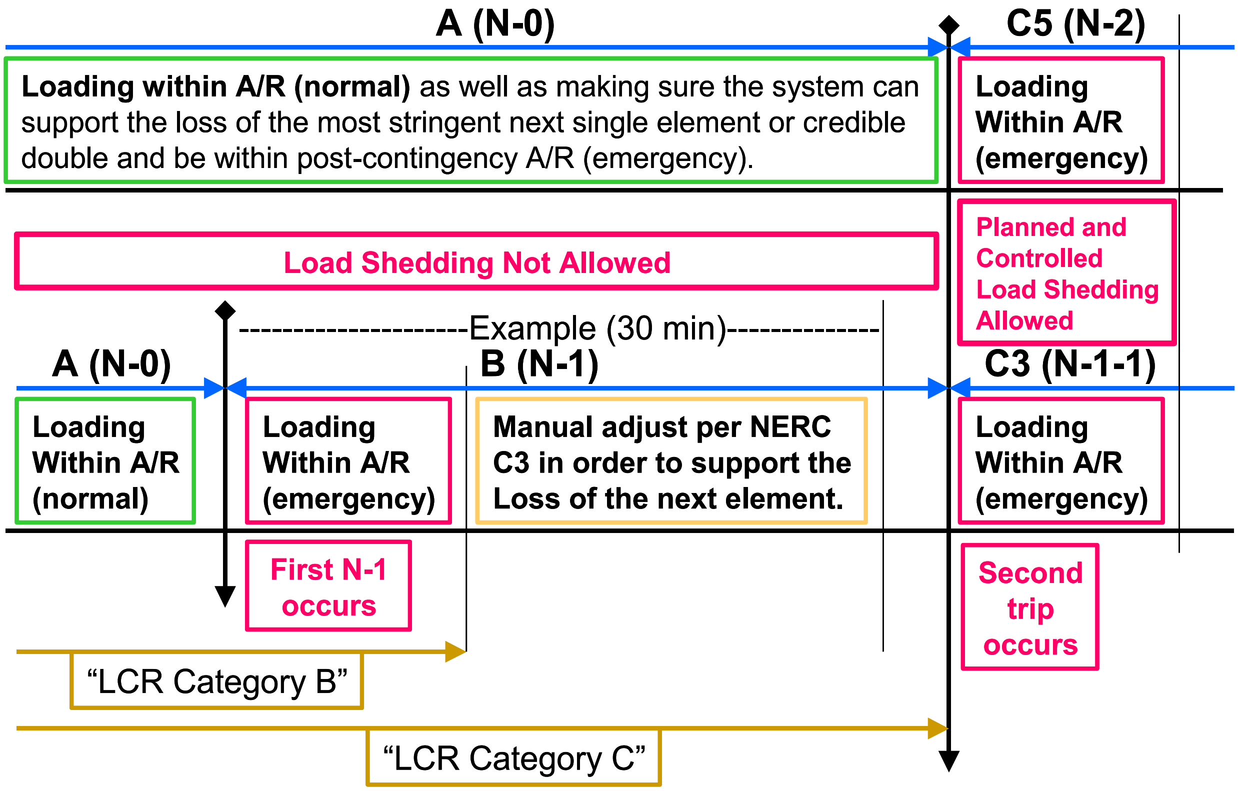
sometimes these systems will operate when not required and other times they will not operate when needed.

Figure 1: Temporal graph of LCR Category B vs. LCR Category C:



The following definitions guide the CAISO's interpretation of the Reliability Standards 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 within their limits in order to assure that proper capacity is available in order to operate the system in real-time in a safe operating zone.

Controlled load drop:

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

Planned load drop:

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

Special Protection Scheme:

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

System Readjustment:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

F. The Two Options Presented In This LCT Report

This LCT Study sets forth different solution “options” with varying ranges of potential service reliability consistent with CAISO’s Planning Standard. 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 LCR 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 Standard 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.[5]

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

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

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

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

III. Assumption Details: How the Study was Conducted

A. System Planning Criteria

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

Table 4: Criteria Comparison

Contingency Component(s)	ISO Grid Planning Standard	Old RMR Criteria	Local Capacity Criteria
<u>A – No Contingencies</u>	X	X	X
<u>B – Loss of a single element</u>			
1. Generator (G-1)	X	X	X[1]
2. Transmission Circuit (L-1)	X	X	X[1]
3. Transformer (T-1)	X	X[2]	X[1,2]
4. Single Pole (dc) Line	X	X	X[1]
5. G-1 system readjusted L-1	X	X	X
<u>C – Loss of two or more elements</u>			
1. Bus Section	X		
2. Breaker (failure or internal fault)	X		
3. L-1 system readjusted G-1	X		X
3. G-1 system readjusted T-1 or T-1 system readjusted G-1	X		X
3. L-1 system readjusted T-1 or T-1 system readjusted L-1	X		X
3. G-1 system readjusted G-1	X		X
3. L-1 system readjusted L-1	X		X
3. T-1 system readjusted T-1	X		
4. Bipolar (dc) Line	X		X
5. Two circuits (Common Mode or Adjacent Circuit) 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-R1.2. Two generators (Common Mode) G-2	X[3]		X
<u>D – Extreme event – loss of two or more elements</u>			
Any B1-4 system readjusted (Common Mode or Adjacent Circuit) L-2	X[4]		X[3]
All other extreme combinations D1-14.	X[4]		

1 System must be able to readjust to a safe operating zone in order to be able to support the loss of the next contingency.
2 A thermal or voltage criterion violation resulting from a transformer outage may not be cause for a local area reliability requirement if the violation is considered marginal (e.g. acceptable loss of facility life or low voltage), otherwise, such a violation will necessitate creation of a requirement.
3 Evaluate for risks and consequence, per NERC standards. No voltage collapse or dynamic instability allowed.
4 Evaluate for risks and consequence, per NERC standards.

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

1. Power Flow Assessment:

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

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

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

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

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

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

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

[7] During normal operation or following the first contingency (N-1), the generation

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

2. Post Transient Load Flow Assessment:

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

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

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

3. Stability Assessment:

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

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

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

B. Load Forecast

1. System Forecast

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

2. Base Case Load Development Method

The method used to develop the loads 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[6] loads that would meet the requirements of 1-in-5 or 1-in-10 system or area base cases and the other part deals with the allocation of the division load to the transmission buses.

i. Determination of division loads

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

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

the division.

ii. Allocation of division load to transmission bus level

Since the base case loads 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 loads in the base case 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 LCT analysis

The technical studies were conducted using General Electric's Power System Load Flow (GE PSLF) program version 19.0. 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. Local Capacity Requirement Study Results

A. Summary of Study Results

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

Table 5: 2017 Local Capacity Needs vs. Peak Load and Local Area Resources

	2017 Total LCR (MW)	Peak Load (1 in10) (MW)	2017 LCR as % of Peak Load	Total Dependable Local Area Resources (MW)	2017 LCR as % of Total Area Resources
Humboldt	157	188	84%	218	72%
North Coast/North Bay	721	1311	55%	850	85%
Sierra	2043	1757	116%	2066	99%**
Stockton	745	1157	64%	598	125%**
Greater Bay	5617	10477	54%	9862	57%**
Greater Fresno	1779	2964	60%	3303	54%**
Kern	492	1139	43%	551	89%
LA Basin	7368	18890	39%	10575	70%
Big Creek/Ventura	2057	4719	44%	5463	38%
San Diego/Imperial Valley	3570	4840	74%	5310	67%
Total	**24549**	**47442***	**52%***	**38796**	**63%**

Table 6: 2016 Local Capacity Needs vs. Peak Load and Local Area Resources

	2016 Total LCR (MW)	Peak Load (1 in10) (MW)	2016 LCR as % of Peak Load	Total Dependable Local Area Resources (MW)	2016 LCR as % of Total Area Resources
Humboldt	167	196	85%	229	73%
North Coast/North Bay	611	1433	43%	867	70%
Sierra	2018	1906	106%	2026	100%**
Stockton	808	1186	68%	594	136%**
Greater Bay	4349	10083	43%	7539	58%**
Greater Fresno	2519	3331	76%	2929	86%**
Kern	400	851	47%	529	76%
LA Basin	8887	20168	44%	10969	81%
Big Creek/Ventura	2398	4806	50%	5535	43%
San Diego/Imperial Valley	3184	5283	60%	4915	65%**
Total	**25341**	**49243***	**51%***	**36132**	**70%**

* Value shown only illustrative, since each local area peaks at a time different from the system coincident peak load.

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

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

The term "Qualifying Capacity" used in this report is the latest "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. Resources scheduled to become operational before 6/1/2017 have been included in this 2017 LCR Report and added to the total NQC values for those respective areas (see detail write-up for each area).

The first column, "Qualifying Capacity," reflects two sets of resources. The first set is comprised of resources that would normally be expected to be on-line such as Municipal and Regulatory Must-take resources (state, federal, QFs, wind and nuclear units). The second set is "market" resources and it also includes net-seller and solar resources. The second column, "2017 LCR Requirement Based on Category B" identifies the local capacity requirements, and deficiencies that must be addressed, in order to achieve a service reliability level based on Performance Criteria-Category B. The third column, "2017 LCR Requirement Based on Category C with Operating Procedure", sets forth the local capacity requirements, and deficiencies that must be addressed, necessary to attain a service reliability level based on Performance Criteria-Category C with operational solutions.

B. Summary of Zonal Needs

Based on the existing import allocation methodology, the only major 500 kV constraint not accounted for is path 26 (Midway-Vincent). ***The current method allocates capacity on path 26 similar to the way imports are allocated to LSEs.*** The total resources needed (based on the latest CEC load forecast) in each the two relevant zones, SP26 and NP26 is:

Zone	Load Forecast (MW)	15% reserves (MW)	(-) Allocated imports (MW)	(-) Allocated Path 26 Flow (MW)	Total Zonal Resource Need (MW)
SP26	27263	4089	-7423	-3750	**20179**
NP26=NP15+ZP26	20704	3106	-4242	-2902	**16666**

Where:

<u>*Load Forecast*</u> is the most recent 1 in 2 CEC forecast for year 2017 - California Energy Demand Updated Forecast, 2016 - 2026, Mid Demand Baseline, Mid AAEE Savings dated January 27, 2016.

<u>*Reserve Margin*</u> is 15% the minimum CPUC approved planning reserve margin.

<u>*Allocated Imports*</u> are the actual 2016 Available Import Capability for loads in the CAISO control area numbers that are not expected to change much by 2017 because there are no additional import transmission additions to the grid.

Allocated Path 26 flow The CAISO determines the amount of Path 26 transfer capacity available for RA counting purposes after accounting for (1) Existing Transmission Contracts (ETCs) that serve load outside the CAISO Balancing Area[7] and (2) loop flow[8] from the maximum path 26 rating of 4000 MW (North-to-South) and 3000 MW (South-to-North).

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

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

Changes compared to last year's results:

- The load forecast went down in Southern California by about 1140 MW and down in Northern California by about 1500 MW.
- The Import Allocations went down in Southern California by about 370 MW and down in Northern California by about 100 MW.
- The Path 26 transfer capability has not changed and is not envisioned to change in the near future. As such, the LSEs should assume that their load/share ratio allocation for path 26 will stay at the same levels as 2016. If there are any changes, they will be heavily influenced by the pre-existing "grandfathered contracts" and when they expire most of the LSEs will likely see their load share ratio going up, while the owners of these grandfathered contracts may see their share decreased to the load-share ratio.

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

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

C. Summary of Results by Local Area

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

1. Humboldt Area

<u>Area Definition</u>

The transmission tie lines into the area include:

1) Bridgeville-Cottonwood 115 kV line #1
2) Humboldt-Trinity 115 kV line #1
3) Willits-Garberville 60 kV line #1
4) Trinity-Maple Creek 60 kV line #1

The substations that delineate the Humboldt Area are:

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

Total 2017 busload within the defined area: 185 MW with -7 MW of AAEE and 10 MW of losses resulting in total load + losses of 188 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
FAIRHV_6_UNIT	31150	FAIRHAVN	13.8	14.52	1	None	Aug NQC	Net Seller
FTSWRD_6_TRFORK				0.16		None	Not modeled Aug NQC	Market
FTSWRD_7_QFUNTS				0.00		None	Not modeled Aug NQC	QF/Selfgen
GRSCRK_6_BGCKWW				0.00		None	Energy Only	QF/Selfgen
HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.25	1	None		Market
HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.25	2	None		Market
HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.25	3	None		Market
HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.25	4	None		Market

HUMBPP_6_UNITS	31181	HUMB_G2	13.8	16.27	5	None		Market
HUMBPP_6_UNITS	31181	HUMB_G2	13.8	16.27	6	None		Market
HUMBPP_6_UNITS	31181	HUMB_G2	13.8	16.27	7	None		Market
HUMBPP_6_UNITS	31182	HUMB_G3	13.8	16.27	8	None		Market
HUMBPP_6_UNITS	31182	HUMB_G3	13.8	16.27	9	None		Market
HUMBPP_6_UNITS	31182	HUMB_G3	13.8	16.27	10	None		Market
HUMBSB_1_QF				0.00		None	Not modeled Aug NQC	QF/Selfgen
KEKAWK_6_UNIT	31166	KEKAWAK	9.1	0.00	1	None	Aug NQC	Net Seller
LAPAC_6_UNIT	31158	LP SAMOA	12.5	20.00	1	None		Market
LOWGAP_1_SUPHR				0.52		None	Not modeled Aug NQC	Market
PACLUM_6_UNIT	31152	PAC.LUMB	13.8	7.62	1	None	Aug NQC	QF/Selfgen
PACLUM_6_UNIT	31152	PAC.LUMB	13.8	7.62	2	None	Aug NQC	QF/Selfgen
PACLUM_6_UNIT	31153	PAC.LUMB	2.4	4.59	3	None	Aug NQC	QF/Selfgen
WLLWCR_6_CEDRFL				0.00		None	Not modeled Aug NQC	QF/Selfgen
BLULKE_6_BLUELK	31156	BLUELKPP	12.5	0.00	1	None	Retired	Market

Major new projects modeled:

1. Humboldt 115/60 kV #1 and #2 transformer replacement
2. Bridgeville 115/60 kV #1 transformer replacement
3. Garberville Reactive Support

Critical Contingency Analysis Summary

Humboldt Overall:

The most critical contingency for the Humboldt area is the outage of the Bridgeville-Cottonwood 115 kV line overlapping with an outage of the Humboldt – Trinity 115 kV line. The area limitation is the overload on the Trinity – Maple Creek 60 kV line. This contingency establishes a LCR of 157 MW in 2017 (includes 20 MW of QF/Selfgen) as the minimum capacity necessary for reliable load serving capability within this area.

For the single contingency, the most critical one is an outage of the Bridgeville-Cottonwood 115 kV line when one of the Humboldt Bay Power Plant units connected to the 115 kV bus is out of service. The limitation is the overload on the Humboldt – Trinity 115 kV line. This limiting contingency establishes a LCR of 110 MW in 2017 (includes 20 MW of QF/Selfgen).

Effectiveness factors:

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

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

Changes compared to last year's results:

Compared to 2015 the total load forecast has decreased by 8 MW and the LCR needs have decreased by 10 MW.

Humboldt Overall Requirements:

2017	QF/Selfgen (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	20	198	218

2017	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[9]	110	0	110
Category C (Multiple)[10]	157	0	157

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

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

2. North Coast / North Bay Area

Area Definition

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

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

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

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

Total 2017 busload within the defined area: 1299 MW with -21 MW of AAEE and 33 MW of losses resulting in total load + losses of 1311 MW.

Total units and qualifying capacity available in this area are shown in the following table:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ADLIN_1_UNITS	31435	GEO.ENGY	9.1	8.00	1	Eagle Rock, Fulton, Lakeville		Market
ADLIN_1_UNITS	31435	GEO.ENGY	9.1	8.00	2	Eagle Rock, Fulton, Lakeville		Market
CLOVDL_1_SOLAR				1.03		Eagle Rock, Fulton, Lakeville	Not modeled Aug NQC	Market
CSTOGA_6_LNDFIL				0.00		Fulton, Lakeville	Not modeled Energy Only	Market
FULTON_1_QF				0.03		Fulton, Lakeville	Not modeled Aug NQC	QF/Selfgen
GEYS11_7_UNIT11	31412	GEYSER11	13.8	68.00	1	Eagle Rock, Fulton, Lakeville		Market
GEYS12_7_UNIT12	31414	GEYSER12	13.8	50.00	1	Fulton, Lakeville		Market
GEYS13_7_UNIT13	31416	GEYSER13	13.8	56.00	1	Lakeville		Market
GEYS14_7_UNIT14	31418	GEYSER14	13.8	50.00	1	Fulton, Lakeville		Market
GEYS16_7_UNIT16	31420	GEYSER16	13.8	49.00	1	Fulton, Lakeville		Market
GEYS17_7_UNIT17	31422	GEYSER17	13.8	53.00	1	Fulton, Lakeville		Market

GEYS18_7_UNIT18	31424	GEYSER18	13.8	45.00	1	Lakeville		Market
GEYS20_7_UNIT20	31426	GEYSER20	13.8	40.00	1	Lakeville		Market
GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	42.50	1	Eagle Rock, Fulton, Lakeville		Market
GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	42.50	2	Eagle Rock, Fulton, Lakeville		Market
GYS7X8_7_UNITS	31408	GEYSER78	13.8	38.00	1	Eagle Rock, Fulton, Lakeville		Market
GYS7X8_7_UNITS	31408	GEYSER78	13.8	38.00	2	Eagle Rock, Fulton, Lakeville		Market
GYSRVL_7_WSPRNG				1.48		Fulton, Lakeville	Not modeled Aug NQC	QF/Selfgen
HILAND_7_YOLOWD				0.00		Eagle Rock, Fulton, Lakeville	Energy Only	Market
HIWAY_7_ACANYN				0.18		Lakeville	Not modeled Aug NQC	QF/Selfgen
IGNACO_1_QF				0.00		Lakeville	Not modeled Aug NQC	QF/Selfgen
INDVLY_1_UNITS	31436	INDIAN V	9.1	1.11	1	Eagle Rock, Fulton, Lakeville	Aug NQC	Net Seller
MONTPH_7_UNITS	32700	MONTICLO	9.1	3.96	1	Fulton, Lakeville	Aug NQC	QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	3.95	2	Fulton, Lakeville	Aug NQC	QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	0.94	3	Fulton, Lakeville	Aug NQC	QF/Selfgen
NCPA_7_GP1UN1	38106	NCPA1GY1	13.8	31.00	1	Lakeville	Aug NQC	MUNI
NCPA_7_GP1UN2	38108	NCPA1GY2	13.8	28.00	1	Lakeville	Aug NQC	MUNI
NCPA_7_GP2UN3	38110	NCPA2GY1	13.8	0.77	1	Fulton, Lakeville	Aug NQC	MUNI
NCPA_7_GP2UN4	38112	NCPA2GY2	13.8	52.73	1	Fulton, Lakeville	Aug NQC	MUNI
POTTER_6_UNITS	31433	POTTRVLY	2.4	4.70	1	Eagle Rock, Fulton, Lakeville	Aug NQC	Market
POTTER_6_UNITS	31433	POTTRVLY	2.4	2.25	3	Eagle Rock, Fulton, Lakeville	Aug NQC	Market
POTTER_6_UNITS	31433	POTTRVLY	2.4	2.25	4	Eagle Rock, Fulton, Lakeville	Aug NQC	Market
POTTER_7_VECINO				0.01		Eagle Rock, Fulton, Lakeville	Not modeled Aug NQC	QF/Selfgen
SANTFG_7_UNITS	31400	SANTA FE	13.8	30.00	1	Lakeville		Market
SANTFG_7_UNITS	31400	SANTA FE	13.8	30.00	2	Lakeville		Market
SMUDGO_7_UNIT 1	31430	SMUDGEO1	13.8	37.00	1	Lakeville		Market
SNMALF_6_UNITS	31446	SONMA LF	9.1	3.56	1	Fulton, Lakeville	Aug NQC	QF/Selfgen
UKIAH_7_LAKEMN	38020	CITY UKH	115	0.49	1	Eagle Rock, Fulton, Lakeville	Aug NQC	MUNI
UKIAH_7_LAKEMN	38020	CITY UKH	115	1.21	2	Eagle Rock, Fulton, Lakeville	Aug NQC	MUNI
WDFRDF_2_UNITS	31404	WEST FOR	13.8	12.51	1	Fulton, Lakeville		Market
WDFRDF_2_UNITS	31404	WEST FOR	13.8	12.49	2	Fulton, Lakeville		Market
BEARCN_2_UNITS	31402	BEAR CAN	13.8	0.00	1	Fulton, Lakeville	Retired	Market
BEARCN_2_UNITS	31402	BEAR CAN	13.8	0.00	2	Fulton, Lakeville	Retired	Market
GEYS17_2_BOTRCK	31421	BOTTLERK	13.8	0.00	1	Fulton, Lakeville	Retired	Market

Major new projects modeled: None.

Critical Contingency Analysis Summary

Eagle Rock Sub-area

The most critical contingency is the outage of Cortina-Mendocino 115 kV line and

Geysers #5-Geysers #3 115 kV line. The sub-area area limitation is thermal overloading of the Eagle Rock-Cortina 115 kV line. This limiting contingency establishes a LCR of 181 MW in 2017 (includes 0 MW of QF/MUNI generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the outage of the Cortina-Mendocino 115 kV line with Geysers 11 generation unit out of service. The sub-area area limitation is thermal overloading of Eagle Rock-Cortina 115 kV line. This limiting contingency establishes a LCR of 166 MW in 2017 (includes 0 MW of QF/MUNI generation).

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
38020	CITY UKH	1	42
38020	CITY UKH	2	42
31406	GEYSR5-6	1	38
31406	GEYSR5-6	2	38
31408	GEYSER78	1	38
31408	GEYSER78	2	38
31412	GEYSER11	1	38
31435	GEO.ENGY	1	38
31435	GEO.ENGY	2	38
31433	POTTRVLY	1	36
31433	POTTRVLY	3	36
31433	POTTRVLY	4	36

Fulton Sub-area

The most critical contingency is the outage of Lakeville-Fulton 230 kV line #1 and Fulton-Ignacio 230 kV line #1. The sub-area limitation is thermal overloading of Santa Rosa-Corona 115 kV line #1. However, if the generation in the Fulton area is insufficient, the critical contingency would be not in the Fulton area, but in the Eagle Rock area: a double contingency of the Cortina-Mendocino 115 kV and Geysers #5-Geysers #3 115 kV lines that overloads the Eagle Rock-Cortina 115 kV line. This limiting contingency establishes a LCR of 304 MW in 2017 (includes 14 MW of QF and 55 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area. All of the resources needed to meet the Eagle Rock sub-area count towards the Fulton sub-area LCR need.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31404	WEST FOR	2	57
31402	BEAR CAN	1	57
31402	BEAR CAN	2	57
31404	WEST FOR	1	57
31414	GEYSER12	1	57
31418	GEYSER14	1	57
31420	GEYSER16	1	57
31422	GEYSER17	1	57
38110	NCPA2GY1	1	57
38112	NCPA2GY2	1	57
31421	BOTTLERK	1	57
31406	GEYSR5-6	1	31
31406	GEYSR5-6	2	31
31405	RPSP1014	1	31
31408	GEYSER78	1	31
31408	GEYSER78	2	31
31412	GEYSER11	1	31
31435	GEO.ENGY	1	31
31435	GEO.ENGY	2	31
31433	POTTRVLY	1	29
31433	POTTRVLY	3	29
31433	POTTRVLY	4	29
38020	CITY UKH	1	27
38020	CITY UKH	2	27

Lakeville Sub-area

The most limiting contingency is the outage of Vaca Dixon-Tulucay 230 kV line with DEC power plant out of service. The area limitation is thermal overloading of Vaca Dixon-Lakeville 230 kV. This limiting contingency establishes a LCR of 721 MW in 2017 (includes 14 MW of QF and 114 MW of MUNI generation) as the minimum capacity necessary for reliable load serving capability within this sub-area. The LCR resources needed for Eagle Rock and Fulton sub-areas can be counted toward fulfilling the requirement of Lakeville sub-area.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31400	SANTA FE	2	38
31430	SMUDGEO1	1	38
31400	SANTA FE	1	38
31416	GEYSER13	1	38
31424	GEYSER18	1	38
31426	GEYSER20	1	38
38106	NCPA1GY1	1	38
38108	NCPA1GY2	1	38
31421	BOTTLERK	1	36
31404	WEST FOR	2	36
31402	BEAR CAN	1	36
31402	BEAR CAN	2	36
31404	WEST FOR	1	36
31414	GEYSER12	1	36
31418	GEYSER14	1	36
31420	GEYSER16	1	36
31422	GEYSER17	1	36
38110	NCPA2GY1	1	36
38112	NCPA2GY2	1	36
31446	SONMA LF	1	36
32700	MONTICLO	1	31
32700	MONTICLO	2	31
32700	MONTICLO	3	31
31406	GEYSR5-6	1	18
31406	GEYSR5-6	2	18
31405	RPSP1014	1	18
31408	GEYSER78	1	18
31408	GEYSER78	2	18
31412	GEYSER11	1	18
31435	GEO.ENGY	1	18
31435	GEO.ENGY	2	18
31433	POTTRVLY	1	15
31433	POTTRVLY	2	15
31433	POTTRVLY	3	15
38020	CITY UKH	1	15
38020	CITY UKH	2	15

Changes compared to last year's results:

The 2017 load forecast went down by 122 MW compared to the 2016 and total LCR need went up by 110 MW. The increase in the LCR requirement for the North Coast/North Bay area is due to the large reduction in the LCR need (about 600 MW) in the Pittsburg/Oakland sub-area of the Bay Area.

North Coast/North Bay Overall Requirements:

2017	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	14	114	722	850

2017	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[11]	721	0	721
Category C (Multiple)[12]	721	0	721

3. Sierra Area

Area Definition

The transmission tie lines into the Sierra Area are:

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

The substations that delineate the Sierra Area are:

1) Table Mountain is out Rio Oso is in
2) Table Mountain is out Palermo is in
3) Table Mt is out Pease is in
4) Caribou is out Palermo is in
5) Drum is in Summit is out
6) Drum is in Summit is out

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

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

7) Spaulding is in Summit is out
8) Brighton is in Bellota is out
9) Rio Oso is in Lockeford is out
10) Gold Hill is in Eight Mile is out
11) Lodi STIG is in Eight Mile Road is out
12) Gold Hill is in Lake is out

Total 2017 busload within the defined area: 1688 MW with -22 MW of AAEE and 91 MW of losses resulting in total load + losses of 1757 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ALLGNY_6_HYDRO1				0.26		South of Table Mountain	Not modeled Aug NQC	Market
APLHIL_1_SLABCK				0.00	1	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Energy Only	Market
BANGOR_6_HYDRO				0.54		South of Table Mountain	Not modeled Aug NQC	Market
BELDEN_7_UNIT 1	31784	BELDEN	13.8	115.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
BIOMAS_1_UNIT 1	32156	WOODLAND	9.11	23.92	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Net Seller
BNNIEN_7_ALTAPH	32376	BONNIE N	60	0.72		Weimer, Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
BOGUE_1_UNITA1	32451	FREC	13.8	45.00	1	Bogue, Drum-Rio Oso, South of Table Mountain	Aug NQC	Market
BOWMN_6_UNIT	32480	BOWMAN	9.11	2.19	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
BUCKCK_7_OAKFLT				0.84		South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
BUCKCK_7_PL1X2	31820	BCKS CRK	11	29.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
BUCKCK_7_PL1X2	31820	BCKS CRK	11	29.00	2	South of Palermo, South of Table Mountain	Aug NQC	Market
CAMPFW_7_FARWST	32470	CMP.FARW	9.11	2.90	1	South of Table Mountain	Aug NQC	MUNI
CHICPK_7_UNIT 1	32462	CHI.PARK	11.5	38.00	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
COLGAT_7_UNIT 1	32450	COLGATE1	13.8	161.65	1	South of Table Mountain	Aug NQC	MUNI
COLGAT_7_UNIT 2	32452	COLGATE2	13.8	161.68	1	South of Table Mountain	Aug NQC	MUNI
CRESTA_7_PL1X2	31812	CRESTA	11.5	35.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
CRESTA_7_PL1X2	31812	CRESTA	11.5	35.00	2	South of Palermo, South of Table Mountain	Aug NQC	Market

DAVIS_1_SOLAR1				0.82		Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
DAVIS_1_SOLAR2				0.88		Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
DAVIS_7_MNMETH				2.06		Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
DEADCK_1_UNIT	31862	DEADWOOD	9.11	0.00	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
DEERCR_6_UNIT 1	32474	DEER CRK	9.11	3.74	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DRUM_7_PL1X2	32504	DRUM 1-2	6.6	13.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DRUM_7_PL1X2	32504	DRUM 1-2	6.6	13.00	2	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DRUM_7_PL3X4	32506	DRUM 3-4	6.6	13.70	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DRUM_7_PL3X4	32506	DRUM 3-4	6.6	13.70	2	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DRUM_7_UNIT 5	32454	DRUM 5	13.8	49.50	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DUTCH1_7_UNIT 1	32464	DTCHFLT1	11	22.00	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DUTCH2_7_UNIT 1	32502	DTCHFLT2	6.9	26.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
ELDORO_7_UNIT 1	32513	ELDRADO1	21.6	11.00	1	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain		Market
ELDORO_7_UNIT 2	32514	ELDRADO2	21.6	11.00	1	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain		Market
FMEADO_6_HELLHL	32486	HELLHOLE	9.11	0.26	1	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
FMEADO_7_UNIT	32508	FRNCH MD	4.2	16.01	1	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
FORBST_7_UNIT 1	31814	FORBSTWN	11.5	37.50	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
GOLDHL_1_QF				0.00		Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled	QF/Selfgen
GRIDLY_6_SOLAR	38054	GRIDLEY	60	0.00	1	Pease, South of Table Mountain	Energy Only	Market
GRNLF1_1_UNITS	32490	GRNLEAF1	13.8	7.69	1	Bogue, Drum-Rio Oso, South of Table Mountain	Aug NQC	Market
GRNLF1_1_UNITS	32490	GRNLEAF1	13.8	39.27	2	Bogue, Drum-Rio Oso, South of Table Mountain	Aug NQC	Market
GRNLF2_1_UNIT	32492	GRNLEAF2	13.8	35.01	1	Pease, Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen

HALSEY_6_UNIT	32478	HALSEY F	9.11	6.44	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
HAYPRS_6_QFUNTS	32488	HAYPRES+	9.11	0.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
HAYPRS_6_QFUNTS	32488	HAYPRES+	9.11	0.00	2	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
HIGGNS_1_COMBIE				0.00		Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Energy Only	Market
HIGGNS_7_QFUNTS				0.24		Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	QF/Selfgen
KANAKA_1_UNIT				0.00		Drum-Rio Oso, South of Table Mountain	Not modeled Aug NQC	MUNI
KELYRG_6_UNIT	31834	KELLYRDG	9.11	10.00	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
LIVEOK_6_SOLAR				0.87		Pease, South of Table Mountain	Not modeled Aug NQC	Market
LODIEC_2_PL1X2	38123	LODI CT1	18	166.00	1	South of Rio Oso, South of Palermo, South of Table Mountain		MUNI
LODIEC_2_PL1X2	38124	LODI ST1	18	114.00	1	South of Rio Oso, South of Palermo, South of Table Mountain		MUNI
MDFKRL_2_PROJCT	32456	MIDLFORK	13.8	62.18	1	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
MDFKRL_2_PROJCT	32456	MIDLFORK	13.8	62.18	2	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
MDFKRL_2_PROJCT	32458	RALSTON	13.8	84.32	1	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
NAROW1_2_UNIT	32466	NARROWS1	9.1	9.59	1	South of Table Mountain	Aug NQC	Market
NAROW2_2_UNIT	32468	NARROWS2	9.1	28.51	1	South of Table Mountain	Aug NQC	MUNI
NWCSTL_7_UNIT 1	32460	NEWCSTLE	13.2	0.00	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
OROVIL_6_UNIT	31888	OROVLLE	9.11	7.50	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	Market
OXBOW_6_DRUM	32484	OXBOW F	9.11	6.00	1	Weimer, Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
PACORO_6_UNIT	31890	PO POWER	9.11	2.58	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
PACORO_6_UNIT	31890	PO POWER	9.11	2.59	2	Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
PLACVL_1_CHILIB	32510	CHILIBAR	4.2	3.88	1	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PLACVL_1_RCKCRE				0.00		Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market

PLSNTG_7_LNCLND	32408	PLSNT GR	60	2.79		Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
POEPH_7_UNIT 1	31790	POE 1	13.8	60.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
POEPH_7_UNIT 2	31792	POE 2	13.8	60.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
RCKCRK_7_UNIT 1	31786	ROCK CK1	13.8	57.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
RCKCRK_7_UNIT 2	31788	ROCK CK2	13.8	56.90	1	South of Palermo, South of Table Mountain	Aug NQC	Market
RIOOSO_1_QF				1.14		Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	QF/Selfgen
ROLLIN_6_UNIT	32476	ROLLINSF	9.11	11.09	1	Weimer, Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
SLYCRK_1_UNIT 1	31832	SLY.CR.	9.11	10.36	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
SPAULD_6_UNIT 3	32472	SPAULDG	9.11	5.74	3	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
SPAULD_6_UNIT12	32472	SPAULDG	9.11	4.96	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
SPAULD_6_UNIT12	32472	SPAULDG	9.11	4.96	2	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
SPI LI_2_UNIT 1	32498	SPILINCF	12.5	9.73	1	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Net Seller
STIGCT_2_LODI	38114	Stig CC	13.8	49.50	1	South of Rio Oso, South of Palermo, South of Table Mountain		MUNI
ULTRCK_2_UNIT	32500	ULTR RCK	9.11	20.89	1	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
WDLEAF_7_UNIT 1	31794	WOODLEAF	13.8	60.00	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
WHEATL_6_LNDFIL	32350	WHEATLND	60	3.00		South of Table Mountain	Not modeled Aug NQC	Market
WISE_1_UNIT 1	32512	WISE	12	10.68	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
WISE_1_UNIT 2	32512	WISE	12	0.00	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
YUBACT_1_SUNSWT	32494	YUBA CTY	9.11	23.98	1	Pease, Drum-Rio Oso, South of Table Mountain	Aug NQC	Net Seller
YUBACT_6_UNITA1	32496	YCEC	13.8	46.00	1	Pease, Drum-Rio Oso, South of Table Mountain		Market
NA	32162	RIV.DLTA	9.11	0.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	No NQC - hist. data	QF/Selfgen

UCDAVS_1_UNIT	32166	UC DAVIS	9.11	3.50	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	No NQC - hist. data	QF/Selfgen

Major new projects modeled:

1. Palermo-Rio Oso 115 kV Reconductoring

Critical Contingency Analysis Summary

Placerville Sub-area

The most critical contingency is the loss of the Gold Hill-Clarksville 115 kV line followed by loss of the Gold Hill-Missouri Flat #2 115 kV line. The area limitation is thermal overloading of the Gold Hill-Missouri Flat #1 115 kV line. This limiting contingency establishes a LCR of 75 MW (includes 0 MW of QF and MUNI generation as well as 49 MW of deficiency) in 2017 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Placer Sub-area

The most critical contingency is the loss of the Gold Hill-Placer #1 115 kV line followed by loss of the Gold Hill-Placer #2 115 kV line. The area limitation is thermal overloading of the Drum-Higgins 115 kV line. This limiting contingency establishes a LCR of 66 MW (includes 38 MW of QF/MUNI generation) in 2017 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency is the loss of the Gold Hill-Placer #1 115 kV line with Chicago Park unit out of service. The area limitation is thermal overloading of the Drum-Higgins 115 kV line. This limiting contingency establishes a local capacity need of 47 MW (includes 38 MW of QF/MUNI) in 2017.

Effectiveness factors:

All units within this area (Chicago Park, Dutch Flat#1, Wise units 1&2, Newcastle and

Halsey) have the same effectiveness factor.

Pease Sub-area

The most critical contingency is the loss of the Palermo-East Nicolaus 115 kV line with Yuba City Energy Center unit out of service. The area limitation is thermal overloading of the Palermo-Pease 115 kV line. This limiting contingency establishes a LCR of 100 MW (includes 35 MW of QF generation) in 2017 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.

Bogue Sub-area

No requirement due to the Palermo-Rio Oso reconductoring project. If this project is delayed all units within this area (Greenleaf #1 units 1&2 and Feather River EC) are needed.

South of Rio Oso Sub-area

The most critical contingency is the loss of the Rio Oso-Gold Hill 230 line followed by loss of the Rio Oso-Lincoln 115 kV line or vice versa. The area limitation is thermal overloading of the Rio Oso-Atlantic 230 kV line. This limiting contingency establishes a LCR of 763 MW (includes 21 MW of QF and 593 MW of MUNI generation as well as 71 MW of deficiency) in 2017 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency is the loss of the Rio Oso-Gold Hill 230 line with the Ralston unit out of service. The area limitation is thermal overloading of the Rio Oso-Atlantic 230 kV line. This limiting contingency establishes a LCR of 429 MW (includes 21 MW of QF and 593 MW of MUNI generation) in 2017.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr. (%)
32498	SPILINCF	1	49
32500	ULTR RCK	1	49
32456	MIDLFORK	1	33
32456	MIDLFORK	2	33
32458	RALSTON	1	33
32513	ELDRADO1	1	32
32514	ELDRADO2	1	32
32510	CHILIBAR	1	32
32486	HELLHOLE	1	31
32508	FRNCH MD	1	30
32460	NEWCSTLE	1	26
32478	HALSEY F	1	24
32512	WISE	1	24
38114	Stig CC	1	14
38123	Q267CT	1	14
38124	Q267ST	1	14
32462	CHI.PARK	1	8
32464	DTCHFLT1	1	4

Drum-Rio Oso Sub-area

The most critical contingency is the loss of the Rio Oso #2 230/115 transformer followed by loss of the Rio Oso-Brighton 230 kV line. The area limitation is thermal overloading of the Rio Oso #1 230/115 kV transformer. This limiting contingency establishes in 2017 a LCR of 579 MW (includes 66 MW of QF and 201 MW of MUNI generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency is the loss of the Palermo #2 230/115 transformer. The area limitation is thermal overloading of the Rio Oso #1 230/115 kV transformer. This limiting contingency establishes in 2017 a LCR of 364 MW (includes 66 MW of QF and 201 MW of MUNI generation).

Effectiveness factors:

The following table has units in Drum-Rio Oso sub-area and their effectiveness factor:

Gen Bus	Gen Name	Gen ID	Eff Fctr. (%)
32156	WOODLAND	1	22
32490	GRNLEAF1	1	22
32490	GRNLEAF1	2	22
32451	FREC	1	21

32166	UC DAVIS	1	18
32498	SPILINCF	1	15
32502	DTCHFLT2	1	15
32494	YUBA CTY	1	14
32496	YCEC	1	14
32492	GRNLEAF2	1	13
32454	DRUM 5	1	13
32476	ROLLINSF	1	13
32474	DEER CRK	1	13
32504	DRUM 1-2	1	13
32504	DRUM 1-2	2	13
32506	DRUM 3-4	1	13
32506	DRUM 3-4	2	13
32484	OXBOW F	1	13
32472	SPAULDG	3	12
32472	SPAULDG	1	12
32472	SPAULDG	2	12
32488	HAYPRES+	1	12
32480	BOWMAN	1	12
32488	HAYPRES+	2	12
32464	DTCHFLT1	1	11
32162	RIV.DLTA	1	11
32462	CHI.PARK	1	9
32500	ULTR RCK	1	6
31862	DEADWOOD	1	5
31814	FORBSTWN	1	5
31832	SLY.CR.	1	5
31794	WOODLEAF	1	5
32478	HALSEY F	1	2
31888	OROVLLE	1	2
32512	WISE	1	2
31834	KELLYRDG	1	2
31890	PO POWER	1	2
31890	PO POWER	2	2
32460	NEWCSTLE	1	1

South of Palermo Sub-area

The most critical contingency is the loss of the Double Circuit Tower Line Table Mountain-Rio Oso and Colgate-Rio Oso 230 kV lines. The area limitation is thermal overloading of the Pease-Rio Oso 115 kV line. This limiting contingency establishes a LCR of 1620 MW (includes 26 MW of QF and 638 MW of MUNI generation as well as 251 MW of deficiency) in 2017 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the loss of the Table Mountain-Rio Oso 230 kV line with Belden unit out of service. The area limitation is thermal overloading of the Pease-Rio Oso 115 kV line. This contingency establishes in 2017 a LCR of 1247 MW (includes 26 MW of QF and 638 MW of MUNI generation).

Effectiveness factors:

All units within the South of Palermo are needed therefore no effectiveness factor is required.

South of Table Mountain Sub-area

The most critical contingency is the loss of the Table Mountain-Rio Oso 230 kV and Table Mountain-Palermo double circuit tower line outage. The area limitation is thermal overloading of the Caribou-Palermo 115 kV line. This limiting contingency establishes in 2017 a LCR of 1731 MW (includes 66 MW of QF and 1110 MW of MUNI generation) as the minimum capacity necessary for reliable load serving capability within this area.

The units required for the South of Palermo sub-area satisfy the single contingency requirement for this sub-area.

Effectiveness factors:

The following table has all units in Sierra area and their effectiveness factor:

Gen Bus	Gen Name	Gen ID	Eff Fctr. (%)
31814	FORBSTWN	1	8
31794	WOODLEAF	1	8
31832	SLY.CR.	1	7
31862	DEADWOOD	1	7
31888	OROVLLE	1	6
31890	PO POWER	2	6
31890	PO POWER	1	6
31834	KELLYRDG	1	6
32452	COLGATE2	1	5
32450	COLGATE1	1	5
32466	NARROWS1	1	5
32468	NARROWS2	1	5
32470	CMP.FARW	1	5
32451	FREC	1	5
32490	GRNLEAF1	2	4
32490	GRNLEAF1	1	4

32496	YCEC	1	3
32494	YUBA CTY	1	3
32492	GRNLEAF2	1	3
32156	WOODLAND	1	3
31820	BCKS CRK	1	2
31820	BCKS CRK	2	2
31788	ROCK CK2	1	2
31812	CRESTA	1	2
31812	CRESTA	2	2
31792	POE 2	1	2
31790	POE 1	1	2
31786	ROCK CK1	1	2
31784	BELDEN	1	2
32166	UC DAVIS	1	2
32500	ULTR RCK	1	2
32498	SPILINCF	1	2
32162	RIV.DLTA	1	2
32510	CHILIBAR	1	2
32514	ELDRADO2	1	2
32513	ELDRADO1	1	2
32478	HALSEY F	1	2
32458	RALSTON	1	2
32456	MIDLFORK	1	2
32456	MIDLFORK	2	2
38114	Stig CC	1	2
32460	NEWCSTLE	1	2
32512	WISE	1	2
32486	HELLHOLE	1	2
32508	FRNCH MD	1	2
32502	DTCHFLT2	1	2
32462	CHI.PARK	1	2
32464	DTCHFLT1	1	1
32454	DRUM 5	1	1
32476	ROLLINSF	1	1
32484	OXBOW F	1	1
32474	DEER CRK	1	1
32506	DRUM 3-4	1	1
32506	DRUM 3-4	2	1
32504	DRUM 1-2	1	1
32504	DRUM 1-2	2	1
32488	HAYPRES+	1	1
32488	HAYPRES+	2	1
32480	BOWMAN	1	1
32472	SPAULDG	1	1
32472	SPAULDG	2	1
32472	SPAULDG	3	1
38123	Q267CT1	1	1
38124	Q267ST1	1	1

Changes compared to last year's results:

The Sierra area load forecast went down by 149 MW and the LCR need has increased by 25 MW. Overall LCR need has increased by 25 MW due to increase in deficiency driven by higher flow on the limiting facility in the South of Palermo sub-area. The "Existing Generation Capacity Needed" had decreased by 34 MW.

Sierra Overall Requirements:

2017	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	66	1110	890	2066

2017	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[13]	1247	0	1247
Category C (Multiple)[14]	1731	312	2043

4. Stockton Area

<u>Area Definition</u>

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

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

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

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

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

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

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

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

The substations that delineate the Lockeford Sub-area are:

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

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

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

The substations that delineate the Weber Sub-area are:

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

Total 2017 busload within the defined area: 1156 MW with -20 MW of AAEE and 21 MW of losses resulting in total load + losses of 1157 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BEARDS_7_UNIT 1	34074	BEARDSLY	6.9	8.36	1	Tesla-Bellota, Stanislaus	Aug NQC	MUNI
CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	0.41	1	Tesla-Bellota	Aug NQC	MUNI
CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	0.41	2	Tesla-Bellota	Aug NQC	MUNI
CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	0.42	3	Tesla-Bellota	Aug NQC	MUNI
COGNAT_1_UNIT	33818	COG.NTNL	12	38.42	1	Weber	Aug NQC	Net Seller
CURIS_1_QF				0.33		Tesla-Bellota	Not modeled Aug NQC	QF/Selfgen
DONNLS_7_UNIT	34058	DONNELLS	13.8	72.00	1	Tesla-Bellota, Stanislaus	Aug NQC	MUNI

FROGTN_7_UTICA				0.00		Tesla-Bellota, Stanislaus	Energy Only	Market
LOCKFD_1_BEARCK				0.00		Tesla-Bellota	Not modeled Energy Only	Market
LOCKFD_1_KSOLAR				0.00		Tesla-Bellota	Not modeled Energy Only	Market
LODI25_2_UNIT 1	38120	LODI25CT	9.11	22.70	1	Lockeford		MUNI
PEORIA_1_SOLAR				0.97		Tesla-Bellota, Stanislaus	Not modeled Aug NQC	Market
PHOENX_1_UNIT				1.35		Tesla-Bellota, Stanislaus	Not modeled Aug NQC	Market
RIVRBK_1_LNDFIL				0.00		Tesla-Bellota, Stanislaus	Not modeled Energy Only	Market
SCHLTE_1_PL1X3	33805	GWFTRCY1	13.8	83.56	1	Tesla-Bellota		Market
SCHLTE_1_PL1X3	33807	GWFTRCY2	13.8	82.88	1	Tesla-Bellota		Market
SCHLTE_1_PL1X3	33811	GWFTRCY3	13.8	132.96	1	Tesla-Bellota		Market
SNDBAR_7_UNIT 1	34060	SANDBAR	13.8	6.29	1	Tesla-Bellota, Stanislaus	Aug NQC	MUNI
SPIFBD_1_PL1X2	33917	FBERBORD	115	1.57	1	Tesla-Bellota, Stanislaus	Aug NQC	Market
SPRGAP_1_UNIT 1	34078	SPRNG GP	6	0.00	1	Tesla-Bellota, Stanislaus	Aug NQC	Market
STANIS_7_UNIT 1	34062	STANISLS	13.8	91.00	1	Tesla-Bellota, Stanislaus	Aug NQC	Market
STNRES_1_UNIT	34056	STNSLSRP	13.8	12.19	1	Tesla-Bellota	Aug NQC	Net Seller
TULLCK_7_UNITS	34076	TULLOCH	6.9	8.43	1	Tesla-Bellota	Aug NQC	MUNI
TULLCK_7_UNITS	34076	TULLOCH	6.9	8.42	2	Tesla-Bellota	Aug NQC	MUNI
ULTPCH_1_UNIT 1	34050	CH.STN.	13.8	15.89	1	Tesla-Bellota, Stanislaus	Aug NQC	QF/Selfgen
VLYHOM_7_SSJID				1.09		Tesla-Bellota, Stanislaus	Not modeled Aug NQC	MUNI
WEBER_6_FORWRD				4.20		Weber	Not modeled Aug NQC	Market
NA	33687	STKTN WW	60	1.50	1	Weber	No NQC - hist. data	QF/Selfgen
NA	33830	GEN.MILL	9.11	2.50	1	Lockeford	No NQC - hist. data	QF/Selfgen
STOKCG_1_UNIT 1	33814	CPC STCN	12.5	0.00	1	Tesla-Bellota		QF/Selfgen
New Unit	34051	Q539	34.5	0.00	1	Tesla-Bellota	Energy Only	Market

Major new projects modeled:

1. Weber-Stockton “A” #1 & #2 60 kV Reconductoring
2. Weber 230/60 kV Transformer Replacement

Critical Contingency Analysis Summary

Stockton overall

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

Stanislaus Sub-area

The critical contingency for the Stanislaus area is the loss of Bellota-Riverbank-Melones 115 kV circuit with Stanislaus PH out of service. The area limitation is thermal overloading of the River Bank Jct.-Manteca 115 kV line. This limiting contingency establishes a local capacity need of 164 MW (including 16 MW of QF and 88 MW of MUNI generation) in 2017 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Tesla-Bellota Sub-area

The two most critical contingencies listed below together establish a local capacity need of 650 MW (includes 16 MW of QF and 106 MW of MUNI generation as well as 301 MW of deficiency) in 2017 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical contingency for the Tesla-Bellota pocket is the loss of Schulte-Kasson-Manteca 115 kV and Schulte-Lammers 115 kV. The area limitation is thermal overload of the Tesla-Tracy 115 kV line above its emergency rating. This limiting contingency establishes a local capacity need of 530 MW (includes 16 MW of QF and 106 MW of MUNI generation as well as 301 MW of deficiency) in 2017.

The second most critical contingency for the Tesla-Bellota pocket is the loss of Tesla-Tracy 115 kV and Tesla-Schulte #1 115 kV lines. The area limitation is thermal overload of the Tesla-Schulte #2 115 kV line. This limiting contingency establishes a 2017 local capacity need of 349 MW (includes 16 MW of QF and 106 MW of MUNI generation).

The single most critical contingency for the Tesla-Bellota pocket is the loss of Tesla-Schulte #1 115 kV line and the loss of the GWF Tracy unit #3. The area limitation is thermal overload of the Tesla-Schulte #2 115 kV line. This single contingency establishes a local capacity need of 340 MW (includes 16 MW of QF and 106 MW of MUNI generation) in 2017.

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

Effectiveness factors:

All units within this sub-area are needed for the most limiting contingencies therefore no effectiveness factor is required.

Lockeford Sub-area

The critical contingency for the Lockeford area is the loss of Lockeford-Industrial 60 kV circuit and Lockeford-Lodi #2 60 kV circuit. The area limitation is thermal overloading of the Lockeford-Lodi Jct. section of the Lockeford-Lodi #3 60 kV circuit. This limiting contingency establishes a 2017 local capacity need of 67 MW (including 2 MW of QF and 23 MW of MUNI generation as well as 42 MW of deficiency) as the minimum capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

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

Weber Sub-area

The critical contingency for the Weber area is the loss of Stockton A-Weber #1 & #2 60 kV lines. The area limitation is thermal overloading of the Stockton A-Weber #3 60 kV line. This limiting contingency establishes a local capacity need of 28 MW (including 2 MW of QF generation) in 2017 as the minimum capacity necessary for reliable load serving capability within this sub-area.

If Weber 230/60 kV transformer # 2 and 2A replacement project is delayed all units within this area (Cogeneration National, Stockton Waste Water and Weber Forward) are needed.

Effectiveness factors:

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

Changes compared to last year's results:

Overall the Stockton area load forecast went down by 29 MW. The overall requirement for the Stockton area decreased by 63 MW mainly due to decrease in load forecast.

Stockton Overall Requirements:

2017	QF (MW)	MUNI (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	20	129	449	598

2017	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[15]	340	0	340
Category C (Multiple)[16]	402	343	745

5. Greater Bay Area

<u>Area Definition</u>

The transmission tie lines into the Greater Bay Area are:

1) Lakeville-Sobrante 230 kV
2) Ignacio-Sobrante 230 kV
3) Parkway-Moraga 230 kV
4) Bahia-Moraga 230 kV
5) Lambie SW Sta-Vaca Dixon 230 kV
6) Peabody-Birds Landing SW Sta 230 kV
7) Tesla-Kelso 230 kV
8) Tesla-Delta Switching Yard 230 kV

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

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

9) Tesla-Pittsburg #1 230 kV
10) Tesla-Pittsburg #2 230 kV
11) Tesla-Newark #1 230 kV
12) Tesla-Newark #2 230 kV
13) Tesla-Ravenswood 230 kV
14) Tesla-Metcalf 500 kV
15) Moss Landing-Los Banos 500 kV
16) Moss Landing-Coburn 230 kV
17) Moss Landing-Las Aguillas 230 kV
18) Oakdale TID-Newark #1 115 kV
19) Oakdale TID-Newark #2 115 kV

The substations that delineate the Greater Bay Area are:

1) Lakeville is out Sobrante is in
2) Ignacio is out Crocket and Sobrante are in
3) Parkway is out Moraga is in
4) Bahia is out Moraga is in
5) Lambie SW Sta is in Vaca Dixon is out
6) Peabody is out Birds Landing SW Sta is in
7) Tesla and USWP Ralph are out Kelso is in
8) Tesla and Altmont Midway are out Delta Switching Yard is in
9) Tesla and Tres Vaqueros are out Pittsburg is in
10) Tesla and Flowind are out Pittsburg is in
11) Tesla is out Newark is in
12) Tesla is out Newark and Patterson Pass are in
13) Tesla is out Ravenswood is in
14) Tesla is out Metcalf is in
15) Los Banos is out Moss Landing is in
16) Coburn is out Moss Landing is in
17) Las Aguillas is out Moss Landing is in
18) Oakdale TID is out Newark is in
19) Oakdale TID is out Newark is in

Total 2017 bus load within the defined area is 9543 MW with -135 MW of AAEE, 191 MW of losses and 264 MW of pumps resulting in total load + losses + pumps of 9863 MW. This total correlates well with the total geographically-defined Bay Area in the CEC’s Mid Demand Baseline with Low AAEE savings forecast for 2017, due to about 520 MW of load behind the meter modeled in the Bay Area base cases. The 2017 expanded Bay Area also includes Moss Landing area load at: 595 MW with -11 MW of AAEE and 30 MW of losses. For a grand total expended Bay Area load + losses + pumps of 10,477 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ALMEGT_1_UNIT 1	38118	ALMDACT1	13.8	23.80	1	Oakland		MUNI
ALMEGT_1_UNIT 2	38119	ALMDACT2	13.8	24.40	1	Oakland		MUNI
BANKPP_2_NSPIN	38760	DELTA E	13.2	13.47	10	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38760	DELTA E	13.2	13.47	11	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38765	DELTA D	13.2	13.47	8	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38765	DELTA D	13.2	13.47	9	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38770	DELTA C	13.2	13.47	6	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38770	DELTA C	13.2	13.47	7	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38815	DELTA B	13.2	13.47	4	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38815	DELTA B	13.2	13.47	5	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38820	DELTA A	13.2	3.37	1	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38820	DELTA A	13.2	3.37	2	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38820	DELTA A	13.2	12.51	3	Contra Costa	Pumps	MUNI
BLHVN_7_MENLOP				0.56			Not modeled	Net Seller
BRDSLD_2_HIWIND	32172	HIGHWINDS	34.5	36.37	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_MTZUM2	32179	MNTZUMA2	0.69	20.14	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_MTZUMA	32188	HIGHWND3	0.69	8.03	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_SHILO1	32176	SHILOH	34.5	45.80	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_SHILO2	32177	SHILOH 2	34.5	35.83	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_SHLO3A	32191	SHILOH3	0.58	22.98	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_SHLO3B	32194	SHILOH4	0.58	29.14	1	Contra Costa	Aug NQC	Wind
CALPIN_1_AGNEW	35860	OLS-AGNE	9.11	28.00	1	San Jose, South Bay-Moss Landing	Aug NQC	Market
CAYTNO_2_VASCO	30531	0162-WD	230	4.30	FW	Contra Costa	Aug NQC	Market
CLRMTK_1_QF				0.00		Oakland	Not modeled	QF/Selfgen
COCOPP_2_CTG1	33188	MARSHCT1	16.4	191.35	1	Contra Costa	Aug NQC	Market
COCOPP_2_CTG2	33188	MARSHCT2	16.4	189.30	2	Contra Costa	Aug NQC	Market
COCOPP_2_CTG3	33189	MARSHCT3	16.4	191.45	3	Contra Costa	Aug NQC	Market
COCOPP_2_CTG4	33189	MARSHCT4	16.4	191.44	4	Contra Costa	Aug NQC	Market
COCOSB_6_SOLAR				0.00		Contra Costa	Not modeled Energy Only	Market
CONTAN_1_UNIT	36856	CCA100	13.8	27.70	1	San Jose, South Bay-Moss Landing	Aug NQC	MUNI
CROKET_7_UNIT	32900	CRCKTCOG	18	184.26	1	Pittsburg	Aug NQC	QF/Selfgen
CSCCOG_1_UNIT 1	36859	Laf300	12	3.00	1	San Jose, South Bay-Moss Landing		MUNI
CSCCOG_1_UNIT 1	36859	Laf300	12	3.00	2	San Jose, South Bay-Moss Landing		MUNI
CSCGNR_1_UNIT 1	36858	Gia100	13.8	24.00	1	San Jose, South Bay-Moss Landing		MUNI
CSCGNR_1_UNIT 2	36895	Gia200	13.8	24.00	2	San Jose, South Bay-Moss Landing		MUNI
CUMBIA_1_SOLAR	33102	Q687	0.36	0.00	1	Pittsburg	Aug NQC	Market
DELTA_2_PL1X4	33107	DEC STG1	24	269.61	1	Pittsburg	Aug NQC	Market
DELTA_2_PL1X4	33108	DEC CTG1	18	181.13	1	Pittsburg	Aug NQC	Market
DELTA_2_PL1X4	33109	DEC CTG2	18	181.13	1	Pittsburg	Aug NQC	Market
DELTA_2_PL1X4	33110	DEC CTG3	18	181.13	1	Pittsburg	Aug NQC	Market

DUANE_1_PL1X3	36863	DVRaGT1	13.8	49.27	1	San Jose, South Bay-Moss Landing		MUNI
DUANE_1_PL1X3	36864	DVRbGT2	13.8	49.27	1	San Jose, South Bay-Moss Landing		MUNI
DUANE_1_PL1X3	36865	DVRaST3	13.8	49.26	1	San Jose, South Bay-Moss Landing		MUNI
FLOWD1_6_ALTPP1	35318	FLOWDPTR	9.11	0.00	1	Contra Costa	Aug NQC	Wind
GATWAY_2_PL1X3	33118	GATEWAY1	18	190.12	1	Contra Costa	Aug NQC	Market
GATWAY_2_PL1X3	33119	GATEWAY2	18	186.19	1	Contra Costa	Aug NQC	Market
GATWAY_2_PL1X3	33120	GATEWAY3	18	186.19	1	Contra Costa	Aug NQC	Market
GILROY_1_UNIT	35850	GLRY COG	13.8	69.30	1	Llagas, South Bay-Moss Landing	Aug NQC	Market
GILROY_1_UNIT	35850	GLRY COG	13.8	35.70	2	Llagas, South Bay-Moss Landing	Aug NQC	Market
GILRPP_1_PL1X2	35851	GROYPKR1	13.8	45.50	1	Llagas, South Bay-Moss Landing	Aug NQC	Market
GILRPP_1_PL1X2	35852	GROYPKR2	13.8	45.50	1	Llagas, South Bay-Moss Landing	Aug NQC	Market
GILRPP_1_PL3X4	35853	GROYPKR3	13.8	46.00	1	Llagas, South Bay-Moss Landing	Aug NQC	Market
GRZZLY_1_BERKLY	32741	HILLSIDE_12	12.5	24.02	1	None	Aug NQC	QF/Selfgen
KELSO_2_UNITS	33813	MARIPCT1	13.8	47.08	1	Contra Costa	Aug NQC	Market
KELSO_2_UNITS	33815	MARIPCT2	13.8	47.07	2	Contra Costa	Aug NQC	Market
KELSO_2_UNITS	33817	MARIPCT3	13.8	47.07	3	Contra Costa	Aug NQC	Market
KELSO_2_UNITS	33819	MARIPCT4	13.8	47.07	4	Contra Costa	Aug NQC	Market
KIRKER_7_KELCYN				3.27		Pittsburg	Not modeled	Market
LAWRNC_7_SUNYVL				0.12		None	Not modeled Aug NQC	Market
LECEF_1_UNITS	35854	LECEFGT1	13.8	46.50	1	San Jose, South Bay-Moss Landing	Aug NQC	Market
LECEF_1_UNITS	35855	LECEFGT2	13.8	46.50	1	San Jose, South Bay-Moss Landing	Aug NQC	Market
LECEF_1_UNITS	35856	LECEFGT3	13.8	46.50	1	San Jose, South Bay-Moss Landing	Aug NQC	Market
LECEF_1_UNITS	35857	LECEFGT4	13.8	46.50	1	San Jose, South Bay-Moss Landing	Aug NQC	Market
LECEF_1_UNITS	35858	LECEFST1	13.8	107.88	1	San Jose, South Bay-Moss Landing		Market
LFC 51_2_UNIT 1	35310	LFC FIN+	9.11	2.02	1	None	Aug NQC	Wind
LMBEPK_2_UNITA1	32173	LAMBGT1	13.8	47.00	1	Contra Costa	Aug NQC	Market
LMBEPK_2_UNITA2	32174	GOOSEHGT	13.8	46.00	2	Contra Costa	Aug NQC	Market
LMBEPK_2_UNITA3	32175	CREEDGT1	13.8	47.00	3	Contra Costa	Aug NQC	Market
LMEC_1_PL1X3	33111	LMECCT2	18	163.20	1	Pittsburg	Aug NQC	Market
LMEC_1_PL1X3	33112	LMECCT1	18	163.20	1	Pittsburg	Aug NQC	Market
LMEC_1_PL1X3	33113	LMECST1	18	229.60	1	Pittsburg	Aug NQC	Market
MARTIN_1_SUNSET				1.88		None	Not modeled Aug NQC	QF/Selfgen
METCLF_1_QF				0.00		None	Not modeled Aug NQC	QF/Selfgen
METEC_2_PL1X3	35881	MEC CTG1	18	178.43	1	South Bay-Moss Landing	Aug NQC	Market

METEC_2_PL1X3	35882	MEC CTG2	18	178.43	1	South Bay-Moss Landing	Aug NQC	Market
METEC_2_PL1X3	35883	MEC STG1	18	213.14	1	South Bay-Moss Landing	Aug NQC	Market
MILBRA_1_QF				0.00		None	Not modeled	QF/Selfgen
MISSIX_1_QF				0.16		None	Not modeled Aug NQC	QF/Selfgen
MLPTAS_7_QFUNTS				0.02		San Jose, South Bay-Moss Landing	Not modeled Aug NQC	QF/Selfgen
MOSSLD_2_PSP1	36221	DUKMOSS1	18	163.20	1	South Bay-Moss Landing		Market
MOSSLD_2_PSP1	36222	DUKMOSS2	18	163.20	1	South Bay-Moss Landing		Market
MOSSLD_2_PSP1	36223	DUKMOSS3	18	183.60	1	South Bay-Moss Landing		Market
MOSSLD_2_PSP2	36224	DUKMOSS4	18	163.20	1	South Bay-Moss Landing		Market
MOSSLD_2_PSP2	36225	DUKMOSS5	18	163.20	1	South Bay-Moss Landing		Market
MOSSLD_2_PSP2	36226	DUKMOSS6	18	183.60	1	South Bay-Moss Landing		Market
MOSSLD_7_UNIT 6	36405	MOSSLND6	22	754.33	1	South Bay-Moss Landing		Market
MOSSLD_7_UNIT 7	36406	MOSSLND7	22	755.70	1	South Bay-Moss Landing		Market
NEWARK_1_QF				0.02		None	Not modeled Aug NQC	QF/Selfgen
OAK C_1_EBMUD				0.73		Oakland	Not modeled Aug NQC	MUNI
OAK C_7_UNIT 1	32901	OAKLND 1	13.8	55.00	1	Oakland		Market
OAK C_7_UNIT 2	32902	OAKLND 2	13.8	55.00	1	Oakland		Market
OAK C_7_UNIT 3	32903	OAKLND 3	13.8	55.00	1	Oakland		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.44	1	Ames		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	2	Ames		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	3	Ames		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	4	Ames		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	5	Ames		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	6	Ames		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	7	Ames		Market
PALALT_7_COBUG				4.50		None	Not modeled	MUNI
PITTSP_7_UNIT 5	33105	PTSB 5	18	312.00	1	Pittsburg		Market
PITTSP_7_UNIT 6	33106	PTSB 6	18	317.00	1	Pittsburg		Market
PITTSP_7_UNIT 7	30000	PTSB 7	20	530.00	1	Pittsburg		Market
RICHMN_7_BAYENV				2.00		None	Not modeled Aug NQC	Market
RUSCTY_2_UNITS	35304	RUSELCT1	15	172.35	1	Ames	No NQC - Pmax	Market
RUSCTY_2_UNITS	35305	RUSELCT2	15	172.35	1	Ames	No NQC - Pmax	Market
RUSCTY_2_UNITS	35306	RUSELST1	15	241.00	1	Ames	No NQC - Pmax	Market
RVRVEW_1_UNITA1	33178	RVEC_GEN	13.8	46.00	1	Contra Costa	Aug NQC	Market
SEAWST_6_LAPOS	35312	SEAWESTF	9.11	0.14	1	Contra Costa	Aug NQC	Wind
SRINTL_6_UNIT	33468	SRI INTL	9.11	0.82	1	None	Aug NQC	QF/Selfgen
STAUFF_1_UNIT	33139	STAUFER	9.11	0.09	1	None	Aug NQC	QF/Selfgen

STOILS_1_UNITS	32921	CHEVGEN1	13.8	0.70	1	Pittsburg	Aug NQC	Market
STOILS_1_UNITS	32922	CHEVGEN2	13.8	0.70	1	Pittsburg	Aug NQC	Market
STOILS_1_UNITS	32923	CHEVGEN3	13.8	0.32	3	Pittsburg	Aug NQC	Market
TIDWTR_2_UNITS	33151	FOSTER W	12.5	7.01	1	Pittsburg	Aug NQC	Net Seller
TIDWTR_2_UNITS	33151	FOSTER W	12.5	7.00	2	Pittsburg	Aug NQC	Net Seller
TIDWTR_2_UNITS	33151	FOSTER W	12.5	7.00	3	Pittsburg	Aug NQC	Net Seller
UNCHEM_1_UNIT	32920	UNION CH	9.11	10.45	1	Pittsburg	Aug NQC	QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.38	1	Pittsburg	Aug NQC	QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.38	2	Pittsburg	Aug NQC	QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.38	3	Pittsburg	Aug NQC	QF/Selfgen
USWNDR_2_SMUD	32169	SOLANOWP	21	21.94	1	Contra Costa	Aug NQC	Wind
USWNDR_2_SMUD2	32186	SOLANO	34.5	42.60	1	Contra Costa	Aug NQC	Wind
USWNDR_2_UNITS	32168	EXNCO	9.11	4.18	1	Contra Costa	Aug NQC	Wind
USWPFK_6_FRICK	35320	USW FRIC	12	0.78	1	Contra Costa	Aug NQC	Wind
USWPFK_6_FRICK	35320	USW FRIC	12	0.78	2	Contra Costa	Aug NQC	Wind
USWPJR_2_UNITS	39233	GRNRDG	0.69	15.66	1	Contra Costa	Aug NQC	Wind
WNDMAS_2_UNIT 1	33170	WINDMSTR	9.11	3.42	1	Contra Costa	Aug NQC	Wind
ZOND_6_UNIT	35316	ZOND SYS	9.11	1.45	1	Contra Costa	Aug NQC	Wind
IBMCTL_1_UNIT 1	35637	IBM-CTLE	115	0.00	1	San Jose, South Bay-Moss Landing	No NQC - hist. data	Market
IMHOFF_1_UNIT 1	33136	CCCSD	12.5	4.40	1	Pittsburg	No NQC - hist. data	QF/Selfgen
MARKHM_1_CATLST	35863	CATALYST	9.11	0.00	1	San Jose, South Bay-Moss Landing		QF/Selfgen
NA	36209	SLD ENRG	12.5	0.00	1	South Bay-Moss Landing		QF/Selfgen
SHELRF_1_UNITS	33141	SHELL 1	12.5	20.00	1	Pittsburg	No NQC - hist. data	Net Seller
SHELRF_1_UNITS	33142	SHELL 2	12.5	40.00	1	Pittsburg	No NQC - hist. data	Net Seller
SHELRF_1_UNITS	33143	SHELL 3	12.5	40.00	1	Pittsburg	No NQC - hist. data	Net Seller
ZANKER_1_UNIT 1	35861	SJ-SCL W	9.11	5.00	1	San Jose, South Bay-Moss Landing	No NQC - hist. data	QF/Selfgen
New Unit	30524	0354-WD	230	1.83	EW	Contra Costa	No NQC - Pmax	Market
New Unit	35622	SWIFT	115	4.00	BT	South Bay-Moss Landing	No NQC - Pmax	Market
CARDCG_1_UNITS	33463	CARDINAL	12.5	0.00	R1	None	Retired	QF/Selfgen
CARDCG_1_UNITS	33463	CARDINAL	12.5	0.00	R2	None	Retired	QF/Selfgen
COCOPP_7_UNIT 6	33116	C.COS 6	18	0.00	RT	Contra Costa	Retired	Market
COCOPP_7_UNIT 7	33117	C.COS 7	18	0.00	RT	Contra Costa	Retired	Market
GWFPW1_6_UNIT	33131	GWF #1	9.11	0.00	1	Pittsburg, Contra Costa	Retired	QF/Selfgen
GWFPW2_1_UNIT 1	33132	GWF #2	13.8	0.00	1	Pittsburg	Retired	QF/Selfgen
GWFPW3_1_UNIT 1	33133	GWF #3	13.8	0.00	1	Pittsburg, Contra Costa	Retired	QF/Selfgen
GWFPW4_6_UNIT 1	33134	GWF #4	13.8	0.00	1	Pittsburg, Contra Costa	Retired	QF/Selfgen
GWFPW5_6_UNIT 1	33135	GWF #5	13.8	0.00	1	Pittsburg	Retired	QF/Selfgen
UNTDQF_7_UNITS	33466	UNTED CO	9.11	0.00	1	None	Retired	QF/Selfgen

Major new projects modeled:

1. A few small renewable resources
2. Contra Costa – Moraga 230 kV Line Reconductoring
3. Embarcadero-Potrero 230 kV Transmission Project
4. Moraga Transformers Capacity Increase
5. Pittsburg-Tesla 230 kV Reconductoring

Critical Contingency Analysis Summary

Oakland Sub-area

The most critical contingency is an outage of the C-X #2 and #3 115 kV cables. The area limitation is thermal overloading of the Moraga – Claremont #1 or #2 115 kV line. This limiting contingency establishes a LCR of 45 MW in 2017 (includes 49 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.

Llagas Sub-area

The most critical contingency is an outage Metcalf D-Morgan Hill 115 kV Line with one of the Gilroy Peaker off-line. The area limitation is thermal overloading of the Morgan Hill-Llagas 115 kV line as well as voltage drop (5%) at the Morgan Hill substation. As documented within a CAISO Operating Procedure, this limitation is dependent on power flowing in the direction from Metcalf to Llagas/Morgan Hill. This limiting contingency establishes a LCR of 131 MW in 2017 (includes 0 MW of QF and MUNI generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area have the same effectiveness factor.

San Jose Sub-area

The most critical contingency is an outage of North Receiving Station-Scott Receiving

Stations115 kV Line #2 (NRS300-SRS#2) with Duane PP out of service. The area limitation is thermal overloading of the North Receiving Station-Scott Receiving Stations 115 kV Line #1 (NRS300-SRS #1). This limiting contingency establishes a LCR of 788 MW in 2017 (includes 5 MW of QF and 230 MW of MUNI generation as well as 232 MW of deficiency) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:
All units within this sub-area are needed for the most limiting contingencies therefore no effectiveness factor is required.

South Bay-Moss Landing Sub-area
During the 2015-2016 Transmission Planning Process (TPP) the ISO identified and discussed with stakeholders the need to mitigate the N-1-1 contingency of Tesla-Metcalf 500 kV and Moss Landing-Los Banos 500 kV, through either transmission expansion or resource capacity requirement. The latter consideration was deferred to the 2017 LCR study. In keeping with that commitment, the ISO has evaluated the resource capacity need and found that there are LCR requirements based on the above mentioned contingency and that some level of capacity is required in the Moss Landing area based on the existing LCR criteria.

Based on technical assessment performed, the ISO has found that depending on resource mix and availability this contingency could result in either thermal overloads, low voltages or potential voltage collapse and that the great majority of the load served by the available transmission system, after this contingency, resides in the South Bay part of the Bay Area. Therefore the ISO considers that it is preferred to include the Moss Landing loads and resources into an expanded Bay Area rather than instituting a new standalone Moss Landing area.

The most critical contingency is an outage of the Tesla-Metcalf 500 kV and Moss Landing-Los Banos 500 kV. The area limitation is thermal overloading of the Las

Aguillas-Moss Landing 230 kV. This limiting contingency establishes a LCR of 2178 MW in 2017 (includes 5 MW of QF and 230 MW of MUNI generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

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

Effectiveness factors:

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

Pittsburg and Oakland Sub-area Combined

No requirement is identified in this sub-area

Contra Costa Sub-area

The most critical contingency is an outage of Kelso-Tesla 230 kV with the Gateway off line. The area limitation is thermal overloading of the Delta Switching Yard-Tesla 230 kV line. This limiting contingency establishes a LCR of 1081 MW in 2017 (includes 289 MW of Wind generation and 264 MW of MUNI pumps) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The following table has units within the Bay Area that are at least 10% effective to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
33175	ALTAMONT	1	83
38760	DELTA E	10	71
38760	DELTA E	11	71
38765	DELTA D	8	71
38765	DELTA D	9	71
38770	DELTA C	6	71
38770	DELTA C	7	71
38815	DELTA B	4	71
38815	DELTA B	5	71

38820	DELTA A	3	71
33170	WINDMSTR	1	68
33118	GATEWAY1	1	23
33119	GATEWAY2	1	23
33120	GATEWAY3	1	23
33116	C.COS 6	1	23
33117	C.COS 7	1	23
33133	GWF #3	1	23
33134	GWF #4	1	23
33178	RVEC_GEN	1	23
33131	GWF #1	1	22
32179	T222	1	18
32188	P0611G	1	18
32190	Q039	1	18
32186	P0609	1	18
32171	HIGHWND3	1	18
32177	Q0024	1	18
32168	ENXCO	2	18
32169	SOLANOWP	1	18
32172	HIGHWNDS	1	18
32176	SHILOH	1	18
33838	USWP_#3	1	18
32173	LAMBGT1	1	14
32174	GOOSEHGT	2	14
32175	CREEDGT1	3	14
35312	SEAWESTF	1	11
35316	ZOND SYS	1	11
35320	USW FRIC	1	11

Ames and Pittsburg Sub-areas Combined

The two most critical contingencies listed below together establish a local capacity need of 2802 MW in 2017 as follows: 721 MW in NCNB (includes 14 MW of QF and 114 MW of MUNI generation) and 2081 MW in the Bay Area – 596 MW in Ames (includes 0 MW of QF and MUNI generation) and 1485 MW in Pittsburg (includes 200 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within these sub-areas.

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

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

Effectiveness factors:

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

Bay Area overall

The most critical need is the aggregate of sub-area requirements. This establishes a LCR of 5385 MW in 2017 (including 232 MW of QF, 547 MW of MUNI and 291 MW of wind generation) as the minimum capacity necessary for reliable load serving capability within this area.

The most critical single contingency is an outage of the Tesla-Metcalf 500 kV line with Delta Energy Center out of service. The sub-area area limitation is reactive margin within the Bay Area. This limiting contingency establishes a LCR of 4260 MW in 2017 (including 232 MW of QF, 547 MW of MUNI and 291 MW of wind generation).

Effectiveness factors:

For most helpful procurement information please read procedure T-133Z effectiveness factors (posted under M-2210Z) at: http://www.caiso.com/Documents/2210Z.pdf

Changes compared to last year's results:

From 2016 the load forecast is down by 220 MW compared with the physically defined Bay Area, however the total load has actually increased by 394 MW due to the new definition that includes the Moss Landing areas as well. The LCR has increased by 1268 MW due to a combination of overall load increase load increase due to the redefinition triggered by new South Bay-Moss Landing sub-area need as well as increase in deficiency in the San Jose sub-area.

Bay Area Overall Requirements:

2017	Wind (MW)	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	291	232	547	8792	9862

2017	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[17]	4260	232	4492
Category C (Multiple)[18]	5385	232	5617

6. Greater Fresno Area

<u>Area Definition</u>

The transmission facilities coming into the Greater Fresno area are:

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

The substations that delineate the Greater Fresno area are:

1) Gates is out Henrietta is in
2) Gates is out Henrietta is in
3) Gates 230 kV is out Gates 70 kV is in
4) Los Banos 230 kV is out Los Banos 70 kV is in
5) Los Banos 230 kV is out Los Banos 70 kV is in
6) Panoche is out Helm is in

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

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

7) Panoche is out Mc Mullin is in
8) Panoche 115 kV is in Panoche 230 kV is out
9) Panoche 115 kV is in Panoche 230 kV is out
10) Warnerville is out Wilson is in
11) Wilson is in Melones is out
12) Quebec SP is out Corcoran is in
13) Coalinga is in San Miguel is out

2017 total busload within the defined area is 2867 MW with -35 MW of AAEE and 132 MW of losses resulting in a total (load plus losses) of 2964 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ADMEST_6_SOLAR	34315	ADAMS_E	12.5	0.00	1	Wilson, Herndon	Energy Only	Market
AGRICO_6_PL3N5	34608	AGRICO	13.8	20.00	3	Wilson, Herndon		Market
AGRICO_7_UNIT	34608	AGRICO	13.8	43.05	2	Wilson, Herndon		Market
AGRICO_7_UNIT	34608	AGRICO	13.8	7.45	4	Wilson, Herndon		Market
AVENAL_6_AVPARK	34265	AVENAL P	12	0.00	1	Wilson, Coalinga	Energy Only	Market
AVENAL_6_SANDDG	34263	SANDDRAG	12	0.00	1	Wilson, Coalinga	Energy Only	Market
AVENAL_6_SUNCTY	34257	SUNCTY D	12	0.00	1	Wilson, Coalinga	Energy Only	Market
BALCHS_7_UNIT 1	34624	BALCH	13.2	33.00	1	Wilson, Herndon	Aug NQC	Market
BALCHS_7_UNIT 2	34612	BLCH	13.8	52.50	1	Wilson, Herndon	Aug NQC	Market
BALCHS_7_UNIT 3	34614	BLCH	13.8	52.50	1	Wilson, Herndon	Aug NQC	Market
BORDEN_2_QF	34253	BORDEN D	12.5	0.78	QF	Wilson	Aug NQC	Net Seller
CANTUA_1_SOLAR	34349	CANTUA_D	12.5	7.15	1	Wilson	Aug NQC	Market
CANTUA_1_SOLAR	34349	CANTUA_D	12.5	7.15	2	Wilson	Aug NQC	Market
CAPMAD_1_UNIT 1	34179	MADERA_G	13.8	4.29	1	Wilson		Market
CHEVCO_6_UNIT 1	34652	CHV.COAL	9.11	1.30	1	Wilson, Coalinga	Aug NQC	QF/Selfgen
CHEVCO_6_UNIT 2	34652	CHV.COAL	9.11	0.85	2	Wilson, Coalinga	Aug NQC	QF/Selfgen
CHWCHL_1_BIOMAS	34305	CHWCHLA2	13.8	8.60	1	Wilson, Herndon	Aug NQC	Market
CHWCHL_1_UNIT	34301	CHOWCOGN	13.8	48.00	1	Wilson, Herndon		Market
COLGA1_6_SHELLW	34654	COLNGAGN	9.11	34.58	1	Wilson, Coalinga	Aug NQC	Net Seller
CORCAN_1_SOLAR1				13.80		Wilson, Herndon, Hanford	Not Modeled Aug NQC	Market
CORCAN_1_SOLAR2				7.59		Wilson, Herndon, Hanford	Not Modeled Aug NQC	Market
CRESSY_1_PARKER	34140	CRESSEY	115	1.21		Wilson	Not modeled Aug NQC	MUNI
CRNEVL_6_CRNVA	34634	CRANEVLY	12	0.71	1	Wilson, Borden	Aug NQC	Market
CRNEVL_6_SJQN 2	34631	SJ2GEN	9.11	3.20	1	Wilson, Borden	Aug NQC	Market
CRNEVL_6_SJQN 3	34633	SJ3GEN	9.11	4.20	1	Wilson, Borden	Aug NQC	Market
DINUBA_6_UNIT	34648	DINUBA E	13.8	9.87	1	Wilson, Herndon, Reedley		Market
ELCAP_1_SOLAR				1.04		Wilson	Not Modeled Aug NQC	Market
ELNIDP_6_BIOMAS	34330	ELNIDO	13.8	8.71	1	Wilson	Aug NQC	Market
EXCHEC_7_UNIT 1	34306	EXCHQUER	13.8	94.20	1	Wilson	Aug NQC	MUNI

FRIANT_6_UNITS	34636	FRIANTDM	6.6	4.66	2	Wilson, Borden	Aug NQC	Net Seller
FRIANT_6_UNITS	34636	FRIANTDM	6.6	2.49	3	Wilson, Borden	Aug NQC	Net Seller
FRIANT_6_UNITS	34636	FRIANTDM	6.6	0.66	4	Wilson, Borden	Aug NQC	Net Seller
GUERNS_6_SOLAR	34461	GUERNSEY	12.5	7.37	1	Wilson	Aug NQC	Market
GUERNS_6_SOLAR	34461	GUERNSEY	12.5	7.37	2	Wilson	Aug NQC	Market
GWFPWR_1_UNITS	34431	GWF_HEP1	13.8	42.20	1	Wilson, Herndon, Hanford		Market
GWFPWR_1_UNITS	34433	GWF_HEP2	13.8	42.20	1	Wilson, Herndon, Hanford		Market
HAASPH_7_PL1X2	34610	HAAS	13.8	72.00	1	Wilson, Herndon	Aug NQC	Market
HAASPH_7_PL1X2	34610	HAAS	13.8	72.00	2	Wilson, Herndon	Aug NQC	Market
HELMPG_7_UNIT 1	34600	HELMS	18	407.00	1	Wilson	Aug NQC	Market
HELMPG_7_UNIT 2	34602	HELMS	18	407.00	2	Wilson	Aug NQC	Market
HELMPG_7_UNIT 3	34604	HELMS	18	404.00	3	Wilson	Aug NQC	Market
HENRTA_6_UNITA1	34539	GWF_GT1	13.8	45.33	1	Wilson		Market
HENRTA_6_UNITA2	34541	GWF_GT2	13.8	45.23	1	Wilson		Market
HURON_6_SOLAR	34557	HURON_DI	12.5	6.87	1	Wilson, Coalinga	Aug NQC	Market
HURON_6_SOLAR	34557	HURON_DI	12.5	6.87	2	Wilson, Coalinga	Aug NQC	Market
INTTRB_6_UNIT	34342	INT.TURB	9.11	2.94	1	Wilson	Aug NQC	QF/Selfgen
JAYNE_6_WLSLR	34639	WESTLNDS	0.48	0.00	1	Wilson, Coalinga	Energy Only	Market
KANSAS_6_SOLAR	34666	KANSASS_S	12.5	0.00	F	Wilson	Energy Only	Market
KERKH1_7_UNIT 1	34344	KERCK1-1	6.6	13.00	1	Wilson, Herndon	Aug NQC	Market
KERKH1_7_UNIT 2	34343	KERCK1-2	6.6	0.00	2	Wilson, Herndon	Aug NQC	Market
KERKH1_7_UNIT 3	34345	KERCK1-3	6.6	12.80	3	Wilson, Herndon	Aug NQC	Market
KERKH2_7_UNIT 1	34308	KERCKHOF	13.8	153.90	1	Wilson, Herndon	Aug NQC	Market
KINGCO_1_KINGBR	34642	KINGSBUR	9.11	23.71	1	Wilson, Herndon, Hanford	Aug NQC	Net Seller
KINGRV_7_UNIT 1	34616	KINGSRIV	13.8	51.20	1	Wilson, Herndon	Aug NQC	Market
KNGBRG_1_KBSLR1				0.00		Wilson	Not modeled Energy Only	Market
KNGBRG_1_KBSLR2				0.00		Wilson	Not modeled Energy Only	Market
KNTSTH_6_SOLAR	34694	KENT_S	0.8	0.00	1	Wilson	Energy Only	Market
LEPRFD_1_KANSAS	34680	Q636	12.5	13.85	1	Wilson, Hanford	Aug NQC	Market
MALAGA_1_PL1X2	34671	KRCDPCT1	13.8	48.00	1	Wilson, Herndon		Market
MALAGA_1_PL1X2	34672	KRCDPCT2	13.8	48.00	1	Wilson, Herndon		Market
MCCALL_1_QF	34219	MCCALL 4	12.5	0.58	QF	Wilson, Herndon	Aug NQC	QF/Selfgen
MCSWAN_6_UNITS	34320	MCSWAIN	9.11	5.82	1	Wilson	Aug NQC	MUNI
MENBIO_6_RENEW1	34339	CALRENEW	12.5	4.02	1	Wilson, Herndon	Aug NQC	Net Seller
MENBIO_6_UNIT	34334	BIO PWR	9.11	20.11	1	Wilson	Aug NQC	QF/Selfgen
MERCED_1_SOLAR1				0.00		Wilson	Not modeled Energy Only	Market
MERCED_1_SOLAR2				0.00		Wilson	Not modeled Energy Only	Market
MERCFL_6_UNIT	34322	MERCEDFL	9.11	2.15	1	Wilson	Aug NQC	Market
MNDOTA_1_SOLAR1	34311	Q607	0.2	41.40	1	Wilson	Aug NQC	Market
ONLLPP_6_UNITS	34316	ONEILPMP	9.11	0.37	1	Wilson	Aug NQC	MUNI
PINFLT_7_UNITS	38720	PINEFLAT	13.8	22.00	1	Wilson, Herndon	Aug NQC	MUNI
PINFLT_7_UNITS	38720	PINEFLAT	13.8	22.00	2	Wilson, Herndon	Aug NQC	MUNI
PINFLT_7_UNITS	38720	PINEFLAT	13.8	22.00	3	Wilson, Herndon	Aug NQC	MUNI
PNCHPP_1_PL1X2	34328	STARGT1	13.8	55.58	1	Wilson		Market
PNCHPP_1_PL1X2	34329	STARGT2	13.8	55.58	1	Wilson		Market
PNOCHE_1_PL1X2	34142	WHD_PAN2	13.8	49.97	1	Wilson, Herndon		Market

PNOCHE_1_UNITA1	34186	DG_PAN1	13.8	48.00	1	Wilson		Market
REEDLY_6_SOLAR				0.00		Wilson, Herndon, Reedley	Not modeled Energy Only	Market
S_RITA_6_SOLAR1				0.00		Wilson	Not modeled Energy Only	Market
SCHNDR_1_FIVPTS	34353	SCHINDLER_D	12.5	4.24	1	Wilson, Coalinga	Aug NQC	Market
SCHNDR_1_FIVPTS	34353	SCHINDLER_D	12.5	2.13	2	Wilson, Coalinga	Aug NQC	Market
SCHNDR_1_WSTSDE	34353	SCHINDLER_D	12.5	6.17	3	Wilson, Coalinga	Aug NQC	Market
SCHNDR_1_WSTSDE	34353	SCHINDLER_D	12.5	3.09	4	Wilson, Coalinga	Aug NQC	Market
SGREGY_6_SANGER	34646	SANGERCO	13.8	24.44	1	Wilson	Aug NQC	Market
SGREGY_6_SANGER	34646	SANGERCO	13.8	5.51	2	Wilson	Aug NQC	Market
STOREY_7_MDRCHW	34209	STOREY D	12.5	0.20	1	Wilson	Aug NQC	Net Seller
STROUD_6_SOLAR	34563	STROUD_D	12.5	6.57	1	Wilson, Herndon	Aug NQC	Market
STROUD_6_SOLAR	34563	STROUD_D	12.5	6.57	2	Wilson, Herndon	Aug NQC	Market
ULTPFR_1_UNIT 1	34640	ULTR.PWR	9.11	22.72	1	Wilson, Herndon	Aug NQC	QF/Selfgen
VEGA_6_SOLAR1	34314	Q548	34.5	0.00	1	Wilson	Energy Only	Market
WAUKNA_1_SOLAR	34696	CORCORANPV_S	21	18.00	1	Wilson, Herndon, Hanford	Aug NQC	Market
WAUKNA_1_SOLAR2	34677	Q558	21	14.78	1	Wilson, Herndon, Hanford	No NQC - Pmax	Market
WFRESN_1_SOLAR				0.00		Wilson	Energy Only	Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	1	Wilson, Borden	Aug NQC	Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	2	Wilson, Borden	Aug NQC	Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	3	Wilson, Borden	Aug NQC	Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	4	Wilson, Borden	Aug NQC	Market
WISHON_6_UNITS	34658	WISHON	2.3	0.36	5	Wilson, Borden	Aug NQC	Market
WRGHTP_7_AMENGY	34207	WRIGHT D	12.5	0.30	QF	Wilson	Aug NQC	QF/Selfgen
BULLRD_7_SAGNES	34213	BULLD 12	12.5	0.06	1	Wilson	Aug NQC	QF/Selfgen
GATES_6_PL1X2	34553	WHD_GAT2	13.8	0.00	1	Wilson, Coalinga		Market
JRWOOD_1_UNIT 1	34332	JRWCOGEN	9.11	7.80	1	Wilson		QF/Selfgen
NA	34485	FRESNOWW	12.5	3.10	1	Wilson	No NQC - hist. data	QF/Selfgen
NA	34485	FRESNOWW	12.5	3.10	2	Wilson	No NQC - hist. data	QF/Selfgen
NA	34485	FRESNOWW	12.5	1.10	3	Wilson	No NQC - hist. data	QF/Selfgen
New Unit	34303	Q612	13.8	0.00	1	Wilson, Coalinga	Energy Only	Market
New Unit	34319	Q644	0.48	20.00	1	Wilson, Herndon	No NQC - Pmax	Market
New Unit	34335	Q723	0.32	50.00	1	Wilson, Borden	No NQC - Pmax	Market
New Unit	34340	Q643X	0.8	200.00	1	Wilson	No NQC - Pmax	Market
New Unit	34420	CORCORAN	115	19.00	WD	Wilson, Herndon, Hanford	No NQC - Pmax	Market
New Unit	34467	GIFFEN_DIST	12.5	10.00	1	Wilson, Herndon	No NQC - Pmax	Market
New Unit	34603	JGBSWLT	12.5	0.00	ST	Wilson, Herndon	Energy Only	Market
New Unit	34659	Q526	33	0.00	1	Wilson, Coalinga	Energy Only	Market
New Unit	34660	Q532	13.8	0.00	1	Wilson, Coalinga	Energy Only	Market
New Unit	34669	Q529A	4.16	0.00	1	Wilson, Herndon	Energy Only	Market
New Unit	34669	Q529A	0.48	0.00	2	Wilson, Herndon	Energy Only	Market
New Unit	34683	Q643W	0.8	100.00	1	Wilson	No NQC - Pmax	Market

Major new projects modeled:

1. A few new renewable resources were added.

Critical Contingency Analysis Summary

Hanford Sub-area

The most critical contingency for the Hanford sub-area is the loss of the McCall-Kingsburg #2 115 kV line and the Henrietta #3 230/115 kV transformer, which would thermally overload the McCall-Kingsburg #1 115 kV line . This limiting contingency establishes a local capacity need of 58 MW (including 0 MW of QF generation) in 2017 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Coalinga Sub-area

The most critical contingency for the Coalinga sub-area is the loss of the Gates #5 230/70 kV transformer followed by the Panoche-Schindler #1 and #2 double circuit tower line, which could cause voltage instability in the pocket. This limiting contingency establishes a local capacity need of 33 MW (including 2 MW of QF generation) in 2017 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Borden Sub-area

The most critical contingency for the Borden sub-area is the loss of the Borden #4 230/70 kV transformer followed by the Friant-Coppermine 70 kV line, which could cause overload on the Borden #1 230/70 kV transformer. This limiting contingency establishes a local capacity need of 4 MW (includes 0 MW of QF generation) in 2017 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Reedley Sub-area

The most critical contingency for the Reedley sub-area is the loss of the McCall-Reedley (McCall-Wahtoke) 115 kV line followed by the Sanger-Reedley 115 kV line, which could thermally overload the Kings River-Sanger-Reedley (Pomegranate-Pomegranate Jct) 115 kV line. This limiting contingency establishes a local capacity need of 29 MW (includes 0 MW of QF generation as well as 19 MW of deficiency) in 2017 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

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

Effectiveness factors:

All units within this sub-area are needed for the most limiting contingencies therefore no effectiveness factor is required.

Herndon Sub-area

The most critical contingency is the loss of Gregg-Herndon #1 & #2 230 kV double circuit tower line (DCTL). This contingency could thermally overload the Herndon-Manchester 115 kV line. This limiting contingency established an LCR of 431 MW (includes 23 MW of QF and 66 MW of Muni generation) in 2017 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The second most critical contingency is the loss of Herndon-Barton 115 kV line with Kings River generating unit out of service. This contingency would thermally overload the Herndon-Manchester 115 kV line. This limiting contingency establishes an LCR of 290 MW (includes 23 MW of QF and 66 MW of Muni generation).

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Factor %
34624	BALCH 1	1	24
34616	KINGSRIV	1	22
34648	DINUBA E	1	21
34671	KRCDPCT1	1	21
34672	KRCDPCT2	1	21
34308	KERCKHOF	1	19
34343	KERCK1-2	2	19
34344	KERCK1-1	1	19
34345	KERCK1-3	3	19
34621	MCCALL3T	1	19
34618	MCCALL1T	1	19
34603	JGBSWLT	ST	16
34677	Q558	1	16
34696	CORCORANPV_S	1	16
34697	Q529	1	16
34610	HAAS	1	15
34610	HAAS	2	15
34612	BLCH 2-2	1	15
34614	BLCH 2-3	1	15
34431	GWF_HEP1	1	10
34433	GWF_HEP2	1	10
34617	Q581	1	6
34680	KANSAS	1	6
34315	ADAMS_E	1	5
34339	CALRENEW	1	5
34467	GIFFEN_DIST	1	5
34563	STROUD_DIST	2	5

Wilson Sub-area

The most critical contingency is the loss of the Melones - Wilson 230 kV line overlapped with one of the Helms units out of service. This contingency would thermally overload the Warnerville - Wilson 230 kV line (most stringent). This limiting contingency establishes a LCR of 1760 MW in 2017 (includes 64 MW of QF and 167 MW of Muni generation) as the minimum generation capacity necessary for reliable load serving capability within this area.

The second most critical contingency is the common mode loss of Gregg-Helms #1 & #2 230 kV lines. This contingency would thermally overload the Warnerville – Wilson 230 kV line. This limiting contingency establishes an LCR of 934 MW (not including the three dropped Helms units) in 2017 (includes 64 MW of QF and 167 MW of Muni generation).

Effectiveness factors:

The following table has units within Fresno that are at least 5% effective to the constraint on the Warnerville – Wilson 230 kV line.

Gen Bus	Gen Name	Gen ID	Eff Factor %
34332	JRWCOGEN	1	38
34330	ELNIDO	1	35
34320	MCSWAIN	1	32
34322	MERCEDFL	1	32
34209	STOREY D	1	32
34306	EXCHQUER	1	31
34319	Q644	1	30
34301	CHOWCOGN	1	27
34305	CHWCHLA2	1	27
34335	Q723	1	26
34253	BORDEN D	1	24
34631	SJ2GEN	1	24
34633	SJ3GEN	1	24
34634	CRANEVLY	1	24
34636	FRIANTDM	1	24
34636	FRIANTDM	2	24
34636	FRIANTDM	3	24
34658	WISHON	1	24
34658	WISHON	2	24
34658	WISHON	3	24
34658	WISHON	4	24
34658	WISHON	SJ	24
34600	HELMS 1	1	22
34600	HELMS 2	1	22
34604	HELMS 3	1	22
34213	BULLD 12	1	21
34632	HERNDN2T	1	21
34630	HERNDN1T	1	21

34485	FRESNOWW	1	18
34308	KERCKHOF	1	18
34343	KERCK1-2	1	18
34344	KERCK1-1	1	18
34345	KERCK1-3	1	18
34660	Q532	1	14
34624	BALCH 1	1	14
34646	SANGERCO	1	13
34616	KINGSRIV	1	13
34648	DINUBA E	1	13
34671	KRCDPCT1	1	13
34672	KRCDPCT2	1	13
34640	ULTR.PWR	1	13
34219	MCCALL 4	1	12
34311	Q607	1	12
34642	KINGSBUR	1	12
34420	CORCORAN	1	12
34603	JGBSWLT	1	12
34677	C0558	1	12
34696	CORCORANPV_S	1	12
34610	HAAS	1	11
34610	HAAS	2	11
34612	BLCH 2-2	1	11
34614	BLCH 2-3	1	11
38720	PINE FLT	1	11
38720	PINE FLT	2	11
38720	PINE FLT	3	11
34431	GWF_HEP1	1	11
34433	GWF_HEP2	1	11
34461	GUERNSEY_DIS	1	11
34539	GWF_GT1	1	11
34541	GWF_GT2	1	11
34666	KANSASS_S	1	11
34694	Q650AB	1	11
34680	Q636	1	10
34315	Q632	1	8
34334	BIO PWR	1	8
34339	CALRENEW	1	8
34467	GIFFEN_DIST	1	8
34563	STROUD_DIST	1	8
34608	AGRICO	2	8
34608	AGRICO	3	8
34608	AGRICO	4	8

34669	Q529A	1	8
34670	Q529A	1	8
34186	DG_PAN1	1	8
34328	STAR_GT1	1	8
34329	STAR_GT2	1	8
34142	WHD_PAN2	1	8
34349	CANTUA_DIST	1	7
34660	Q532	1	7
34314	Q548	1	7
34353	SCHINDLER D	1	7
34353	SCHINDLER D	2	7
34353	SCHINDLER D	3	7
34353	SCHINDLER D	4	7
34326	PANO_BS1	1	6
34327	PANO_BS2	1	6
34652	CHV.COAL	1	6
34654	COLNGAGN	1	5
34557	HURON_DIST	1	5
34553	WHD_GAT2	1	5
34257	SUNCTY D	1	5
34263	SANDDRAG	1	5
34265	AVENAL P	1	5
34639	Q633	1	5

Changes compared to last year's results:

From 2016 the load forecast has decreased by 367 MW and the LCR by 740 MW.

Fresno Area Overall Requirements:

2017	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	64	167	3072	3303

2017	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single) [19]	1760	0	1760
Category C (Multiple) [20]	1760	19	1779

[19] 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.

[20] Multiple contingencies means that the system will be able the survive the loss of a single element, and

7. Kern Area

Area Definition

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

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

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

1) Midway 230 kV is out Bakersfield and Stockdale230 kV are in
2) Midway 230 kV is out Kern and Stockdale 230 kV are in
3) Midway 230 kV is out Kern PP 230 kV is in
4) Charca 115kV is out Famoso 115 kV is in
5) Wasco 70 kV is out Mc Farland 70 kV is in
6) Basic School Junction 70 kV is out, Copus 70 kV is in
7) Lakeview 70 kV is out, San Emidio Junction 70 kV is in
8) Magunden Junction 70 kV is out, Magunden 70 kV is in
9) Wheeler Ridge 115 kV is out, Adobe Solar 115 kV is in

2017 total busload within the defined area: 1142 MW with -12 MW of AAEE and 9 MW of losses resulting in a total (load plus losses) of 1139 MW.

Total units and qualifying capacity available in this Kern area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
7STDRD_1_SOLAR1	34709	7STNDRD	115	13.80		South Kern PP, Kern Oil	Not modeled Aug NQC	Market
DEXZEL_1_UNIT	35024	DEXEL +	9.11	20.00	1	South Kern PP, Kern Oil	Aug NQC	Net Seller
DISCOV_1_CHEVRN	35062	DISCOVRY	9.11	3.21	1	South Kern PP, Kern Oil	Aug NQC	QF/Selfgen
LIVOAK_1_UNIT 1	35058	PSE-LVOK	9.11	41.14	1	South Kern PP, Kern Oil	Aug NQC	Net Seller

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.

MTNPOS_1_UNIT	35036	MT POSO	9.11	31.12	1	South Kern PP, Kern Oil	Aug NQC	Net Seller
OILDAL_1_UNIT 1	35028	OILDALE	9.11	38.67	1	South Kern PP, Kern Oil	Aug NQC	Net Seller
VEDDER_1_SEKERN	35046	SEKR	9.11	11.96	1	South Kern PP, Kern Oil	Aug NQC	QF/Selfgen
ADOBEE_1_SOLAR	35021	Q622B	34.5	15.76	1	South Kern PP	Aug NQC	Market
BDGRCK_1_UNITS	35029	BADGERCK	9.11	36.29	1	South Kern PP	Aug NQC	Net Seller
BEARMT_1_UNIT	35066	PSE-BEAR	9.11	44.58	1	South Kern PP, West Park	Aug NQC	QF/Selfgen
DOUBLC_1_UNITS	35023	DOUBLE C	9.11	52.23	1	South Kern PP	Aug NQC	Net Seller
KERNFT_1_UNITS	35026	KERNFRNT	9.11	47.00	1	South Kern PP	Aug NQC	Net Seller
LAMONT_1_SOLAR1	35019	REGULUS	0.48	41.54	1	South Kern PP	Aug NQC	Market
LAMONT_1_SOLAR3	35087	Q744G3	0.38	10.38	1	South Kern PP	Aug NQC	Market
LAMONT_1_SOLAR4	35059	Q744G2	0.38	18.46	1	South Kern PP	Aug NQC	Market
LAMONT_1_SOLAR5	35054	Q744G1	0.38	15.60	1	South Kern PP	Aug NQC	Market
OLDRIV_6_BIOGAS				1.51		South Kern PP	Not modeled Aug NQC	Market
OLDRV1_6_SOLAR	35091	OLD_RVR1	12.5	13.85	1	South Kern PP	Aug NQC	Market
SIERRA_1_UNITS	35027	HISIERRA	9.11	52.43	1	South Kern PP	Aug NQC	Net Seller
SKERN_6_SOLAR1	35089	S_KERN	0.48	13.80	1	South Kern PP	Aug NQC	Market
New Unit	35069	Q885	0.36	8.00	1	South Kern PP	No NQC - est. data	Market
New Unit	35092	Q744G4	0.38	20.00	1	South Kern PP	No NQC - est. data	Market
ULTOGL_1_POSO	35035	ULTR PWR	9.11	0.00	1	South Kern PP, Kern Oil	Retired	QF/Selfgen

Major new projects modeled:

1. Upgrade terminal equipment on Kern PP #4 230/115kV transformer

Critical Contingency Analysis Summary

West Park Sub-area

The most critical contingency is the Kern PP-Magunden-Witco 115 kV Line and Kern PP-Westpark #1 or #2 115 kV Line resulting in the thermal overload of the remaining Kern PP-Wespark 115 kV Line. This limiting contingency establishes a LCR of 44 MW in 2017 (includes 45 MW of QF generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area are needed for the most limiting contingencies therefore no effectiveness factor is required.

Kern Oil Sub-area

The most critical contingency is the Kern PP-Magunden-Witco 115 kV Line and Kern PP-7th Standard 115 kV Line resulting in the thermal overload of the Kern PP-Live Oak 115 kV Line. This limiting contingency establishes a LCR of 148 MW in 2017 (includes 15 MW of QF generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the Kern PP-Magunden-Witco 115 kV Line with the PSE Live Oak generation out-of-service resulting in the thermal overload of the Kern PP-Live Oak 115 kV Line. This limiting contingency establishes a LCR of 137 MW in 2017 (includes 15 MW of QF generation).

Effectiveness factors:

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

South Kern PP Sub-area

The South Kern PP sub-area requirement is smaller than the Kern Oil and Westpark sub-areas combined therefore the need is already satisfied by resources located in the Kern Oli and Westpark sub areas.

The most critical contingency is the outage of the PSE Bear generator overlapping with Kern PP #5 230/115 kV transformer, which could thermally overload the Kern PP #4 230/115kV transformer. This limiting contingency establishes a LCR of 106 MW in 2017 (includes 60 MW of QF generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency is the loss of Kern PP #5 230/115 kV transformer, which could thermally overload the Kern PP #4 230/115kV transformer. This limiting contingency establishes a local capacity requirement of 61 MW in 2017 (includes 60 MW of QF generation).

Effectiveness factors:

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

South Kern Overall

The most critical contingency is the outage of the Midway-Kern #3 and #4 230 kV lines, which thermally overloads the Midway-Kern #1 230 kV line. This limiting contingency establishes a LCR of 492 MW in 2017 (includes 60 MW of QF generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency is the loss of Midway-Kern #3 230 kV line with High Sierra generator out of service, which thermally overloads the Midway-Kern #1 230 kV line. This limiting contingency is already mitigated by the category B requirement in the Kern Oil sub-area.

Effectiveness factors:

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

Changes compared to last year's results:

Overall the load forecast remained about the same. The requirement has increased by over 92 MW mostly due to Kern PP #3 & #4 230/115 kV transformer capacity upgrades and additional load (about 280 MW) triggered by re-definition to account for the new 230 kV binding constraint.

Kern Area Overall Requirements:

2017	QF/Selfgen (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	60	491	551

2017	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single) [21]	137	0	137
Category C (Multiple) [22]	492	0	492

[21] 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.

[22] Multiple contingencies means that the system will be able the survive the loss of a single element, and

8. LA Basin Area

Area Definition

The transmission tie lines into the LA Basin Area are:

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

These substations form the boundary surrounding the LA Basin area:

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

The total 2017 busload within the electrically defined area is 19,033 MW with -272 MW of AAEE, 109 MW of losses and 20 MW pumps resulting in total net load + losses +

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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.

pumps of 18,890 MW. The electrically defined LA Basin LCR area does not include Saugus substation load. When this load is added to the electrically defined LA Basin load, the total geographically-defined LA Basin load is 19,892 MW, which correlates with the CEC's Mid Demand Baseline with Low AAEE Savings forecast for 2017.

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
ALAMIT_7_UNIT 1	24001	ALAMT1 G	18	174.56	1	Western		Market
ALAMIT_7_UNIT 2	24002	ALAMT2 G	18	175.00	2	Western		Market
ALAMIT_7_UNIT 3	24003	ALAMT3 G	18	332.18	3	Western		Market
ALAMIT_7_UNIT 4	24004	ALAMT4 G	18	335.67	4	Western		Market
ALAMIT_7_UNIT 5	24005	ALAMT5 G	20	497.97	5	Western		Market
ALAMIT_7_UNIT 6	24161	ALAMT6 G	20	495.00	6	Western		Market
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	53.69	1	Western	Aug NQC	Net Seller
ARCOGN_2_UNITS	24012	ARCO 2G	13.8	53.69	2	Western	Aug NQC	Net Seller
ARCOGN_2_UNITS	24013	ARCO 3G	13.8	53.69	3	Western	Aug NQC	Net Seller
ARCOGN_2_UNITS	24014	ARCO 4G	13.8	53.69	4	Western	Aug NQC	Net Seller
ARCOGN_2_UNITS	24163	ARCO 5G	13.8	26.85	5	Western	Aug NQC	Net Seller
ARCOGN_2_UNITS	24164	ARCO 6G	13.8	26.86	6	Western	Aug NQC	Net Seller
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	5.01	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	1.36		Eastern, Valley-Devers	Not modeled Aug NQC	Wind
BUCKWD_1_QF	25634	BUCKWIND	115	1.94	QF	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
BUCKWD_7_WINTCV	25634	BUCKWIND	115	0.10	W5	Eastern, Valley-Devers	Aug NQC	Wind
CABZON_1_WINDA1	29290	CABAZON	33	5.98	1	Eastern, Valley-Devers	Aug NQC	Wind
CENTER_2_QF	24203	CENTER S	66	17.98		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	4.97	1	Western, El Nido	Aug NQC	Net Seller
CHEVMN_2_UNITS	24023	CHEVGEN2	13.8	4.98	2	Western, El Nido	Aug NQC	Net Seller
CHINO_2_JURUPA				0.00		Eastern, Eastern Metro	Not modeled Energy Only	Market
CHINO_2_QF	24024	CHINO	66	5.35		Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
CHINO_2_SASOLAR				0.00		Eastern, Eastern Metro	Not modeled Energy Only	Market
CHINO_2_SOLAR	24024	CHINO	66	0.47		Eastern, Eastern Metro	Not modeled Energy Only	Market

CHINO_2_SOLAR2				0.00		Eastern, Eastern Metro	Not modeled Energy Only	Market
CHINO_6_CIMGEN	24026	CIMGEN	13.8	26.11	D1	Eastern, Eastern Metro	Aug NQC	QF/Selfgen
CHINO_6_SMPPAP	24140	SIMPSON	13.8	26.63	D1	Eastern, Eastern Metro	Aug NQC	QF/Selfgen
CHINO_7_MILIKN	24024	CHINO	66	1.19		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_SOLAR1				1.12		Western	Not modeled Aug NQC	Market
DELAMO_2_SOLAR2				1.31		Western	Not modeled Aug NQC	Market
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	1.24	QF	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25632	TERAWND	115	2.42	QF	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25633	CAPWIND	115	0.46	QF	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25635	ALTWIND	115	1.11	Q1	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25635	ALTWIND	115	2.06	Q2	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	0.49	Q1	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	0.22	W1	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25639	SEAWIND	115	1.65	QF	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25645	VENWIND	115	1.26	EU	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25645	VENWIND	115	2.94	Q1	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25645	VENWIND	115	1.98	Q2	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25646	SANWIND	115	0.66	Q1	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_SEPV05				0.00		Eastern, Valley-Devers	Energy Only	Market
DEVERS_1_SOLAR				0.00		Eastern, Valley-Devers	Not modeled Energy Only	Market
DEVERS_1_SOLAR1				0.00		Eastern, Valley-Devers	Not modeled Energy Only	Market
DEVERS_1_SOLAR2				0.00		Eastern, Valley-Devers	Not modeled Energy Only	Market
DMDVLY_1_UNITS	25425	ESRP P2	6.9	7.51		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	0.01		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_CHMPNE				0.00		Eastern, Eastern Metro	Not modeled Energy Only	Market

ETIWND_2_FONTNA	24055	ETIWANDA	66	0.40		Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
ETIWND_2_RTS010	24055	ETIWANDA	66	0.92		Eastern, Eastern Metro	Not modeled Aug NQC	Market
ETIWND_2_RTS015	24055	ETIWANDA	66	1.17		Eastern, Eastern Metro	Not modeled Aug NQC	Market
ETIWND_2_RTS017	24055	ETIWANDA	66	1.72		Eastern, Eastern Metro	Not modeled Aug NQC	Market
ETIWND_2_RTS018	24055	ETIWANDA	66	0.92		Eastern, Eastern Metro	Not modeled Aug NQC	Market
ETIWND_2_RTS023	24055	ETIWANDA	66	1.09		Eastern, Eastern Metro	Not modeled Aug NQC	Market
ETIWND_2_RTS026	24055	ETIWANDA	66	1.50		Eastern, Eastern Metro	Not modeled Aug NQC	Market
ETIWND_2_RTS027	24055	ETIWANDA	66	1.50		Eastern, Eastern Metro	Not modeled Aug NQC	Market
ETIWND_2_SOLAR	24055	ETIWANDA	66	0.00		Eastern, Eastern Metro	Not modeled Energy Only	Market
ETIWND_2_UNIT1	24055	ETIWANDA	66	14.71		Eastern, Eastern Metro	Not modeled Aug NQC	Market
ETIWND_6_GRPLND	29305	ETWPKGEN	13.8	46.00	1	Eastern, Eastern Metro		Market
ETIWND_6_MWDETI	25422	ETI MWDG	13.8	1.62	1	Eastern, Eastern Metro	Aug NQC	Market
ETIWND_7_MIDVLY	24055	ETIWANDA	66	1.67		Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
ETIWND_7_UNIT 3	24052	MTNVIST3	18	320.00	3	Eastern, Eastern Metro		Market
ETIWND_7_UNIT 4	24053	MTNVIST4	18	320.00	4	Eastern, Eastern Metro		Market
GARNET_1_SOLAR	24815	GARNET	115	0.00		Eastern, Valley-Devers	Not modeled Energy Only	Market
GARNET_1_SOLAR2	24815	GARNET	115	2.77		Eastern, Valley-Devers	Not modeled Aug NQC	Market
GARNET_1_UNITS	24815	GARNET	115	0.66	G1	Eastern, Valley-Devers	Aug NQC	Market
GARNET_1_UNITS	24815	GARNET	115	0.23	G2	Eastern, Valley-Devers	Aug NQC	Market
GARNET_1_UNITS	24815	GARNET	115	0.48	G3	Eastern, Valley-Devers	Aug NQC	Market
GARNET_1_WIND	24815	GARNET	115	0.29	PC	Eastern, Valley-Devers	Aug NQC	Wind
GARNET_1_WINDS	24815	GARNET	115	1.46	W2	Eastern, Valley-Devers	Aug NQC	Wind
GARNET_1_WINDS	24815	GARNET	115	1.46	W3	Eastern, Valley-Devers	Aug NQC	Wind
GARNET_1_WT3WND	24815	GARNET	115	0.00		Eastern, Valley-Devers	Not modeled Energy Only	Market
GARNET_2_WIND1				1.79		Eastern, Valley-Devers	Not modeled Aug NQC	Wind
GARNET_2_WIND4				1.54		Eastern, Valley-Devers	Not modeled Aug NQC	Wind
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	CARBGEN1	13.8	14.68	1	Western	Aug NQC	Market
HINSON_6_CARBGN	24328	CARBGEN2	13.8	14.68	1	Western	Aug NQC	Market
HINSON_6_LBECH1	24170	LBEACH12	13.8	65.00	1	Western		Market
HINSON_6_LBECH2	24170	LBEACH12	13.8	65.00	2	Western		Market
HINSON_6_LBECH3	24171	LBEACH34	13.8	65.00	3	Western		Market

HINSON_6_LBECH4	24171	LBEACH34	13.8	65.00	4	Western		Market
HINSON_6_SERRGN	24139	SERRFGEN	13.8	25.73	D1	Western	Aug NQC	QF/Selfgen
HNTGBH_7_UNIT 1	24066	HUNT1 G	13.8	225.75	1	Western		Market
HNTGBH_7_UNIT 2	24067	HUNT2 G	13.8	225.80	2	Western		Market
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	0.00		Western	Not modeled Aug NQC	QF/Selfgen
LACIEN_2_VENICE	24337	VENICE	13.8	1.38	1	Western, El Nido	Aug NQC	MUNI
LAFRES_6_QF	24073	LA FRESA	66	0.00		Western, El Nido	Not modeled Aug NQC	QF/Selfgen
LAGBEL_6_QF	24075	LAGUBELL	66	9.79		Western	Not modeled Aug NQC	QF/Selfgen
LGHTHP_6_ICEGEN	24070	ICEGEN	13.8	48.00	1	Western	Aug NQC	QF/Selfgen
LGHTHP_6_QF	24083	LITEHIPE	66	0.30		Western	Not modeled Aug NQC	QF/Selfgen
MESAS_2_QF	24209	MESA CAL	66	0.04		Western	Not modeled Aug NQC	QF/Selfgen
MIRLOM_2_CORONA				2.03		Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
MIRLOM_2_ONTARO				2.38		Eastern, Eastern Metro	Energy Only	Market
MIRLOM_2_RTS032				0.75		Eastern, Eastern Metro	Not modeled Aug NQC	Market
MIRLOM_2_RTS033				0.75		Eastern, Eastern Metro	Not modeled Aug NQC	Market
MIRLOM_2_TEMESC				2.13		Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
MIRLOM_6_DELGEN	24030	DELGEN	13.8	27.66	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	4.60		Eastern, Eastern Metro	Not modeled Aug NQC	MUNI
MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	4.20	1	Eastern, Eastern Metro	Aug NQC	MUNI
MOJAVE_1_SIPHON	25658	MJVSPHN1	13.8	4.19	2	Eastern, Eastern Metro	Aug NQC	MUNI
MOJAVE_1_SIPHON	25659	MJVSPHN1	13.8	4.19	3	Eastern, Eastern Metro	Aug NQC	MUNI
MTWIND_1_UNIT 1	29060	MOUNTWND	115	4.07	S1	Eastern, Valley-Devers	Aug NQC	Wind
MTWIND_1_UNIT 2	29060	MOUNTWND	115	1.88	S2	Eastern, Valley-Devers	Aug NQC	Wind
MTWIND_1_UNIT 3	29060	MOUNTWND	115	1.64	S3	Eastern, Valley-Devers	Aug NQC	Wind
OLINDA_2_COYCRK	24211	OLINDA	66	3.13		Western	Not modeled	QF/Selfgen
OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	3.88	C1	Western	Aug NQC	Market
OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	3.88	C2	Western	Aug NQC	Market
OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	3.88	C3	Western	Aug NQC	Market
OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	3.88	C4	Western	Aug NQC	Market
OLINDA_2_LNDFL2	29011	BREAPWR2	13.8	6.98	S1	Western	Aug NQC	Market
OLINDA_2_QF	24211	OLINDA	66	0.11	1	Western	Aug NQC	QF/Selfgen

OLINDA_7_LNDFIL	24211	OLINDA	66	0.05		Western	Not modeled Aug NQC	QF/Selfgen
PADUA_2_ONTARO	24111	PADUA	66	0.19		Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
PADUA_2_SOLAR1	24111	PADUA	66	0.00		Eastern, Eastern Metro	Not modeled Energy Only	Market
PADUA_6_MWDSDM	24111	PADUA	66	3.71		Eastern, Eastern Metro	Not modeled Aug NQC	MUNI
PADUA_6_QF	24111	PADUA	66	0.48		Eastern, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
PADUA_7_SDIMAS	24111	PADUA	66	1.05		Eastern, Eastern Metro	Not modeled Aug NQC	Market
PANSEA_1_PANARO	25640	PANAERO	115	0.26	QF	Eastern, Valley-Devers	Aug NQC	Wind
PWEST_1_UNIT				0.12		Western	Not modeled Aug NQC	Market
REDOND_7_UNIT 5	24121	REDON5 G	18	178.87	5	Western		Market
REDOND_7_UNIT 6	24122	REDON6 G	18	175.00	6	Western		Market
REDOND_7_UNIT 7	24123	REDON7 G	20	505.96	7	Western		Market
REDOND_7_UNIT 8	24124	REDON8 G	20	495.90	8	Western		Market
RENWD_1_QF	25636	RENWIND	115	2.47	Q2	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
RHONDO_2_QF	24213	RIOHONDO	66	0.40		Western	Not modeled Aug NQC	QF/Selfgen
RHONDO_6_PUENTE	24213	RIOHONDO	66	0.00		Western	Not modeled Aug NQC	Net Seller
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_SOLAR1	24244	SPRINGEN	13.8	7.02		Eastern, Eastern Metro	Not modeled Aug NQC	Market
RVSIDE_6_SPRING	24244	SPRINGEN	13.8	36.00	1	Eastern, Eastern Metro		Market
SANTGO_6_COYOTE	24133	SANTIAGO	66	5.63	1	Western	Aug NQC	Market
SANWD_1_QF	25646	SANWIND	115	1.75	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	0.06		Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
SBERDO_2_REDLND	24214	SANBRDNO	66	0.66		Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	Market
SBERDO_2_RTS005	24214	SANBRDNO	66	1.28		Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	Market
SBERDO_2_RTS007	24214	SANBRDNO	66	1.15		Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	Market
SBERDO_2_RTS011	24214	SANBRDNO	66	2.62		Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	Market
SBERDO_2_RTS013	24214	SANBRDNO	66	2.62		Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	Market

SBERDO_2_RTS016	24214	SANBRDNO	66	1.12		Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	Market
SBERDO_2_RTS048	24214	SANBRDNO	66	0.00		Eastern, West of Devers, Eastern Metro	Not modeled Energy Only	Market
SBERDO_2_SNTANA	24214	SANBRDNO	66	0.00		Eastern, West of Devers, Eastern Metro	Not modeled Aug NQC	QF/Selfgen
SBERDO_6_MILLCK	24214	SANBRDNO	66	0.64		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				4.01		Western	Not modeled Aug NQC	Wind
TRNSWD_1_QF	25637	TRANWIND	115	4.66	QF	Eastern, Valley-Devers	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	1.52		Eastern, Valley, Valley-Devers	Not modeled Aug NQC	QF/Selfgen
VALLEY_5_RTS044	24160	VALLEYSC	115	3.90		Eastern, Valley, Valley-Devers	Not modeled Aug NQC	Market
VALLEY_5_SOLAR1	24160	VALLEYSC	115	0.00		Eastern, Valley, Valley-Devers	Not modeled Energy Only	Market
VALLEY_5_SOLAR2	24160	VALLEYSC	115	14.97		Eastern, Valley, Valley-Devers	Not modeled Aug NQC	Market
VALLEY_7_BADLND	24160	VALLEYSC	115	0.30		Eastern, Valley, Valley-Devers	Not modeled Aug NQC	Market
VALLEY_7_UNITA1	24160	VALLEYSC	115	2.30		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	3.40		Western	Not modeled Aug NQC	MUNI
VISTA_2_RIALTO	24901	VSTA	230	0.00		Eastern, Eastern Metro	Energy Only	Market
VISTA_2_RTS028	24901	VSTA	230	2.25		Eastern, Eastern Metro	Not modeled Aug NQC	Market
VISTA_6_QF	24902	VSTA	66	0.11	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	96.65	1	Western		Market
WALNUT_2_SOLAR				0.00		Western	Not modeled Energy Only	Market
WALNUT_6_HILLGEN	24063	HILLGEN	13.8	47.73	D1	Western	Aug NQC	QF/Selfgen

WALNUT_7_WCOVCT	24157	WALNUT	66	0.00		Western	Not modeled Aug NQC	Market
WALNUT_7_WCOVST	24157	WALNUT	66	5.08		Western	Not modeled Aug NQC	Market
WHTWTR_1_WINDA1	29061	WHITEWTR	33	3.97	1	Eastern, Valley-Devers	Aug NQC	Wind
ARCOGN_2_UNITS	24018	BRIGEN	13.8	0.00	1	Western	No NQC - hist. data	Net Seller
HINSON_6_QF	24064	HINSON	66	0.00	1	Western	No NQC - hist. data	QF/Selfgen
INLAND_6_UNIT	24071	INLAND	13.8	15.20	1	Eastern, Eastern Metro	No NQC - hist. data	QF/Selfgen
MOBGEN_6_UNIT 1	24094	MOBGEN	13.8	0.00	1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24324	SANIGEN	13.8	1.40	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	0.00	1	Western	No NQC - hist. data	QF/Selfgen
NA	24329	MOBGEN2	13.8	0.00	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	1.40	D1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24341	COYGEN	13.8	6.30	1	Western	No NQC - hist. data	QF/Selfgen
NA	24342	FEDGEN	13.8	5.80	1	Western	No NQC - hist. data	QF/Selfgen
NA	29021	WINTEC6	115	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	20.70	G1	Eastern, Eastern Metro	No NQC - hist. data	QF/Selfgen
NA	29339	DELGEN	13.8	29.50	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	9.80	D1	Western	No NQC - Pmax	QF/Selfgen
NA	29953	SIGGEN	13.8	18.60	D1	Western	No NQC - Pmax	QF/Selfgen
ELSEGN_7_UNIT 4	24048	ELSEG4 G	18	0.00	4	Western, El Nido	Retired	Market
SONGS_7_UNIT 2	24129	S.ONOFR2	22	0.00	R2	None	Retired	Nuclear
SONGS_7_UNIT 3	24130	S.ONOFR3	22	0.00	R3	None	Retired	Nuclear

Major new projects modeled:

1. Talega Synchronous Condensers
2. Imperial Valley Phase Shifting Transformers (230/230kV 2x400 MVA)

Critical Contingency Analysis Summary

El Nido sub-area

The most critical contingency for the El Nido sub-area is the loss of the La Fresa – Hinson 230 kV line followed by the loss of the La Fresa – Redondo #1 and #2 230 kV lines, which would cause voltage collapse. This limiting contingency establishes a LCR of 318 MW in 2017 (includes 1 MW of QF and 1 MW of MUNI generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Western Sub-Area:

The most critical contingency for the Western sub-area is the loss of Serrano – Villa Park #2 230 kV line followed by the loss of the Serrano – Lewis 230 kV line or vice versa, which would result in thermal overload of the remaining Serrano – Villa Park #1 230 kV line. This limiting contingency establishes a LCR of 3,871 MW (includes 201 MW of QF, 4 MW of Wind and 582 MW of Muni generation) in 2017 as the generation 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:

Gen Bus	Gen Name	Gen ID	MW Eff Fctr (%)
29309	BARPKGEN	1	24
25208	DowlingCTG	1	23
25211	CanyonGT 1	1	23
25212	CanyonGT 2	2	23
25213	CanyonGT 3	3	23
25214	CanyonGT 4	4	23
24066	HUNT1 G	1	20
24067	HUNT2 G	2	20
24325	ORCOGEN	1	20
24005	ALAMT5 G	5	17
24161	ALAMT6 G	6	17
24001	ALAMT1 G	1	17
24002	ALAMT2 G	2	17
24003	ALAMT3 G	3	17
24004	ALAMT4 G	4	17

24162	ALAMT7 G	R7	17
24133	SANTIAGO	1	13
24341	COYGEN	1	13
24018	BRIGEN	1	13
24011	ARCO 1G	1	11
24012	ARCO 2G	2	11
24013	ARCO 3G	3	11
24014	ARCO 4G	4	11
24020	CARBGEN1	1	11
24064	HINSON	1	11
24080	LBEACH8G	R8	11
24081	LBEACH9G	R9	11
24139	SERRFGEN	D1	11
24163	ARCO 5G	5	11
24164	ARCO 6G	6	11
24170	LBEACH12	2	11
24170	LBEACH12	1	11
24171	LBEACH34	3	11
24171	LBEACH34	4	11
24327	THUMSGEN	1	11
24328	CARBGEN2	1	11
24062	HARBOR G	1	11
24062	HARBOR G	HP	11
25510	HARBORG4	LP	11
24079	LBEACH7G	R7	11
24173	LBEACH5G	R5	11
24174	LBEACH6G	R6	11
24070	ICEGEN	D1	11
29308	CTRPKGEN	1	10
29953	SIGGEN	D1	10
24022	CHEVGEN1	1	9
24023	CHEVGEN2	2	9
24047	ELSEG3 G	3	9
24048	ELSEG4 G	4	9
24094	MOBGEN1	1	9
24329	MOBGEN2	1	9
24330	OUTFALL1	1	9
24331	OUTFALL2	1	9
24332	PALOGEN	D1	9
24333	REDON1 G	R1	9
24334	REDON2 G	R2	9
24335	REDON3 G	R3	9
24336	REDON4 G	R4	9
24337	VENICE	1	9
29009	CHEVGEN5	1	9

29009	CHEVGEN5	2	9
29901	ELSEG5GT	5	9
29902	ELSEG6ST	6	9
29903	ELSEG7GT	7	9
29904	ELSEG8ST	8	9
24121	REDON5 G	5	9
24122	REDON6 G	6	9
24123	REDON7 G	7	9
24124	REDON8 G	8	9
24239	MALBRG1G	C1	8
24240	MALBRG2G	C2	8
24241	MALBRG3G	S3	8
24342	FEDGEN	1	8
29951	REFUSE	D1	8
29005	PASADNA1	1	5
29006	PASADNA2	1	5
29007	BRODWYSC	1	5

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

West of Devers Sub-area:

The most critical contingency is the loss of San Bernardino – Etiwanda 230 kV, followed by the San Bernardino – Vista 230 kV line outage, which could result in voltage collapse. This limiting contingency establishes a local capacity need of 261 MW (includes 1 MW of QF generation) in 2017 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Valley-Devers Sub-Area:

The most critical contingency for the Valley-Devers sub-area is the loss of Palo Verde – Colorado River 500 kV line, system readjustment, followed by Serrano - Valley 500 kV line or vice versa, which would result in overload on Iron Mountain – Eagle Mountain 230 kV line. This limiting contingency establishes a LCR of 1,415 MW (includes 30 MW of QF and 37 MW of wind generation) in 2017 as the generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The generators inside the sub-area have the same effectiveness factors.

Valley Sub-area:

Resources needed to meet the Valley-Devers sub-area are adequate to meet this sub-area requirement as well.

Eastern LA Basin Sub-area:

Resources needed to meet the West of Devers and Valley-Devers sub-areas are adequate to meet this sub-area requirement as well.

LA Basin Area and San Diego Sub-area Combined:

The needs of the LA Basin area and San Diego sub-area have been considered taking into account two exceptional circumstances. These circumstances include concerns for the potential of a peak shift issue associated with the impact of behind the meter solar generation which may be understating the local area peak load in the LA Basin and San Diego sub-area, and concerns with the availability of the Aliso Canyon gas storage facility affecting the ability of LA Basin gas fired generation to be called upon on short notice.

The most critical contingency resulting in voltage stability concerns for the combined LA Basin and San Diego sub-area is the loss of the ECO-Miguel 500kV line, system readjustment, followed by the loss of Ocotillo-Suncrest 500 kV line or vice versa. In considering this potential outage, the ISO considered a sensitivity analysis with less contribution from rooftop solar PV during the hour of 6:00 PM when customer demand remains high, and with a more conservative assumption that key static shunt capacitor switching does not occur in a timely manner for the shorter post-transient condition[23]

[23] According to the WECC, the post-transient time frame lasts anywhere from one minute to a maximum of

following immediately after the second contingency given the capacitor switching necessitated by the first contingency as part of a longer system adjustment[24]. The amount of peak shift due to loads remaining high without the contribution of solar photovoltaic distributed generation at early evening hour (i.e., 6:00 PM) is approximately 651 MW[25] in the SCE service area, and approximately 228 MW[25] in the San Diego metropolitan area. This sensitivity assessment resulted in a San Diego sub-area local capacity need of approximately 2,743 MW, approaching the level of the rebalancing of resources to support mitigating the loss of the Aliso Canyon gas storage facility as discussed in the sections below. The LCR need for the LA Basin associated with this sensitivity voltage stability assessment is 7,094 MW. In light of this, the requirements are being set based on the Aliso Canyon discussion below.

The Aliso Canyon gas storage facility, in addition to gas transmission pipelines, provides gas to customers in the LA Basin, including seventeen gas-fired generating facilities in the ISO and LADWP Balancing Authority Areas. Limited use or unavailability of Aliso Canyon would affect delivery of gas to generating facilities in the LA Basin during summer peak load conditions. In an effort to help mitigate the Aliso Canyon gas storage constraints, the ISO balanced the gas generation resource needs in the LA Basin and the San Diego sub-area to lessen the impact that the absence of Aliso Canyon has on the reliability of the electric transmission system in the LA Basin and San Diego area. The gas generation in the LA Basin and San Diego sub-area are served from two different gas transmission zones and different transmission gas pipelines. North and South LA Basin gas transmission zones, as well as Aliso Canyon, serve the LA Basin customers and gas-fired generation. For San Diego subarea, the

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three minutes after occurrence of a contingency. Based on evaluation of actual WECC-wide disturbance events, there is a risk of voltage instability if there are not adequate reactive supports that can be brought automatically on-line during this time frame to provide voltage support to address critical contingencies that resulted in large transfer of power between areas.

[24] It is allowed up to 30 minutes to complete system adjustment after the first contingency to bring the electric system back to steady-state condition.

[25] This amount was provided by the CEC to the ISO for "SCE (or SDG&E) TAC Peak and Energy Forecasts: CED 2015 Revised/Final Forecast, Mid Baseline" for Self-Generation Item No. 7 (Photovoltaic Distributed Generation peak load impact)

gas-fired generation is served from the South of Moreno/SDG&E gas transmission system. With the shift of required resources from the LA Basin to the San Diego sub-area, the binding constraint for the San Diego subarea becomes the same contingency that affects the overall LA Basin since the resources in San Diego subarea are needed to mitigate this overarching contingency as well as for the more localized reliability constraints.

The most critical contingency for the combined LA Basin and San Diego sub-area under this condition is the loss of the Lugo – Victorville 500 kV line, system readjustment, followed by the loss of Sylmar – Gould 230 kV line or vice versa. This overlapping contingency could thermally overload the Sylmar - Eagle Rock 230 kV line. This contingency establishes a total local capacity need for the combined LA Basin/San Diego sub-area of 10,283 MW in 2017 time frame as follows: 7,368 MW in the LA Basin (includes 399 MW of QF, 41 MW of wind and 1175 MW of MUNI generation, as well as 321 MW of 20-minute demand response[26]) and 2,915 MW in the San Diego sub-area (includes 103 MW of QF generation and 5 MW of wind) as the minimum capacity necessary for reliable load serving capability within these areas.

The capacity reduction in the LA Basin is about 716 MW, or 7 million cubic feet (MMcf)[27] per hour or approximately 167 MMcf per day. This reduction is relative to the generation need in the scenario where more effective gas-fired resources in the western LA Basin could have been relied upon if the full availability of the Aliso Canyon gas storage was more certain.

The most critical single contingency resulting in a transmission thermal overload for the combined LA Basin and San Diego sub-area is the overlapping outage of Redondo Unit #7, system readjustment, followed by Sylmar – Gould 230 kV line, which could result in thermal overload of the Sylmar – Eagle Rock 230 kV line. This limiting contingency establishes a total overall LCR need of 8,929 MW in 2017 time frame as follows: 6,873

[26] Event-triggered 20-minute demand response is considered a resource meeting the local capacity need.
[27] Total MMcf per hour = Total MW / (103 MWh/MMcf)

MW for the LA Basin (includes 399 MW of QF, 41 MW of wind and 1175 MW of MUNI generation) and 2,056 MW for the San Diego sub-area (includes 103 MW of QF generation and 5 MW of wind).

Effectiveness factors:

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

GENERATOR	MW Eff Fctr (%)
PASADNA1 13.8 #1	-25.58
PASADNA2 13.8 #1	-25.57
BRODWYSC 13.8 #1	-25.25
MALBRG3G 13.8 #S3	-15.52
ELSEG8ST 13.8 #8	-13.47
ELSEG7GT 16.5 #7	-13.46
ELSEG3 G 18.0 #3	-13.43
ELSEG4 G 18.0 #4	-13.42
CHEVGEN1 13.8 #1	-13.37
CHEVGEN2 13.8 #2	-13.37
VENICE 13.8 #1	-13.37
CHEVGEN5 13.8 #1	-13.36
CHEVGEN5 13.8 #2	-13.36
MOBGEN1 13.8 #1	-13.34
MOBGEN2 13.8 #1	-13.34
PALOGEN 13.8 #D1	-13.34
REDON5 G 18.0 #5	-13.27
REDON6 G 18.0 #6	-13.26
ARCO 1G 13.8 #1	-12.54
ARCO 2G 13.8 #2	-12.54
HARBOR G 13.8 #1	-12.54
HARBORG4 4.2 #LP	-12.54
HARBOR G 13.8 #HP	-12.54
LBEACH12 13.8 #2	-12.51
THUMSGEN 13.8 #1	-12.49
CARBGEN1 13.8 #1	-12.48
SERRFGEN 13.8 #D1	-12.48
CARBGEN2 13.8 #1	-12.48
LBEACH34 13.8 #3	-12.47
ICEGEN 13.8 #D1	-12.23
CTRPKGEN 13.8 #1	-11.36
SIGGEN 13.8 #D1	-11.35

ALAMT3 G 18.0 #3	-10.66
ALAMT4 G 18.0 #4	-10.66
EME WCG1 13.8 #1	-9.96
OLINDA 66.0 #1	-9.51
BREAPWR2 13.8 #C1	-9.5
BARPKGEN 13.8 #1	-8.7
HUNT1 G 13.8 #1	-8.3
HUNT2 G 13.8 #2	-8.3
SANTIAGO 66.0 #1	-7.73
CanyonGT 1 13.8 #1	-7.34
CanyonGT 2 13.8 #2	-7.34
DowlingCTG 13.8 #1	-7.34
SANIGEN 13.8 #D1	-5.99
CIMGEN 13.8 #D1	-5.98
SIMPSON 13.8 #D1	-5.97
MRLPKGEN 13.8 #1	-5.75
DELGEN 13.8 #1	-5.72
VSTA 66.0 #1	-5.29
MESAHGTS 69.0 #1	-5.28
ETWPKGEN 13.8 #1	-5.27
CLTNDREW 13.8 #1	-5.27
CLTNCTRY 13.8 #1	-5.27
CLTNAGUA 13.8 #1	-5.27
RERC1G 13.8 #1	-5.26
RERC2G 13.8 #1	-5.26
SPRINGEN 13.8 #1	-5.26
INLAND 13.8 #1	-5.25
RERC2G3 16.5 #1	-5.21
RERC2G4 16.5 #1	-5.21
MTNVIST3 18.0 #3	-5.15
MTNVIST4 18.0 #4	-5.14
MNTV-CT1 18.0 #1	-5.06
MNTV-CT2 18.0 #1	-5.06

Changes compared to last year's results:

Compared with 2016, the latest CEC-adopted load forecast for 2017 is reduced by 1,400 MW for geographic area, or by 1,278 MW for the electrical boundary area for the LA Basin. The LCR need has decreased by 1,519 MW, mainly due to decrease in load and addition of new transmission upgrades in the San Diego area associated with mitigation for SONGS and OTC generation retirement.

LA Basin Overall Requirements:

2017	QF (MW)	Wind (MW)	Muni (MW)	Nuclear (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	399	41	1175	0	8960	10575

2017	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[28]	6,873	0	6,873
Category C (Multiple)[29]	7,368	0	7,368

9. Big Creek/Ventura Area

Area Definition

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

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

These sub-stations form the boundary surrounding the Big Creek/Ventura area:

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

Total 2017 busload within the defined area is 4,377 MW with -78 MW of AAEE, 51 MW

[28] 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.

[29] 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.

of losses and 369 MW of pumps resulting in total load + losses + pumps of 4,719 MW.

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

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ACACIA_6_SOLAR	29878	ACACIA_G	0.48	0.00	EQ	Big Creek	Energy Only	Market
ALAMO_6_UNIT	25653	ALAMO SC	13.8	15.07	1	Big Creek	Aug NQC	MUNI
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
DELSUR_6_DRYFRB				3.46		Big Creek	Not modeled Aug NQC	Market
DELSUR_6_SOLAR1				4.49		Big Creek	Not modeled 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	16.86	1	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25606	EDMON2AP	14.4	16.86	2	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25607	EDMON3AP	14.4	16.86	3	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25607	EDMON3AP	14.4	16.86	4	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25608	EDMON4AP	14.4	16.86	5	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25608	EDMON4AP	14.4	16.86	6	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25609	EDMON5AP	14.4	16.86	7	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25609	EDMON5AP	14.4	16.86	8	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25610	EDMON6AP	14.4	16.86	9	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25610	EDMON6AP	14.4	16.86	10	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25611	EDMON7AP	14.4	16.86	11	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25611	EDMON7AP	14.4	16.86	12	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25612	EDMON8AP	14.4	16.86	13	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25612	EDMON8AP	14.4	16.86	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	0.08		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[30]	24326	EXGEN1	13.8	0.32	S1	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
GOLETA_6_EXGEN	24362	EXGEN2	13.8	0.47	G1	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
GOLETA_6_GAVOTA	24057	GOLETA	66	0.68		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	Market
GOLETA_6_TAJIGS	24057	GOLETA	66	2.90		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
LITLRK_6_SOLAR1				3.45		Big Creek	Not modeled Aug NQC	Market
LITLRK_6_SOLAR4				2.08		Big Creek	Not modeled Aug NQC	Market

[30] Las Flores Canyon Cogeneration Facility (Resource ID: GOLETA_6_EXGEN) is on a long-term shutdown due to the Plains All American Pipeline rupture as of June 16, 2015. (http://www.sbcountyplanning.org/energy/projects/exxon.asp)

LNCSTR_6_SOLAR				7.02		Big Creek	Not modeled Aug NQC	Market
MNDALY_6_MCGRTH	29306	MCGPKGEN	13.8	47.20	1	Ventura, S.Clara, Moorpark		Market
MNDALY_7_UNIT 1	24089	MANDLY1G	13.8	215.00	1	Ventura, S.Clara, Moorpark		Market
MNDALY_7_UNIT 2	24090	MANDLY2G	13.8	215.29	2	Ventura, S.Clara, Moorpark		Market
MNDALY_7_UNIT 3	24222	MANDLY3G	16	130.00	3	Ventura, S.Clara, Moorpark		Market
MOORPK_2_CALABS	24099	MOORPARK	230	4.19		Ventura, Moorpark	Not modeled	Market
MOORPK_6_QF	24098	MOORPARK	66	26.81		Ventura, Moorpark	Not modeled Aug NQC	QF/Selfgen
MOORPK_7_UNITA1	24098	MOORPARK	66	2.12		Ventura, Moorpark	Not modeled Aug NQC	QF/Selfgen
NEENCH_6_SOLAR	29900	ALPINE_G	0.48	50.05	EQ	Big Creek	Aug NQC	Market
OASIS_6_SOLAR2				13.85		Big Creek	Not modeled Aug NQC	Market
OMAR_2_UNIT 1	24102	OMAR 1G	13.8	77.10	1	Big Creek		Net Seller
OMAR_2_UNIT 2	24103	OMAR 2G	13.8	77.25	2	Big Creek		Net Seller
OMAR_2_UNIT 3	24104	OMAR 3G	13.8	77.25	3	Big Creek		Net Seller
OMAR_2_UNIT 4	24105	OMAR 4G	13.8	77.25	4	Big Creek		Net Seller
ORMOND_7_UNIT 1	24107	ORMOND1G	26	741.27	1	Ventura, Moorpark		Market
ORMOND_7_UNIT 2	24108	ORMOND2G	26	775.00	2	Ventura, Moorpark		Market
OSO_6_NSPIN	25614	OSO A P	13.2	2.25	1	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25614	OSO A P	13.2	2.25	2	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25614	OSO A P	13.2	2.25	3	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25614	OSO A P	13.2	2.25	4	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	2.25	5	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	2.25	6	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	2.25	7	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	2.25	8	Big Creek	Pumps	MUNI
PANDOL_6_UNIT	24113	PANDOL	13.8	25.70	1	Big Creek, Vestal	Aug NQC	Market
PANDOL_6_UNIT	24113	PANDOL	13.8	20.94	2	Big Creek, Vestal	Aug NQC	Market
PLAINV_6_BSOLAR				0.00		Big Creek	Not modeled Energy Only	Market
RECTOR_2_KAWEAH	24212	RECTOR	66	0.00		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
RECTOR_2_KAWH 1	24212	RECTOR	66	0.31		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
RECTOR_2_QF	24212	RECTOR	66	0.41		Big Creek, Rector, Vestal	Not modeled Aug NQC	QF/Selfgen
RECTOR_7_TULARE	24212	RECTOR	66	0.00		Big Creek, Rector, Vestal	Not modeled	Market
RSMSLR_6_SOLAR1				16.81		Big Creek	Not modeled Aug NQC	Market
RSMSLR_6_SOLAR2				15.57		Big Creek	Not modeled Aug NQC	Market
SAUGUS_2_TOLAND	24135	SAUGUS	66	0.00		Big Creek	Not modeled Energy Only	Market
SAUGUS_6_MWDFTH	24135	SAUGUS	66	7.36		Big Creek	Not modeled Aug NQC	MUNI
SAUGUS_6_PTCHGN	24118	PITCHGEN	13.8	19.47	D1	Big Creek	Aug NQC	MUNI

SAUGUS_6_QF	24135	SAUGUS	66	0.78		Big Creek	Not modeled Aug NQC	QF/Selfgen
SAUGUS_7_CHIQCN	24135	SAUGUS	66	3.96		Big Creek	Not modeled Aug NQC	Market
SAUGUS_7_LOPEZ	24135	SAUGUS	66	5.34		Big Creek	Not modeled Aug NQC	QF/Selfgen
SNCLRA_6_OXGEN	24110	OXGEN	13.8	34.62	D1	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SNCLRA_6_PROCGN	24119	PROCGEN	13.8	44.22	D1	Ventura, S.Clara, Moorpark	Aug NQC	Market
SNCLRA_6_QF				0.00		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	QF/Selfgen
SNCLRA_6_WILLMT	24159	WILLAMET	13.8	13.61	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	0.00		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
SPRGVL_2_TULESC	24215	SPRINGVL	66	0.29		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
SUNSHN_2_LNDFL	29954	WDT273	13.7	3.05	1	Big Creek	Aug NQC	Market
SUNSHN_2_LNDFL	29954	WDT273	13.7	3.05	2	Big Creek	Aug NQC	Market
SUNSHN_2_LNDFL	29954	WDT273	13.7	3.05	3	Big Creek	Aug NQC	Market
SUNSHN_2_LNDFL	29954	WDT273	13.7	3.04	4	Big Creek	Aug NQC	Market
SUNSHN_2_LNDFL	29954	WDT273	13.7	3.04	5	Big Creek	Aug NQC	Market
SYCAMR_2_UNIT 1	24143	SYCCYN1G	13.8	75.52	1	Big Creek	Aug NQC	Net Seller
SYCAMR_2_UNIT 2	24144	SYCCYN2G	13.8	85.00	2	Big Creek	Aug NQC	Net Seller
SYCAMR_2_UNIT 3	24145	SYCCYN3G	13.8	75.25	3	Big Creek	Aug NQC	Net Seller
SYCAMR_2_UNIT 4	24146	SYCCYN4G	13.8	85.00	4	Big Creek	Aug NQC	Net Seller
TENGEN_2_PL1X2	24148	TENNGEN1	13.8	18.12	D1	Big Creek	Aug NQC	Net Seller
TENGEN_2_PL1X2	24149	TENNGEN2	13.8	18.12	D2	Big Creek	Aug NQC	Net Seller
VESTAL_2_KERN	24372	KR 3-1	11	0.22	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
VESTAL_2_KERN	24373	KR 3-2	11	0.22	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
VESTAL_2_RTS042				0.00		Big Creek, Vestal	Not modeled Energy Only	Market
VESTAL_2_WELLHD	24116	WELLGEN	13.8	49.00	1	Big Creek, Vestal		Market
VESTAL_6_QF	24152	VESTAL	66	0.31		Big Creek, Vestal	Not modeled Aug NQC	QF/Selfgen
VESTAL_6_ULTRGN	24150	ULTRAGEN	13.8	27.87	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
VESTAL_6_WDFIRE	24152	VESTAL	66	5.63		Big Creek, Vestal	Not modeled Aug NQC	QF/Selfgen
WARNE_2_UNIT	25651	WARNE1	13.8	38.00	1	Big Creek	Aug NQC	MUNI
WARNE_2_UNIT	25652	WARNE2	13.8	38.00	1	Big Creek	Aug NQC	MUNI
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	24340	CHARMIN	13.8	15.00	1	Ventura, S.Clara, Moorpark	No NQC - hist. data	QF/Selfgen
NA	24370	KAWGEN	13.8	17.00	1	Big Creek, Rector, Vestal	No NQC - hist. data	Market
NA	24422	PALMDALE	66	0.00	1	Big Creek	No NQC - hist. data	Market

NA	29952	CAMGEN	14.2	26.20	D1	Ventura, S.Clara, Moorpark	No NQC - hist. data	QF/Selfgen
VESTAL_6_WDFIRE	29008	LAKEGEN	13.8	11.00	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
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

Major new projects modeled: None

Critical Contingency Analysis Summary

Rector Sub-area

The most critical contingency for the Rector sub-area is the loss of one of the Rector-Vestal 230 kV lines with the Eastwood unit out of service, which would thermally overload the remaining Rector-Vestal 230 kV line. This limiting contingency establishes a LCR of 513 MW (includes 1 MW of QF generation) in 2017 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:

Gen Bus	Gen Name	Gen ID	MW Eff Fctr (%)
24370	KAWGEN	1	51
24306	B CRK1-1	1	45
24306	B CRK1-1	2	45
24307	B CRK1-2	3	45
24307	B CRK1-2	4	45
24319	EASTWOOD	1	45
24323	PORTAL	1	45
24308	B CRK2-1	1	45
24308	B CRK2-1	2	45
24309	B CRK2-2	3	45
24309	B CRK2-2	4	45
24310	B CRK2-3	5	45
24310	B CRK2-3	6	45
24315	B CRK 8	81	45
24315	B CRK 8	82	45
24311	B CRK3-1	1	45
24311	B CRK3-1	2	45

24312	B CRK3-2	3	45
24312	B CRK3-2	4	45
24313	B CRK3-3	5	45
24317	MAMOTH1G	1	45
24318	MAMOTH2G	2	45
24314	B CRK 4	41	43
24314	B CRK 4	42	43

Vestal Sub-area

The most critical contingency for the Vestal sub-area is the loss of one of the Magunden-Vestal 230 kV lines with the Eastwood unit out of service, which would thermally overload the remaining Magunden-Vestal 230 kV line. This limiting contingency establishes a LCR of 715 MW in 2017 (includes 46 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:

Gen Bus	Gen Name	Gen ID	MW Eff Fctr (%)
24113	PANDOL	1	64
24113	PANDOL	2	64
24116	WELLGEN	1	64
24150	ULTRAGEN	1	64
24372	KR 3-1	1	64
24373	KR 3-2	2	64
28019	WDT190G	1	64
29008	LAKEGEN	1	64
24370	KAWGEN	1	49
24306	B CRK1-1	1	44
24306	B CRK1-1	2	44
24307	B CRK1-2	3	44
24307	B CRK1-2	4	44
24319	EASTWOOD	1	44
24323	PORTAL	1	44
24308	B CRK2-1	1	44
24308	B CRK2-1	2	44
24309	B CRK2-2	3	44
24309	B CRK2-2	4	44
24310	B CRK2-3	5	44
24310	B CRK2-3	6	44

24315	B CRK 8	81	44
24315	B CRK 8	82	44
24311	B CRK3-1	1	44
24311	B CRK3-1	2	44
24312	B CRK3-2	3	44
24312	B CRK3-2	4	44
24313	B CRK3-3	5	44
24317	MAMOTH1G	1	44
24318	MAMOTH2G	2	44
24314	B CRK 4	41	42
24314	B CRK 4	42	42

S. Clara sub-area

The most critical contingency for the S.Clara sub-area is the loss of the Pardee to S.Clara 230 kV line followed by the loss of the Moorpark to S.Clara #1 and #2 230 kV lines, which would cause voltage collapse. This limiting contingency establishes a LCR of 227 MW in 2017 (which includes 90 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The generators inside the sub-area have the same effectiveness factors.

Moorpark sub-area

The most critical contingency for the Moorpark sub-area is the loss of one of the Pardee to Moorpark 230 kV lines followed by the loss of the remaining two Moorpark to Pardee 230 kV lines, which would cause voltage collapse. This limiting contingency establishes a LCR of 511 MW in 2017 (which includes 119 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The generators inside the sub-area have the same effectiveness factors.

Big Creek/Ventura overall:

The most critical contingency is the loss of the Lugo-Victorville 500 kV followed by Sylmar-Pardee #1 or #2 230 kV line, which could thermally overload the remaining

Sylmar-Pardee 230 kV line. This limiting contingency establishes a LCR of 2,057 MW in 2017 (includes 171 MW of QF and 372 MW of MUNI generation) as the minimum generation capacity necessary for reliable load serving capability within this area.

The most critical single contingency is the loss of Ormond Beach Unit #2 followed by Sylmar-Pardee #1 (or # 2) line, which could thermally overload the remaining Sylmar-Pardee 230 kV line. This limiting contingency establishes a LCR of 1,841 MW in 2017 (includes 171 MW of QF and 372 MW of MUNI generation).

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	MW Eff Fctr (%)
24009	APPGEN1G	1	29
24010	APPGEN2G	2	29
24118	PITCHGEN	D1	29
24148	TENNGEN1	D1	29
24149	TENNGEN2	D2	29
24361	APPGEN3G	3	29
29954	WDT273	EQ	29
24107	ORMOND1G	1	28
24108	ORMOND2G	2	28
25651	WARNE1	1	26
25652	WARNE2	1	26
24089	MANDLY1G	1	25
24090	MANDLY2G	2	25
24110	OXGEN	D1	25
24119	PROCGEN	D1	25
24159	WILLAMET	D1	25
24222	MANDLY3G	3	25
24326	EXGEN1	S1	25
24340	CHARMIN	1	25
24362	EXGEN2	G1	25
29004	ELLWOOD	1	25
29306	MCGPKGEN	1	25
29952	CAMGEN	D1	25
25653	ALAMO SC	1	24
29051	PSTRIAG1	G1	24
29052	PSTRIAG2	G2	24
29053	PSTRIAS1	S1	24
29054	PSTRIAG3	G3	24

29055	PSTRIAS2	S2	24
24102	OMAR 1G	1	20
24103	OMAR 2G	2	20
24104	OMAR 3G	3	20
24105	OMAR 4G	4	20
24113	PANDOL	1	20
24113	PANDOL	2	20
24116	WELLGEN	1	20
24143	SYCCYN1G	1	20
24144	SYCCYN2G	2	20
24145	SYCCYN3G	3	20
24146	SYCCYN4G	4	20
24150	ULTRAGEN	1	20
24306	B CRK1-1	1	20
24306	B CRK1-1	2	20
24307	B CRK1-2	3	20
24307	B CRK1-2	4	20
24308	B CRK2-1	1	20
24308	B CRK2-1	2	20
24309	B CRK2-2	3	20
24309	B CRK2-2	4	20
24310	B CRK2-3	5	20
24310	B CRK2-3	6	20
24311	B CRK3-1	1	20
24311	B CRK3-1	2	20
24312	B CRK3-2	3	20
24312	B CRK3-2	4	20
24313	B CRK3-3	5	20
24314	B CRK 4	41	20
24314	B CRK 4	42	20
24315	B CRK 8	81	20
24315	B CRK 8	82	20
24317	MAMOTH1G	1	20
24318	MAMOTH2G	2	20
24319	EASTWOOD	1	20
24323	PORTAL	1	20
24370	KAWGEN	1	20
24372	KR 3-1	1	20
24373	KR 3-2	2	20
29008	LAKEGEN	1	20
29900	ALPINE_G	EQ	17
29884	DAWNGEN	EQ	10
29888	TWILGHTG	EQ	10
29896	APPINV	EQ	10
29918	VLYFLR_G	EQ	10

29878	ACACIA_G	EQ	10

Changes compared to last year's results:

Compared with 2016 the load forecast is down by 87 MW and the LCR need has decreased by 341 MW.

Big Creek Overall Requirements:

2017	QF (MW)	MUNI (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	171	372	4920	5463

2017	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[31]	1841	0	1841
Category C (Multiple)[32]	2057	0	2057

10. San Diego-Imperial Valley Area

Area Definition

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

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

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

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

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

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

Total 2017 busload within the defined area: 4760 MW with -84 MW of AAEE and 164 MW of losses resulting in total load + losses of 4840 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BORDER_6_UNITA1	22149	CALPK_BD	13.8	48.00	1	San Diego, Border		Market
BREGGO_6_DEGRSL				4.36		San Diego	Not modeled Aug NQC	Market
BREGGO_6_SOLAR	22082	BR GEN1	0.21	20.46	1	San Diego	Aug NQC	Market
CBRLLO_6_PLSTP1	22092	CABRILLO	69	2.83	1	San Diego	Aug NQC	Market
CCRITA_7_RPPCHF	22124	CHCARITA	138	3.25	1	San Diego	Aug NQC	Market
CHILLS_1_SYCENG	22120	CARLTNHS	138	0.54	1	San Diego	Aug NQC	QF/Selfgen
CHILLS_1_SYCLFL	22120	CARLTNHS	138	0.54		San Diego	Not modeled Aug NQC	Net Seller
CHILLS_7_UNITA1	22120	CARLTNHS	138	1.52	2	San Diego	Aug NQC	QF/Selfgen
CNTNLA_2_SOLAR1	23463	DW GEN3&4	0.33	97.02	1	None	Aug NQC	Market
CNTNLA_2_SOLAR2	23463	DW GEN3&4	0.33	0.00	2	None	Energy Only	Market
CPSTNO_7_PRMADS	22112	CAPSTRNO	138	5.12	1	San Diego	Aug NQC	Market
CPVERD_2_SOLAR	23301	IV GEN3 G2	0.31	48.54	G2	None	Aug NQC	Market
CPVERD_2_SOLAR	23309	IV GEN3 G1	0.31	48.54	G1	None	Aug NQC	Market
CRELMN_6_RAMON1				1.53		San Diego	Not modeled Aug NQC	Market
CRELMN_6_RAMON2				3.89		San Diego	Not modeled Aug NQC	Market
CRSTWD_6_KUMYAY	22915	KUMEYAAY	0.69	5.00	1	San Diego	Aug NQC	Wind
CSLR4S_2_SOLAR	23298	DW GEN1 G1	0.32	42.33	G1	None	Aug NQC	Market
CSLR4S_2_SOLAR	23299	DW GEN1 G2	0.32	42.32	G2	None	Aug NQC	Market
DIVSON_6_NSQF	22172	DIVISION	69	41.54	1	San Diego	Aug NQC	QF/Selfgen
EGATE_7_NOCITY	22204	EASTGATE	69	0.24	1	San Diego	Aug NQC	QF/Selfgen
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
ENCINA_7_EA1	22233	ENCINA 1	14.4	106.00	1	San Diego, Encina		Market
ENCINA_7_EA2	22234	ENCINA 2	14.4	104.00	1	San Diego, Encina		Market
ENCINA_7_EA3	22236	ENCINA 3	14.4	110.00	1	San Diego, Encina		Market

ENCINA_7_EA4	22240	ENCINA 4	22	300.00	1	San Diego, Encina		Market
ENCINA_7_EA5	22244	ENCINA 5	24	330.00	1	San Diego, Encina		Market
ENCINA_7_GT1	22248	ENCINAGT	12.5	14.50	1	San Diego, Encina		Market
ENERSJ_2_WIND				24.82		None	Aug NQC	Wind
ESCNDO_6_PL1X2	22257	ESGEN	13.8	48.71	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	36.41	1	San Diego, Esco, Escondido	Aug NQC	Net Seller
IVSLRP_2_SOLAR1	23440	DW GEN2 G1	0.36	50.28	1	None	Aug NQC	Market
IVSLRP_2_SOLAR1	23441	DW GEN2 G2	0.36	50.27	1	None	Aug NQC	Market
IVSLRP_2_SOLAR1	23442	DW GEN2 G3	0.36	50.27	1	None	Aug NQC	Market
LAKHDG_6_UNIT 1	22625	LKHODG1	13.8	20.00	1	San Diego		Market
LAKHDG_6_UNIT 2	22626	LKHODG2	13.8	20.00	2	San Diego		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, Miramar		Market
MRGT_6_MMAREF	22486	MEF_MR1	13.8	48.00	1	San Diego, Miramar		Market
MSHGTS_6_MMARLF	22448	MESAHGTS	69	3.36	1	San Diego, Mission	Aug NQC	Market
MSSION_2_QF	22496	MISSION	69	0.73	1	San Diego	Aug NQC	QF/Selfgen
NIMTG_6_NIQF	22576	NOISLMTR	69	34.47	1	San Diego	Aug NQC	QF/Selfgen
OCTILO_5_WIND	23314	OCO GEN G1	0.69	12.21	G1	None	Aug NQC	Wind
OCTILO_5_WIND	23318	OCO GEN G2	0.69	12.21	G2	None	Aug NQC	Wind
OGROVE_6_PL1X2	22628	PA GEN1	13.8	48.00	1	San Diego, Pala		Market
OGROVE_6_PL1X2	22629	PA GEN2	13.8	48.00	2	San Diego, Pala		Market
OTAY_6_LNDFL5	22604	OTAY	69	0.00		San Diego, Border	Not modeled Energy Only	Market
OTAY_6_LNDFL6	22604	OTAY	69	0.00		San Diego, Border	Not modeled Energy Only	Market
OTAY_6_PL1X2	22617	OYGEN	13.8	35.50	1	San Diego, Border		Market
OTAY_6_UNITB1	22604	OTAY	69	2.90	1	San Diego, Border	Aug NQC	Market
OTAY_7_UNITC1	22604	OTAY	69	2.29	3	San Diego, Border	Aug NQC	QF/Selfgen
OTMESA_2_PL1X3	22605	OTAYMGT1	18	185.06	1	San Diego		Market
OTMESA_2_PL1X3	22606	OTAYMGT2	18	185.06	1	San Diego		Market
OTMESA_2_PL1X3	22607	OTAYMST1	16	233.48	1	San Diego		Market
PALOMR_2_PL1X3	22262	PEN_CT1	18	162.39	1	San Diego		Market
PALOMR_2_PL1X3	22263	PEN_CT2	18	162.39	1	San Diego		Market
PALOMR_2_PL1X3	22265	PEN_ST	18	240.83	1	San Diego		Market
PTLOMA_6_NTCCGN	22660	POINTLMA	69	2.06	2	San Diego	Aug NQC	QF/Selfgen
PTLOMA_6_NTCQF	22660	POINTLMA	69	18.41	1	San Diego	Aug NQC	QF/Selfgen
SAMPSN_6_KELCO1	22704	SAMPSON	12.5	0.60	1	San Diego	Aug NQC	Net Seller
SMRCOS_6_LNDFIL	22724	SANMRCOS	69	1.40	1	San Diego	Aug NQC	QF/Selfgen
TERMEX_2_PL1X3	22981	TDM STG	21	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
VLCNTR_6_VCSLR1				1.82		San Diego, Pala	Not modeled Aug NQC	Market

VLCNTR_6_VCSLR2				4.02		San Diego, Pala	Not modeled Aug NQC	Market
ELCAJN_7_GT1	22212	ELCAJNGT	12.5	16.00	1	San Diego, El Cajon	Not modeled	Market
KEARNY_7_KY3	22375	KEARN3AB	12.5	14.98	1	San Diego, Mission	Not modeled	Market
KEARNY_7_KY3	22375	KEARN3AB	12.5	16.05	2	San Diego, Mission	Not modeled	Market
KEARNY_7_KY3	22376	KEARN3CD	12.5	14.98	1	San Diego, Mission	Not modeled	Market
KEARNY_7_KY3	22376	KEARN3CD	12.5	14.98	2	San Diego, Mission	Not modeled	Market
MRGT_7_UNITS	22488	MIRAMRGT	12.5	18.55	1	San Diego, Miramar	Not modeled	Market
MRGT_7_UNITS	22488	MIRAMRGT	12.5	17.45	2	San Diego, Miramar	Not modeled	Market
NA	22916	PFC-AVC	0.6	0.00	1	San Diego	No NQC - hist. data	QF/Selfgen
New Unit	22942	BUE GEN 1 G1	0.69	15.40	G1	None	No NQC - est. data	Wind
New Unit	22945	BUE GEN 1 G2	0.69	15.40	G2	None	No NQC - est. data	Wind
New Unit	23100	ECO GEN1 G1	0.69	51.00	G1	None	No NQC - est. data	Wind
New Unit	23120	BULLMOOS	13.8	27.00	1	San Diego, Border	No NQC - P max	Market
New Unit	23155	c608 G1	0.36	75.00	G1	None	No NQC - P max	Market
New Unit	23156	c608_G2	0.36	75.00	G2	None	No NQC - P max	Market
New Unit	23162	PIO PICO CT1	13.8	103.00	1	San Diego	No NQC - Pmax	Market
New Unit	23163	PIO PICO CT2	13.8	103.00	1	San Diego	No NQC - Pmax	Market
New Unit	23164	PIO PICO CT3	13.8	103.00	1	San Diego	No NQC - Pmax	Market
New Unit	23287	Q429 G1	0.31	100.00	1	None	No NQC - P max	Market
New Unit	23352	Q644G	0.31	20.00	1	None	No NQC - P max	Market
New Unit	23487	Q653EDG	0.31	20.00	1	None	No NQC - P max	Market

Major new projects modeled:

1. Reactor on TL23040 Otay Mesa-Tijuana 230 kV line with the tie line rated at 850 MVA under emergency
2. Miguel Synchronous Condenser (2x225 Mvar)
3. 2nd Encina 230/138 Bank #61
4. East County 500kV Substation (ECO)
5. Reconductor of San Luis Rey-Oceanside Tap 69 kV line
6. IV Tertiary Reactors
7. Reconductor of Mission-Mesa Heights 69 kV line
8. Reconductor of Kearny-Mission 69 kV line
9. Imperial Valley Phase Shifting Transformers
10. By-passing 500 kV series capacitor banks on SWPL and SPL
11. 2nd Hassayampa-North Gila 500 kV line
12. A few new solar generation in the IV area
13. A few new wind generation in the Ocotillo and ECO area
14. PioPico Power Plant

<u>Critical Contingency Analysis Summary</u>

El Cajon Sub-area:

The most critical contingency for the El Cajon sub-area is the loss of the El Cajon-Jamacha 69 kV line (TL624) followed by the loss of Miguel-Granite-Los Coches 69 kV line (TL632), which could thermally overload the El Cajon – Los Coches 69 kV line (TL631). This limiting contingency establishes a LCR of 62 MW (including 0 MW of QF generation) in 2017 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Mission Sub-area

The most critical contingency for the Mission sub-area is the loss of Mission - Kearny 69 kV line (TL663) followed by the loss of Mission – Mesa Heights 69kV line (TL676), which could thermally overload the Kearny - Clairmont Tap 69kV line (TL600). This limiting contingency establishes a local capacity need of 22 MW (including 0 MW of QF generation) in 2017 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

It is recommended to retain part of Kearney peakers operational (at least 22 MW), until the concern is mitigated. Without part of the Kearney peakers this sub-area will have a 22 MW deficiency.

Effectiveness factors:

All Kearny peakers have the same effectiveness factor.

Esco Sub-area

The most critical contingency for the Esco sub-area is the loss of anyone of two Sycamore Canyon-Pomerado 69 kV lines (TL6915 or TL6924) followed by the loss of Esco - Escondido 69kV line (TL6908) which could thermally overload the other Sycamore Canyon-Pomerado 69 kV line (TL6924 or TL6915). This limiting contingency establishes a LCR of 35 MW (including 0 MW of QF generation) in 2017 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:
Only unit within this sub-area (Goal line) is needed so no effectiveness factor is required.

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 69kV line (TL6932) which could thermally overload the Melrose – Morro Hill Tap 69 kV line (TL694). This limiting contingency establishes a LCR of 21 MW (including 0 MW of QF generation) in 2017 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

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

Border Sub-area
The most critical contingency for the Border sub-area is the loss of Bay Boulevard – Otay 69kV line #1 (TL645) followed by Bay Boulevard - Otay 69kV line #2 (TL646), which could overload the Imperial Beach – Bay Boulevard 69 kV line (TL647). This limiting contingency establishes a local capacity need of 27 MW in 2017 (includes 2 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 – Silvergate 230 kV line (TL23042) followed by the loss of Sycamore – Palomar 230 kV line (TL23051), which could thermally overload the Sycamore - Scripps 69 kV line (TL6916). This limiting contingency establishes a LCR of 75 MW (including 0 MW of QF generation) in 2017 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area (Miramar Energy Facility and Miramar GTs) have the same effectiveness factor.

San Diego Sub-area and LA Basin Area Combined:

The needs of the LA Basin area and San Diego sub-area have been considered taking into account two exceptional circumstances. These circumstances include concerns for the potential of a peak shift issue associated with the impact of behind the meter solar generation which may be understating the local area peak load in the LA Basin and San Diego sub-area, and concerns with the availability of the Aliso Canyon gas storage facility affecting the ability of LA Basin gas fired generation to be called upon on short notice.

The most critical contingency resulting in voltage stability concerns for the combined LA Basin and San Diego sub-area is the loss of the ECO-Miguel 500kV line, system readjustment, followed by the loss of Ocotillo-Suncrest 500 kV line or vice versa. In considering this potential outage, the ISO considered a sensitivity analysis with less contribution from rooftop solar PV during the hour of 6:00 PM when customer demand remains high, and with a more conservative assumption that key static shunt capacitor switching does not occur in a timely manner for the shorter post-transient condition[33] following immediately after the second contingency given the capacitor switching necessitated by the first contingency as part of a longer system adjustment[34]. The amount of peak shift due to loads remaining high without the contribution of solar photovoltaic distributed generation at early evening hour (i.e., 6:00 PM) is approximately 651 MW[35] in the SCE service area, and approximately 228 MW[25] in the San Diego metropolitan area. This sensitivity assessment resulted in a San Diego sub-area local capacity need of approximately 2,743 MW, approaching the level of the rebalancing of resources to support mitigating the loss of the Aliso Canyon gas storage facility as discussed in the sections below. The LCR need for the LA Basin associated with this sensitivity voltage stability assessment is 7,094 MW. In light of this, the requirements are being set based on the Aliso Canyon discussion below.

The Aliso Canyon gas storage facility, in addition to gas transmission pipelines, provides gas to customers in the LA Basin, including seventeen gas-fired generating facilities in the ISO and LADWP Balancing Authority Areas. Limited use or unavailability of Aliso Canyon would affect delivery of gas to generating facilities in the LA Basin during summer peak load conditions. In an effort to help mitigate the Aliso Canyon gas storage constraints, the ISO balanced the gas generation resource needs in the LA Basin and the San Diego sub-area to lessen the impact that the absence of Aliso Canyon has on the reliability of the electric transmission system in the LA Basin and San Diego area. The gas generation in the LA Basin and San Diego sub-area are served from two different gas transmission zones and different transmission gas pipelines. North and South LA Basin gas transmission zones, as well as Aliso Canyon,

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[33] According to the WECC, the post-transient time frame lasts anywhere from one minute to a maximum of three minutes after occurrence of a contingency. Based on evaluation of actual WECC-wide disturbance events, there is a risk of voltage instability if there are not adequate reactive supports that can be brought automatically on-line during this time frame to provide voltage support to address critical contingencies that resulted in large transfer of power between areas.

[34] It is allowed up to 30 minutes to complete system adjustment after the first contingency to bring the electric system back to steady-state condition.

[35] This amount was provided by the CEC to the ISO for “SCE (or SDG&E) TAC Peak and Energy Forecasts: CED 2015 Revised/Final Forecast, Mid Baseline” for Self-Generation Item No. 7 (Photovoltaic Distributed Generation peak load impact)

serve the LA Basin customers and gas-fired generation. For San Diego subarea, the gas-fired generation is served from the South of Moreno/SDG&E gas transmission system. With the shift of required resources from the LA Basin to the San Diego sub-area, the binding constraint for the San Diego subarea becomes the same contingency that affects the overall LA Basin since the resources in San Diego subarea are needed to mitigate this overarching contingency as well as for the more localized reliability constraints.

The most critical contingency for the combined LA Basin and San Diego sub-area under this condition is the loss of the Lugo – Victorville 500 kV line, system readjustment, followed by the loss of Sylmar – Gould 230 kV line or vice versa. This overlapping contingency could thermally overload the Sylmar - Eagle Rock 230 kV line. This contingency establishes a total local capacity need for the combined LA Basin/San Diego sub-area of 10,283 MW in 2017 time frame as follows: 7,368 MW in the LA Basin (includes 399 MW of QF, 41 MW of wind and 1175 MW of MUNI generation, as well as 321 MW of 20-minute demand response[36]) and 2,915 MW in the San Diego sub-area (includes 103 MW of QF generation and 5 MW of wind) as the minimum capacity necessary for reliable load serving capability within these areas.

The capacity reduction in the LA Basin is about 716 MW, or 7 million cubic feet (MMcf)[37] per hour or approximately 167 MMcf per day. This reduction is relative to the generation need in the scenario where more effective gas-fired resources in the western LA Basin could have been relied upon if the full availability of the Aliso Canyon gas storage was more certain.

The most critical single contingency resulting in a transmission thermal overload for the combined LA Basin and San Diego subarea is the overlapping outage of Redondo Unit #7, system readjustment, followed by Sylmar – Gould 230 kV line, which would result in thermal overload of the Sylmar – Eagle Rock 230 kV line. This limiting contingency

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[36] Event-triggered 20-minute demand response is considered a resource meeting the local capacity need.
[37] Total MMcf per hour = Total MW / (103 MWh/MMcf)

establishes a total overall LCR need of 8,929 MW in 2017 time frame as follows: 6,873 MW for the LA Basin (includes 399 MW of QF, 41 MW of wind and 1175 MW of MUNI generation) and 2,056 MW for the San Diego sub-area (includes 103 MW of QF generation and 5 MW of wind).

Effectiveness factors: Units that have 5% or more effectiveness are listed here.

GENERATOR	MW Eff Fctr (%)
CAPSTRNO 138.0 #1	-6.37
SANMRCOS 69.0 #1	-5.65
ENCINA 5 24.0 #1	-5.63
ENCINAGT 12.5 #1	-5.52
ENCINA 1 14.4 #1	-5.5
ENCINA 2 14.4 #1	-5.5
PA GEN1 13.8 #1	-5.49
EASTGATE 69.0 #1	-5.39
PEN_CT2 18.0 #1	-5.37
PEN_ST 18.0 #1	-5.37
GOALLINE 69.0 #1	-5.36
CALPK_ES 13.8 #1	-5.34
LkHodG1 13.8 #1	-5.33
MESAHGTS 69.0 #1	-5.28
CABRILLO 69.0 #1	-5.22
POINTLMA 69.0 #1	-5.2
CHCARITA 138.0 #1	-5.17
NOISLMTR 69.0 #1	-5.16
DIVISION 69.0 #1	-5.13
KUMEYAAY 0.7 #1	-5.12
CARLTNHS 138.0 #1	-5.08
OTAY 69.0 #3	-5.05
OTAY 69.0 #1	-5.05

San Diego-Imperial Valley Area Overall:

The most limiting contingency in the San Diego-Imperial Valley area is described by the outage of 500 kV Southwest Power Link (SWPL) between Imperial Valley and North Gila Substations over-lapping with an outage of the TDM power plant (593 MW), which could thermally overload the 230 kV tie line (S-Line) between the Imperial Valley and IID's El Centro 230 kV substations. This limiting constraint establishes a local capacity need of 3570 MW in 2017 (includes 103 MW of QF and 136 MW of Wind generation) as the minimum capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

All resources located at Imperial Valley are most effective in mitigating the S-Line overload concern and have the same effectiveness factor.

Changes compared to last year's results:

The load forecast went down by 443 MW and overall the LCR need for the San Diego-Imperial Valley increased by 386 MW mostly due to cancellation of previously planned upgrade projects connecting to the Imperial Valley 230 kV substation. Further, It is recommended to retain part of Kearny GTs generating facilities until the most limiting contingencies are mitigated in the Mission sub-area.

San Diego-Imperial Valley Area Overall Requirements:

2017	QF (MW)	Wind (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	103	136	5071	5310

2017	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[38]	3570	0	3570
Category C (Multiple)[39]	3570	0	3570

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

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

11. Valley Electric Area

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

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

California Independent System Operator Corporation

Final Flexible Capacity Needs Assessment for 2017

Final Flexible Capacity Needs Assessment for 2017

April 29, 2016

Table of Contents

1. Introduction

The ISO conducts an annual flexible capacity technical study to determine the flexible capacity needed to help ensure the ISO system reliability as provided in ISO tariff section 40.10.1. The ISO developed the study process in the ISO's Flexible Resource Adequacy Criteria and Must-Offer Obligation ("FRAC-MOO") stakeholder initiative, in conjunction with the CPUC annual Resource Adequacy proceeding (R.11-10-023). In this filing, the ISO presents this final flexible capacity needs assessment outlining the ISO's forecast flexible capacity needs in 2017.

The ISO calculates the overall flexible capacity need of the ISO system and the relative contributions to this flexible capacity need attributable to the load serving entities (LSEs) under each local regulatory authority (LRA). This report details the system-level flexible capacity needs as well as the aggregate flexible capacity need attributable to CPUC jurisdictional load serving entities (LSEs). This report does not break-out the flexible capacity need attributable to individual LRAs other than the CPUC.

The ISO will use the results from the draft study to allocate shares of the system flexible capacity[1] need to each of the LRAs responsible for load in the ISO balancing authority area consistent with the allocation methodology detailed in the ISO's tariff section 40.10.2. Based on that allocation, the ISO will advise each Local Regulatory Authority of the MW amount of its share of the ISO's flexible capacity need.

2. Summary

The ISO determines the quantity of flexible capacity needed to reliably address the various flexibility and ramping needs for the upcoming resource adequacy year and publishes this finding through this flexible capacity needs assessment. To calculate the flexible capacity needs, the ISO uses the calculation method developed in the FRAC-MOO stakeholder initiative and codified in the ISO tariff. This methodology includes the ISO's calculation of the seasonal amounts of three flexible capacity categories as well as seasonal must-offer obligations for two of these flexible capacity categories.

The key results of the ISO's flexible capacity needs assessment for 2017 are --

1) The only significant enhancement made to 2017 study methodology is the use of a shaped profile for additional achievable energy efficiency that was provided by the CEC.

2) System-wide flexible capacity needs are greatest in the non-summer months and range from 9,918 MW in August to 14,977 MW in November.

3) The minimum amount of flexible capacity needed from the "base flexibility" category is 64 percent of the total amount of flexible capacity in the summer months (May – September) and 50 percent of the total amount of flexible capacity for the non-summer months (October – April).

4) The ISO will establish the time period of the must-offer obligation for resources counted in the "Peak" and "Super-Peak" flexible capacity categories as the five-hour periods of 12:00 p.m. to 5:00 p.m. during May through September, and 3:00 p.m. to 8:00 p.m. during January through April and October through December.

5) In previous years, the ISO has published advisory requirements the two years following the upcoming RA year. At the time of publication, the ISO is processing results for 2018 and 2019. As this data is processed, the ISO will issue advisory results for those years.

In calculating the allocations of flexible capacity needs, the ISO has identified one non-CPUC LSE's data was accidentally omitted. The ISO has contacted this LSE and will provide a draft of its flexible capacity requirements for that LSE by calculating the percentage contributions to the delta wind and solar components using the wind and solar portfolios identified in table 1 plus the LSE's additional input, below. However, the ISO was not able to rerun the complete assessment to account for this omission. As such, the ISO will not increase the flexible capacity requirement and the system wide requirement remains unchanged from the draft assessment. The omitted LRA will receive a flexible capacity allocation based only on the delta load component of the requirement with no contribution for the delta wind and solar components. The ISO is using this approach because the error was the ISO's and not the submitting LSE.

Additionally, given stakeholder comments, the ISO has made the following modifications or corrections to the draft study results:

- The contribution of the base flexible capacity category has been recalculated and is longer simply based on AM and PM ramps to ensure there of no overlap.
- As noted in the draft report, the ISO inadvertently omitted an LSE's data that had been submitted as part of the data collection process. The ISO was not able to complete a rerun of the full model to correct this. Because the error was the ISO's and not the submitting LSE, the ISO will provide a flexible capacity requirement to the omitted LRA that only includes the delta load component of the requirement with no contribution for the delta wind and solar components.

The following additions or corrections have been made to the individual LRA draft results:

- Based on the ISO enhancement regarding the calculation of secondary net load ramps, the ISO has modified all months in which the enhanced calculation had an impact. This results in a lower percent contribution to the base flexible capacity contribution for summer months. There was no change in non-summer months. All LRAs will receive a revised flexible capacity requirement that reflects this adjustment. The adjusted flexible capacity requirements for the system and CPUC's are included below.

Five stakeholder submitted comments on the draft study results. The ISO's responses to these comments are as follows:

- The ISO has responded to CDWR's data request and refers back to the original FRACMOO proposal regarding the calculations of the three hour net load ramp and the allocating factors.
- The ISO will, in response to AReM's comments, try to provide additional time for comments in future iterations.
- The ISO did, this year proactively reach out to all LSEs to ensure a 100 percent response rate. LSEs that failed to respond or did so late are subject to ISO provisions regarding late data submissions. The ISO has clarified its treatment of the omitted LSE, above, and the reason for this treatment. Additional clarifications have been made per requests of PG&E.
- Based on CPUC staff comments, the ISO enhanced its calculation methodology of the secondary net load ramps to eliminate any potential overlap between primary and secondary net load ramps.
- While NRDC asserts that AAEE is not a contributing factor to the increases in net load ramps, the profiles by the CEC show that a shaped AAEE profile yields slightly larger net load ramps when compared to a flat AAEE profile. The ISO is NOT asserting that AAEE cannot help mitigate the net load ramps over time, only that the transition from a flat to a shaped profile has had an impact. The ISO has clarified this point.

3. Defining the ISO System-Wide Flexible Capacity Need

Based on the methodology described in the ISO tariff and the business practice manual,[2] the ISO calculated the ISO system-wide flexible capacity needs as follows:

$$Flexibility\ Need_{MTH_y} = Max\left[\left(3RR_{HR_x}\right)_{MTH_y}\right] + Max\left(MSSC, 3.5\% * E\left(PL_{MTH_y}\right)\right) + \varepsilon$$

Where:

$Max[(3RR_{HRx})_{MTHy}]$ = Largest three hour contiguous ramp starting in hour x for month y
E(PL) = Expected peak load
MTHy = Month y
MSSC = Most Severe Single Contingency

2 Reliability Requirements business practice manual Section 10. Available at http://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Reliability%20Requirements

ε = Annually adjustable error term to account for load forecast errors and variability methodology

For the 2017 RA compliance year, the ISO will continue to set ε equal to zero. The ISO is conferring with the Department of Market Monitoring to determine if there is a need for future revisions based on the overlap between flexible capacity resources and the resources utilized for contingency reserves. At this time, there not sufficient data to warrant a non-zero ε term.

In order to determine the flexible capacity needs, including the quantities needed in each of the defined flexible capacity categories, the ISO conducted a six-step assessment process:

1) Forecast minute-by-minute net load using all expected and existing wind and solar resources and the most recent year of actual load, as adjusted for load growth

2) Calculate the monthly system-level 3-hour net load ramps needs using forecast minute-to-minute net load forecast;

3) Calculate the percentages needed in each category in each month and add the contingency requirements into the categories proportionally to the percentages established calculated in step 2

4) Analyze the distributions of both largest three-hour net load ramps for the primary and secondary net load ramps to determine appropriate seasonal demarcations;

5) Calculate a simple average of the percent of base flexibility needs from all months within a season; and

6) Determine each LRA's contribution to the flexible capacity need.

This methodology allows the ISO make enhancements and assumptions as new information becomes available and experience allows. Based on experience gained through the previous iteration of this study process, the ISO has made minor enhancements to the methodology used for the 2017 Flexible Capacity Needs Assessment. Further, the CEC staff has provided the ISO this shaped profiles for Additional Achievable Energy Efficiency that have been applied to the load profiles used by the ISO.[3] The following section details the methodology employed by the ISO as well as the assumptions used and their implication on the results.

[3] The additional achievable energy efficiency the CEC provided is available at http://www.caiso.com/Documents/CECStaffEstimates-AdditionalAchievableEnergyEfficiencyProfiles.xlsx.

4. Forecasting Minute-by-Minute Net load

The first step in developing the flexible capacity needs assessment was to forecast the net load. To produce this forecast, the ISO collected the requisite information about the expected build-out of the fleet of variable energy resources. Once this data was collected from all LSE's the ISO constructed the forecast minute-by-minute net load curves for 2017.[4]

4.1 Building the Forecasted Variable Energy Resource Portfolio

To collect this data, the ISO sent a data request on December 18, 2015 to the scheduling coordinators for all LSEs representing load in the ISO balancing area. The deadline for submission of the data was January 15, 2016. The ISO sent follow-up data requests to all LSEs that did not submit data by the January 15 deadline. At the time of this report, the ISO received data from all but two LSEs very small LSEs.[5] This data request asked for information on each wind, solar, and distributed wind and solar resource that is owned, in whole or in part, by the Load Serving Entity or under contractual commitment to the Load Serving Entity for all or a portion of its capacity. As part of the data request, the ISO asked for information on resources internal and external to the ISO. For resources that are external to the ISO, additional information was requested as to whether the resource is or will be a dynamic system resource or pseudo-tie resource. The ISO only included external resources in the flexible capacity requirements assessment if they were dynamic system resources or pseudo-tie resources.

Based on ISO review of the responses to the data request, it appears that the information submitted in response to the data request represents all wind, solar, and distributed wind and solar resources that are owned, in whole or in part, by the Load Serving Entity or under contractual commitment to the Load Serving Entity for all or a portion of its capacity within the ISO balancing area.

Using the LSEs' data, the ISO simulated the variable energy resources' output to produce forecast minute-by-minute net load curves[6] for 2017. The forecasted aggregated variable energy resource fleet capacity is provided in Table 1.

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[4] In previous years, the ISO has published advisory requirements the two years following the upcoming RA year. At the time of publication, the ISO is processing results for 2018 and 2019. As this data is processed, the ISO will issue advisory results for those years.

[5] Data was submitted late by five LSEs. The ISO was unable to include these LSEs in the study. The ISO will seek to apply applicable tariff provisions for late submission of data.

[6] Net-load load is defined as load minus wind minus solar.

Table 1: Total ISO System Variable Energy Resource Capacity (Net Dependable Capacity-MW)[7]

Resource Type	Existing MW (2015)	2016 MW	2017 MW
ISO Solar PV	5,754	7,583	8,686
ISO Solar Thermal	1,219	1,204	1,183
ISO Wind	4,991	4,643	4,519
Incremental distributed PV		1,208	1,072
Total Variable Energy Resource Capacity in the 2017 Flexible Capacity Needs Assessment[8]	11,964	14,638	15,460
Non ISO Resources All external VERS not-firmed by external BAA		552	850
Total internal and non-firmed external VERs	11,964	15,190	16,310
Incremental New Additions in Each Year		3,226	1,120

While Table 1 aggregates the variable energy resources system wide, the ISO conducted the assessment using location-specific information. This ensured that the assessment captured the geographic diversity benefits. Additionally, for existing solar and wind resources, the ISO used the most recent full year of actual solar output data available, which was 2015. For future wind resources, the ISO scaled overall wind production for each minute of the most recent year by the expected future capacity divided by the installed wind capacity of the most recent year. Specifically, to develop the wind profiles for wind resources, the ISO used the following formula:

$$2016\ W_{Mth\_Sim\_1\text{-}min} = 2015W_{Act\_1\text{-}min} * 2016W_{Mth\ Capacity} / 2015W_{Mth\ Capacity}$$

Given the small amount of incremental wind resources coming on line, this approach allows the ISO to maintain the load/wind correlation for over 94% of the forecasted wind capacity output.

In the case of solar resources' production profiles, for future years, the ISO assumptions were primarily based on the overall capacity of the new resources.

The ISO has also included incremental behind-the-meter solar production for behind-the-meter solar PV that occurs after 2015. While existing behind-the-meter solar PV is captured by changes in load, new behind-the-meter solar PV would be missed and would lead to an undercounting of the net load ramps. Including this incremental capacity allows the ISO to more accurately capture the Δ Solar PV component of the net load calculation. Therefore, the ISO agrees with PG&E's recommendation and has calculated the impact of the incremental

7 Data shown is for December of the corresponding year. Variable energy resources have been aggregated across the ISO system to avoid concerns regarding the release of confidential information.

8 Includes all internal variable energy resources

behind-the-meter solar PV. Because behind-the-meter solar is solar PV, the ISO included the contribution of the incremental behind-the-meter solar PV in the Δ Solar PV for purposes of determining an LRA's allocable share of the flexible capacity needs. During the stakeholder meeting on the draft results, the CEC and PG&E asked about the treatment or impact of the additional behind the meter solar resources and the CEC treatment of these resources in the Integrated Energy Policy Report (IEPR). The ISO has reviewed these concerns and has not identified any change in non-summer months. The ISO has not identified a material change from the inclusion of the behind-the-meter resources in the summer months at this time, but will continue to work with the CEC to determine if additional modifications are needed as part of the next flexible capacity technical needs study.

4.2 Building Minute-by-Minute Net Load Curves

The ISO used the CEC 2015 Integrated Energy Policy Report (IEPR) 1-in-2 monthly peak load forecast (Mid Demand Scenario, with mid-additional achievable energy efficiency) to develop minute-by-minute load forecasts for each month.[9] The ISO scaled the actual load for each minute of each month of 2015 using an expected load growth factor of the monthly peak forecast divided by the actual 2015 monthly peak. This is the same methodology used in the 2016 assessment.

As noted above, the ISO used the mid-additional achievable energy efficiency forecast. Specifically, the ISO included additional achievable energy efficiency profile for 2017 provided by the CEC. This profile is shaped to reflect both hourly and seasonal additional achievable energy efficiency. This differs from the 2016 assessment which applied additional achievable energy efficiency uniformly to all load. The impact of this change likely contributes to some portion of the increased flexible capacity needs identified in this year's study, though no specific assessment of the two additional achievable energy efficiency approaches has been done, the shape of shaped profiles show high energy efficiency during the days and lower levels in the evening. As a part of future initiatives, the ISO, CEC, and CPUC can assess how future additional achievable energy efficiency growth can be used to more effectively shrink the net load ramps.

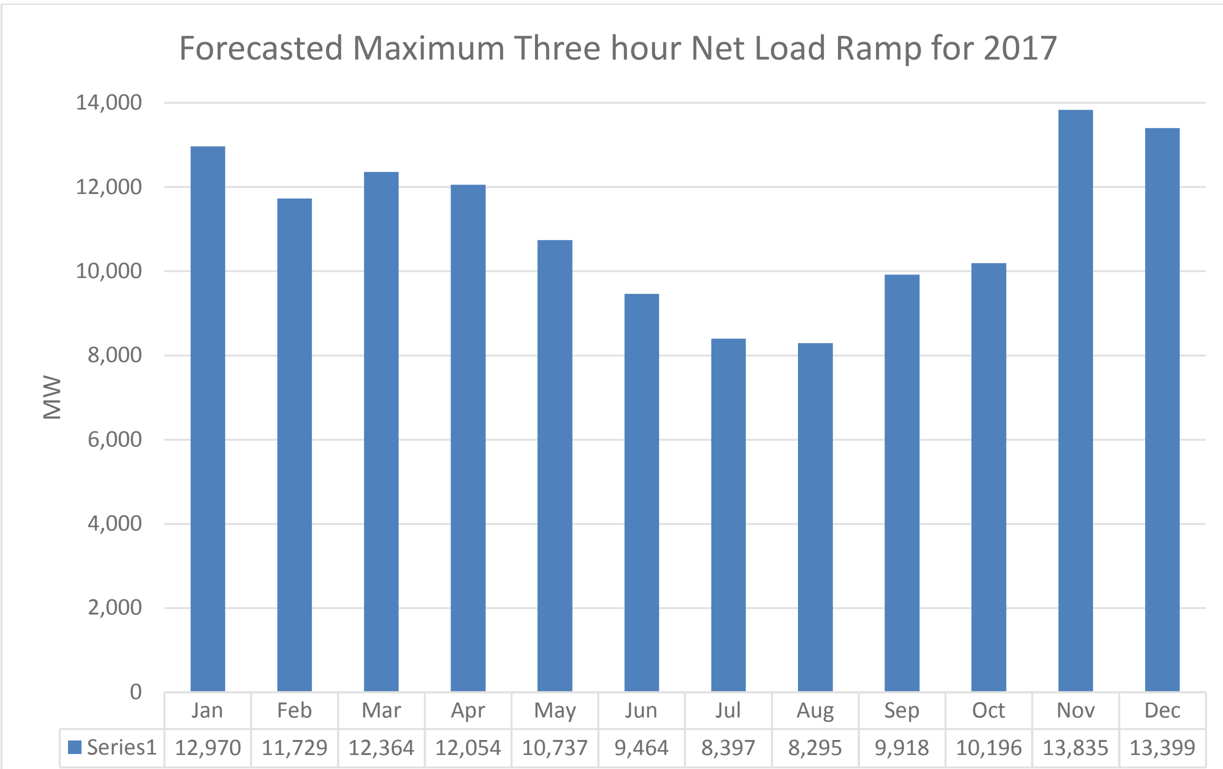
With this forecasted load, and expected wind and solar expansions, the ISO developed the minute-by-minute load, wind, and solar profiles. The ISO aligned these profiles and subtracted the output of the wind and solar resources from the load to generate the minute-by-minute net load curves necessary to conduct the flexible capacity needs assessment.

[9] http://www.energy.ca.gov/2014publications/CEC-200-2014-009/CEC-200-2014-009-SD.pdf

5. Calculating the Monthly Maximum Three-Hour Net load Ramps Plus 3.5 Percent Expected Peak-Load

The ISO, using the net load forecast developed in Section 4, calculated the maximum three-hour net load ramp for each month. The ISO system-wide, largest three-hour net load ramps for each month are detailed in Figure 1.

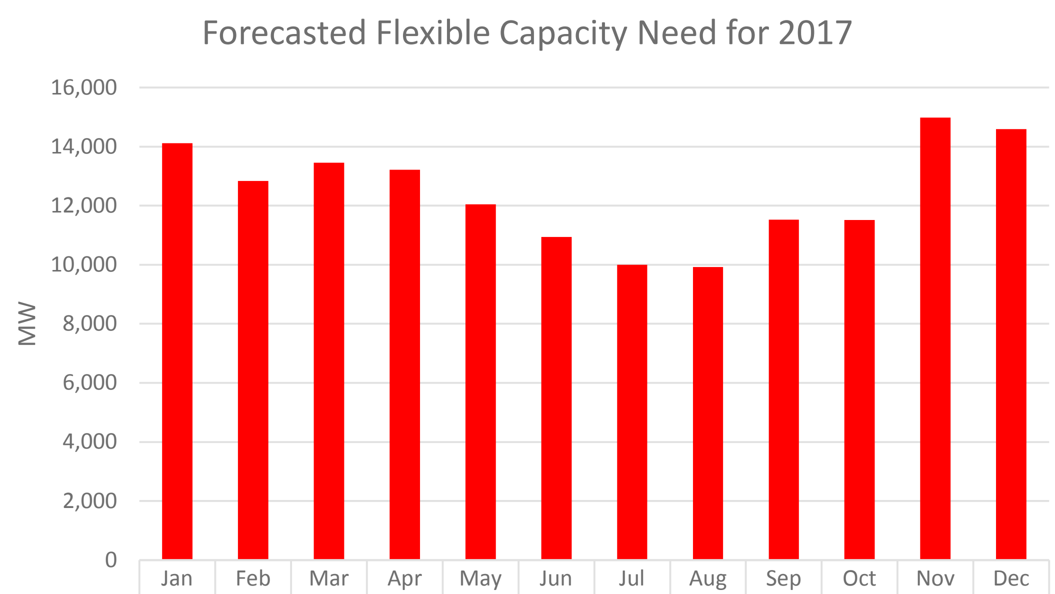
Figure 1: ISO System Maximum 3-hour Net load Ramps



The results for the non-summer months of 2017 are higher than those predicted in the previous flexible capacity needs assessment. This is due to the inclusion of a much higher base of behind-the-meter solar. Specifically, the base of existing behind-the-meter solar in thee 2016 assessment was 4,442 MW for 2017, while this year's assessment shows a base of 5,976 MW. This is important because the year-over-year incremental behind-the-meter solar is not dramatically different from the previous studies.

As part of the 2017 Flexible Capacity Needs Assessment, the ISO assessed the weather patterns to identify anomalous results. As shown in figure 1, flexible capacity needs follow a predictable pattern, whereby the flexible capacity needs for all summer months remain low relative to the flexible capacity needs for non-summer months. Finally, the ISO summed the monthly largest three-hour contiguous ramps and 3.5 percent of the forecast peak-load for each month.[10] This sum yields the ISO system-wide flexible capacity needs for 2017. These totals are shown in Figure 2 below.

Figure 2: ISO System Maximum 3-Hour Net load Ramps Plus 3.5 Percent of Forecast Peak Load



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017	14,110	12,840	13,456	13,220	12,044	10,939	9,994	9,918	11,525	11,514	14,977	14,588

6. Calculating the Seasonal Percentages Needed in Each Category

As described in the ISO's tariff, sections 40.10.3.2 and 40.10.3.3, the ISO divided its flexible capacity needs into various categories based on the system's operational needs. These categories are based on the characteristics of the system's net load ramps and define the mix of resources that can be used to meet the system's flexible capacity needs. Certain use-limited resources may not qualify to be counted under the base flexibility category and may only be counted under the peak flexibility or super-peak flexibility categories, depending on their characteristics. While there is no limit to the amount of resources that meet the base flexibility criteria that can be used to meet the system's flexible capacity, there is maximum amount of flexible capacity that can come from resources that only meet the criteria to be counted under the peak flexibility or super-peak flexibility categories.

The ISO structured the flexible capacity categories to meet the following needs:

[10] The most severe single contingency was consistently less than 3.5 expected peak-load.

Base Flexibility: Operational needs determined by the magnitude of the largest 3-hour secondary net load[11] ramp

Peak Flexibility: Operational need determined by the difference between 95 percent of the maximum 3-hour net load ramp and the largest 3-hour secondary net load ramp

Super-Peak Flexibility: Operational need determined by five percent of the maximum 3-hour net load ramp of the month

These categories include different minimum flexible capacity operating characteristics and different limits on the total quantity of flexible capacity within each category. In order to calculate the quantities needed in each flexible capacity category, the ISO conducted a three-step assessment process:

1) Calculate the forecast percentages needed in each category in each month;
2) Analyze the distributions of both largest three-hour net load ramps for the primary and secondary net load ramps to determine appropriate seasonal demarcations; and
3) Calculate a simple average of the percent of base flexibility needs from all months within a season.

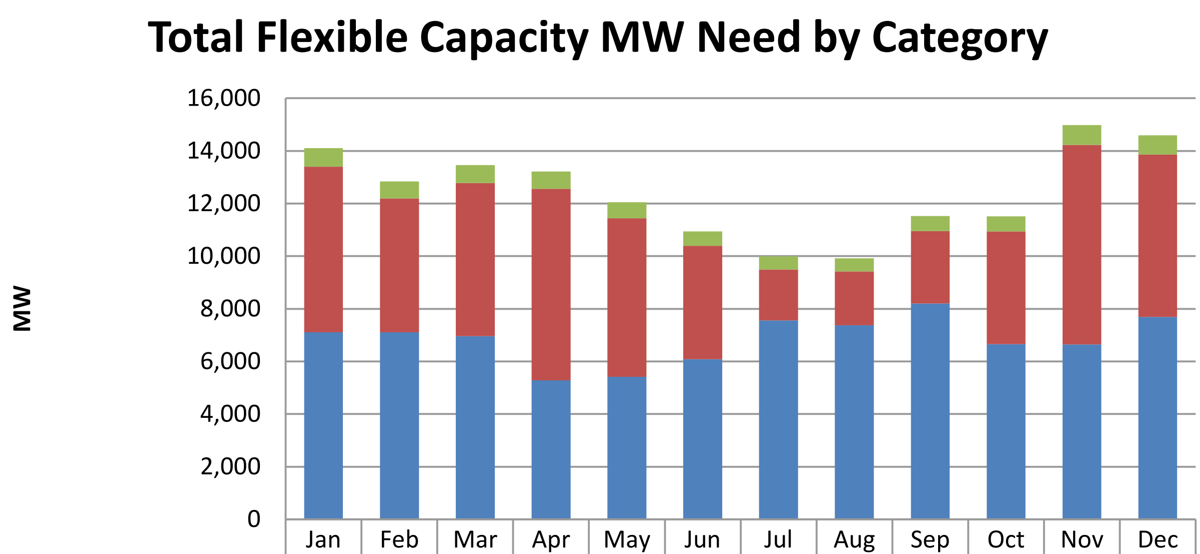
6.1 Calculating the Forecast Percentages Needed in Each Category in Each Month

Based on the categories defined above, the ISO calculated the system level needs for 2017 based only on the maximum monthly 3-hour net load calculation. Then the ISO calculated the quantity needed in each category in each month based on the above descriptions. Based on stakeholder feedback, the ISO reviewed the publically available tool that has been used to calculate flexible capacity category needs. The tool searched morning and afternoon ramps based on the start time of the ramps. This lead to possibility that the secondary net load ramp could start late enough in the morning and overlap with portions of the primary net load ramp. This possibility was not contemplated when the initial tool was created. Therefore, for this final assessment the ISO, using SAS, recalculated the secondary net load ramps such that the possibility of over-lapping time intervals was eliminated. The allocations to flexible capacity categories remained unchanged for all non-summer months. However, this new calculation methodology resulted in lower percentages in the base flexible capacity category for summer months. These new allocations are shown below. The ISO then added the contingency requirements into the categories proportionally to the percentages established by the

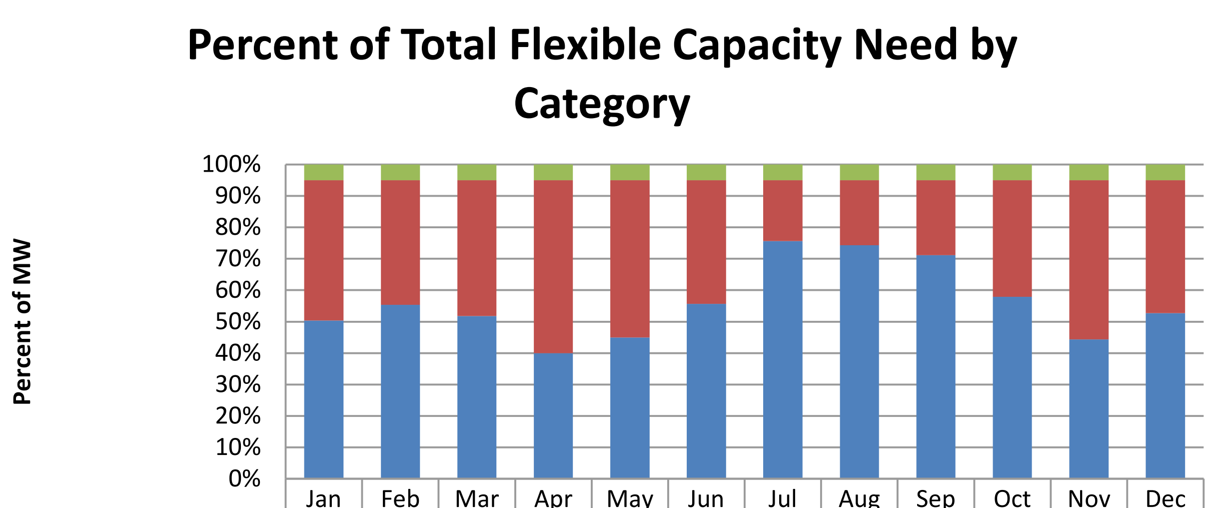
[11] The largest daily secondary 3-hour net-load ramp is calculated as the largest net load ramp that does not correspond with the daily maximum net-load ramp. For example, if the daily maximum 3-hour net-load ramp occurs between 5:00 p.m. and 8:00 p.m., then the largest secondary ramp would be determined by the largest morning 3-hour net-load ramp.

maximum 3-hour net load ramp. For example, for the month of January, the ISO added 90 percent of the contingency reserves portion into the base flexibility category 1, 5 percent into the peak flexibility category 2, and the final 5 percent into the super-peak flexibility category 3. The calculation of flexible capacity needs for each category for 2017 is shown in Figure 3.

Figure 3: ISO System-Wide Flexible Capacity Monthly Calculation by Category for 2017



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Super-Peak Flexibility	706	642	673	661	602	547	500	496	576	576	749	729
Peak Flexibility	6,301	5,088	5,821	7,274	6,029	4,306	1,940	2,050	2,750	4,276	7,578	6,164
Base Flexibility	7,104	7,110	6,962	5,285	5,412	6,086	7,554	7,372	8,199	6,662	6,650	7,694



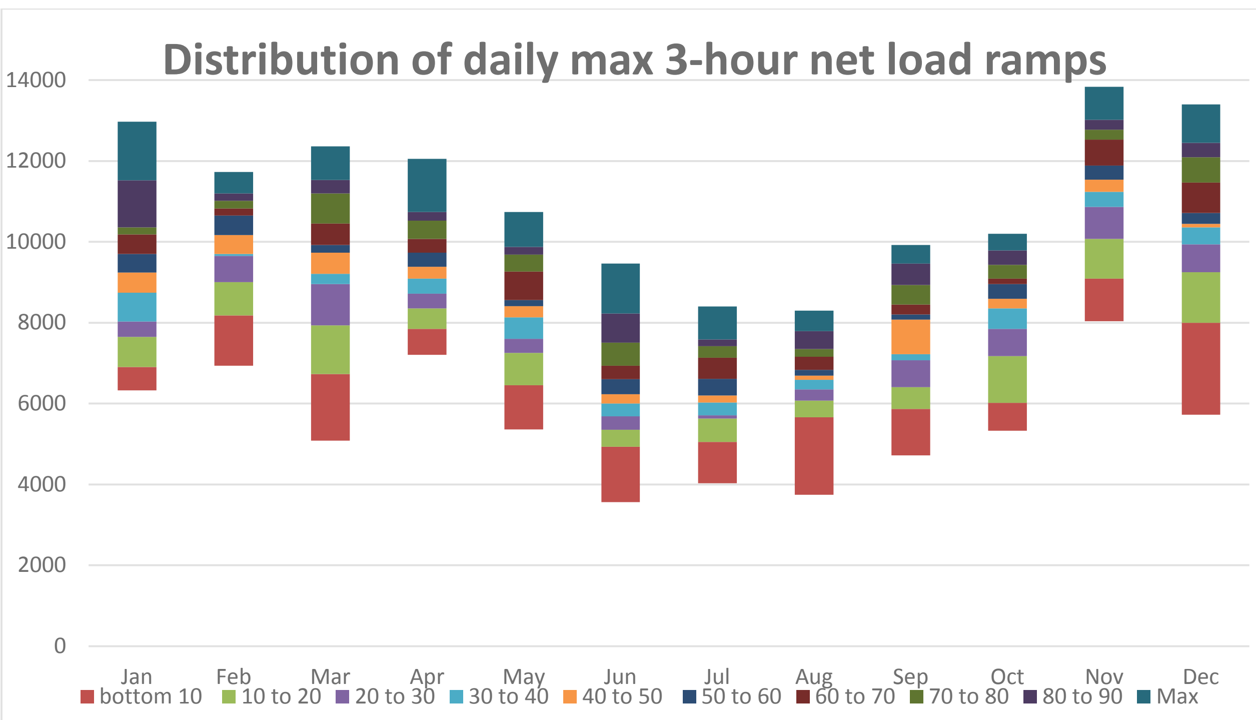
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Super-Peak Flexibility	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
Peak Flexibility	45%	40%	43%	55%	50%	39%	19%	21%	24%	37%	51%	42%
Base Flexibility	50%	55%	52%	40%	45%	56%	76%	74%	71%	58%	44%	53%

Again, the large quantity of existing and incremental behind-the-meter solar PV results in a greater difference between the primary and secondary net load ramps, particularly in the non-summer months. This results in a lower percent requirement for base flexible capacity resources relative to last year's study.

6.2 Analyzing Ramp Distributions to Determine Appropriate Seasonal Demarcations

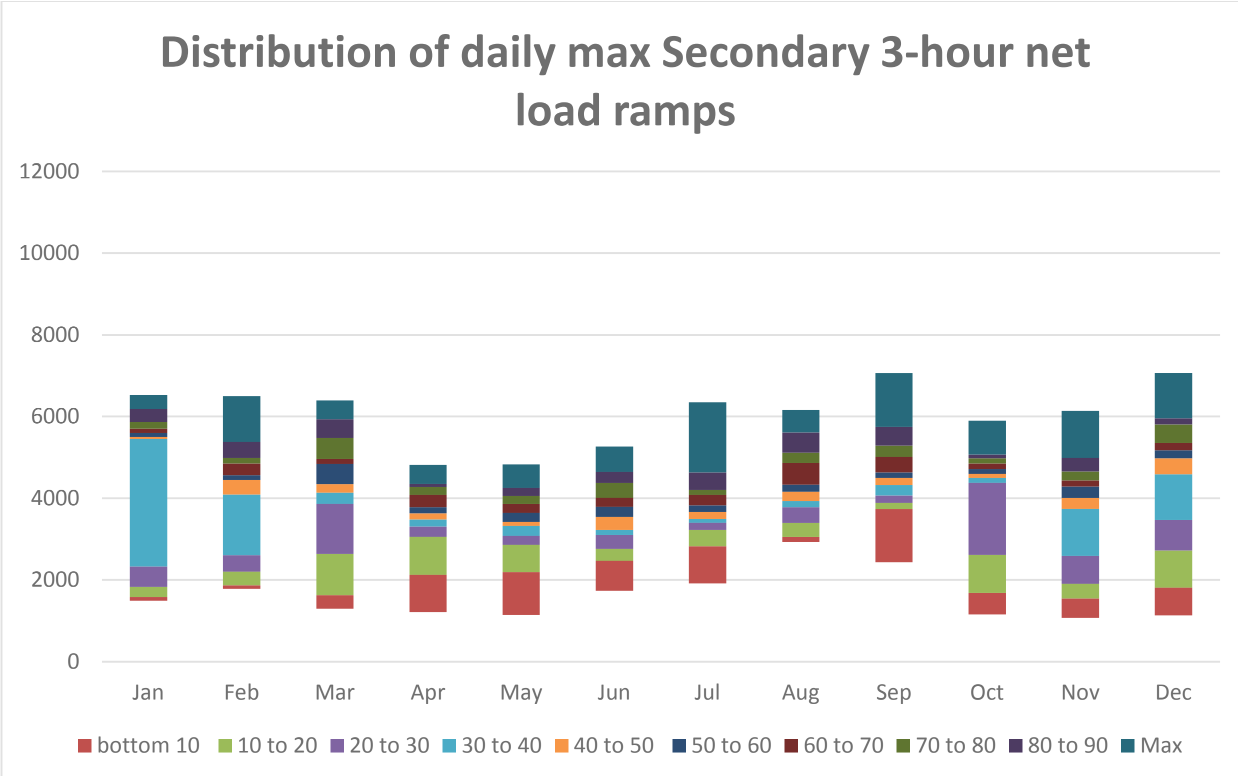
To determine the seasonal percentages for each category, the ISO analyzed the distributions of the largest three-hour net load ramps for the primary and secondary net load ramps to determine appropriate seasonal demarcations for the base flexibility category. The secondary net load ramps provide the ISO with the frequency and magnitude of secondary net load ramps. Assessing these distributions helps the ISO identify seasonal differences that are needed for the final determination of percent of each category of flexible capacity that is needed. While this year's assessment focused on the data produced in this study process, the ISO also referred back to last year's[12] assessment to confirm that the patterns persist. The primary and secondary net load ramp distributions are shown for each month in figures 4 and 5 respectively.

Figure 4: Distribution of Daily Primary 3-hour Net Load Ramps for 2016



[12] Last year's assessment refers to the 2014 Flexible Capacity Needs Assessment. The ISO has changed the naming convention to refer to the RA year, and not the year in which the study was conducted.

Figure 5: Distribution of Secondary 3-hour Net load Ramps for 2016



As Figure 4 shows, the distribution (i.e. the width of the distribution for each month) of the daily maximum three-hour net load ramps is slightly narrower during the summer months. Transitional months like May and October differ slightly from their seasonal counterparts, but not sufficiently to warrant changes to any seasonal treatment for those months. Further, the daily secondary three-hour net load ramps are also similar except for July and September. These distribution indicates two things. First, given the breadth of this distribution, it is unlikely that all base flexible capacity resources will be used for two ramps every day. The base flexibility resources were designed to address days with two separate significant net load ramps. The distributions of these secondary net load ramps indicates that the ISO need not set seasonal percentages in the base flexibility category at the percentage of the higher month within that season. Second, because there are still numerous bimodal ramping days in the distribution, many of the base flexibility resources will still be needed to address bimodal ramping needs. Accordingly, the ISO must ensure enough base ramping for all days of the month. Further, particularly for summer months, the ISO does not identify two distinct ramps each day. Instead, the secondary net-load ramp may be a part of single long net load ramp. The ISO is currently exploring the impact this may have for determining the quantity of based flexible capacity resources needed during summer months.

Figures 3-5 shows that the seasonal divide established in last year's assessment remains reasonable. The distributions of the primary and secondary ramps provide additional support for the summer/non-summer split. While not as distinct for May and September as was observed in the previous Flexible capacity needs assessment, the distributions of the secondary net load ramps from May through September remain more compact than the secondary net load ramps in the other months. This distribution change is a reflection of changes in the seasons and weather patterns. Accordingly, the ISO proposes to maintain two flexible capacity needs seasons that mirror the existing summer season (May through September) and non-summer season (January through April and October through December) used for resource adequacy.[13] This approach has two benefits.

First, it mitigates the impact that variations in the net load ramp in any given month can have on determining the amounts for the various flexible capacity categories for a given season. For example, a month may have either very high or low secondary ramps that are simply the result of the weather in the year. However, because differences in the characteristics of net load ramps are largely due to variations in the output of variable energy resources, and these variations are predominantly due to weather and seasonal conditions, it is reasonable to breakout the flexibility categories by season. Because the main differences in weather in the ISO system are between the summer and non-summer months, the ISO proposes to use this as the basis for the seasonal breakout of the needs for the flexible capacity categories.

Second, adding flexible capacity procurement to the RA program will increase the process and information requirements. Maintaining a seasonal demarcation that is consistent with the current RA program will reduce the potential for errors in resource adequacy showings.

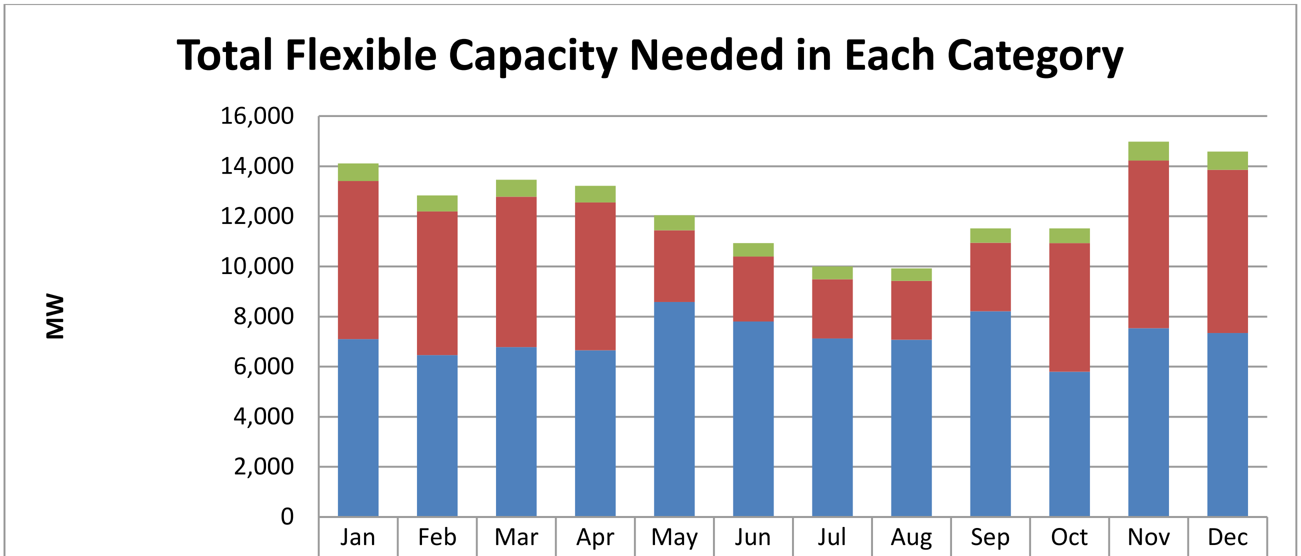
6.3 Calculate a Simple Average of the Percent of Base Flexibility Needs

The ISO calculated the percentage of base flexibility needed using a simple average of the percent of base flexibility needs from all months within a season. Based on that calculation, the ISO proposes that flexible capacity meeting the base-flexibility category criteria comprise 50 percent of the ISO system flexible capacity need for the non-summer months and 64 percent for the summer months. As noted above, the ISO adjusted the calculation tool for determining the base flexible capacity need. The percentages on the summer reflect an overall decrease from the draft assessment of seven percent. Peak flexible capacity resources could be used to fulfill up to 50 percent of non-summer flexibility needs and 36 percent of summer flexible capacity needs. The super-peak flexibility category is fixed at a maximum five percent across the year. These percentages are significantly different from those of in the 2016 Flexible Capacity Needs Assessment. As with the increase in the flexible capacity need, the change is largely attributable to the inclusion of the incremental behind-the-meter solar. The

[13] The ISO also reviewed the results of the initial calculations for categories used in the 2013 Flexible Capacity Needs Assessment to determine if the categories aligned with the previous assessment as well.

incremental behind-the-meter solar will reduce the secondary net load ramp in the non-summer months but will increase the primary net load ramp, which reduces the percentage of base-ramping capacity in the non-summer months. However, it would have the opposite effect in the summer months. The ISO's proposed system-wide flexible capacity categories are provided in Figure 6.

Figure 6: System-wide Flexible Capacity Need in Each Category for 2017



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Super-Peak Flexibility	706	642	673	661	602	547	500	496	576	576	749	729
Peak Flexibility	6,300	5,733	6,008	5,903	2,856	2,594	2,370	2,352	2,733	5,141	6,687	6,514
Base Flexibility	7,104	6,465	6,775	6,656	8,585	7,798	7,124	7,070	8,216	5,797	7,541	7,345

7. Allocating the Flexible Capacity Needs to Local Regulatory Authorities

The ISO's allocation methodology is based on the contribution of a local regulatory authority's LSEs to the maximum 3-hour net load ramp.

Specifically, the ISO calculated the LSEs under each local regulatory authority's contribution to the flexible capacity needs using the following inputs:

1) The maximum of the most severe single contingency or 3.5 percent of forecasted peak load for each LRA based on its jurisdictional LSEs' peak load ratio share.

2) Δ Load – LRA's average contribution to load change during top five daily maximum three-hour net load ramps within a given month from the previous year x total change in ISO load.

3) Δ Wind Output – LRA's average percent contribution to changes in wind output during the five greatest forecasted 3-hour net load changes x ISO total change in wind output during the largest 3-hour net load change

4) Δ Solar PV – LRA's average percent contribution to changes in solar PV output during the five greatest forecasted 3-hour net load changes x total change in solar PV output during the largest 3-hour net load change

5) Δ Solar Thermal – LRA's average percent contribution to changes in solar PV output during the five greatest forecasted 3-hour net load changes x total change in solar thermal output during the largest 3-hour net load change

These amounts are combined using the equation below to determine the contribution of each LRA, including the CPUC and its jurisdictional load serving entities, to the flexible capacity need.

Flexible Capacity Need = Δ Load – Δ Wind Output – Δ Solar PV – Δ Solar Thermal + (3.5% * Expected Peak * Peak Load Ratio Share)

Any LRA with a negative contribution to the flexible capacity need is limited to a zero megawatt allocation, not a negative contribution. As such, the total allocable share of all LRAs may sum to a number that is slightly larger than the flexible capacity need.[14] The ISO does not currently have a process by which a negative contribution could be reallocated or used as a credit for another LRA or LSE. The ISO is examining ways to address this issue as part of the Flexible Resource Adequacy Criteria and Must Offer Obligation – Phase 2 stakeholder initiative.

The ISO has made available all non-confidential working papers and data that the ISO relied on for the Final Flexible Capacity Needs Assessment for 2017. Specifically, the ISO posted materials and data used to determine the monthly flexible capacity needs, the contribution of CPUC jurisdictional load serving entities to the change in load, and seasonal needs for each flexible capacity category.[15] This data is available at http://www.caiso.com/Documents/CPUCFlexibleCapacityAllocation-2017.xlsx.

Table 2 shows the final calculations of the individual contributions of each of the inputs to the calculation of the maximum 3-hour continuous net load ramp at a system level.

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[14] Some small LRAs had negative contributions to the flexible capacity needs. The ISO is proposing to change this limitation as part of the Flexible Resource Adequacy Criteria and Offer Obligation – Phase 2 stakeholder initiative. However, this initiative is not yet complete, and thus the ISO cannot modify this rule.

[15] The data sets posted on the webpage reflect the corrected data. The draft data sets have been removed to avoid confusion.

Table 2: Contribution to Maximum 3-hour Continuous Net load Ramp for 2016[16]

Month	Average of Load contribution 2017	Average of solar PV contribution 2017	Average of BTM Solar contribution 2017	Average of Wind contribution 2017	Average of OOS Wind contribution 2017	Total percent 2017
January	49.09%	-47.68%	-2.66%	-0.52%	-0.05%	100%
February	31.99%	-63.00%	-3.77%	-0.77%	-0.47%	100%
March	27.28%	-63.69%	-8.15%	-1.28%	0.40%	100%
April	23.01%	-68.11%	-9.61%	0.71%	0.02%	100%
May	23.87%	-64.15%	-9.83%	-1.65%	-0.50%	100%
June	8.76%	-79.58%	-11.52%	-0.55%	0.41%	100%
July	11.66%	-78.87%	-11.11%	1.47%	0.17%	100%
August	-0.72%	-94.04%	-12.81%	5.93%	0.21%	100%
September	6.27%	-82.42%	-10.82%	-0.28%	-0.21%	100%
October	18.23%	-72.80%	-11.45%	1.61%	0.86%	100%
November	34.75%	-55.91%	-8.69%	-0.51%	-0.15%	100%
December	42.28%	-48.62%	-6.05%	-2.02%	-1.04%	100%

As Table 2 shows, Δ Load is not the largest contributor to the net load ramp during the summer months. This is because the incremental solar PV mitigates morning net load ramps. This changed the timing of the largest net load ramps and changed the Δ Load impact on the net load ramps. However, the percentage contribution of load to the net load ramp is down in all months relative to last year's study. Again, this is attributable to the inclusion of the incremental behind-the-meter solar resources. The behind-the-meter solar resources are leading to maximum three-hour net load ramps during summer months that occur in the afternoon. This is particularly evident during August, when the contribution of delta load is negative. This implies that load is less at the end of the net load ramp than it was at the beginning. This is caused by the timing of the largest three net load ramp in August. It typically occurs midday and occurs when both load and solar are decreasing. Further, the contribution of solar PV resources has increased relative to last year's study and remains a significant driver of the three-hour net load ramps.

Consistent with the ISO's flexible capacity needs allocation methodology, the ISO used 2015 actual load data to determine each local regulatory authority's contribution to the Δ Load component. The ISO calculated minute-by-minute net load curves for 2015. Then, using the

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[16] The contribution of behind-the-meter solar is captured in the solar PV calculations. All contributions are captured on the "contributing factors" worksheet in the ISO's 2016 data set. As shown in the formula above, the flexible capacity requirement will be 100 percent.

same methodology as that for determining the maximum 3-hour continuous net load ramp described above, the ISO calculated the maximum three-hour net load ramps for 2015 and applied the Δ load calculation methodology described above. The ISO used settlements data to determine the LRA's contribution the Δ load component. This data is generated in 10-minute increments. This number may be the same for some LSEs over the entire hour. The ISO smoothed these observations by using a 60-minute rolling average of the load data. This allowed the ISO to simulate a continuous ramp using actual settled load data.

Based on this methodology, the ISO determined the flexible capacity need attributable to the CPUC jurisdictional LSEs.[17] Table 3 shows the CPUC jurisdictional LSEs' combined relative contribution to each of the each of the factors (Δ Load, Δ Wind, Δ Solar PV, and Δ Solar Thermal) included in the allocation methodology.

Table 3: CPUC Jurisdictional LSEs' Contribution to Flexible Capacity Needs[18]

	Δ Load	Δ PV	Δ BTM Solar	Δ Wind	Δ OOS Wind
Jan	95.02%	93.38%	99.35%	96.90%	100%
Feb	99.70%	93.38%	99.35%	96.90%	100%
Mar	102.52%	93.43%	99.35%	96.90%	100%
Apr	70.38%	93.56%	99.35%	96.87%	100%
May	104.90%	93.56%	99.35%	96.86%	100%
Jun	96.69%	93.56%	99.35%	96.85%	100%
Jul	93.67%	93.56%	99.35%	96.86%	100%
Aug	95.05%	93.62%	99.35%	96.86%	100%
Sep	42.62%	93.64%	99.35%	96.86%	100%
Oct	91.08%	93.64%	99.35%	96.86%	100%
Nov	101.01%	93.65%	99.35%	96.86%	100%
Dec	103.81%	93.68%	99.35%	96.86%	100%

Finally, the ISO multiplied the flexible capacity needs from Figure 2 and the contribution to each factor to determine the relative contribution of each component at a system level. The ISO then multiplied the resultant numbers by the Local Regulatory Authority's calculated contribution to each individual component. Finally, the ISO added the 3.5 percent expected peak load times the LRA's peak load ratio share. The resulting CPUC allocations are shown in

[17] Because the Energy Division proposal states that the CPUC will allocate flexible capacity requirements to its jurisdictional LSEs based on peak load ratio share, the ISO has not calculated the individual contribution of each LSE.

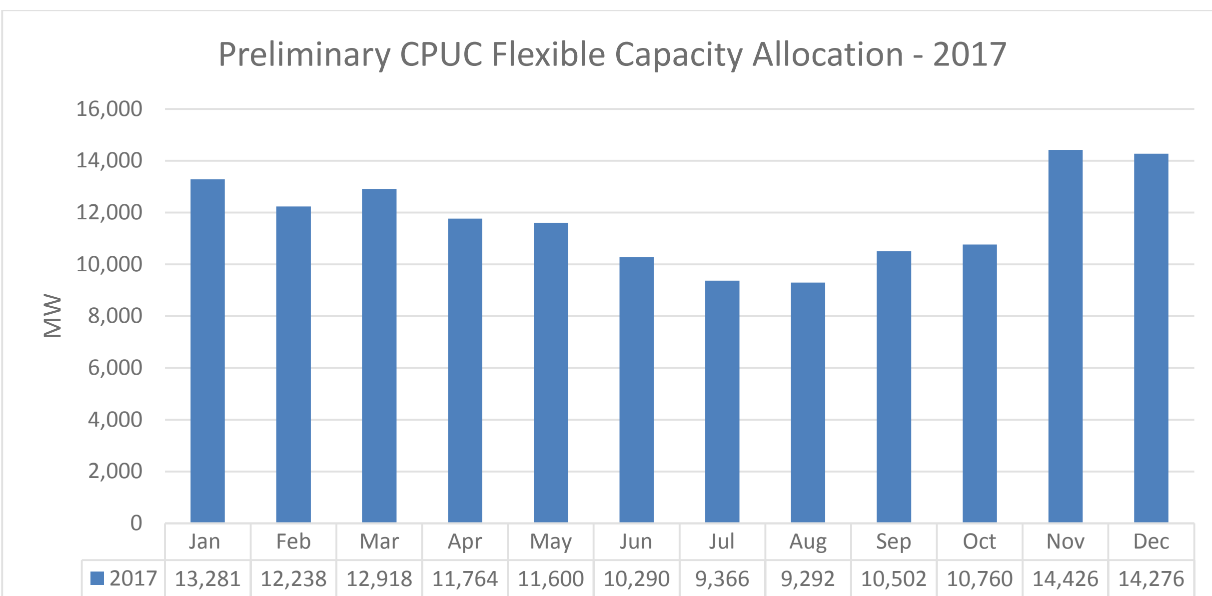
[18] Because of the geographic differences in the output, at some times one LRA's resources could be reducing the net-load ramp while another's could be increasing it.

Table 4 and Figure 7. The contributions of individual LSEs will only be provided to its jurisdictional LRA as per section 40.10.2.1 of the ISO tariff.

Table 4: CPUC Jurisdictional LSEs' Contribution to Flexible Capacity Needs

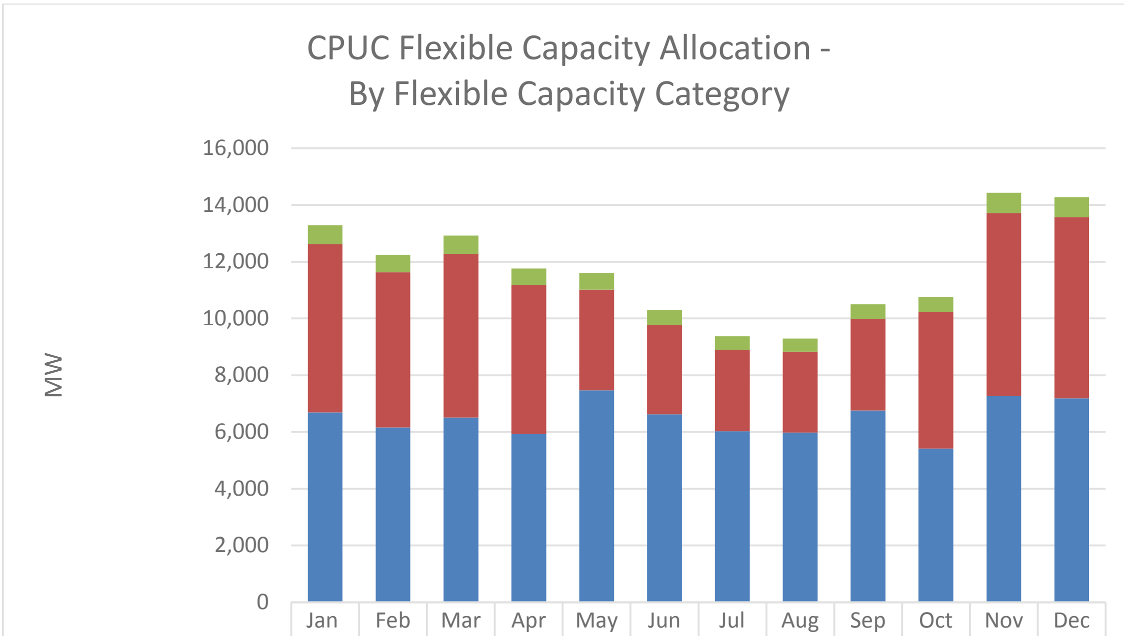
	Δ Load MW	Δ PV MW	Δ BTM Solar MW	Δ Wind MW	Δ OOS Wind MW	Net Load Allocation MW	3.5% expected peak load* Peak load ratio share 2017	Total Allocation
Jan	6049	-5774	-343	-65	-7	12239	1042	13281
Feb	3741	-6901	-439	-87	-55	11223	1015	12238
Mar	3457	-7358	-1001	-153	49	11920	998	12918
Apr	1952	-7681	-1151	83	2	10699	1065	11764
May	2689	-6444	-1048	-171	-54	10407	1194	11600
Jun	802	-7047	-1083	-51	39	8943	1347	10290
Jul	917	-6197	-927	120	14	7907	1459	9366
Aug	-56	-7304	-1055	476	17	7809	1483	9292
Sep	265	-7654	-1066	-27	-21	9033	1468	10502
Oct	1692	-6950	-1160	159	88	9556	1205	10760
Nov	4856	-7244	-1194	-68	-20	13383	1043	14426
Dec	5881	-6102	-805	-262	-139	13189	1086	14276

Figure 7: CPUC Jurisdictional LSEs' Contribution to Flexible Capacity Needs



Finally, the ISO applied the seasonal percentage established in section 6 to the contribution of CPUC jurisdictional load serving entities to determine the quantity of flexible capacity needed in each flexible capacity category. These results are detailed in figure 8**.**

Figure 8: CPUC Flexible Capacity Need in Each Category for 2016



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Super-Peak Flexibility	664	612	646	588	580	515	468	465	525	538	721	714
Peak Flexibility	5,930	5,464	5,768	5,253	3,558	3,156	2,873	2,850	3,221	4,805	6,441	6,374
Base Flexiblity	6,687	6,162	6,504	5,923	7,462	6,619	6,025	5,977	6,755	5,418	7,263	7,188

8. Determining the Seasonal Must-Offer Obligation Period

Under ISO tariff sections 40.10.3.3 and 40.10.3.4, the ISO establishes by season the specific five-hour period during which flexible capacity counted in the peak and super-peak categories will be required to submit economic energy bids into the ISO market (*i.e.* have an economic bid must-offer obligation). Whether the ISO needs peak and super-peak category resources more in the morning or afternoon depends on when the larger of the two ramps occurs. The average net load curves for each month provide the most reliable assessment of whether a flexible capacity resource would be greatest benefit in the morning or evening net load ramps. The ISO looked at the average ramp over the day to see if the bigger ramp was in the morning or afternoon and then set the hours for the must-offer obligation accordingly. The ISO calculated the maximum three-hour net load for all months. Table 5 shows the hours in which the maximum monthly average net load ramp began.

Table 5: 2016 Forecasted Hour in Which Monthly Maximum 3-Hour Net load Ramp Began

Month	Starting Hour	Month	Starting Hour
Jan	14	Jul	12
Feb	15	Aug	12
Mar	16	Sep	14
Apr	16	Oct	15
May	16	Nov	14
Jun	15	Dec	14

Based on this data, the ISO has determined that the appropriate flexible capacity must-offer obligation period for peak and super-peak flexible capacity categories is the five-hour period of 12:00 p.m. to 5:00 p.m. for May through September, and 3:00 p.m. to 8:00 p.m. for January through April and October through December. The hours for January through April and October through December are unchanged from the previous year's study. In its comments, CDWR suggested the ISO adjust the time period to 2:00 p.m. to 7:00 p.m. The ISO considered making this adjustment as part of the draft results. At this time, the ISO believes that the appropriate must-offer obligation period is between 3:00 p.m. to 8:00 p.m. because the summer hour net load ramps are now later in the day. The later timing of net load ramps is attributable to the fact that increased solar PV continues to mitigate the morning ramps in the summer. This pushed the maximum net load ramps further into the day. However, the ISO will consider changing these hours if the trend of non-summer net load ramps starting at 2:00 p.m. continues in the next study process.

The ISO continues to believe it is appropriate to align the must-offer obligations with the summer/non-summer demarcation used for the RA program and contributions to the categories described above. Because these months align with the with the summer/non-summer demarcation in the RA program and aforementioned contributions to the categories, the ISO expects that this will also make the procurement process less complicated.

9. Next Steps

The ISO will commence the flexible capacity needs assessment to establish the ISO system flexible capacity needs for 2018 in late 2016. At that time, the ISO will host a stakeholder meeting to discuss potential enhancements needs assessment methodology as identified in stakeholder comments and in this final paper. Specifically, the ISO will continue to assess the modeling approach used for distributed solar resources, further review methods to address year-to-year volatility, and account for potential controllability of some variable energy resources.