2014
LOCAL CAPACITY TECHNICAL ANALYSIS

FINAL REPORT
AND STUDY RESULTS

April 30, 2013

Local Capacity Technical Study
Overview and Results

I. Executive Summary

This Report documents the results and recommendations of the 2014 Local Capacity Technical (LCT) Study. The LCT Study assumptions, processes, and criteria were discussed and recommended through the 2014 Local Capacity Technical Study Criteria, Methodology and Assumptions Stakeholder Meeting held on November 8, 2012. On balance, the assumptions, processes, and criteria used for the 2014 LCT Study mirror those used in the 2007-2013 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 2014 LCT study results are provided to the CPUC for consideration in its 2014 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]

Please note that these studies present LCR results for LA Basin and San Diego local areas based on three different scenarios for the availability of the SONGS units during 2014: 1) two SONGS are available, 2) one SONGS unit is available at 70% power, and 3) SONGS is not available.

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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 2014 vs. 2013 total LCR:

2014 Local Capacity Requirements

	Qualifying Capacity			2014 LCR Need Based on Category B			2014 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	70	173	243	145	0	**145**	195	0	**195**
North Coast / North Bay	150	771	921	623	0	**623**	623	0	**623**
Sierra	1288	762	2050	1414	0	**1414**	1803	285*	**2088**
Stockton	212	392	604	354	25*	**379**	446	255*	**701**
Greater Bay	1336	6280	7616	3747	0	**3747**	4423	215*	**4638**
Greater Fresno	318	2510	2828	1857	0	**1857**	1857	0	**1857**
Kern	613	64	677	421	14*	**435**	421	41*	**462**
LA Basin***	2242	9547	11789	10063	0	**10063**	10430	0	**10430**
Big Creek/ Ventura	1112	4206	5318	2156	0	**2156**	2250	0	**2250**
San Diego/ Imperial Valley***	200	4506	4706	3605	167*	**3772**	3605	458*	**4063**
Total	7541	29211	36752	24385	206	**24591**	26053	1254	**27307**

2013 Local Capacity Requirements

	Qualifying Capacity			2013 LCR Need Based on Category B			2013 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	55	162	217	143	0	**143**	190	22*	**212**
North Coast / North Bay	130	739	869	629	0	**629**	629	0	**629**
Sierra	1274	765	2039	1408	0	**1408**	1712	218*	**1930**
Stockton	216	404	620	242	0	**242**	413	154*	**567**
Greater Bay	1368	6296	7664	3479	0	**3479**	4502	0	**4502**
Greater Fresno	314	2503	2817	1786	0	**1786**	1786	0	**1786**
Kern	684	0	684	295	0	**295**	483	42*	**525**
LA Basin	4452	8675	13127	10295	0	**10295**	10295	0	**10295**
Big Creek/ Ventura	1179	4097	5276	2161	0	**2161**	2241	0	**2241**
San Diego	158	3991	4149	2938	0	**2938**	2938	144*	**3082**
Total	**9830**	**27632**	**37462**	**23376**	**0**	**23376**	**25189**	**580**	**25769**

* 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.
*** Requirements are presented for No SONGS scenario.

Overall, the LCR needs have increased by more than 1,500 MW or about 6% from 2013 to 2014. The LCR needs have decreased in the following areas: North Coast/North Bay and Valley Electric Association due to downward trend for load; Humboldt and Kern due to downward trend for load and new transmission projects. The LCR needs have increased in Sierra, Bay Area, Fresno and LA Basin due to load growth; Stockton due to load growth and delay in development of transmission projects. The San Diego LCR needs have slightly increased due to load growth and significantly increased due to the absence of SONGS.

The overall LCR needs in the main tables above are based on the third scenario, where SONGS is not available during 2014. The ISO will continue to monitor the status of SONGS and may change this assumption if circumstances that affect its availability change before the 2014 LCR allocations are released to LSEs.

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 2014 and 2013 LCRs.

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I. Study Overview: Inputs, Outputs and Options

A. Objectives

As was the objective of the five previous annual LCT Studies, the intent of the 2014 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 2014 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 2014 LCT Study Criteria, Methodology and Assumptions Stakeholder Meeting held on November 8, 2012.

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 2014 LCT Study:

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

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

Further details regarding the 2014 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. LCR Performance Criteria- Category B

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

Category B system performance requires that 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. LCR Performance Criteria- Category C

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 C requirements in this report refer to situations when in real time

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[4] A Special Protection Scheme is typically proposed as an operational solution that does not require

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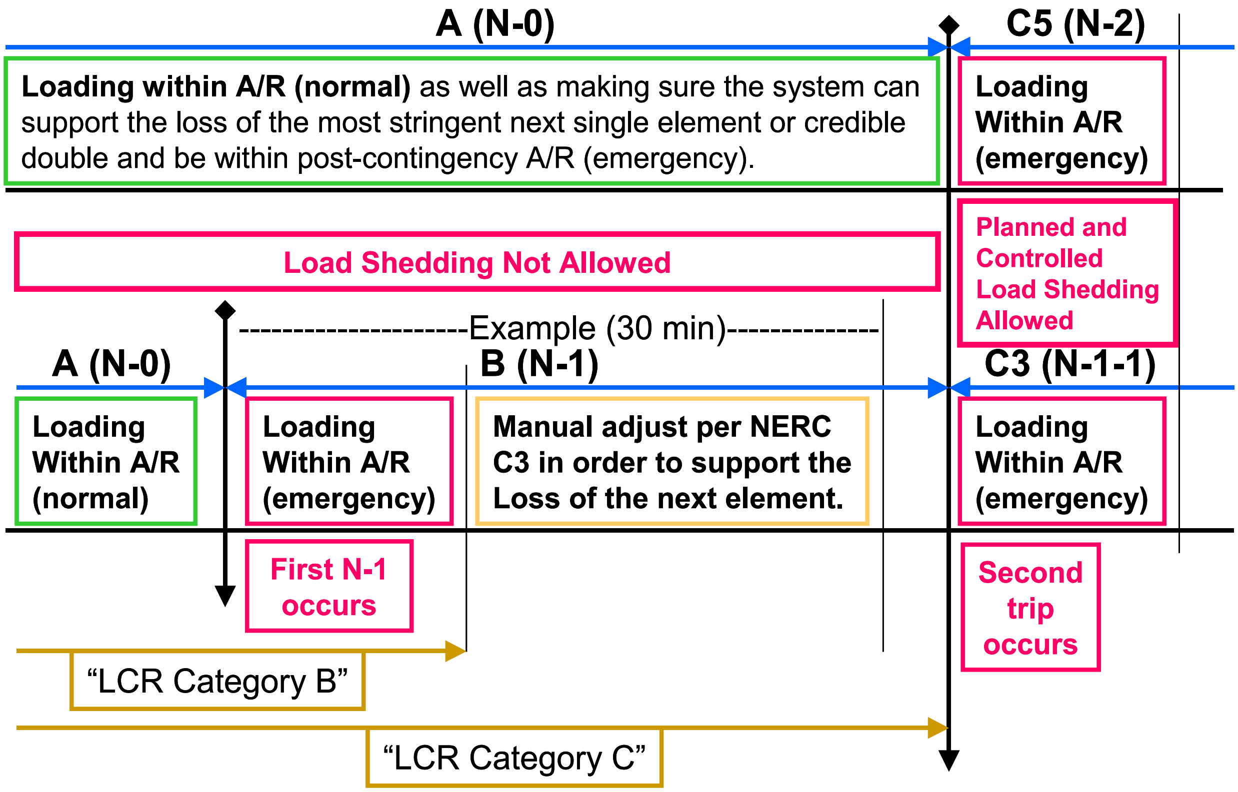
additional generation and permits operators to effectively prepare for the next event as well as ensure security should the next event occur. However, these systems have their own risks, which limit the extent to which they could be deployed as a solution for grid reliability augmentation. While they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

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.

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

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

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

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

This is one of the most controversial aspects of the interpretation of NERC Transmission Planning Standards since footnote b) 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 TPL Standards, and should not be planned based on footnote b) 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>

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

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

F. The Two Options Presented In This LCT Report

This LCT Study sets forth different solution “options” with varying ranges of potential service reliability consistent with CAISO’s 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]

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.

II. Assumption Details: How the Study was Conducted

A. System Planning Criteria

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.

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
A – No Contingencies	X	X	X
B – Loss of a single element			
1. Generator (G-1)	X	X	X[1]
2. Transmission Circuit (L-1)	X	X	X[1]
3. Transformer (T-1)	X	X[2]	X[1,2]
4. Single Pole (dc) Line	X	X	X[1]
5. G-1 system readjusted L-1	X	X	X
C – Loss of two or more elements			
1. Bus Section	X		
2. Breaker (failure or internal fault)	X		
3. L-1 system readjusted G-1	X		X
3. G-1 system readjusted T-1 or T-1 system readjusted G-1	X		X
3. L-1 system readjusted T-1 or T-1 system readjusted L-1	X		X
3. G-1 system readjusted G-1	X		X
3. L-1 system readjusted L-1	X		X
3. T-1 system readjusted T-1	X		
4. Bipolar (dc) Line	X		X
5. Two circuits (Common Mode 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
D – Extreme event – loss of two or more elements			
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 base case loads 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 the division.

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[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.

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 base case loads is generally higher than the load forecast because some load, i.e., self-generation and generation-plant, are behind the meter and must be modeled in the base cases. However, for the most part, metered or aggregated data with telemetry is used to come up with the load forecast.

b. Municipal Loads in Base Case

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

C. Power Flow Program Used in the LCT analysis

The technical studies were conducted using General Electric's Power System Load Flow (GE PSLF) program version 18.0. 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.

III. Local Capacity Requirement Study Results

A. Summary of Study Results

LCR is defined as the amount of generating 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: 2014 Local Capacity Needs vs. Peak Load and Local Area Generation

	2014Total LCR (MW)	Peak Load (1 in10) (MW)	2014 LCR as % of Peak Load	Total Dependable Local Area Generation (MW)	2014 LCR as % of Total Area Generation
Humboldt	195	195	100%	243	80%
North Coast/North Bay	623	1465	43%	921	68%
Sierra	2088	1958	107%	2050	102%**
Stockton	701	1163	60%	604	116%**
Greater Bay	4638	10419	45%	7616	61%**
Greater Fresno	1857	3246	57%	2828	66%
Kern	462	1281	36%	677	68%**
LA Basin	10430	19694	53%	11789	88%
Big Creek/Ventura	2250	4580	49%	5318	42%
San Diego	4063	5200	78%	4706	86%**
Total	**27307**	**49201***	**56%***	**36752**	**74%**

Table 6: 2013 Local Capacity Needs vs. Peak Load and Local Area Generation

	2013 Total LCR (MW)	Peak Load (1 in10) (MW)	2013 LCR as % of Peak Load	Total Dependable Local Area Generation (MW)	2013 LCR as % of Total Area Generation
Humboldt	212	210	101%	217	98%**
North Coast/North Bay	629	1479	43%	869	72%
Sierra	1930	1738	111%	2039	95%**
Stockton	567	1109	51%	620	91%**
Greater Bay	4502	10233	44%	7664	59%
Greater Fresno	1786	3032	59%	2817	63%
Kern	525	1311	40%	584	90%**
LA Basin	10295	19460	53%	13127	78%
Big Creek/Ventura	2241	4596	49%	5276	42%
San Diego	3082	5114	60%	4149	74%**
Total	**25,769**	**48282***	**53%***	**37,362**	**69%**

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

** Generation deficient LCA (or with sub-area that is deficient) – deficiency included in LCR. Generator 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 generation and how much local generation 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 generation 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 generation.

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/1796/179688b22c970.html

The NQC list includes the area (if applicable) where each resource is located for units already operational. Neither the NQC list nor this report incorporates Demand Side Management programs and their related NQC. Units scheduled to become operational before 6/1/2014 have been included in this 2014 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 generation. The first set is comprised of generation that would normally be expected to be on-line such as Municipal generation and Regulatory Must-take generation (state, federal, QFs, wind and nuclear units). The second set is "market" generation. The second column, "2014 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, "2014 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	28647	4297	-8511	-3750	**20683**
NP26=NP15+ZP26	22174	3326	-4914	-2902	**17684**

Where:

Load Forecast is the most recent 1 in 2 CEC forecast for year 2014.

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

Allocated Imports are the actual 2013 Available Import Capability for loads in the CAISO control area numbers that are not expected to change much by 2014 because there are no additional import transmission additions to the grid between now and summer of 2014.

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 up in Southern California by about 400 MW and up in Northern California by about 300 MW.
- The Import Allocations went up in Southern California by about 700 MW and up in Northern California by about 300 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 2013. 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 2014 busload within the defined area: 187 MW with 8 MW of losses resulting in total load + losses of 195 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BLULKE_6_BLUELK	31156	BLUELKPP	12.5	12.00	1	Humboldt 60 kV		Market
BRDGVL_7_BAKER				0.00		None	Not modeled Aug NQC	QF/Selfgen
FAIRHV_6_UNIT	31150	FAIRHAVN	13.8	15.29	1	Humboldt 60 kV	Aug NQC	QF/Selfgen
FTSWRD_7_QFUNTS				0.62		Humboldt 60 kV	Not modeled Aug NQC	QF/Selfgen
GRSCRK_6_BGCKWW				0.00		Humboldt 60 kV	Energy Only	QF/Selfgen

HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.27	1	None		Market
HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.27	2	None		Market
HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.27	3	None		Market
HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.27	4	None		Market
HUMBPP_6_UNITS1	31181	HUMB_G2	13.8	16.27	5	Humboldt 60 kV		Market
HUMBPP_6_UNITS1	31181	HUMB_G2	13.8	16.27	6	Humboldt 60 kV		Market
HUMBPP_6_UNITS1	31181	HUMB_G2	13.8	16.27	7	Humboldt 60 kV		Market
HUMBPP_6_UNITS2	31182	HUMB_G2	13.8	16.27	8	Humboldt 60 kV		Market
HUMBPP_6_UNITS2	31182	HUMB_G2	13.8	16.27	9	Humboldt 60 kV		Market
HUMBPP_6_UNITS2	31182	HUMB_G2	13.8	16.27	10	Humboldt 60 kV		Market
HUMBSB_1_QF				0.00		None	Not modeled Aug NQC	QF/Selfgen
KEKAWK_6_UNIT	31166	KEKAWAK	9.1	0.00	1	Humboldt 60 kV	Aug NQC	QF/Selfgen
LAPAC_6_UNIT	31158	LP SAMOA	12.5	20.00	1	Humboldt 60 kV		QF/Selfgen
PACLUM_6_UNIT	31152	PAC.LUMB	13.8	7.51	1	Humboldt 60 kV	Aug NQC	QF/Selfgen
PACLUM_6_UNIT	31152	PAC.LUMB	13.8	7.52	2	Humboldt 60 kV	Aug NQC	QF/Selfgen
PACLUM_6_UNIT	31153	PAC.LUMB	2.4	4.52	3	Humboldt 60 kV	Aug NQC	QF/Selfgen
WLLWCR_6_CEDRFL				0.02		Humboldt 60 kV	Not modeled Aug NQC	QF/Selfgen
New Unit	31161	RPSP1016	34.5	8	1	Humboldt 60 kV	No NQC - est. data	Wind
New Unit	31161	RPSP1016	34.5	7	2	Humboldt 60 kV	No NQC - est. data	Wind

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
4. Two new small wind resources

<u>Critical Contingency Analysis Summary</u>

Humboldt 60 kV Sub-area:

This sub-area has been eliminated due to the new transmission projects. If the transmission projects are not operational by January 1, 2014 all resources within this sub-area are needed.

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 one of the tie-line connecting the new Humboldt Bay units on the 115 kV side. The area limitation is the overload on the Humboldt – Trinity 115 kV Line. This contingency establishes a LCR of 195 MW in

2014 (includes 55 MW of QF/Selfgen and 15 MW of wind generation) 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 145 MW in 2014 (includes 55 MW of QF/Selfgen and 15 MW of wind generation).

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
31161	RPSP1016	1	57
31161	RPSP1016	2	57

Changes compared to last year's results:

Compared to 2013 the total load and losses for the Humboldt area came down by 15 MW in 2014. The 60 kV sub-area has been eliminated due to the transformer upgrades, however the change in impedance has resulted in overall Humboldt LCR requirements to increase slightly by about 5 MW.

Humboldt Overall Requirements:

2014	QF/Selfgen (MW)	Wind (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	55	15	173	243

2014	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[9]	145	0	145
Category C (Multiple)[10]	195	0	195

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

[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.

Total 2014 busload within the defined area: 1425 MW with 40 MW of losses resulting in total load + losses of 1465 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
BEARCN_2_UNITS	31402	BEAR CAN	13.8	6.50	1	Fulton, Lakeville		Market
BEARCN_2_UNITS	31402	BEAR CAN	13.8	6.50	2	Fulton, Lakeville		Market
FULTON_1_QF				0.09		Fulton, Lakeville	Not modeled Aug NQC	QF/Selfgen
GEYS11_7_UNIT11	31412	GEYSER11	13.8	65.00	1	Eagle Rock, Fulton, Lakeville		Market
GEYS12_7_UNIT12	31414	GEYSER12	13.8	50.00	1	Fulton, Lakeville		Market
GEYS13_7_UNIT13	31416	GEYSER13	13.8	56.00	1	Lakeville		Market
GEYS14_7_UNIT14	31418	GEYSER14	13.8	50.00	1	Fulton, Lakeville		Market
GEYS16_7_UNIT16	31420	GEYSER16	13.8	49.00	1	Fulton, Lakeville		Market
GEYS17_2_BOTRCK	31421	BOTTLERK	13.8	14.70	1	Fulton, Lakeville		Market
GEYS17_7_UNIT17	31422	GEYSER17	13.8	53.00	1	Fulton, Lakeville		Market
GEYS18_7_UNIT18	31424	GEYSER18	13.8	45.00	1	Lakeville		Market
GEYS20_7_UNIT20	31426	GEYSER20	13.8	40.00	1	Lakeville		Market
GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	40.00	1	Eagle Rock, Fulton, Lakeville		Market
GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	40.00	2	Eagle Rock, Fulton, Lakeville		Market
GYS7X8_7_UNITS	31408	GEYSER78	13.8	38.00	1	Eagle Rock, Fulton, Lakeville		Market
GYS7X8_7_UNITS	31408	GEYSER78	13.8	38.00	2	Eagle Rock, Fulton, Lakeville		Market
GYSRVL_7_WSPRNG				1.68		Fulton, Lakeville	Not modeled Aug NQC	QF/Selfgen
HILAND_7_YOLOWD				0.00		Eagle Rock, Fulton, Lakeville	Energy Only	Market
HIWAY_7_ACANYN				0.71		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	0.74	1	Eagle Rock, Fulton, Lakeville	Aug NQC	QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	3.89	1	Fulton, Lakeville	Aug NQC	QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	3.89	2	Fulton, Lakeville	Aug NQC	QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	0.92	3	Fulton, Lakeville	Aug NQC	QF/Selfgen
NAPA_2_UNIT				0.00		Lakeville	Not modeled 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	8.53	1	Fulton, Lakeville	Aug NQC	MUNI
NCPA_7_GP2UN4	38112	NCPA2GY2	13.8	52.70	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				0.02		Eagle Rock, Fulton, Lakeville	Not modeled Aug NQC	QF/Selfgen
SANTFG_7_UNITS	31400	SANTA FE	13.8	30.00	1	Lakeville		Market
SANTFG_7_UNITS	31400	SANTA FE	13.8	30.00	2	Lakeville		Market
SMUDGO_7_UNIT 1	31430	SMUDGEO1	13.8	37.00	1	Lakeville		Market
SNMALF_6_UNITS	31446	SONMA LF	9.1	4.40	1	Fulton, Lakeville	Aug NQC	QF/Selfgen
UKIAH_7_LAKEMN				1.70		Eagle Rock, Fulton, Lakeville	Not modeled	MUNI
WDFRDF_2_UNITS	31404	WEST FOR	13.8	12.51	1	Fulton, Lakeville		Market
WDFRDF_2_UNITS	31404	WEST FOR	13.8	12.49	2	Fulton, Lakeville		Market
New Unit	31405	RPSP1014	13.8	32	1	Eagle Rock, Fulton, Lakeville	No NQC - Pmax	Market
New Unit	31439	RPSP1015	13.8	12	1	Eagle Rock, Fulton, Lakeville	No NQC - est. data	Wind
New Unit	31447	RPSP1008	4.2	0	1	Lakeville	Energy Only	Market

Major new projects modeled:

1. Three new small renewable resources

<u>Critical Contingency Analysis Summary</u>

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 210 MW in 2014 (includes 2 MW of QF/MUNI and 12 MW of wind 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 195 MW in 2014 (includes 2 MW of QF/MUNI and 12 MW of wind generation).

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31406	GEYSR5-6	1	38
31406	GEYSR5-6	2	38
31405	RPSP1014	1	38
31408	GEYSER78	1	38
31408	GEYSER78	2	38
31412	GEYSER11	1	38
31435	GEO.ENGY	1	38
31435	GEO.ENGY	2	38
31439	RPSP1015	1	36
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. This limiting contingency establishes a LCR of 316 MW in 2014 (includes 16 MW of QF, 63 MW of Muni and 12 MW of wind 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% effective 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
31439	RPSP1015	1	29
31433	POTTRVLY	1	29
31433	POTTRVLY	3	29
31433	POTTRVLY	4	29

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 623 MW in 2014 (includes 16 MW of QF, 122 MW of MUNI and 12 MW of wind generation). 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% effective 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
31447	PRSR1008	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
31439	RPSP1015	1	15
31433	POTTRVLY	1	15
31433	POTTRVLY	2	15
31433	POTTRVLY	3	15

Changes compared to last year's results:

The 2014 load forecast went down by 14 MW compared to the 2013 and the LCR need went down by 6 MW.

North Coast/North Bay Overall Requirements:

2014	QF/Selfgen (MW)	Muni (MW)	Wind (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	16	122	12	771	921

2014	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[11]	623	0	623
Category C (Multiple)[12]	623	0	623

[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.

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
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 2014 busload within the defined area: 1843 MW with 115 MW of losses resulting in total load + losses of 1958 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
APLHIL_1_SLABCK				0.00	1	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled 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	9.1	23.87	1	Drum-Rio Oso, South	Aug NQC	QF/Selfgen

						of Palermo, South of Table Mountain		
BNNIEN_7_ALTAPH	32376	BONNIE N	60	0.71		Weimer, Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
BOGUE_1_UNITA1	32451	FREC	13.8	45.00	1	Bogue, Drum-Rio Oso, South of Table Mountain	Aug NQC	Market
BOWMN_6_UNIT	32480	BOWMAN	9.1	2.94	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
BUCKCK_7_OAKFLT				1.12		South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
BUCKCK_7_PL1X2	31820	BCKS CRK	11	29.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
BUCKCK_7_PL1X2	31820	BCKS CRK	11	29.00	2	South of Palermo, South of Table Mountain	Aug NQC	Market
CAMPFW_7_FARWST	32470	CMP.FARW	9.1	4.04	1	South of Table Mountain	Aug NQC	MUNI
CHICPK_7_UNIT 1	32462	CHI.PARK	11.5	38.00	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
COLGAT_7_UNIT 1	32450	COLGATE1	13.8	161.65	1	South of Table Mountain	Aug NQC	MUNI
COLGAT_7_UNIT 2	32452	COLGATE2	13.8	161.68	1	South of Table Mountain	Aug NQC	MUNI
CRESTA_7_PL1X2	31812	CRESTA	11.5	35.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
CRESTA_7_PL1X2	31812	CRESTA	11.5	35.00	2	South of Palermo, South of Table Mountain	Aug NQC	Market
DAVIS_7_MNMETH				2.10		Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
DEADCK_1_UNIT	31862	DEADWOOD	9.1	0.00	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
DEERCR_6_UNIT 1	32474	DEER CRK	9.1	3.38	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	Aug NQC	Market

						Table Mountain		
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	9.1	0.55	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	39.00	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
GRNLF1_1_UNITS	32490	GRNLEAF1	13.8	5.65	1	Bogue, Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
GRNLF1_1_UNITS	32490	GRNLEAF1	13.8	28.84	2	Bogue, Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
GRNLF2_1_UNIT	32492	GRNLEAF2	13.8	38.78	1	Pease, Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
HALSEY_6_UNIT	32478	HALSEY F	9.1	7.96	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
HAYPRS_6_QFUNTS	32488	HAYPRES+	9.1	0.14	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
HAYPRS_6_QFUNTS	32488	HAYPRES+	9.1	0.15	2	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
HIGGNS_1_COMBIE				0.00		Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Energy Only	Market
HIGGNS_7_QFUNTS				0.18		Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	QF/Selfgen
KANAKA_1_UNIT				0.00		Drum-Rio Oso, South of Table Mountain	Not modeled Aug NQC	MUNI

KELYRG_6_UNIT	31834	KELLYRDG	9.1	10.00	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
LODIEC_2_PL1X2	38123	LODI CT1	18	166.00	1	South of Rio Oso, South of Palermo, South of Table Mountain		MUNI
LODIEC_2_PL1X2	38124	LODI ST1	18	114.00	1	South of Rio Oso, South of Palermo, South of Table Mountain		MUNI
MDFKRL_2_PROJCT	32456	MIDLFORK	13.8	62.18	1	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
MDFKRL_2_PROJCT	32456	MIDLFORK	13.8	62.18	2	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
MDFKRL_2_PROJCT	32458	RALSTON	13.8	84.32	1	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
NAROW1_2_UNIT	32466	NARROWS1	9.1	9,58	1	South of Table Mountain	Aug NQC	Market
NAROW2_2_UNIT	32468	NARROWS2	9.1	27.93	1	South of Table Mountain	Aug NQC	MUNI
NWCSTL_7_UNIT 1	32460	NEWCSTLE	13.2	0.03	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
OROVIL_6_UNIT	31888	OROVLLE	9.1	4.87	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
OXBOW_6_DRUM	32484	OXBOW F	9.1	6.00	1	Weimer, Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
PACORO_6_UNIT	31890	PO POWER	9.1	7.20	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
PACORO_6_UNIT	31890	PO POWER	9.1	7.21	2	Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
PLACVL_1_CHILIB	32510	CHILIBAR	4.2	3.18	1	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PLACVL_1_RCKCRE				0.00		Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
PLSNTG_7_LNCLND	32408	PLSNT GR	60	1.79		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	56.00	1	South of Palermo, South of Table	Aug NQC	Market

						Mountain		
RCKCRK_7_UNIT 2	31788	ROCK CK2	13.8	56.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
RIOOSO_1_QF				1.35		Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	QF/Selfgen
ROLLIN_6_UNIT	32476	ROLLINSF	9.1	11.09	1	Weimer, Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
SLYCRK_1_UNIT 1	31832	SLY.CR.	9.1	10.36	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
SPAULD_6_UNIT 3	32472	SPAULDG	9.1	6.00	3	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
SPAULD_6_UNIT12	32472	SPAULDG	9.1	4.96	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
SPAULD_6_UNIT12	32472	SPAULDG	9.1	4.96	2	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
SPI LI_2_UNIT 1	32498	SPILINCF	12.5	10.15	1	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
STIGCT_2_LODI	38114	Stig CC	13.8	49.50	1	South of Rio Oso, South of Palermo, South of Table Mountain		MUNI
ULTRCK_2_UNIT	32500	ULTR RCK	9.1	21.80	1	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
WDLEAF_7_UNIT 1	31794	WOODLEAF	13.8	55.00	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
WHEATL_6_LNDFIL	32350	WHEATLND	60	1.20		South of Table Mountain	Not modeled Aug NQC	Market
WISE_1_UNIT 1	32512	WISE	12	11.57	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	0.12	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
YUBACT_1_SUNSWT	32494	YUBA CTY	9.1	26.39	1	Pease, Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
YUBACT_6_UNITA1	32496	YCEC	13.8	46.00	1	Pease, Drum-Rio Oso, South of Table Mountain		Market
NA	32162	RIV.DLTA	9.11	0.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	No NQC - hist. data	QF/Selfgen
UCDAVS_1_UNIT	32166	UC DAVIS	9.1	3.50	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	No NQC - hist. data	QF/Selfgen

Major new projects modeled:

1. Table Mountain-Rio Oso Reconductor and Tower Upgrade
2. Gold Hill – Horseshoe 115 kV line Reconductoring
3. Palermo-Rio Oso 115 kV Reconductoring

<u>Critical Contingency Analysis Summary</u>

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 6 MW (includes 0 MW of QF and MUNI generation) in 2014 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area (El Dorado units 1&2 and Chili Bar) 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 107 MW (includes 38 MW of QF and MUNI generation as well as 27 MW of deficiency) in 2014 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 #2 115 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 87 MW (includes 38 MW of QF and MUNI generation) in 2014.

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 122 MW (includes 65 MW of QF generation and 11 MW of deficiency) in 2014 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area (Greenleaf #2, Yuba City and Yuba City EC) 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 726 MW (includes 32 MW of QF and 593 MW of MUNI generation as well as 32 MW of deficiency) in 2014 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 635 MW (includes 32 MW of QF and 593 MW of MUNI generation) in 2014.

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 2014 a LCR of 698 MW (includes 180 MW of QF and 198 MW of MUNI generation as well as 60 MW of deficiency) 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 #2 230/115 transformer. The area limitation is thermal overloading of the Rio Oso #1 230/115 kV transformer. This limiting contingency establishes in 2014 a LCR of 247 MW (includes 180 MW of QF and 198 MW of MUNI generation).

Effectiveness factors:

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

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 1643 MW (includes 61 MW of QF and 639 MW of MUNI generation as well as 273 MW of deficiency) in 2014 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the loss of the Palermo- East Nicolaus 115 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 2014 a LCR of 1275 MW (includes 61 MW of QF and 639 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 2014 a LCR of 1803 MW (includes 180 MW of QF and 1108 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 to the above-mentioned constraint.

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 up by 220 MW and the LCR need has increased by 158 MW.

Sierra Overall Requirements:

2014	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	180	1108	762	2050

2014	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[13]	1414	0	1414
Category C (Multiple)[14]	1803	285	2088

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

[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.

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:

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 2014 busload within the defined area: 1141 MW with 22 MW of losses resulting in total load + losses of 1163 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BEARDS_7_UNIT 1	34074	BEARDSLY	6.9	8.36	1	Tesla-Bellota, Stanislaus	Aug NQC	MUNI
CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	1.84	1	Tesla-Bellota	Aug NQC	MUNI
CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	1.84	2	Tesla-Bellota	Aug NQC	MUNI

CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	1.85	3	Tesla-Bellota	Aug NQC	MUNI
CURIS_1_QF				0.90		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
LODI25_2_UNIT 1	38120	LODI25CT	9.11	22.70	1	Lockeford		MUNI
PHOENX_1_UNIT				1.36		Tesla-Bellota, Stanislaus	Not modeled Aug NQC	Market
SCHLTE_1_PL1X3	33805	GWFTRCY1	13.8	83.56	1	Tesla-Bellota		Market
SCHLTE_1_PL1X3	33807	GWFTRCY2	13.8	82.88	1	Tesla-Bellota		Market
SCHLTE_1_PL1X3	33811	GWFTRCY3	13.8	132.96	1	Tesla-Bellota		Market
SNDBAR_7_UNIT 1	34060	SANDBAR	13.8	13.91	1	Tesla-Bellota, Stanislaus	Aug NQC	MUNI
SPIFBD_1_PL1X2	33917	FBERBORD	115	1.26	1	Tesla-Bellota, Stanislaus	Aug NQC	QF/Selfgen
SPRGAP_1_UNIT 1	34078	SPRNG GP	6	0.06	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	16.01	1	Tesla-Bellota	Aug NQC	QF/Selfgen
STOKCG_1_UNIT 1	33814	CPC STCN	12.5	32.67	1	Tesla-Bellota	Aug NQC	QF/Selfgen
TULLCK_7_UNITS	34076	TULLOCH	6.9	8.23	1	Tesla-Bellota	Aug NQC	MUNI
TULLCK_7_UNITS	34076	TULLOCH	6.9	8.24	2	Tesla-Bellota	Aug NQC	MUNI
ULTPCH_1_UNIT 1	34050	CH.STN.	13.8	16.98	1	Tesla-Bellota, Stanislaus	Aug NQC	QF/Selfgen
VLYHOM_7_SSJID				1.41		Tesla-Bellota, Stanislaus	Not modeled Aug NQC	QF/Selfgen
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
COGNAT_1_UNIT	33818	COG.NTNL	12	0.00	1	Weber	Retired	QF/Selfgen

Major new projects modeled:

1. Weber-Stockton "A" #1 & #2 60 kV Reconductoring

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 127 MW (including 20 MW of QF and 94 MW of MUNI generation) in 2014 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 617 MW (includes 69 MW of QF and 116 MW of MUNI generation as well as 198 MW of deficiency) in 2014 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 476 MW (includes 69 MW of QF and 116 MW of MUNI generation as well as 198 MW of deficiency) in 2014.

The second most critical contingency for the Tesla-Bellota pocket is the loss of Tesla-Tracy 115 kV and Tesla-Schulte #2 115 kV lines. The area limitation is thermal overload of the Tesla-Schulte #1 115 kV line. This limiting contingency establishes a 2014 local capacity need of 419 MW (includes 69 MW of QF and 116 MW of MUNI generation).

The single most critical contingency for the Tesla-Bellota pocket is the loss of Tesla-Tracy 115 kV line and the loss of the GWF Tracy unit #3. The area limitation is thermal overload of the Tesla-Schulte #1 115 kV line. This single contingency establishes a local capacity need of 352 MW (includes 69 MW of QF and 116 MW of MUNI generation) in 2014.

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 2014 local capacity need of 55 MW (including 2 MW of QF and 23 MW of MUNI generation as well as 30 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 most critical contingency is the loss of the Weber 230/60 kV Transformer #1 and Stockton Wastewater unit. The area limitation is thermal overloading of the Weber 230/60 kV Transformer #2 & 2A. This limiting contingency establishes a LCR of 29 MW (includes 2 MW of QF generation as well as 27 MW of deficiency) in 2014 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the loss of the Weber 230/60 kV Transformer #1. The area limitation is thermal overloading of the Weber 230/60 kV Transformer #2 & 2A. This contingency establishes in 2014 a LCR of 27 MW (includes 2 MW of QF generation as well as 25 MW of deficiency).

Changes compared to last year's results:

Overall the Stockton area load forecast went up by 54 MW. The Weber 230/60 kV transformer # replacement project was delayed. The overall requirement for the Stockton area increased by 134 MW.

Stockton Overall Requirements:

2014	QF (MW)	MUNI (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	73	139	392	604

2014	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[15]	354	25	379
Category C (Multiple)[16]	446	255	701

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
9) Tesla-Pittsburg #1 230 kV
10) Tesla-Pittsburg #2 230 kV
11) Tesla-Newark #1 230 kV
12) Tesla-Newark #2 230 kV
13) Tesla-Ravenswood 230 kV
14) Tesla-Metcalf 500 kV
15) Moss Landing-Metcalf 500 kV
16) Moss Landing-Metcalf #1 230 kV
17) Moss Landing-Metcalf #2 230 kV

[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.

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) Moss Landing is out Metcalf is in
16) Moss Landing is out Metcalf is in
17) Moss Landing is out Metcalf is in
18) Oakdale TID is out Newark is in
19) Oakdale TID is out Newark is in

Total 2014 bus load within the defined area is 9983 MW with 202 MW of losses and 234 MW of pumps resulting in total load + losses + pumps of 10419 MW. This corresponds to about 9819 MW of load per CEC forecast since there are about 600 MW of loads behind the meter modeled in the base cases.

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	25.00	10	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38760	DELTA E	13.2	25.00	11	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38765	DELTA D	13.2	25.00	8	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38765	DELTA D	13.2	25.00	9	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38770	DELTA C	13.2	25.00	6	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38770	DELTA C	13.2	25.00	7	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38815	DELTA B	13.2	25.00	4	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38815	DELTA B	13.2	25.00	5	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38820	DELTA A	13.2	7.00	1	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38820	DELTA A	13.2	7.00	2	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38820	DELTA A	13.2	20.00	3	Contra Costa	Pumps	MUNI

BLHVN_7_MENLOP				0.95		None	Not modeled Aug NQC	QF/Selfgen
BRDSLD_2_HIWIND	32172	HIGHWINDS	34.5	34.87	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_MTZUM2	32179	MNTZUMA2	0.69	13.02	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_MTZUMA	32171	HIGHWND3	34.5	8.77	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_SHILO1	32176	SHILOH	34.5	35.79	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_SHILO2	32177	SHILOH 2	34.5	30.71	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_SHLO3A	32191	SHLH3AC2	0.58	17.07	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_SHLO3B	32194	SHLH3BC2	0.58	16.23	1	Contra Costa	Aug NQC	Wind
CALPIN_1_AGNEW	35860	OLS-AGNE	9.11	28.00	1	San Jose	Aug NQC	QF/Selfgen
CARDCG_1_UNITS	33463	CARDINAL	12.5	10.69	1	None	Aug NQC	QF/Selfgen
CARDCG_1_UNITS	33463	CARDINAL	12.5	10.70	2	None	Aug NQC	QF/Selfgen
CLRMTK_1_QF				0.00		Oakland	Not modeled	QF/Selfgen
COCOPP_7_UNIT 6	33116	C.COS 6	18	0.00	1	Contra Costa	Retired	Market
COCOPP_7_UNIT 7	33117	C.COS 7	18	0.00	1	Contra Costa	Retired	Market
CONTAN_1_UNIT	36856	CCA100	13.8	25.80	1	San Jose	Aug NQC	QF/Selfgen
CROKET_7_UNIT	32900	CRCKTCOG	18	208.97	1	Pittsburg	Aug NQC	QF/Selfgen
CSCCOG_1_UNIT 1	36854	Cogen	12	3.00	1	San Jose		MUNI
CSCCOG_1_UNIT 1	36854	Cogen	12	3.00	2	San Jose		MUNI
CSCGNR_1_UNIT 1	36858	Gia100	13.8	24.00	1	San Jose		MUNI
CSCGNR_1_UNIT 2	36895	Gia200	13.8	24.00	2	San Jose		MUNI
DELTA_2_PL1X4	33107	DEC STG1	24	269.61	1	Pittsburg	Aug NQC	Market
DELTA_2_PL1X4	33108	DEC CTG1	18	181.13	1	Pittsburg	Aug NQC	Market
DELTA_2_PL1X4	33109	DEC CTG2	18	181.13	1	Pittsburg	Aug NQC	Market
DELTA_2_PL1X4	33110	DEC CTG3	18	181.13	1	Pittsburg	Aug NQC	Market
DUANE_1_PL1X3	36863	DVRaGT1	13.8	49.27	1	San Jose		MUNI
DUANE_1_PL1X3	36864	DVRbGT2	13.8	49.27	1	San Jose		MUNI
DUANE_1_PL1X3	36865	DVRaST3	13.8	49.26	1	San Jose		MUNI
FLOWD1_6_ALTPP1	35318	FLOWDPTR	9.11	0.00	1	Contra Costa	Aug NQC	Wind
GATWAY_2_PL1X3	33118	GATEWAY1	18	189.27	1	Contra Costa	Aug NQC	Market
GATWAY_2_PL1X3	33119	GATEWAY2	18	185.36	1	Contra Costa	Aug NQC	Market
GATWAY_2_PL1X3	33120	GATEWAY3	18	185.36	1	Contra Costa	Aug NQC	Market
GILROY_1_UNIT	35850	GLRY COG	13.8	69.30	1	Llagas	Aug NQC	Market
GILROY_1_UNIT	35850	GLRY COG	13.8	35.70	2	Llagas	Aug NQC	Market
GILRPP_1_PL1X2	35851	GROYPKR1	13.8	45.50	1	Llagas	Aug NQC	Market
GILRPP_1_PL1X2	35852	GROYPKR2	13.8	45.50	1	Llagas	Aug NQC	Market
GILRPP_1_PL3X4	35853	GROYPKR3	13.8	46.00	1	Llagas	Aug NQC	Market
GRZZLY_1_BERKLY	32740	HILLSIDE	115	24.88	1	None	Aug NQC	QF/Selfgen
GWFPW1_6_UNIT	33131	GWF #1	9.11	16.55	1	Pittsburg, Contra Costa	Aug NQC	QF/Selfgen
GWFPW2_1_UNIT 1	33132	GWF #2	13.8	17.87	1	Pittsburg	Aug NQC	QF/Selfgen
GWFPW3_1_UNIT 1	33133	GWF #3	13.8	15.95	1	Pittsburg, Contra Costa	Aug NQC	QF/Selfgen
GWFPW4_6_UNIT 1	33134	GWF #4	13.8	18.23	1	Pittsburg, Contra Costa	Aug NQC	QF/Selfgen
GWFPW5_6_UNIT 1	33135	GWF #5	13.8	18.10	1	Pittsburg	Aug NQC	QF/Selfgen
HICKS_7_GUADLP				1.84		None	Not modeled Aug NQC	QF/Selfgen
KELSO_2_UNITS	33813	MARIPCT1	13.8	45.95	1	Contra Costa	Aug NQC	Market
KELSO_2_UNITS	33815	MARIPCT2	13.8	45.95	2	Contra Costa	Aug NQC	Market
KELSO_2_UNITS	33817	MARIPCT3	13.8	45.95	3	Contra Costa	Aug NQC	Market
KELSO_2_UNITS	33819	MARIPCT4	13.8	45.96	4	Contra Costa	Aug NQC	Market
KIRKER_7_KELCYN	32951	KIRKER	115	3.21		Pittsburg	Not modeled	Market
LAWRNC_7_SUNYVL				0.14		None	Not modeled Aug NQC	Market
LECEF_1_UNITS	35854	LECEFGT1	13.8	46.50	1	San Jose	Aug NQC	Market

LECEF_1_UNITS	35855	LECEFGT2	13.8	46.50	1	San Jose	Aug NQC	Market
LECEF_1_UNITS	35856	LECEFGT3	13.8	46.50	1	San Jose	Aug NQC	Market
LECEF_1_UNITS	35857	LECEFGT4	13.8	46.50	1	San Jose	Aug NQC	Market
LFC 51_2_UNIT 1	35310	LFC FIN+	9.11	1.91	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
MARKHM_1_CATLST	35863	CATALYST	9.11	0.00	1	San Jose		QF/Selfgen
MARTIN_1_SUNSET				1.59		None	Not modeled Aug NQC	QF/Selfgen
METCLF_1_QF				0.22		None	Not modeled Aug NQC	QF/Selfgen
METEC_2_PL1X3	35881	MEC CTG1	18	178.43	1	None	Aug NQC	Market
METEC_2_PL1X3	35882	MEC CTG2	18	178.43	1	None	Aug NQC	Market
METEC_2_PL1X3	35883	MEC STG1	18	213.14	1	None	Aug NQC	Market
MILBRA_1_QF				0.00		None	Not modeled	QF/Selfgen
MISSIX_1_QF				0.25		None	Not modeled Aug NQC	QF/Selfgen
MLPTAS_7_QFUNTS				0.01		San Jose	Not modeled Aug NQC	QF/Selfgen
MNTAGU_7_NEWBYI				2.09		None	Not modeled Aug NQC	QF/Selfgen
NEWARK_1_QF				0.03		None	Not modeled Aug NQC	QF/Selfgen
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
OAK L_7_EBMUD				0.66		Oakland	Not modeled Aug NQC	MUNI
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	1	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	2	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	3	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	4	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	5	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	6	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	7	None		Market
PALALT_7_COBUG				4.50		None	Not modeled	MUNI
PITTSP_7_UNIT 5	33105	PTSB 5	18	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	682.00	1	Pittsburg		Market
RICHMN_7_BAYENV				2.00		None	Not modeled Aug NQC	QF/Selfgen
RVRVEW_1_UNITA1	33178	RVEC_GEN	13.8	46.00	1	Contra Costa	Aug NQC	Market
SEAWST_6_LAPOS	35312	SEAWESTF	9.11	0.28	1	Contra Costa	Aug NQC	Wind
SRINTL_6_UNIT	33468	SRI INTL	9.11	0.96	1	None	Aug NQC	QF/Selfgen
STAUFF_1_UNIT	33139	STAUFER	9.11	0.01	1	None	Aug NQC	QF/Selfgen
STOILS_1_UNITS	32921	CHEVGEN1	13.8	1.41	1	Pittsburg	Aug NQC	QF/Selfgen
STOILS_1_UNITS	32922	CHEVGEN2	13.8	1.41	1	Pittsburg	Aug NQC	QF/Selfgen
TIDWTR_2_UNITS	33151	FOSTER W	12.5	5.86	1	Pittsburg	Aug NQC	QF/Selfgen
TIDWTR_2_UNITS	33151	FOSTER W	12.5	5.86	2	Pittsburg	Aug NQC	QF/Selfgen
TIDWTR_2_UNITS	33151	FOSTER W	12.5	5.86	3	Pittsburg	Aug NQC	QF/Selfgen
UNCHEM_1_UNIT	32920	UNION CH	9.11	17.59	1	Pittsburg	Aug NQC	QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.03	1	Pittsburg	Aug NQC	QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.03	2	Pittsburg	Aug NQC	QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.04	3	Pittsburg	Aug NQC	QF/Selfgen
UNTDQF_7_UNITS	33466	UNTED CO	9.11	25.08	1	None	Aug NQC	QF/Selfgen
USWNDR_2_SMUD	32169	SOLANOWP	21	18.11	1	Contra Costa	Aug NQC	Wind

USWNDR_2_UNITS	32168	EXNCO	9.11	19.81	1	Contra Costa	Aug NQC	Wind
USWPFK_6_FRICK	35320	USW FRIC	12	0.47	1	Contra Costa	Aug NQC	Wind
USWPFK_6_FRICK	35320	USW FRIC	12	0.47	2	Contra Costa	Aug NQC	Wind
USWPJR_2_UNITS	33838	USWP_#3	9.11	12.69	1	Contra Costa	Aug NQC	Wind
WNDMAS_2_UNIT 1	33170	WINDMSTR	9.11	3.21	1	Contra Costa	Aug NQC	Wind
ZOND_6_UNIT	35316	ZOND SYS	9.11	4.00	1	Contra Costa	Aug NQC	Wind
IBMCTL_1_UNIT 1	35637	IBM-CTLE	115	0.00	1	San Jose	No NQC - hist. data	Market
IMHOFF_1_UNIT 1	33136	CCCSD	12.5	4.40	1	Pittsburg	No NQC - hist. data	QF/Selfgen
SHELRF_1_UNITS	33141	SHELL 1	12.5	20.00	1	Pittsburg	No NQC - hist. data	QF/Selfgen
SHELRF_1_UNITS	33142	SHELL 2	12.5	40.00	1	Pittsburg	No NQC - hist. data	QF/Selfgen
SHELRF_1_UNITS	33143	SHELL 3	12.5	40.00	1	Pittsburg	No NQC - hist. data	QF/Selfgen
ZANKER_1_UNIT 1	35861	SJ-SCL W	9.11	5.00	1	San Jose	No NQC - hist. data	QF/Selfgen
COCOPP_2_CTG1	33188	MARSHBS1	16.4	193.5	1	Contra Costa	No NQC - Pmax	Market
COCOPP_2_CTG2	33188	MARSHBS1	16.4	193.5	2	Contra Costa	No NQC - Pmax	Market
COCOPP_2_CTG3	33189	MARSHBS2	16.4	193.5	3	Contra Costa	No NQC - Pmax	Market
COCOPP_2_CTG4	33189	MARSHBS2	16.4	193.5	4	Contra Costa	No NQC - Pmax	Market
LECEF_1_UNITS	35858	LECEFST1	13.8	120.00	1	San Jose	No NQC - Pmax	Market
NA	32186	RPSP1001	34.5	42	1	Contra Costa	No NQC - est. data	Wind
NA	32188	RPSP1012	34.5	9.8	1	Contra Costa	No NQC - est. data	Wind
RUSCTY_2_UNITS	35304	RUSELCT1	15	177.50	1	None	No NQC - Pmax	Market
RUSCTY_2_UNITS	35305	RUSELCT2	15	177.50	1	None	No NQC - Pmax	Market
RUSCTY_2_UNITS	35306	RUSELST1	15	245.00	1	None	No NQC - Pmax	Market

Major new projects modeled:

1. Two small wind farms connected to Birds Landing
2. Russell City Energy Center
3. Marsh Landing Generating Station
4. Los Esteros Critical Energy Facility (LECEF) capacity increase
5. Contra Costa – Moraga 230 kV Line 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 – Clamant #1 or #2 230kV Line. This limiting contingency establishes a LCR of 96 MW in 2014 (includes 49 MW of MUNI generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

This Oakland requirement does not include the need for Pittsburg/Oakland 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 123 MW in 2014 (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 Metcalf-El Patio #1 or #2 115 kV line followed by Metcalf-Evergreen #1 115 kV line. The area limitation is thermal overloading of the Metcalf-Evergreen #1 115 kV Line. This limiting contingency establishes a LCR of 782 MW in 2014 (includes 59 MW of QF and 202 MW of MUNI generation as well as 215 MW of deficiency) as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is an outage of the Metcalf-Evergreen #2 115 kV line with Duane PP out of service. The sub-area area limitation is thermal overloading of the Metcalf-Evergreen #1 115 kV Line. This limiting contingency establishes a LCR of 452 MW in 2014 (including 59 MW of QF and 202 MW of Muni generation).

Effectiveness factors:

The following table has units within the Bay Area that are at least 5% effective to the above-mentioned most critical constraint.

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
35863	CATALYST	1	20
36856	CCCA100	1	6
36854	Cogen	1	6
36854	Cogen	2	6
36863	DVRaGT1	1	6
36864	DVRbGT2	1	6
36865	DVRaST3	1	6
35860	OLS-AGNE	1	5
36858	Gia100	1	5
36859	Gia200	2	5
35854	LECEFGT1	1	5
35855	LECEFGT2	2	5
35856	LECEFGT3	3	5
35857	LECEFGT4	4	5

Pittsburg and Oakland Sub-area Combined

The most critical contingency is an outage of the Moraga #3 230/115 kV transformer combined with the loss of Delta Energy Center. The sub-area area limitation is thermal overloading of Moraga #1 230/115 kV transformer. This limiting contingency establishes a LCR of 2461 MW in 2014 (including 438 MW of QF and 49 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is an outage of the Moraga #3 230/115 kV transformer. The sub-area area limitation is thermal overloading of the Moraga #1 230/115 kV transformer. This limiting contingency establishes a LCR of 1917 MW in 2014 (including 438 MW of QF and 49 MW of Muni generation).

Effectiveness factors:

Please see Bay Area overall.

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 1217 MW in 2014 (includes 51 MW of QF, 267 MW of Wind generation and 234 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

Bay Area overall

The most critical contingency is an overlapping outage of the Tesla-Metcalf 500 kV line and Tesla-Newark #1 230 kV line. The sub-area area limitation is thermal overload on the Tesla-Delta Switching Yard 230 kV line. This limiting contingency establishes a LCR of 4423 MW in 2014 (including 578 MW of QF, 489 MW of MUNI and 269 MW of wind generation) as the minimum capacity necessary for reliable load serving capability within this sub-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 3747 MW in 2014 (including 578 MW of QF, 489 MW of MUNI and 269 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:

Overall the load forecast went up by 186 MW and the LCR has increased by 138 MW.

Bay Area Overall Requirements:

2014	Wind (MW)	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	269	578	489	6280	7616

2014	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[17]	3747	0	3747
Category C (Multiple)[18]	4423	215	4638

[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.

6. Greater Fresno Area

Area Definition

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
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

2014 total busload within the defined area is 3157 MW with 89 MW of losses resulting in a total (load plus losses) of 3246 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
AGRICO_6_PL3N5	34608	AGRICO	13.8	20.00	3	Wilson, Herndon		Market
AGRICO_7_UNIT	34608	AGRICO	13.8	43.05	2	Wilson, Herndon		Market
AGRICO_7_UNIT	34608	AGRICO	13.8	7.45	4	Wilson, Herndon		Market

AVENAL_6_AVPARK	34265	AVENAL P	12	0.00	1	Wilson	Energy Only	Market
AVENAL_6_SANDDG	34263	SANDDRAG	12	0.00	1	Wilson	Energy Only	Market
AVENAL_6_SUNCTY	34257	SANCTY D	12	0.00	1	Wilson	Energy Only	Market
BALCHS_7_UNIT 1	34624	BALCH	13.2	33.00	1	Wilson, Herndon	Aug NQC	Market
BALCHS_7_UNIT 2	34612	BLCH	13.8	52.50	1	Wilson, Herndon	Aug NQC	Market
BALCHS_7_UNIT 3	34614	BLCH	13.8	52.50	1	Wilson, Herndon	Aug NQC	Market
BORDEN_2_QF	34253	BORDEN D	12.5	1.27	QF	Wilson	Aug NQC	QF/Selfgen
BULLRD_7_SAGNES	34213	BULLD 12	12.5	0.00	1	Wilson	Aug NQC	QF/Selfgen
CAPMAD_1_UNIT 1	34179	MADERA_G	13.8	17.00	1	Wilson		Market
CHEVCO_6_UNIT 1	34652	CHV.COAL	9.11	4.16	1	Wilson	Aug NQC	QF/Selfgen
CHEVCO_6_UNIT 2	34652	CHV.COAL	9.11	1.40	2	Wilson	Aug NQC	QF/Selfgen
CHWCHL_1_BIOMAS	34305	CHWCHLA2	13.8	4.15	1	Wilson, Herndon	Aug NQC	Market
CHWCHL_1_UNIT	34301	CHOWCOGN	13.8	48.00	1	Wilson, Herndon		Market
COLGA1_6_SHELLW	34654	COLNGAGN	9.11	35.70	1	Wilson	Aug NQC	QF/Selfgen
CRESSY_1_PARKER	34140	CRESSEY	115	1.53		Wilson	Not modeled Aug NQC	MUNI
CRNEVL_6_CRNVA	34634	CRANEVLY	12	0.71	1	Wilson	Aug NQC	Market
CRNEVL_6_SJQN 2	34631	SJ2GEN	9.11	3.20	1	Wilson	Aug NQC	Market
CRNEVL_6_SJQN 3	34633	SJ3GEN	9.11	4.20	1	Wilson	Aug NQC	Market
DINUBA_6_UNIT	34648	DINUBA E	13.8	9.87	1	Wilson, Herndon		Market
ELNIDP_6_BIOMAS	34330	ELNIDO	13.8	2.67	1	Wilson	Aug NQC	Market
EXCHEC_7_UNIT 1	34306	EXCHQUER	13.8	61.77	1	Wilson	Aug NQC	MUNI
FRIANT_6_UNITS	34636	FRIANTDM	6.6	13.18	2	Wilson	Aug NQC	QF/Selfgen
FRIANT_6_UNITS	34636	FRIANTDM	6.6	7.04	3	Wilson	Aug NQC	QF/Selfgen
FRIANT_6_UNITS	34636	FRIANTDM	6.6	1.86	4	Wilson	Aug NQC	QF/Selfgen
GATES_6_PL1X2	34553	WHD_GAT2	13.8	46.00	1	Wilson	NQC List has 0 MW	Market
GWFPWR_1_UNITS	34431	GWF_HEP1	13.8	42.20	1	Wilson, Herndon		Market
GWFPWR_1_UNITS	34433	GWF_HEP2	13.8	42.20	1	Wilson, Herndon		Market
HAASPH_7_PL1X2	34610	HAAS	13.8	68.15	1	Wilson, Herndon	Aug NQC	Market
HAASPH_7_PL1X2	34610	HAAS	13.8	68.15	2	Wilson, Herndon	Aug NQC	Market
HELMPG_7_UNIT 1	34600	HELMS	18	404.00	1	Wilson	Aug NQC	Market
HELMPG_7_UNIT 2	34602	HELMS	18	404.00	2	Wilson	Aug NQC	Market
HELMPG_7_UNIT 3	34604	HELMS	18	404.00	3	Wilson	Aug NQC	Market
HENRTA_6_UNITA1	34539	GWF_GT1	13.8	45.33	1	Wilson, Henrietta		Market
HENRTA_6_UNITA2	34541	GWF_GT2	13.8	45.23	1	Wilson, Henrietta		Market
INTTRB_6_UNIT	34342	INT.TURB	9.11	2.84	1	Wilson	Aug NQC	QF/Selfgen
JRWOOD_1_UNIT 1	34332	JRWCOGEN	9.11	0.00	1	Wilson	Aug NQC	QF/Selfgen
KERKH1_7_UNIT 1	34344	KERCKHOF	6.6	13.00	1	Wilson, Herndon	Aug NQC	Market
KERKH1_7_UNIT 2	34344	KERCKHOF	6.6	8.50	2	Wilson, Herndon	Aug NQC	Market
KERKH1_7_UNIT 3	34344	KERCKHOF	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	25.35	1	Wilson, Herndon	Aug NQC	QF/Selfgen
KINGRV_7_UNIT 1	34616	KINGSRIV	13.8	51.20	1	Wilson, Herndon	Aug NQC	Market
MALAGA_1_PL1X2	34671	KRCDPCT1	13.8	48.00	1	Wilson, Herndon		Market
MALAGA_1_PL1X2	34672	KRCDPCT2	13.8	48.00	1	Wilson, Herndon		Market
MCCALL_1_QF	34219	MCCALL 4	12.5	0.54	QF	Wilson, Herndon	Aug NQC	QF/Selfgen
MCSWAN_6_UNITS	34320	MCSWAIN	9.11	6.53	1	Wilson	Aug NQC	MUNI
MENBIO_6_UNIT	34334	BIO PWR	9.11	20.87	1	Wilson	Aug NQC	QF/Selfgen
MERCFL_6_UNIT	34322	MERCEDFL	9.11	2.74	1	Wilson	Aug NQC	Market
PINFLT_7_UNITS	38720	PINEFLAT	13.8	24.73	1	Wilson, Herndon	Aug NQC	MUNI
PINFLT_7_UNITS	38720	PINEFLAT	13.8	24.73	2	Wilson, Herndon	Aug NQC	MUNI
PINFLT_7_UNITS	38720	PINEFLAT	13.8	24.74	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	45.00	1	Wilson		Market
SCHNDR_1_FIVPTS	34354	SCHINDLR	115	0.00		Wilson	Energy Only	Market
SCHNDR_1_WSTSDE	34354	SCHINDLR	115	0.00		Wilson	Energy Only	Market
SGREGY_6_SANGER	34646	SANGERCO	9.11	28.05	1	Wilson	Aug NQC	QF/Selfgen
STOREY_7_MDRCHW	34209	STOREY D	12.5	1.10	1	Wilson	Aug NQC	QF/Selfgen
STROUD_6_SOLAR	34564	STROUD	70	0.00		Wilson	Energy Only	Market
ULTPFR_1_UNIT 1	34640	ULTR.PWR	9.11	20.72	1	Wilson, Herndon	Aug NQC	QF/Selfgen
WISHON_6_UNITS	34658	WISHON	2.3	4.51	1	Wilson	Aug NQC	Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	2	Wilson	Aug NQC	Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	3	Wilson	Aug NQC	Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	4	Wilson	Aug NQC	Market
WISHON_6_UNITS	34658	WISHON	2.3	0.36	5	Wilson	Aug NQC	Market
WRGHTP_7_AMENGY	24207	WRIGHT D	12.5	0.48	QF	Wilson	Aug NQC	QF/Selfgen
NA	34485	FRESNOWW	12.5	4.00	1	Wilson	No NQC - hist. data	QF/Selfgen
NA	34485	FRESNOWW	12.5	4.00	2	Wilson	No NQC - hist. data	QF/Selfgen
NA	34485	FRESNOWW	12.5	1.00	3	Wilson	No NQC - hist. data	QF/Selfgen
ONLLPP_6_UNIT 1	34316	ONEILPMP	9.11	0.50	1	Wilson	No NQC - hist. data	MUNI
GWFPWR_6_UNIT	34650	GWF-PWR.	9.11	0.00	1	Wilson, Henrietta	Retired	QF/Selfgen
MENBIO_6_RENEW1	34339	CALRENEW	12.5	0.00	1	Wilson	Energy Only	Market
New Unit	34603	JQBSWLT	12.5	0.00	ST	Wilson	Energy Only	Market
New Unit	34673	RPSP1005	0.48	20.00	1	Wilson, Henrietta	No NQC - Pmax	Market
New Unit	34674	RPSP1006	0.48	20.00	1	Wilson, Henrietta	No NQC - Pmax	Market
New Unit	34675	RPSP1007	0.48	20.00	1	Wilson, Henrietta	No NQC - Pmax	Market
New Unit	34696	RPSP1004	21	20.00	1	Wilson, Herndon	No NQC - Pmax	Market

Major new projects modeled:

1. A few new small resources were added.

Critical Contingency Analysis Summary

Henrietta Sub-area

This sub-area has been eliminated since Henrietta 230/70 bank # 2 which was identified as the limiting element in the previous LCR analysis has been taken out of service and is available as spare for the outage of the 230/70 bank # 4.

Herndon Sub-area

The most critical contingency is the loss of Herndon-Barton 115 kV with Kerckhoff 2 PH unit out of service. This contingency could thermally overload the Herndon-Manchester 115 kV line. This limiting contingency established an LCR of 444 MW (includes 42 MW of QF and 83 MW of Muni generation) in 2014 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

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 Fctr (%)
34648	DINUBA E	1	32%
34616	KINGSRIV	1	31%
34671	KRCDPCT1	1	31%
34672	KRCDPCT2	1	31%
34624	BALCH 1	1	31%
34640	ULTR.PWR	1	30%
34646	SANGERCO	1	30%
34618	MCCALL1T	1	30%
34610	HAAS	1	30%
34614	BLCH 2-3	1	30%
34612	BLCH 2-2	1	29%
38720	PINE FLT	3	29%
38720	PINE FLT	2	29%
38720	PINE FLT	1	29%
34696	Q478	1	29%
34642	KINGSBUR	1	28%
34344	KERCKHOF	3	20%
34344	KERCKHOF	2	20%
34344	KERCKHOF	1	20%
34308	KERCKHOF	1	19%
34433	GWF_HEP2	1	15%
34431	GWF_HEP1	1	15%

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) and possibly also the Gates-McCall 230 kV line. This limiting contingency establishes a LCR of 1857 MW in 2014 (includes 174 MW of QF and 144 MW of Muni generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

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 Fctr (%)
34332	JRWCOGEN	1	40%
34330	ELNIDO	1	37%
34209	STOREY D	1	35%
34322	MERCEDFL	1	35%
34320	MCSWAIN	1	34%
34306	EXCHQUER	1	34%
34305	CHWCHLA2	1	32%
34301	CHOWCOGN	1	32%
34253	BORDEN D	1	28%
34658	WISHON	1	28%
34658	WISHON	1	28%
34658	WISHON	1	28%
34658	WISHON	1	28%
34658	WISHON	1	28%
34631	SJ2GEN	1	28%
34633	SJ3GEN	1	27%
34636	FRIANTDM	2	27%
34636	FRIANTDM	3	27%
34636	FRIANTDM	4	27%
34600	HELMS 1	1	27%
34602	HELMS 2	1	27%
34604	HELMS 3	1	27%
34308	KERCKHOF	1	26%
34344	KERCKHOF	1	26%
34344	KERCKHOF	2	26%
34344	KERCKHOF	3	26%
34485	FRESNOWW	1	24%
34648	DINUBA E	1	22%
34179	MADERA_G	1	22%
34616	KINGSRIV	1	22%
34624	BALCH 1	1	21%
34671	KRCDPCT1	1	21%
34672	KRCDPCT2	1	21%
34640	ULTR.PWR	1	21%
34646	SANGERCO	1	21%
34642	KINGSBUR	1	19%
34696	Q478	1	18%
34610	HAAS	1	18%
34610	HAAS	1	18%
34614	BLCH 2-3	1	18%
34612	BLCH 2-2	1	17%
38720	PINE FLT	1	17%
38720	PINE FLT	2	17%
38720	PINE FLT	3	17%
34431	GWF_HEP1	1	17%
34433	GWF_HEP2	1	17%
34334	BIO PWR	1	14%
34673	Q372	1	13%
34674	Q470	1	13%
34675	Q471	1	13%
34608	AGRICO	2	13%

34608	AGRICO	3	13%
34608	AGRICO	4	13%
34539	GWF_GT1	1	13%
34541	GWF_GT2	1	13%
34650	GWF-PWR.	1	13%
34186	DG_PAN1	1	11%
34142	WHD_PAN2	1	11%
34652	CHV.COAL	1	10%
34652	CHV.COAL	2	10%
34553	WHD_GAT2	1	9%
34654	COLNGAGN	1	9%
34342	INT.TURB	1	6%
34316	ONEILPMP	1	6%

Changes compared to last year's results:

From 2013 the load forecast has increased by 133 MW and the LCR needs by 71 MW.

Fresno Area Overall Requirements:

2014	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	174	144	2510	2828

2014	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single) [19]	1857	0	1857
Category C (Multiple) [20]	1857	0	1857

7. Kern Area

<u>Area Definition</u>

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

1) Wheeler Ridge-Lamont 115 kV line
2) Kern PP 230/115 kV Bank # 3
3) Kern PP 230/115 kV Bank # 4
4) Kern PP 230/115 kV Bank # 5

[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 the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

5) Midway 230/115 Bank # 1
6) Midway 230/115 Bank # 2
7) Midway 230/115 Bank #3
8) Temblor – San Luis Obispo 115 kV line

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

1) Wheeler Ridge is out Lamont is in
2) Kern PP 230 kV is out Kern PP 115 kV is in
3) Kern PP 230 kV is out Kern PP 115 kV is in
4) Kern PP 230 kV is out Kern PP 115 kV is in
5) Midway 230 kV is out Midway 115 kV is in
6) Midway 230 kV is out Midway 115 kV is in
7) Midway 230 kV is out Midway 115 kV is in
8) Temblor is in San Luis Obispo is out

2014 total busload within the defined area: 1268 MW with 13 MW of losses resulting in a total (load plus losses) of 1281 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
ALPSLR_1_SPSSLR	35001	RPSP1018	21	44.64	1		Aug NQC	Market
BDGRCK_1_UNITS	35029	BADGERCK	9.11	45.21	1	Kern PP	Aug NQC	QF/Selfgen
BEARMT_1_UNIT	35066	PSE-BEAR	9.11	45.64	1	Kern PP, West Park	Aug NQC	QF/Selfgen
CHALK_1_UNIT	35038	CHLKCLF+	9.11	44.58	1		Aug NQC	QF/Selfgen
CHEVCD_6_UNIT	35052	CHEV.USA	9.11	2.36	1		Aug NQC	QF/Selfgen
CHEVCY_1_UNIT	35032	CHV-CYMR	9.11	6.66	1		Aug NQC	QF/Selfgen
DEXZEL_1_UNIT	35024	DEXEL +	9.11	28.25	1	Kern PP	Aug NQC	QF/Selfgen
DISCOV_1_CHEVRN	35062	DISCOVRY	9.11	1.77	1	Kern PP	Aug NQC	QF/Selfgen
DOUBLC_1_UNITS	35023	DOUBLE C	9.11	47.00	1	Kern PP	Aug NQC	QF/Selfgen
FELLOW_7_QFUNTS	34778	FELLOWS	21	1.33	QF		Aug NQC	QF/Selfgen
FRITO_1_LAY	35048	FRITOLAY	9.11	0.08	1		Aug NQC	QF/Selfgen
KERNFT_1_UNITS	35026	KERNFRNT	9.11	47.00	1	Kern PP	Aug NQC	QF/Selfgen
KERNRG_1_UNITS	35040	KERNRDGE	9.11	0.61	1		Aug NQC	QF/Selfgen
KERNRG_1_UNITS	35040	KERNRDGE	9.11	0.62	2		Aug NQC	QF/Selfgen
KRNOIL_7_TEXEXP				0.00			Energy Only	QF/Selfgen
LIVOAK_1_UNIT 1	35058	PSE-LVOK	9.11	44.40	1	Kern PP	Aug NQC	QF/Selfgen
MIDSET_1_UNIT 1	35044	TX MIDST	9.11	33.14	1		Aug NQC	QF/Selfgen
MIDWAY_1_QF	34215	MIDWY D7	12.5	0.03	QF		Aug NQC	QF/Selfgen
MKTRCK_1_UNIT 1	35060	PSEMCKIT	9.11	40.84	1		Aug NQC	QF/Selfgen
MTNPOS_1_UNIT	35036	MT POSO	9.11	29.68	1	Kern PP	Aug NQC	QF/Selfgen
OILDAL_1_UNIT 1	35028	OILDALE	9.11	39.36	1	Kern PP	Aug NQC	QF/Selfgen
SIERRA_1_UNITS	35027	HISIERRA	9.11	47.00	1	Kern PP	Aug NQC	QF/Selfgen
TANHIL_6_SOLART	35050	SLR-TANN	9.11	10.35	1		Aug NQC	QF/Selfgen
TEMBLR_7_WELLPT	34201	TEMBLORD	12.5	0.38	WP		Aug NQC	QF/Selfgen
TXMCKT_6_UNIT	34783	TEXCO_NM	9.11	1.87	1		Aug NQC	QF/Selfgen
TXMCKT_6_UNIT	34783	TEXCO_NM	9.11	1.87	2		Aug NQC	QF/Selfgen

TXMCKT_6_UNIT				3.74			Not modeled Aug NQC	QF/Selfgen
ULTOGL_1_POSO	35035	ULTR PWR	9.11	34.17	1	Kern PP	Aug NQC	QF/Selfgen
UNVRSY_1_UNIT 1	35037	UNIVRSTY	9.11	34.19	1		Aug NQC	QF/Selfgen
VEDDER_1_SEKERN	35046	SEKR	9.11	11.82	1	Kern PP	Aug NQC	QF/Selfgen
MIDSUN_1_PL1X2	35034	MIDSUN +	9.11	0.00	1		Retired	Market
NA	35056	TX-LOSTH	4.16	8.80	1		No NQC - hist. data	QF/Selfgen
New Unit	35000	RPSP1003	21	0.00	1		Energy Only	Market
New Unit	35012	RPSP1019	21	0.00	1		Energy Only	Market
New Unit	35013	RPSP1020	21	0.00	1		Energy Only	Market
New Unit	35014	RPSP1021	21	20.00	1		No NQC - Pmax	Market

Major new projects modeled:

1. Fixed incorrect rating on Kern PP #4 230/115kV transformer

Critical Contingency Analysis Summary

West Park Sub-area

The most critical contingency is the loss of common mode Kern - West Park # 1 & #2 115 kV lines, resulting in the overload of the 6/42 To Magunden section of Kern – Magunden - Witco 115 kV line. This limitation establishes a LCR of 76 MW (includes 46 MW of QF generation and 30 MW of deficiency) 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 therefore no effectiveness factor is required.

Kern PP Sub-area

The most critical contingency is the outage of Smyrna-Semitropic-Midway 115 kV with Ultra Power Poso unit out of service, which could thermally overload the Midway-Semitropic 115 kV. This limiting contingency establishes a LCR of 435 MW in 2013 (includes 421 MW of effective QF generation as 14 MW deficiency) 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 therefore no effectiveness factor is required.

Changes compared to last year's results:

From 2013 the load forecast has decreased by 30 MW, the Kern #4 230/115 kV bank ratings have been corrected and the effect is that LCR has decreased by 63 MW.

Kern Area Overall Requirements:

2014	QF/Selfgen (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	613	64	677

2014	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single) [21]	421	14	435
Category C (Multiple) [22]	421	41	462

8. LA Basin Area

<u>Area Definition</u>

The transmission tie lines into the LA Basin Area are:

1) San Onofre - San Luis Rey #1, #2, & #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 - Palo Verde 500 kV Line
11) Mirage - Coachelv 230 kV Line
12) Mirage - Ramon 230 kV Line
13) Mirage - Julian Hinds 230 kV Line

[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 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.

These sub-stations 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 Palo Verde is out
11) Mirage is in Coachelv is out
12) Mirage is in Ramon is out
13) Mirage is in Julian Hinds is out

Total 2014 busload within the defined area is 19,560 MW with 113 MW of losses and 21 MW pumps resulting in total load + losses + pumps of 19,694 MW.

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

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
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	62.63	1	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24012	ARCO 2G	13.8	62.63	2	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24013	ARCO 3G	13.8	62.63	3	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24014	ARCO 4G	13.8	62.63	4	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24163	ARCO 5G	13.8	31.32	5	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24164	ARCO 6G	13.8	31.33	6	Western	Aug NQC	QF/Selfgen
BARRE_2_QF	24016	BARRE	230	0.00		Western	Not modeled	QF/Selfgen
BARRE_6_PEAKER	29309	BARPKGEN	13.8	47.00	1	Western		Market
BLAST_1_WIND	24839	BLAST	115	8.16	1	Eastern	Aug NQC	Wind
BRDWAY_7_UNIT 3	29007	BRODWYSC	13.8	65.00	1	Western		MUNI
BUCKWD_1_NPALM1	25634	BUCKWIND	115	2.23		Eastern, Valley-Devers	Not modeled Aug NQC	Wind
BUCKWD_1_QF	25634	BUCKWIND	115	2.75	QF	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
BUCKWD_7_WINTCV	25634	BUCKWIND	115	0.18	W5	Eastern, Valley-Devers	Aug NQC	Wind

CABZON_1_WINDA1	29290	CABAZON	33	13.53	1	Eastern, Valley-Devers	Aug NQC	Wind
CENTER_2_QF	24203	CENTER S	66	18.58		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	Aug NQC	MUNI
CHEVMN_2_UNITS	24022	CHEVGEN1	13.8	0.00	1	Western, El Nido	Aug NQC	QF/Selfgen
CHEVMN_2_UNITS	24023	CHEVGEN2	13.8	0.00	2	Western, El Nido	Aug NQC	QF/Selfgen
CHINO_2_QF	24024	CHINO	66	6.18		None	Not modeled Aug NQC	QF/Selfgen
CHINO_2_SOLAR	24024	CHINO	66	0.00		None	Not modeled	Market
CHINO_6_CIMGEN	24026	CIMGEN	13.8	26.00	D1	None	Aug NQC	QF/Selfgen
CHINO_6_SMPPAP	24140	SIMPSON	13.8	28.71	D1	None	Aug NQC	QF/Selfgen
CHINO_7_MILIKN	24024	CHINO	66	1.47		None	Not modeled Aug NQC	Market
COLTON_6_AGUAM1	25303	CLTNAGUA	13.8	43.00	1	Eastern		MUNI
CORONS_6_CLRWTR	24210	MIRALOMA	66	14.00		Eastern	Not modeled	MUNI
CORONS_6_CLRWTR	24210	MIRALOMA	66	14.00		Eastern	Not modeled	MUNI
DEVERS_1_QF	24815	GARNET	115	2.06	QF	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25632	TERAWND	115	4.01	QF	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25633	CAPWIND	115	0.77	QF	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25635	ALTWIND	115	1.84	Q1	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25635	ALTWIND	115	3.41	Q2	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	0.80	Q1	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	0.37	W1	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25637	TRANWIND	115	9.10	QF	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25639	SEAWIND	115	2.74	QF	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25640	PANAERO	115	2.44	QF	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25645	VENWIND	115	2.09	EU	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25645	VENWIND	115	4.88	Q1	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25645	VENWIND	115	3.29	Q2	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25646	SANWIND	115	1.09	Q1	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DEVERS_1_QF	25646	SANWIND	115	3.66	Q2	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
DMDVLY_1_UNITS	25425	ESRP P2	6.9	2.18		Eastern	Not modeled Aug NQC	QF/Selfgen
DREWS_6_PL1X4	25301	CLTNDREW	13.8	36.00	1	Eastern	Aug NQC	MUNI
DVLCYN_1_UNITS	25603	DVLCYN3G	13.8	67.15	3	Eastern	Aug NQC	MUNI
DVLCYN_1_UNITS	25604	DVLCYN4G	13.8	67.15	4	Eastern	Aug NQC	MUNI
DVLCYN_1_UNITS	25648	DVLCYN1G	13.8	50.35	1	Eastern	Aug NQC	MUNI
DVLCYN_1_UNITS	25649	DVLCYN2G	13.8	50.35	2	Eastern	Aug NQC	MUNI
ELLIS_2_QF	24197	ELLIS	66	0.00		Western, Ellis	Not modeled Aug NQC	QF/Selfgen

ELSEGN_7_UNIT 3	24047	ELSEG3 G	18	335.00	3	Western, El Nido		Market
ELSEGN_7_UNIT 4	24048	ELSEG4 G	18	335.00	4	Western, El Nido		Market
ETIWND_2_FONTNA	24055	ETIWANDA	66	1.08		Eastern	Not modeled Aug NQC	QF/Selfgen
ETIWND_2_QF	24055	ETIWANDA	66	14.97		Eastern	Not modeled Aug NQC	QF/Selfgen
ETIWND_2_SOLAR	24055	ETIWANDA	66	0.00		Eastern	Not modeled Aug NQC	Market
ETIWND_6_GRPLND	29305	ETWPKGEN	13.8	46.00	1	Eastern		Market
ETIWND_6_MWDETI	25422	ETI MWDG	13.8	11.86	1	Eastern	Aug NQC	Market
ETIWND_7_MIDVLY	24055	ETIWANDA	66	1.54		Eastern	Not modeled Aug NQC	QF/Selfgen
ETIWND_7_UNIT 3	24052	MTNVIST3	18	320.00	3	Eastern		Market
ETIWND_7_UNIT 4	24053	MTNVIST4	18	320.00	4	Eastern		Market
GARNET_1_UNITS	24815	GARNET	115	1.10	G1	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
GARNET_1_UNITS	24815	GARNET	115	0.39	G2	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
GARNET_1_UNITS	24815	GARNET	115	0.79	G3	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
GARNET_1_WIND	24815	GARNET	115	0.43	PC	Eastern, Valley-Devers	Aug NQC	Wind
GARNET_1_WINDS	24815	GARNET	115	1.87	W2	Eastern, Valley-Devers	Aug NQC	Wind
GARNET_1_WINDS	24815	GARNET	115	1.88	W3	Eastern, Valley-Devers	Aug NQC	Wind
GLNARM_7_UNIT 1	29005	PASADNA1	13.8	22.30	1	Western		MUNI
GLNARM_7_UNIT 2	29006	PASADNA2	13.8	22.30	1	Western		MUNI
GLNARM_7_UNIT 3	29005	PASADNA1	13.8	44.83		Western	Not modeled	MUNI
GLNARM_7_UNIT 4	29006	PASADNA2	13.8	42.42		Western	Not modeled	MUNI
HARBGN_7_UNITS	24062	HARBOR G	13.8	76.28	1	Western		Market
HARBGN_7_UNITS	24062	HARBOR G	13.8	11.86	HP	Western		Market
HARBGN_7_UNITS	25510	HARBORG4	4.16	11.86	LP	Western		Market
HINSON_6_CARBGN	24020	CARBOGEN	13.8	28.94	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	28.37	D1	Western	Aug NQC	QF/Selfgen
HNTGBH_7_UNIT 1	24066	HUNT1 G	13.8	225.75	1	Western, Ellis		Market
HNTGBH_7_UNIT 2	24067	HUNT2 G	13.8	225.80	2	Western, Ellis		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	0.01		Western, Ellis	Not modeled Aug NQC	QF/Selfgen
LACIEN_2_VENICE	24337	VENICE	13.8	4.74	1	Western, El Nido	Aug NQC	MUNI
LAFRES_6_QF	24073	LA FRESA	66	2.21		Western, El Nido	Not modeled Aug NQC	QF/Selfgen

LAGBEL_6_QF	24075	LAGUBELL	66	10.04		Western	Not modeled Aug NQC	QF/Selfgen
LGHTHP_6_ICEGEN	24070	ICEGEN	13.8	46.95	1	Western	Aug NQC	QF/Selfgen
LGHTHP_6_QF	24083	LITEHIPE	66	1.00		Western	Not modeled Aug NQC	QF/Selfgen
MESAS_2_QF	24209	MESA CAL	66	0.69		Western	Not modeled Aug NQC	QF/Selfgen
MIRLOM_2_CORONA				2.35		Eastern	Not modeled Aug NQC	QF/Selfgen
MIRLOM_2_ONTARO				0.00		Eastern	Energy Only	Market
MIRLOM_2_TEMESC				2.53		Eastern	Not modeled Aug NQC	QF/Selfgen
MIRLOM_6_DELGEN	24030	DELGEN	13.8	33.98	1	Eastern	Aug NQC	QF/Selfgen
MIRLOM_6_PEAKER	29307	MRLPKGEN	13.8	46.00	1	Eastern		Market
MIRLOM_7_MWDLKM	24210	MIRALOMA	66	3.58		Eastern	Not modeled Aug NQC	MUNI
MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	4.66	1	Eastern	Aug NQC	Market
MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	4.67	2	Eastern	Aug NQC	Market
MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	4.67	3	Eastern	Aug NQC	Market
MTWIND_1_UNIT 1	29060	MOUNTWND	115	9.20	S1	Eastern, Valley-Devers	Aug NQC	Wind
MTWIND_1_UNIT 2	29060	MOUNTWND	115	3.64	S2	Eastern, Valley-Devers	Aug NQC	Wind
MTWIND_1_UNIT 3	29060	MOUNTWND	115	3.54	S3	Eastern, Valley-Devers	Aug NQC	Wind
OLINDA_2_COYCRK	24211	OLINDA	66	3.13		Western	Not modeled	QF/Selfgen
OLINDA_2_LNDFL2	24211	OLINDA	66	28.10		Western	Not modeled	Market
OLINDA_2_QF	24211	OLINDA	66	0.17	1	Western	Aug NQC	QF/Selfgen
OLINDA_7_LNDFIL	24211	OLINDA	66	4.50		Western	Not modeled Aug NQC	QF/Selfgen
PADUA_2_ONTARO	24111	PADUA	66	0.88		Eastern	Not modeled Aug NQC	QF/Selfgen
PADUA_6_MWDSDM	24111	PADUA	66	6.48		Eastern	Not modeled Aug NQC	MUNI
PADUA_6_QF	24111	PADUA	66	0.68		Eastern	Not modeled Aug NQC	QF/Selfgen
PADUA_7_SDIMAS	24111	PADUA	66	1.05		Eastern	Not modeled Aug NQC	QF/Selfgen
PWEST_1_UNIT				0.13		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	1.70	Q2	Eastern, Valley-Devers	Aug NQC	QF/Selfgen
RHONDO_2_QF	24213	RIOHONDO	66	2.50		Western	Not modeled Aug NQC	QF/Selfgen
RHONDO_6_PUENTE	24213	RIOHONDO	66	0.00		Western	Not modeled Aug NQC	Market
RVSIDE_2_RERCU3	24299	RERC2G3	13.8	48.50	1	Eastern		MUNI
RVSIDE_2_RERCU4	24300	RERC2G4	13.8	48.50	1	Eastern		MUNI
RVSIDE_6_RERCU1	24242	RERC1G	13.8	48.35	1	Eastern		MUNI
RVSIDE_6_RERCU2	24243	RERC2G	13.8	48.50	1	Eastern		MUNI
RVSIDE_6_SPRING	24244	SPRINGEN	13.8	36.00	1	Eastern		Market
SANTGO_6_COYOTE	24133	SANTIAGO	66	5.94	1	Western, Ellis	Aug NQC	Market
SBERDO_2_PSP3	24921	MNTV-CT1	18	129.71	1	Eastern, West of		Market

						Devers		
SBERDO_2_PSP3	24922	MNTV-CT2	18	129.71	1	Eastern, West of Devers		Market
SBERDO_2_PSP3	24923	MNTV-ST1	18	225.08	1	Eastern, West of Devers		Market
SBERDO_2_PSP4	24924	MNTV-CT3	18	129.71	1	Eastern, West of Devers		Market
SBERDO_2_PSP4	24925	MNTV-CT4	18	129.71	1	Eastern, West of Devers		Market
SBERDO_2_PSP4	24926	MNTV-ST2	18	225.08	1	Eastern, West of Devers		Market
SBERDO_2_QF	24214	SANBRDNO	66	0.12		Eastern, West of Devers	Not modeled Aug NQC	QF/Selfgen
SBERDO_2_REDLND	24214	SANBRDNO	66	0.00		Eastern, West of Devers	Energy Only	Market
SBERDO_2_SNTANA	24214	SANBRDNO	66	0.60		Eastern, West of Devers	Not modeled Aug NQC	QF/Selfgen
SBERDO_6_MILLCK	24214	SANBRDNO	66	1.68		Eastern, West of Devers	Not modeled Aug NQC	QF/Selfgen
SONGS_7_UNIT 2	24129	S.ONOFR2	22	1122.00	2	None		Nuclear
SONGS_7_UNIT 3	24130	S.ONOFR3	22	1124.00	3	None		Nuclear
TIFFNY_1_DILLON				6.23		Western	Not modeled Aug NQC	Wind
VALLEY_5_PERRIS	24160	VALLEYSC	115	7.94		Eastern, Valley, Valley-Devers	Not modeled Aug NQC	QF/Selfgen
VALLEY_5_REDMTN	24160	VALLEYSC	115	2.66		Eastern, Valley, Valley-Devers	Not modeled Aug NQC	QF/Selfgen
VALLEY_7_BADLND	24160	VALLEYSC	115	0.83		Eastern, Valley, Valley-Devers	Not modeled Aug NQC	Market
VALLEY_7_UNITA1	24160	VALLEYSC	115	1.88		Eastern, Valley, Valley-Devers	Not modeled Aug NQC	Market
VERNON_6_GONZL1				5.75		Western	Not modeled	MUNI
VERNON_6_GONZL2				5.75		Western	Not modeled	MUNI
VERNON_6_MALBRG	24239	MALBRG1G	13.8	42.37	C1	Western		MUNI
VERNON_6_MALBRG	24240	MALBRG2G	13.8	42.37	C2	Western		MUNI
VERNON_6_MALBRG	24241	MALBRG3G	13.8	49.26	S3	Western		MUNI
VILLPK_2_VALLYV	24216	VILLA PK	66	4.10		Western	Not modeled Aug NQC	QF/Selfgen
VILLPK_6_MWDYOR	24216	VILLA PK	66	0.00		Western	Not modeled Aug NQC	MUNI
VISTA_2_RIALTO	24901	VSTA	230	0.00		Eastern	Energy Only	Market
VISTA_6_QF	24902	VSTA	66	0.17	1	Eastern	Aug NQC	QF/Selfgen
WALNUT_6_HILLGEN	24063	HILLGEN	13.8	47.60	1	Western	Aug NQC	QF/Selfgen
WALNUT_7_WCOVCT	24157	WALNUT	66	3.33		Western	Not modeled Aug NQC	Market
WALNUT_7_WCOVST	24157	WALNUT	66	3.65		Western	Not modeled Aug NQC	Market
WHTWTR_1_WINDA1	29061	WHITEWTR	33	11.11	1	Eastern, Valley-Devers	Aug NQC	Wind
ARCOGN_2_UNITS	24018	BRIGEN	13.8	0.00	1	Western	No NQC - hist. data	Market
HINSON_6_QF	24064	HINSON	66	0.00	1	Western	No NQC - hist. data	QF/Selfgen
INLAND_6_UNIT	24071	INLAND	13.8	30.30	1	Eastern	No NQC - hist. data	QF/Selfgen
MOBGEN_6_UNIT 1	24094	MOBGEN	13.8	20.20	1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24063	HILLGEN	13.8	0.00	D1	Western	No NQC - hist. data	QF/Selfgen
NA	24324	SANIGEN	13.8	6.80	D1	Eastern	No NQC - hist. data	QF/Selfgen
NA	24325	ORCOGEN	13.8	0.00	1	Western, Ellis	No NQC - hist. data	QF/Selfgen
NA	24327	THUMSGEN	13.8	40.00	1	Western	No NQC - hist. data	QF/Selfgen
NA	24328	CARBGEN2	13.8	15.2	1	Western	No NQC - hist. data	Market

NA	24329	MOBGEN2	13.8	20.2	1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24330	OUTFALL1	13.8	0.00	1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24331	OUTFALL2	13.8	0.00	1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24332	PALOGEN	13.8	3.60	D1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24341	COYGEN	13.8	0.00	1	Western, Ellis	No NQC - hist. data	QF/Selfgen
NA	24342	FEDGEN	13.8	0.00	1	Western	No NQC - hist. data	QF/Selfgen
NA	29021	WINTEC6	115	45.00	1	Eastern, Valley-Devers	No NQC - hist. data	Wind
NA	29023	WINTEC4	12	16.50	1	Eastern, Valley-Devers	No NQC - hist. data	Wind
NA	29060	SEAWEST	115	44.40	S1	Eastern	No NQC - hist. data	Wind
NA	29060	SEAWEST	115	22.20	S2	Eastern	No NQC - hist. data	Wind
NA	29060	SEAWEST	115	22.40	S3	Eastern	No NQC - hist. data	Wind
NA	29260	ALTAMSA4	115	40.00	1	Eastern, Valley-Devers	No NQC - hist. data	Wind
NA	29338	CLRWTRCT	13.8	0.00	G1	Eastern	No NQC - hist. data	QF/Selfgen
NA	29339	DELGEN	13.8	0.00	1	Eastern	No NQC - hist. data	QF/Selfgen
NA	29340	CLRWTRST	13.8	0.00	S1	Eastern	No NQC - hist. data	QF/Selfgen
NA	29951	REFUSE	13.8	9.90	D1	Western	No NQC - Pmax	QF/Selfgen
NA	29953	SIGGEN	13.8	24.90	D1	Western	No NQC - Pmax	QF/Selfgen
HNTGBH_7_UNIT 3	24167	HUNT3 G	13.8	0.00	3	Western, Ellis	Retired	Market
HNTGBH_7_UNIT 4	24168	HUNT4 G	13.8	0.00	4	Western, Ellis	Retired	Market
New unit	28174	RPS11031	13.8	37	EQ	Eastern, Valley-Devers	No NQC - Pmax	Market
New unit	29101	RPS10501	13.8	107	1	Eastern, Valley-Devers	No NQC - Pmax	Market
New unit	29102	RPS10500	13.8	107	1	Eastern, Valley-Devers	No NQC - Pmax	Market
New unit	29103	RPS10499	13.8	107	1	Eastern, Valley-Devers	No NQC - Pmax	Market
New unit	29104	RPS10498	13.8	107	1	Eastern, Valley-Devers	No NQC - Pmax	Market
New unit	29105	RPS10497	13.8	107	1	Eastern, Valley-Devers	No NQC - Pmax	Market
New unit	29106	RPS10496	13.8	107	1	Eastern, Valley-Devers	No NQC - Pmax	Market
New unit	29107	RPS10495	13.8	107	1	Eastern, Valley-Devers	No NQC - Pmax	Market
New unit	29108	RPS10494	13.8	107	1	Eastern, Valley-Devers	No NQC - Pmax	Market
New unit	29201	EME WCG1	13.8	100	1	Western	No NQC - Pmax	Market
New unit	29202	EME WCG2	13.8	100	1	Western	No NQC - Pmax	Market
New unit	29203	EME WCG3	13.8	100	1	Western	No NQC - Pmax	Market
New unit	29204	EME WCG4	13.8	100	1	Western	No NQC - Pmax	Market
New unit	29205	EME WCG5	13.8	100	1	Western	No NQC - Pmax	Market
New unit	29901	ELSEG8ST	18	77	8	Western, El Nido	No NQC - Pmax	Market
New unit	29902	ELSEG7GT	18	205	7	Western, El Nido	No NQC - Pmax	Market
New unit	29903	ELSEG6ST	18	77	6	Western, El Nido	No NQC - Pmax	Market
New unit	29904	ELSEG5ST	18	205	5	Western, El Nido	No NQC - Pmax	Market

Major new projects modeled:

1. Barre – Ellis 230 kV lines split to create four 230 kV lines between Barre and Ellis
2. Vincent-Mira Loma 500 kV (part of TRPT)

Critical Contingency Analysis Summary

Ellis sub-area

No requirements due to Barre-Ellis 230 kV split project, as well as the use of Ellis SPS for N-1 followed by N2 conditions.

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 514 MW in 2014 (includes 46 MW of QF and 5 MW of MUNI generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Western Sub-Area – 2 SONGS:

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 230 kV line. This limiting contingency establishes a LCR of 3825 MW (includes 604 MW of QF, 6 MW of Wind and 583 MW of Muni generation) in 2014 as the generation capacity necessary for reliable load serving capability within this sub-area.

Western Sub-Area – 1 SONGS (70%):

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 230 kV line. This limiting contingency establishes a LCR of 4005 MW (includes 604 MW of QF, 6 MW of Wind and 583 MW of Muni generation) in 2014 as the generation capacity necessary for reliable load serving capability within this sub-area.

Western Sub-Area – 0 SONGS:

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 230 kV line. This limiting contingency establishes a LCR of 4175 MW (includes 604 MW of QF, 6 MW of Wind and 583 MW of Muni generation) in 2014 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	31
25203	ANAHEIMG	1	30
25211	CanyonGT 1	1	29
25212	CanyonGT 2	2	29
25213	CanyonGT 3	3	29
25214	CanyonGT 4	4	29
24005	ALAMT5 G	5	23
24161	ALAMT6 G	6	23
24001	ALAMT1 G	1	22
24002	ALAMT2 G	2	22
24003	ALAMT3 G	3	22
24004	ALAMT4 G	4	22
24162	ALAMT7 G	R7	22
24066	HUNT1 G	1	22
24067	HUNT2 G	2	22
24167	HUNT3 G	3	22
24168	HUNT4 G	4	22
24325	ORCOGEN	1	21
24133	SANTIAGO	1	16
24341	COYGEN	1	16
24011	ARCO 1G	1	15
24012	ARCO 2G	2	15
24013	ARCO 3G	3	15
24014	ARCO 4G	4	15
24018	BRIGEN	1	15
24020	CARBGEN1	1	15
24064	HINSON	1	15
24070	ICEGEN	D1	15
24170	LBEACH12	2	15

24171	LBEACH34	3	15
24062	HARBOR G	1	15
25510	HARBORG4	LP	15
24062	HARBOR G	HP	15
24139	SERRFGEN	D1	15
24170	LBEACH12	1	15
24171	LBEACH34	4	15
24173	LBEACH5G	R5	15
24174	LBEACH6G	R6	15
24327	THUMSGEN	1	15
24328	CARBGEN2	1	15
24079	LBEACH7G	R7	15
24080	LBEACH8G	R8	15
24081	LBEACH9G	R9	15
24163	ARCO 5G	5	14
24164	ARCO 6G	6	14
24022	CHEVGEN1	1	14
24023	CHEVGEN2	2	14
24048	ELSEG4 G	4	14
24094	MOBGEN1	1	14
29308	CTRPKGEN	1	14
24329	MOBGEN2	1	14
24330	OUTFALL1	1	14
24331	OUTFALL2	1	14
24332	PALOGEN	D1	14
24333	REDON1 G	R1	14
24334	REDON2 G	R2	14
24335	REDON3 G	R3	14
24336	REDON4 G	R4	14
24337	VENICE	1	14
29953	SIGGEN	D1	14
29901	NRG ELG5	5	14
29903	NRG ELG6	6	14
29902	NRG ELS7	7	14
24047	ELSEG3 G	3	13
24121	REDON5 G	5	13
24122	REDON6 G	6	13
24123	REDON7 G	7	13
24124	REDON8 G	8	13
29951	REFUSE	D1	12
24342	FEDGEN	1	12
24241	MALBRG3G	S3	11
24240	MALBRG2G	C2	11

24239	MALBRG1G	C1	11
29005	PASADNA1	1	9
29006	PASADNA2	1	9
29007	BRODWYSC	1	9
24063	HILLGEN	D1	6
29201	EME WCG1	1	5
29203	EME WCG3	1	5
29204	EME WCG4	1	5
29205	EME WCG5	1	5
29202	EME WCG2	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 could be the loss of San Bernardino – Etiwanda 230 kV and San Bernardino – Vista 230 kV lines, which would result in voltage collapse. This limiting contingency establishes a local capacity need of 485 MW (includes 2 MW of QF generation) in 2014 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Valley-Devers Sub-Area – 2 SONGS:

The most critical contingency for the Valley-Devers sub-area is the loss of Palo Verde – Devers 500 kV line and Alberhill – Serrano 500 kV line or vice versa, which would result in overload on Camino – Iron Mountain 230 kV line. This limiting contingency establishes a LCR of 1726 MW (includes 60 MW of QF and 149 MW of wind generation) in 2014 as the generation capacity necessary for reliable load serving capability within this sub-area.

Valley-Devers Sub-Area – 1 SONGS (70%):

The most critical contingency for the Valley-Devers sub-area is the loss of Palo Verde –

Devers 500 kV line and Alberhill – Serrano 500 kV line or vice versa, which would result in overload on Camino – Iron Mountain 230 kV line. This limiting contingency establishes a LCR of 1817 MW (includes 60 MW of QF and 149 MW of wind generation) in 2014 as the generation capacity necessary for reliable load serving capability within this sub-area.

Valley-Devers Sub-Area – 0 SONGS:

The most critical contingency for the Valley-Devers sub-area is the loss of Palo Verde – Devers 500 kV line and Alberhill – Serrano 500 kV line or vice versa, which would result in overload on Camino – Iron Mountain 230 kV line. This limiting contingency establishes a LCR of 1889 MW (includes 60 MW of QF and 149 MW of wind generation) in 2014 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 enough 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 enough to meet this sub-area requirement as well.

LA Basin Overall – 2 SONGS:

The most critical contingency for LA Basin is the loss of SONGS #3 unit followed by Palo Verde-Devers 500 kV line, which could exceed the approved 6400 MW rating for the South of Lugo path. This limiting contingency establishes a LCR of 10,466 MW in 2014 (includes 825 MW of QF, 253 MW of wind, 1164 MW of MUNI and 2246 MW of Nuclear generation) as the minimum generation capacity necessary for reliable load serving capability within this area.

LA Basin Overall – 1 SONGS (70%):

The most critical contingency for LA Basin is the loss of SONGS #2 unit followed by Palo Verde-Devers 500 kV line, which could exceed the approved 6400 MW rating for the South of Lugo path. This limiting contingency establishes a LCR of 10,342 MW in 2014 (includes 825 MW of QF, 253 MW of wind, 1164 MW of MUNI and 785 MW of Nuclear generation) as the minimum generation capacity necessary for reliable load serving capability within this area.

LA Basin Overall – 0 SONGS:

The most limiting contingency for San Diego sub-area is the loss of Ocotillo -Suncrest 500 kV line followed by the loss of ECO-Miguel 500 kV line. The limiting constraint is reactive margin. This contingency establishes a LCR of 10,430 MW in 2014 (includes 825 MW of QF, 253 MW of wind, 1164 MW of MUNI and 0 MW of Nuclear generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency for LA Basin is the loss of Redondo #7 unit followed by Palo Verde-Devers 500 kV line, which could exceed the approved 6400 MW rating for the South of Lugo path. This limiting contingency establishes a LCR of 10,063 MW in 2014 (includes 825 MW of QF, 253 MW of wind, 1164 MW of MUNI and 0 MW of Nuclear generation).

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	MW Eff Fctr (%)
24052	MTNVIST3	3	34
24053	MTNVIST4	4	34
24071	INLAND	1	32
25422	ETI MWDG	1	32
29305	ETWPKGEN	1	32

24921	MNTV-CT1	1	28
24922	MNTV-CT2	1	28
24923	MNTV-ST1	1	28
24924	MNTV-CT3	1	28
24925	MNTV-CT4	1	28
24926	MNTV-ST2	1	28
29041	IEEC-G1	1	28
29042	IEEC-G2	2	28
24905	RVCANAL1	R1	27
24906	RVCANAL2	R2	27
24907	RVCANAL3	R3	27
24908	RVCANAL4	R4	27
29190	WINTECX2	1	27
29191	WINTECX1	1	27
29180	WINTEC8	1	27
24815	GARNET	QF	27
24815	GARNET	W3	27
29023	WINTEC4	1	27
29021	WINTEC6	1	27
24242	RERC1G	1	27
24243	RERC2G	1	27
24244	SPRINGEN	1	27
25301	CLTNDREW	1	27
25302	CLTNCTRY	1	27
25303	CLTNAGUA	1	27
24299	RERC2G3	1	27
24300	RERC2G4	1	27
24839	BLAST	1	27
25648	DVLCYN1G	1	26
25649	DVLCYN2G	2	26
25603	DVLCYN3G	3	26
25604	DVLCYN4G	4	26
25632	TERAWND	QF	26
25634	BUCKWND	QF	26
25635	ALTWIND	Q1	26
25635	ALTWIND	Q2	26
25637	TRANWND	QF	26
25639	SEAWIND	QF	26
25640	PANAERO	QF	26
25645	VENWIND	EU	26
25645	VENWIND	Q2	26
25645	VENWIND	Q1	26
25646	SANWIND	Q2	26

29060	MOUNTWND	S1	26
29060	MOUNTWND	S3	26
29060	MOUNTWND	S2	26
29061	WHITEWTR	1	26
29260	ALTAMSA4	1	26
29290	CABAZON	1	26
25633	CAPWIND	QF	25
25657	MJVSPHN1	1	25
25658	MJVSPHN2	2	25
25659	MJVSPHN3	3	25
25203	ANAHEIMG	1	23
25211	CanyonGT 1	1	22
25212	CanyonGT 2	2	22
25213	CanyonGT 3	3	22
25214	CanyonGT 4	4	22
24030	DELGEN	1	21
29309	BARPKGEN	1	21
24026	CIMGEN	D1	21
24140	SIMPSON	D1	21
29307	MRLPKGEN	1	20
29338	CLEARGEN	1	20
29339	DELGEN	1	20
24005	ALAMT5 G	5	19
24066	HUNT1 G	1	19
24067	HUNT2 G	2	19
24167	HUNT3 G	3	19
24168	HUNT4 G	4	19
24129	S.ONOFR2	2	19
24130	S.ONOFR3	3	19
24133	SANTIAGO	1	19
24325	ORCOGEN	1	19
24341	COYGEN	1	19
24001	ALAMT1 G	1	18
24002	ALAMT2 G	2	18
24003	ALAMT3 G	3	18
24004	ALAMT4 G	4	18
24161	ALAMT6 G	6	18
24162	ALAMT7 G	R7	17
24063	HILLGEN	D1	17
29201	EME WCG1	1	17
29203	EME WCG3	1	17
29204	EME WCG4	1	17
29205	EME WCG5	1	17

29202	EME WCG2	1	17
24018	BRIGEN	1	16
29308	CTRPKGEN	1	16
29953	SIGGEN	D1	16
24011	ARCO 1G	1	15
24012	ARCO 2G	2	15
24013	ARCO 3G	3	15
24014	ARCO 4G	4	15
24163	ARCO 5G	5	15
24164	ARCO 6G	6	15
24020	CARBGEN1	1	15
24022	CHEVGEN1	1	15
24023	CHEVGEN2	2	15
24064	HINSON	1	15
24070	ICEGEN	D1	15
24170	LBEACH12	2	15
24171	LBEACH34	3	15
24094	MOBGEN1	1	15
24062	HARBOR G	1	15
25510	HARBORG4	LP	15
24062	HARBOR G	HP	15
24139	SERRFGEN	D1	15
24170	LBEACH12	1	15
24171	LBEACH34	4	15
24173	LBEACH5G	R5	15
24174	LBEACH6G	R6	15
24327	THUMSGEN	1	15
24328	CARBGEN2	1	15
24330	OUTFALL1	1	15
24331	OUTFALL2	1	15
24332	PALOGEN	D1	15
24333	REDON1 G	R1	15
24334	REDON2 G	R2	15
24335	REDON3 G	R3	15
24336	REDON4 G	R4	15
24337	VENICE	1	15
24079	LBEACH7G	R7	15
24080	LBEACH8G	R8	15
24081	LBEACH9G	R9	15
24047	ELSEG3 G	3	14
24048	ELSEG4 G	4	14
24121	REDON5 G	5	14
24122	REDON6 G	6	14

24123	REDON7 G	7	14
24124	REDON8 G	8	14
24329	MOBGEN2	1	14
29901	NRG ELG5	5	14
29903	NRG ELG6	6	14
29902	NRG ELS7	7	14
29951	REFUSE	D1	13
29209	BLY1ST1	1	13
29207	BLY1CT1	1	13
29208	BLY1CT2	1	13
24342	FEDGEN	1	13
24241	MALBRG3G	S3	12
24240	MALBRG2G	C2	12
24239	MALBRG1G	C1	12
29005	PASADNA1	1	10
29006	PASADNA2	1	10
29007	BRODWYSC	1	10

Changes compared to last year's results:

Compared with 2017 the load forecast went up by 234 MW resulting in 171 MW increase in LCR needs for the 2 SONGS case.

At this time the ISO considers that the most likely scenario for 2014 is no SONGS scenario therefore overall LCR needs in the main tables reflects this outcome. The ISO will continue to monitor the situation and may change this assumption before the 2014 LCR allocations are released to LSEs (Load Serving Entities).

LA Basin Overall Requirements:

2014	QF (MW)	Wind (MW)	Muni (MW)	Nuclear (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	825	253	1164	0	9547	11789

2014	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[23]	10,063	0	10,063
Category C (Multiple)[24]	10,430	0	10,430

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

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) Eagle Rock-Pardee #1 230 kV Line
5) Vincent-Pardee 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) Eagle Rock is out Pardee is in
5) Vincent is out Pardee is in
6) Vincent is out Santa Clara is in

Total 2014 busload within the defined area is 4189 MW with 64 MW of losses and 327 MW of pumps resulting in total load + losses + pumps of 4580 MW.

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

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ALAMO_6_UNIT	25653	ALAMO SC	13.8	16.00	1	Big Creek	Aug NQC	Market
BIGCRK_2_EXESWD	24306	B CRK1-1	7.2	19.38	1	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24306	B CRK1-1	7.2	21.03	2	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24307	B CRK1-2	13.8	21.03	3	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24307	B CRK1-2	13.8	30.39	4	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24308	B CRK2-1	13.8	49.48	1	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24308	B CRK2-1	13.8	50.64	2	Big Creek, Rector, Vestal	Aug NQC	Market

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

BIGCRK_2_EXESWD	24309	B CRK2-2	7.2	18.22	3	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24309	B CRK2-2	7.2	19.19	4	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24310	B CRK2-3	7.2	16.55	5	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24310	B CRK2-3	7.2	18.02	6	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24311	B CRK3-1	13.8	34.09	1	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24311	B CRK3-1	13.8	34.09	2	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24312	B CRK3-2	13.8	34.09	3	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24312	B CRK3-2	13.8	39.93	4	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24313	B CRK3-3	13.8	37.99	5	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24314	B CRK 4	11.5	49.09	41	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24314	B CRK 4	11.5	49.28	42	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24315	B CRK 8	13.8	23.76	81	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24315	B CRK 8	13.8	42.85	82	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24317	MAMOTH1G	13.8	91.07	1	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24318	MAMOTH2G	13.8	91.07	2	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24323	PORTAL	4.8	9.35	1	Big Creek, Rector, Vestal	Aug NQC	Market
EASTWD_7_UNIT	24319	EASTWOOD	13.8	199.00	1	Big Creek, Rector, Vestal		Market
EDMONS_2_NSPIN	25605	EDMON1AP	14.4	22.15	1	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25606	EDMON2AP	14.4	22.15	2	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25607	EDMON3AP	14.4	22.15	3	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25607	EDMON3AP	14.4	22.15	4	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25608	EDMON4AP	14.4	22.15	5	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25608	EDMON4AP	14.4	22.15	6	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25609	EDMON5AP	14.4	22.15	7	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25609	EDMON5AP	14.4	22.15	8	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25610	EDMON6AP	14.4	22.15	9	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25610	EDMON6AP	14.4	22.15	10	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25611	EDMON7AP	14.4	22.14	11	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25611	EDMON7AP	14.4	22.14	12	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25612	EDMON8AP	14.4	22.14	13	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25612	EDMON8AP	14.4	22.14	14	Big Creek	Pumps	MUNI
GOLETA_2_QF	24057	GOLETA	66	0.11		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	QF/Selfgen
GOLETA_6_ELLWOD	28004	ELLWOOD	13.8	54.00	1	Ventura, S.Clara, Moorpark		Market
GOLETA_6_EXGEN	24057	GOLETA	66	1.45		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	QF/Selfgen
GOLETA_6_GAVOTA	24057	GOLETA	66	1.25		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	QF/Selfgen

GOLETA_6_TAJIGS	24057	GOLETA	66	2.93		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	Market
KERRGN_1_UNIT 1	24437	KERNRVR	66	13.67	1	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	28051	PSTRIAG1	18	157.90	G1	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	28052	PSTRIAG2	18	157.90	G2	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	28053	PSTRIAS1	18	162.40	S1	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	28054	PSTRIAG3	18	157.90	G3	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	28055	PSTRIAS2	18	78.90	S2	Big Creek	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, Moorpark		Market
MNDALY_7_UNIT 2	24090	MANDLY2G	13.8	215.29	2	Ventura, Moorpark		Market
MNDALY_7_UNIT 3	24222	MANDLY3G	16	130.00	3	Ventura, S.Clara, Moorpark		Market
MOORPK_2_CALABS	24099	MOORPARK	230	6.96		Ventura, Moorpark	Not modeled	Market
MOORPK_6_QF	24098	MOORPARK	66	26.39		Ventura, Moorpark	Not modeled Aug NQC	QF/Selfgen
MOORPK_7_UNITA1	24098	MOORPARK	66	1.65		Ventura, Moorpark	Not modeled Aug NQC	QF/Selfgen
NEENCH_6_SOLAR	24420	NEENACH	66	58.92		Big Creek	Not modeled Aug NQC	Market
OMAR_2_UNIT 1	24102	OMAR 1G	13.8	77.25	1	Big Creek		QF/Selfgen
OMAR_2_UNIT 2	24103	OMAR 2G	13.8	77.25	2	Big Creek		QF/Selfgen
OMAR_2_UNIT 3	24104	OMAR 3G	13.8	77.25	3	Big Creek		QF/Selfgen
OMAR_2_UNIT 4	24105	OMAR 4G	13.8	77.25	4	Big Creek		QF/Selfgen
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	2.13	1	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25614	OSO A P	13.2	2.13	2	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25614	OSO A P	13.2	2.13	3	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25614	OSO A P	13.2	2.13	4	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	2.13	5	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	2.13	6	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	2.13	7	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	2.13	8	Big Creek	Pumps	MUNI
PANDOL_6_UNIT	24113	PANDOL	13.8	25.70	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
PANDOL_6_UNIT	24113	PANDOL	13.8	20.94	2	Big Creek, Vestal	Aug NQC	QF/Selfgen
RECTOR_2_KAWEAH	24212	RECTOR	66	1.91		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
RECTOR_2_KAWH 1	24212	RECTOR	66	1.04		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
RECTOR_2_QF	24212	RECTOR	66	9.72		Big Creek, Rector, Vestal	Not modeled Aug NQC	QF/Selfgen
RECTOR_7_TULARE	24212	RECTOR	66	0.49		Big Creek, Rector, Vestal	Not modeled	QF/Selfgen
SAUGUS_2_TOLAND	24135	SAUGUS	66	0.00		Big Creek	Not modeled Aug NQC	Market
SAUGUS_6_MWDFTH	24135	SAUGUS	66	8.13		Big Creek	Not modeled Aug NQC	MUNI
SAUGUS_6_PTCHGN	24118	PITCHGEN	13.8	19.01	1	Big Creek	Aug NQC	MUNI
SAUGUS_6_QF	24135	SAUGUS	66	0.88		Big Creek	Not modeled Aug NQC	QF/Selfgen

SAUGUS_7_CHIQCN	24135	SAUGUS	66	2.21		Big Creek	Not modeled Aug NQC	Market
SAUGUS_7_LOPEZ	24135	SAUGUS	66	5.21		Big Creek	Not modeled Aug NQC	QF/Selfgen
SNCLRA_6_OXGEN	24110	OXGEN	13.8	34.62	1	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SNCLRA_6_PROCGN	24119	PROCGEN	13.8	47.11	1	Ventura, S.Clara, Moorpark	Aug NQC	Market
SNCLRA_6_QF	24127	S.CLARA	66	0.52	1	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SNCLRA_6_WILLMT	24159	WILLAMET	13.8	12.56	1	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SPRGVL_2_QF	24215	SPRINGVL	66	0.17		Big Creek, Rector, Vestal	Not modeled Aug NQC	QF/Selfgen
SPRGVL_2_TULE	24215	SPRINGVL	66	0.93		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
SPRGVL_2_TULESC	24215	SPRINGVL	66	0.20		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
SYCAMR_2_UNITS	24143	SYCCYN1G	13.8	56.54	1	Big Creek	Aug NQC	QF/Selfgen
SYCAMR_2_UNITS	24144	SYCCYN2G	13.8	56.53	2	Big Creek	Aug NQC	QF/Selfgen
SYCAMR_2_UNITS	24145	SYCCYN3G	13.8	56.53	3	Big Creek	Aug NQC	QF/Selfgen
SYCAMR_2_UNITS	24146	SYCCYN4G	13.8	56.53	4	Big Creek	Aug NQC	QF/Selfgen
TENGEN_2_PL1X2	24148	TENNGEN1	13.8	18.18	1	Big Creek	Aug NQC	Market
TENGEN_2_PL1X2	24149	TENNGEN2	13.8	18.19	2	Big Creek	Aug NQC	Market
VESTAL_2_KERN	24152	VESTAL	66	16.63	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
VESTAL_2_WELLHD	24152	VESTAL	66	49.00		Big Creek, Vestal	Not modeled	Market
VESTAL_6_QF	24152	VESTAL	66	7.51		Big Creek, Vestal	Not modeled Aug NQC	QF/Selfgen
VESTAL_6_ULTRGN	24150	ULTRAGEN	13.8	34.75	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
VESTAL_6_WDFIRE	28008	LAKEGEN	13.8	7.00	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
WARNE_2_UNIT	25651	WARNE1	13.8	38.00	1	Big Creek	Aug NQC	Market
WARNE_2_UNIT	25652	WARNE2	13.8	38.00	1	Big Creek	Aug NQC	Market
APPGEN_6_UNIT 1	24009	APPGEN1G	13.8	0.00	1	Big Creek	No NQC - hist. data	Market
APPGEN_6_UNIT 1	24010	APPGEN2G	13.8	0.00	2	Big Creek	No NQC - hist. data	Market
NA	24326	Exgen1	13.8	0.00	S1	Ventura, S.Clara, Moorpark	No NQC - hist. data	QF/Selfgen
NA	24340	CHARMIN	13.8	15.20	1	Ventura, S.Clara, Moorpark	No NQC - hist. data	QF/Selfgen
NA	24362	Exgen2	13.8	0.00	G1	Ventura, S.Clara, Moorpark	No NQC - hist. data	QF/Selfgen
NA	24370	Kawgen	13.8	0.00	1	Big Creek, Rector, Vestal	No NQC - hist. data	Market
NA	24372	KR 3-1	13.8	0.00	1	Big Creek, Vestal	No NQC - hist. data	QF/Selfgen
NA	24373	KR 3-2	13.8	0.00	1	Big Creek, Vestal	No NQC - hist. data	QF/Selfgen
NA	24422	PALMDALE	66	0.00	1	Big Creek	No NQC - hist. data	Market

Major new projects modeled:

1. Segments of TRTP project
2. East Kern wind resource area project (Antelope system split)
3. New Rector-Springville 230 kV line

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 453 MW (includes 10 MW of QF generation) in 2014 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
24370	KAWGEN	1	45
24319	EASTWOOD	1	41
24306	B CRK1-1	1	41
24306	B CRK1-1	2	41
24307	B CRK1-2	3	41
24307	B CRK1-2	4	41
24323	PORTAL	1	41
24308	B CRK2-1	1	40
24308	B CRK2-1	2	40
24309	B CRK2-2	3	40
24309	B CRK2-2	4	40
24315	B CRK 8	81	40
24315	B CRK 8	82	40
24310	B CRK2-3	5	39
24310	B CRK2-3	6	39
24311	B CRK3-1	1	39
24311	B CRK3-1	2	39
24312	B CRK3-2	3	39
24312	B CRK3-2	4	39
24313	B CRK3-3	5	39
24317	MAMOTH1G	1	39
24318	MAMOTH2G	2	39
24314	B CRK 4	41	38
24314	B CRK 4	42	38

Vestal Sub-area

The most critical contingency 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 631 MW in 2014 (includes 123 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
28008	LAKEGEN	1	46
24113	PANDOL	1	45
24113	PANDOL	2	45
24150	ULTRAGEN	1	45
24372	KR 3-1	1	45
24373	KR 3-2	2	45
24152	VESTAL	1	45
24370	KAWGEN	1	45
24319	EASTWOOD	1	24
24306	B CRK1-1	1	24
24306	B CRK1-1	2	24
24307	B CRK1-2	3	24
24307	B CRK1-2	4	24
24308	B CRK2-1	1	24
24308	B CRK2-1	2	24
24309	B CRK2-2	3	24
24309	B CRK2-2	4	24
24310	B CRK2-3	5	24
24310	B CRK2-3	6	24
24315	B CRK 8	81	24
24315	B CRK 8	82	24
24323	PORTAL	1	24
24311	B CRK3-1	1	23
24311	B CRK3-1	2	23
24312	B CRK3-2	3	23
24312	B CRK3-2	4	23
24313	B CRK3-3	5	23
24317	MAMOTH1G	1	23
24318	MAMOTH2G	2	23
24314	B CRK 4	41	22
24314	B CRK 4	42	22

S. Clara sub-areas

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 304 MW in 2014 (which includes 66 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-areas

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 519 MW in 2014 (which includes 94 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 2250 MW in 2014 (includes 758 MW of QF and 354 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 Sylmar-Pardee #1 (or # 2) line followed by Ormond Beach Unit #2, which could thermally overload the remaining Sylmar-Pardee 230 kV line. This limiting contingency establishes a LCR of 2156 MW in 2014 (includes 758 MW of QF and 354 MW of MUNI generation).

Effectiveness factors:

The following table has units that have at least 5% effectiveness to any one of the

Sylmar-Pardee 230 kV lines after the loss of the Lugo-Victorville 500 kV followed by one of the other Sylmar-Pardee 230 kV line in this area:

Gen Bus	Gen Name	Gen ID	MW Eff Fctr
24118	PITCHGEN	D1	35
24148	TENNGEN1	D1	35
24149	TENNGEN2	D2	35
24009	APPGEN1G	1	34
24010	APPGEN2G	2	34
24107	ORMOND1G	1	34
24108	ORMOND2G	2	34
24361	APPGEN3G	3	34
25651	WARNE1	1	33
25652	WARNE2	1	33
24090	MANDLY2G	2	32
29306	MCGPKGEN	1	32
24089	MANDLY1G	1	31
29004	ELLWOOD	1	31
29952	CAMGEN	D1	31
24326	EXGEN1	S1	31
24362	EXGEN2	G1	31
29055	PSTRIAS2	S2	30
29054	PSTRIAG3	G3	30
29053	PSTRIAS1	S1	30
29052	PSTRIAG2	G2	30
29051	PSTRIAG1	G1	30
25605	EDMON1AP	1	30
25606	EDMON2AP	2	30
25607	EDMON3AP	3	30
25607	EDMON3AP	4	30
25608	EDMON4AP	5	30
25608	EDMON4AP	6	30
25609	EDMON5AP	7	30
25609	EDMON5AP	8	30
25610	EDMON6AP	9	30
25610	EDMON6AP	10	30
25612	EDMON8AP	13	30
25612	EDMON8AP	14	30
24127	S.CLARA	1	30
24110	OXGEN	D1	30
24119	PROCGEN	D1	30

24159	WILLAMET	D1	30
24340	CHARMIN	1	30
25611	EDMON7AP	11	29
25611	EDMON7AP	12	29
24222	MANDLY3G	3	29
25614	OSO A P	1	29
25614	OSO A P	2	29
25615	OSO B P	7	29
25615	OSO B P	8	29
25653	ALAMO SC	1	29
24370	KAWGEN	1	28
24113	PANDOL	1	27
24113	PANDOL	2	27
29008	LAKEGEN	1	27
24150	ULTRAGEN	1	27
24152	VESTAL	1	27
24372	KR 3-1	1	27
24373	KR 3-2	2	27
24102	OMAR 1G	1	26
24103	OMAR 2G	2	26
24104	OMAR 3G	3	26
24105	OMAR 4G	4	26
24143	SYCCYN1G	1	26
24144	SYCCYN2G	2	26
24145	SYCCYN3G	3	26
24146	SYCCYN4G	4	26
24319	EASTWOOD	1	25
24306	B CRK1-1	1	25
24306	B CRK1-1	2	25
24307	B CRK1-2	3	25
24307	B CRK1-2	4	25
24308	B CRK2-1	1	25
24308	B CRK2-1	2	25
24309	B CRK2-2	3	25
24309	B CRK2-2	4	25
24310	B CRK2-3	5	25
24310	B CRK2-3	6	25
24311	B CRK3-1	1	25
24311	B CRK3-1	2	25
24312	B CRK3-2	3	25

24312	B CRK3-2	4	25
24313	B CRK3-3	5	25
24314	B CRK 4	41	25
24314	B CRK 4	42	25
24315	B CRK 8	81	25
24315	B CRK 8	82	25
24317	MAMOTH1G	1	25
24318	MAMOTH2G	2	25
24437	KERNRVR	1	22
24457	ARBWIND	1	17
24465	MORWIND	1	17
24481	MIDWIND	1	17
24483	NORTHWND	1	17
24484	ZONDWND1	1	17
24485	ZONDWND2	1	17
24458	ENCANWND	1	16
24459	FLOWIND	1	16
24460	DUTCHWND	1	16
24436	GOLDTOWN	1	16
24456	BOREL	1	15

Changes compared to last year's results:

Overall the load forecast went down by 16 MW. The new Rector-Springville 230 kV line and the east Kern wind resource area projects have been modeled. The overall effect is that the LCR has increased by 9 MW.

Big Creek Overall Requirements:

2014	QF (MW)	MUNI (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	758	354	4206	5318

2014	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[25]	2156	0	2156
Category C (Multiple)[26]	2250	0	2250

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

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

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 – Dixieland 230 kV Line
10) Imperial Valley – La Rosita 230 kV Line

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

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

Total 2014 busload within the defined area: 5073 MW with 127 MW of losses resulting in total load + losses of 5200 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	45.00	1	San Diego, Border		Market

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.

BREGGO_6_SOLAR	22082	BR GEN1	0.21	23.21	1	San Diego	Aug NQC	Market
CBRLLO_6_PLSTP1	22092	CABRILLO	69	2.66	1	San Diego	Aug NQC	QF/Selfgen
CCRITA_7_RPPCHF	22124	CHCARITA	138	3.63	1	San Diego	Aug NQC	QF/Selfgen
CHILLS_1_SYCENG	22120	CARLTNHS	138	0.00	1	San Diego	Aug NQC	QF/Selfgen
CHILLS_1_SYCLFL	22120	CARLTNHS	138	0.43		San Diego	Not modeled Aug NQC	QF/Selfgen
CHILLS_7_UNITA1	22120	CARLTNHS	138	1.54	2	San Diego	Aug NQC	QF/Selfgen
CPSTNO_7_PRMADS	22112	CAPSTRNO	138	4.99	1	San Diego	Aug NQC	QF/Selfgen
CRSTWD_6_KUMYAY	22915	KUMEYAAY	34.5	7.55	1	San Diego	Aug NQC	Wind
DIVSON_6_NSQF	22172	DIVISION	69	41.95	1	San Diego	Aug NQC	QF/Selfgen
EGATE_7_NOCITY	22204	EASTGATE	69	0.27	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
ESCNDO_6_PL1X2	22257	ESGEN	13.8	35.50	1	San Diego, Escondido		Market
ESCNDO_6_UNITB1	22153	CALPK_ES	13.8	45.00	1	San Diego, Escondido		Market
ESCO_6_GLMQF	22332	GOALLINE	69	37.32	1	San Diego, Esco, Escondido	Aug NQC	QF/Selfgen
LAKHDG_6_UNIT 1	22625	LKHODG1	13.8	20.00	1	San Diego, Bernardo, Encinitas		Market
LAKHDG_6_UNIT 2	22626	LKHODG2	13.8	20.00	2	San Diego, Bernardo, Encinitas		Market
LARKSP_6_UNIT 1	22074	LRKSPBD1	13.8	46.00	1	San Diego, Border		Market
LARKSP_6_UNIT 2	22075	LRKSPBD2	13.8	46.00	1	San Diego, Border		Market
LAROA1_2_UNITA1	20187	LRP-U1	16	165	1	None		Market
LAROA2_2_UNITA1	22996	INTBST	18	157	1	None		Market
LAROA2_2_UNITA1	22997	INTBCT	16	165	1	None		Market
MRGT_6_MEF2	22487	MEF_MR2	13.8	47.90	1	San Diego, Mission, Miramar		Market
MRGT_6_MMAREF	22486	MEF_MR1	13.8	48.00	1	San Diego, Mission, Miramar		Market
MSHGTS_6_MMARLF	22448	MESAHGTS	69	3.30	1	San Diego, Mission	Aug NQC	QF/Selfgen
MSSION_2_QF	22496	MISSION	69	0.73	1	San Diego	Aug NQC	QF/Selfgen
NIMTG_6_NIQF	22576	NOISLMTR	69	36.76	1	San Diego	Aug NQC	QF/Selfgen
OGROVE_6_PL1X2	22628	PA99MWQ1	13.8	49.95	1	San Diego, Pala		Market
OGROVE_6_PL1X2	22629	PA99MWQ2	13.8	49.95	2	San Diego, Pala		Market
OTAY_6_PL1X2	22617	OYGEN	13.8	35.50	1	San Diego, Border		Market

OTAY_6_UNITB1	22604	OTAY	69	2.79	1	San Diego, Border	Aug NQC	QF/Selfgen
OTAY_7_UNITC1	22604	OTAY	69	2.68	3	San Diego, Border	Aug NQC	QF/Selfgen
OTMESA_2_PL1X3	22605	OTAYMGT1	18	185.06	1	San Diego		Market
OTMESA_2_PL1X3	22606	OTAYMGT2	18	185.06	1	San Diego		Market
OTMESA_2_PL1X3	22607	OTAYMST1	16	233.48	1	San Diego		Market
PALOMR_2_PL1X3	22262	PEN_CT1	18	162.39	1	San Diego		Market
PALOMR_2_PL1X3	22263	PEN_CT2	18	162.39	1	San Diego		Market
PALOMR_2_PL1X3	22265	PEN_ST	18	240.83	1	San Diego		Market
PTLOMA_6_NTCCGN	22660	POINTLMA	69	1.86	2	San Diego	Aug NQC	QF/Selfgen
PTLOMA_6_NTCQF	22660	POINTLMA	69	19.44	1	San Diego	Aug NQC	QF/Selfgen
SAMPSN_6_KELCO1	22704	SAMPSON	12.5	1.43	1	San Diego	Aug NQC	QF/Selfgen
SMRCOS_6_UNIT 1	22724	SANMRCOS	69	0.65	1	San Diego	Aug NQC	QF/Selfgen
TERMEX_2_PL1X3	22981	TDM STG	18	281	1	None		Market
TERMEX_2_PL1X3	22982	TDM CTG2	18	156	1	None		Market
TERMEX_2_PL1X3	22983	TDM CTG3	18	156	1	None		Market
NA	22444	MESA RIM	69	0.00	1	San Diego	No NQC - hist. data	QF/Selfgen
NA	22592	OLD TOWN	69	0.00	1	San Diego	No NQC - hist. data	QF/Selfgen
NA	22602	OMWD	69	0.00	1	San Diego	No NQC - hist. data	QF/Selfgen
NA	22708	SANLUSRY	69	0.00	1	San Diego	No NQC - hist. data	QF/Selfgen
NA	22916	PFC-AVC	0.6	0.00	1	San Diego	No NQC - hist. data	QF/Selfgen
New unit	22942	RPS	0.69	15.00	G1	None	No NQC - est. data	Wind
New unit	22945	RPS	0.69	15.00	G2	None	No NQC - est. data	Wind
New unit	23120	BULLMOOS	13.8	27.00	1	San Diego, Border	No NQC - Pmax	Market
New unit	23262	RPS	0.32	290.00	T	None	No NQC - Pmax	Market
New unit	23265	RPS	32.5	45.00	C3	None	No NQC - Pmax	Market
New unit	23265	RPS	32.5	125.00	T	None	No NQC - Pmax	Market
New unit	23279	RPS	0.31	100.00	1	None	No NQC - Pmax	Market
New unit	23280	RPS	0.31	100.00	1	None	No NQC - Pmax	Market
ELCAJN_7_GT1	22212	ELCAJNGT	12.5	0.00	1	San Diego, El Cajon	Retired	Market
KEARNY_7_KY1	22377	KEARNGT1	12.5	0.00	1	San Diego, Mission	Retired	Market
KEARNY_7_KY2	22373	KEARN2AB	12.5	0.00	1	San Diego, Mission	Retired	Market
KEARNY_7_KY2	22373	KEARN2AB	12.5	0.00	2	San Diego, Mission	Retired	Market
KEARNY_7_KY2	22374	KEARN2CD	12.5	0.00	1	San Diego, Mission	Retired	Market
KEARNY_7_KY2	22374	KEARN2CD	12.5	0.00	2	San Diego, Mission	Retired	Market
KEARNY_7_KY3	22375	KEARN3AB	12.5	0.00	1	San Diego, Mission	Retired	Market
KEARNY_7_KY3	22375	KEARN3AB	12.5	0.00	2	San Diego, Mission	Retired	Market
KEARNY_7_KY3	22376	KEARN3CD	12.5	0.00	1	San Diego, Mission	Retired	Market
KEARNY_7_KY3	22376	KEARN3CD	12.5	0.00	2	San Diego, Mission	Retired	Market
MRGT_7_UNITS	22488	MIRAMRGT	12.5	0.00	1	San Diego, Mission, Miramar	Retired	Market
MRGT_7_UNITS	22488	MIRAMRGT	12.5	0.00	2	San Diego, Mission, Miramar	Retired	Market

Major new projects modeled:

1. New Imperial Valley-Dixieland 230 kV line
2. East County 500 kV substation (ECO)

<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 85 MW (including 0 MW of QF generation) in 2013 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency for this sub-area is the loss of Miguel-Granite-Los Coches 69 kV line (TL632) with El Cajon Energy Center out of service, which could thermally overload the El Cajon – Los Coches 69 kV line (TL631). This limiting contingency establishes a LCR of 54 MW (including 0 MW of QF generation) in 2013.

Effectiveness factors:

All units within this sub-area (El Cajon Peaker, 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 Mission - Clairmont 69kV line (TL670). This limiting contingency establishes a local capacity need of 219 MW (including 3 MW of QF generation as well as 120 MW of deficiency) in 2014 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

It is recommended to retain the Kearny peakers and Miramar GTs (Cabrillo Power II), generating facilities until the limiting component, Mission - Clairmont 69kV line (TL670), is reconductored, which has been approved in 2010-2011 ISO Transmission Plan.

Effectiveness factors:
Miramar Energy Facility units and Miramar GTs (Cabrillo Power II) are 8% effective, Miramar Landfill unit and all Kearny peakers are 32% effective.

Bernardo Sub-area:
The most critical contingency for the Bernardo sub-area is the loss of Artesian - Sycamore 69 kV line (TL6920) followed by the loss of Poway-Rancho Carmel 69 kV line (TL649), which could thermally overload the Felicita Tap-Bernardo 69 kV line (TL689). This limiting contingency establishes a LCR of 120 MW (including 0 MW of QF generation and 80 MW of deficiency) in 2014 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:
All units within this sub-area (Lake Hodges) are needed so there is no effectiveness factor required.

Esco Sub-area
The most critical contingency for the Esco sub-area is the loss of Poway-Pomerado 69 kV line (TL6913) followed by the loss of Esco - Escondido 69kV line (TL6908) which could thermally overload the Bernardo – Rancho Carmel 69 kV line (TL633). This limiting contingency establishes a LCR of 110 MW (including 37 MW of QF generation and 73 MW of deficiency) in 2014 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. This limiting contingency establishes a LCR of 35 MW (including 0 MW of QF generation) in 2014 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area (Orange Grove) 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 60 MW in 2014 (includes 5 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area have the same effectiveness factor.

Miramar Sub-area

The most critical contingency for the Miramar sub-area is the loss of Otay Mesa – Miguel Tap – Silvergate 230kV line (TL23042) followed by the loss of Sycamore 230/138 kV Bank #60, which could thermally overload the Sycamore - Scripps 69 kV line (TL6916). This limiting contingency establishes a LCR of 128 MW (including 0 MW of QF generation as well as 32 MW of deficiency) in 2014 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency for this sub-area is the loss of Otay Mesa – Miguel Tap – Silvergate 230kV line (TL23042) with Miramar Energy Facility #1 or #2 out of service, which could thermally overload the Sycamore - Scripps 69 kV line (TL6916). This limiting contingency establishes a LCR of 96 MW (including 0 MW of QF generation) in 2014.

It is recommended to retain the Miramar GTs (Cabrillo Power II) until the most limiting contingency is mitigated.

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

San Diego Sub-area – 2 SONGS:
The most limiting contingency in the San Diego sub-area is a (G-1/N-1) contingency described by the outage of ECO-Miguel 500 kV line with Otay Mesa Combined-Cycle Power Plant (603 MW) already out of service. The limiting constraint is reactive margin. This contingency establishes a LCR of 2370 MW in 2014 (includes 162 MW of QF generation and 8 MW of Wind) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The second most limiting contingency for San Diego sub-area is the loss of Ocotillo - Suncrest 500 kV line followed by the loss of ECO-Miguel 500 kV line. The limiting constraint is reactive margin. This contingency establishes a LCR of 2265 MW in 2014 (includes 162 MW of QF generation and 8 MW of Wind).

San Diego Sub-area – 1 SONGS (70%):
The most limiting contingency in the San Diego sub-area is a (G-1/N-1) contingency described by the outage of ECO-Miguel 500 kV line with Otay Mesa Combined-Cycle Power Plant (603 MW) already out of service. The limiting constraint is reactive margin. This contingency establishes a LCR of 2885 MW in 2014 (includes 162 MW of QF

generation and 8 MW of Wind) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The second most limiting contingency for San Diego sub-area is the loss of Ocotillo - Suncrest 500 kV line followed by the loss of ECO-Miguel 500 kV line. The limiting constraint is reactive margin. This contingency establishes a LCR of 2883 MW in 2014 (includes 162 MW of QF generation and 8 MW of Wind) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

San Diego Sub-area – 0 SONGS:

The most limiting contingency for San Diego sub-area is the loss of Ocotillo -Suncrest 500 kV line followed by the loss of ECO-Miguel 500 kV line. The limiting constraint is reactive margin. This contingency establishes a LCR of 3394 MW in 2014 (includes 162 MW of QF generation and 8 MW of Wind as well as 458 MW of deficiency) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The most limiting single contingency in the San Diego sub-area is a (G-1/N-1) contingency described by the outage of ECO-Miguel 500 kV line with Otay Mesa Combined-Cycle Power Plant (603 MW) already out of service. The limiting constraint is reactive margin. This contingency establishes a LCR of 3103 MW in 2014 (includes 162 MW of QF generation and 8 MW of Wind as well as 167 MW of deficiency).

It is recommended to retain the Kearny peakers, Miramar GTs and El Cajon CT, generating facilities until the most limiting contingency is mitigated.

Effectiveness factors:

All units within this area have the same effectiveness factor.

San Diego-Imperial Valley Area Overall – 2 SONGS:

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 N. Gila Substations over-lapping with an outage of the Otay Mesa Combined-Cycle Power plant (603 MW) while staying within the South of San Onofre (WECC Path 44) non-simultaneous import capability rating of 2,500 MW. This limiting contingency establishes a local capacity need of 2945 MW in 2014 (includes 162 MW of QF generation and 38 MW of Wind) as the minimum capacity necessary for reliable load serving capability within this area.

San Diego-Imperial Valley Area Overall – 1 SONGS (70%):

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 N. Gila Substations with Otay Mesa Combined-Cycle Power plant (603 MW) already out of service. This limiting constraint is reactive margin and establishes a local capacity need of 3120 MW in 2014 (includes 162 MW of QF generation and 38 MW of Wind) as the minimum capacity necessary for reliable load serving capability within this area.

The second most limiting contingency in the San Diego-Imperial Valley area is the outage of 500 kV Southwest Power Link (SWPL) between Imperial Valley and N. Gila Substations followed by an outage of Otay Mesa Combined-Cycle Power plant (603 MW) while staying within the South of San Onofre (WECC Path 44) non-simultaneous import capability rating of 2,500 MW. This limiting contingency establishes a local capacity need of 2820 MW in 2014 (includes 162 MW of QF generation and 38 MW of Wind).

San Diego-Imperial Valley Area Overall – 0 SONGS:

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 N. Gila Substations over-lapping with an outage of the Otay Mesa Combined-Cycle Power plant (603 MW). This limiting constraint is reactive margin and establishes a local capacity need of 3605 MW in 2014 (includes 162 MW of QF generation and 38 MW of Wind) as the minimum capacity necessary for reliable load serving capability within this area.

The second most limiting contingency is the outage of 500 kV Southwest Power Link (SWPL) between Imperial Valley and N. Gila Substations followed by an outage of Otay Mesa Combined-Cycle Power plant (603 MW). This limiting constraint is reactive margin and establishes a local capacity need of 3403 MW in 2014 (includes 162 MW of QF generation and 38 MW of Wind).

It is worth mentioning that Imperial Valley – Dixieland 230kV line was modeled between IID and CAISO. There were no additional upgrades modeled between CFE and CAISO control areas at Imperial Valley 230 kV bus in 2014 base case. The CAISO acknowledges that the LCR needs for the San Diego-Imperial Valley area will decrease as additional transmission is constructed between the IID/CFE systems and Imperial Valley and more power is flowing in real-time from these control areas into the CAISO control area.

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

Changes compared to last year's results:
The load forecast went up by 86 MW and total local resource capacity needed for the San Diego-Imperial Valley increased (including deficiencies that cannot be contracted for due to unavailability of resources) by 168 MW overall, for the case with 2 SONGS in service, mainly due to the deficiency increase in the Mission sub-area.

It is recommended to retain the Kearny peakers, Miramar GTs and El Cajon CT, generating facilities until the most limiting contingencies are mitigated in the Mission, Miramar and San Diego sub-areas.

At this time the ISO considers that the most likely scenario for 2014 is no SONGS scenario therefore overall LCR needs in the main tables reflect this outcome. The ISO will continue to monitor the situation and may change this assumption before the 2014

LCR allocations are released to LSEs.

San Diego-Imperial Valley Area Overall Requirements:

2014	QF (MW)	Wind (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	162	38	4506	4706

2014	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[27]	3605	167	3772
Category C (Multiple)[28]	3605	458	4063

11. Valley Electric Area

Area Definition

The transmission tie lines into the area include:

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

The substations that delineate the area are:

1) Amargosa is out Sandy is in
2) Jackass Flats is out Lathrop Switch is in
3) Mead is out Bob Switchyard is in
4) Northwest is out Desert View is in
5) Mercury is out Innovation is in
6) SCE Eldorado is out Bob Switchyard is in

Total 2014 busload within the defined area was: 118 MW along with 2 MW of transmission losses resulting in total load + losses of 120 MW.

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

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

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

Major new transmission projects modeled:

1. Northwest-Desert View 230 kV Line #1 (under construction)
2. Bob Switchyard 230 kV Switchyard
3. Innovation-Mercury 138 kV line
4. Innovation 230 kV Switchyard

Critical Contingency Analysis Summary

Pahrump South Sub-Area

The most critical contingency for the Pahrump South Sub-Area is the loss of Pahrump-Gamebird 138 kV line with the biggest resource in the area out of service. This contingency results in voltage deviation greater than 5% at Gamebird sub, Thousandaire sub, and Charleston sub, and establishes a local capacity need of 17 MW plus the biggest future resource in the area (includes 17 MW of deficiency) in 2014 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

There is no generation available in this sub-area.

Valley Electric Association Overall Area

The most critical contingency for the Valley Electric Association Area is the loss of Innovation – Desert View 230 kV line followed by the loss of Pahrump – Crazy Eye 230 kV line or vice versa. This double contingency event may result in thermal overload on Northwest – Snow Mountain 138kV line (Nevada Energy), and establishes a local capacity need of 33 MW (including 33 MW of deficiency) in 2014 as the minimum capacity necessary for reliable load serving capability within the area. An SPS or operating procedure to drop load for this N-1-1 contingency could eliminate this overall local capacity need.

Effectiveness factors:

There is no generation available in this area.

Changes compared to last year's results:

Compared with 2013 the VEA load forecast went down by 1 MW and the LCR need went down by 4 MW.

Valley Electric Area Overall Requirements:

2014	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	0	0	0	0

2014	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single) [29]	0	17	17
Category C (Multiple) [30]	0	33	33

[29] 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.

[30] 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.