BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider Annual Revisions to Local Procurement Obligations and Refinements to the Resource Adequacy Program	)))))	R.08-01-025

UPDATED 2010 LOCAL CAPACITY TECHNICAL ANALYSIS PREPARED BY THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

The California Independent System Operator Corporation ("ISO") respectfully submits its Updated 2010 Local Capacity Technical Analysis and supporting documentation in the above-referenced docket, in accordance with the October 30, 2008 Administrative Law Judge's Ruling Adopting Dates Certain For, And Making Other Changes To, The Phase 2 Schedule..

Respectfully Submitted:

By: ***/s/ Judith B. Sanders***
Judith B. Sanders
Attorney for
California Independent System Operator Corporation

May 1, 2009

California Independent
System Operator

2010
LOCAL CAPACITY TECHNICAL ANALYSIS

FINAL REPORT
AND STUDY RESULTS

May 1, 2009

Local Capacity Technical Study
Overview and Results

I. Executive Summary

This Report documents the results and recommendations of the 2010 Local Capacity Technical (LCT) Study. The LCT Study assumptions, processes, and criteria were discussed and recommended through the 2010 Local Capacity Technical Study Criteria, Methodology and Assumptions Stakeholder Meeting held on November 3, 2008. On balance, the assumptions, processes, and criteria used for the 2010 LCT Study mirror those used in the 2007, 2008 and 2009 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 2010 LCT study results are provided to the CPUC for consideration in its 2010 resource adequacy requirements program. These results will also be used by the CAISO for identifying the minimum quantity of local capacity necessary to meet the North American Electric Reliability Corporation (NERC) Reliability Criteria used in the LCT Study (this may be referred to as "Local Capacity Requirements" or "LCR") and for assisting in the allocation of costs of any CAISO procurement of capacity needed to achieve the Reliability Criteria notwithstanding the resource adequacy procurement of Load Serving Entities (LSEs).[2] In this regard, the 2010 LCT Study also provides additional information on sub-area needs and effectiveness factors (where applicable) in order to allow LSEs to engage in more informed procurement.

Below is a comparison of the 2010 vs. 2009 total LCR:

[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.

2010 Local Capacity Requirements

	Qualifying Capacity			2010 LCR Need Based on Category B			2010 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	48	135	183	176	0	**176**	176	0	**176**
North Coast / North Bay	149	736	885	787	0	**787**	787	3	**790**
Sierra	1066	769	1835	1133	102	**1235**	1717	385	**2102**
Stockton	229	266	495	357	0	**357**	432	249	**681**
Greater Bay	1096	5608	6704	4224	0	**4224**	4651	0	**4651**
Greater Fresno	502	2439	2941	2310	0	**2310**	2640	0	**2640**
Kern	656	9	665	187	0	**187**	403	1	**404**
LA Basin	3918	8212	12130	9735	0	**9735**	9735	0	**9735**
Big Creek/ Ventura	947	4146	5093	3212	0	**3212**	3334	0	**3334**
San Diego	205	3502	3707	3200	0	**3200**	3200	14	**3214**
Total	**8816**	**25822**	**34638**	**25321**	**102**	**25423**	**27075**	**652**	**27727**

2009 Local Capacity Requirements

	Qualifying Capacity			2009 LCR Need Based on Category B			2009 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	48	135	183	177	0	**177**	177	0	**177**
North Coast / North Bay	217	728	945	766	0	**766**	766	0	**766**
Sierra	1012	768	1780	1453	226	**1679**	1617	703	**2320**
Stockton	276	265	541	491	34	**525**	541	185	**726**
Greater Bay	1111	5662	6773	4791	0	**4791**	4791	0	**4791**
Greater Fresno	510	2319	2829	2414	0	**2414**	2680	0	**2680**
Kern	646	31	677	208	0	**208**	417	5	**422**
LA Basin	3942	8222	12164	9728	0	**9728**	9728	0	**9728**
Big Creek/ Ventura	931	4201	5132	3178	0	**3178**	3178	0	**3178**
San Diego	201	3442	3663	3113	0	**3113**	3113	14	**3127**
Total	**8894**	**25773**	**34687**	**26319**	**260**	**26579**	**27008**	**907**	**27915**

Overall, the LCR needs are steady from 2009 to 2010. The total LCR needs have decreased by about 190 MW, however the existing capacity needed to meet the LCR has increased by about 70 MW. The LCR needs have decreased in the following areas: (1) Sierra and Stockton, where the LCR need has decreased mainly because of new transmission projects; and (2) Humboldt, Bay Area, Fresno and Kern where the load trend is downward. The LCR needs have slightly increased in the North Coast/North Bay, LA Basin and Big Creek/Ventura mostly due to load growth. The San Diego area LCR need has increased partly because of load growth and partly because of the new Otay Mesa generating facility becoming the biggest single generation contingency in the area. 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 2010 and 2009 LCRs.

Table of Contents

II. Study Overview: Inputs, Outputs and Options

A. Objectives

As was the objective of the four previous annual LCT Studies, the intent of the 2010 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. Ke y Study Assumptions

1. Inputs and Methodology

The CAISO incorporated into its 2010 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 2010 LCT Study Criteria, Methodology and Assumptions Stakeholder Meeting held on November 3, 2008.

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 2010 LCT Study:

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

Issue:	HOW INCORPORATED INTO THIS LCT STUDY:
Input Assumptions:	
• Transmission System Configuration	The existing transmission system has been modeled, including all projects operational on or before June 1, of the study year and all other feasible operational solutions brought forth by the PTOs and as agreed to by the CAISO.
• Generation Modeled	The existing generation resources has been modeled and also includes all projects that will be on-line and commercial on or before June 1, of the study year
• Load Forecast	Uses a 1-in-10 year summer peak load forecast
Methodology:	
• **Maximize Import Capability**	Import capability into the load pocket has been maximized, thus minimizing the generation required in the load pocket to meet applicable reliability requirements.
• **QF/Nuclear/State/Federal Units**	Regulatory Must-take and similarly situated units like QF/Nuclear/State/Federal resources have been modeled on-line at qualifying capacity output values for purposes of this LCT Study.
• **Maintaining Path Flows**	Path flows have been maintained below all established path ratings into the load pockets, including the 500 kV. For clarification, given the existing transmission system configuration, the only 500 kV path that flows directly into a load pocket and will, therefore, be considered in this 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 2010 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 planning standards of the Western Electricity Coordinating Council ("WECC") that incorporate standards set by the North American Electric Reliability Council ("NERC") (collectively "NERC Planning Standards"). The NERC Planning Standards apply to the interconnected electric system in the United States and are intended to address the reality that within an integrated network, whatever one Balancing Authority Area does can affect the reliability of other Balancing Authority Areas. Consistent with the mandatory nature of the NERC Planning Standards, the CAISO is under a statutory obligation to ensure efficient use and reliable operation of the transmission grid consistent with achievement of the NERC Planning Standards.[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 NERC Planning Standards as well as reliability criteria adopted by the CAISO, in consultation with the CAISO's Participating Transmission Owners ("PTOs"), which affect a PTO's individual system.

The NERC Planning Standards define reliability on interconnected electric systems using the terms "adequacy" and "security." "Adequacy" is the ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account physical characteristics of the transmission system such as transmission ratings and scheduled and reasonably expected unscheduled outages of system elements. "Security" is the ability of the electric systems to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements. The NERC Planning Standards are organized by Performance Categories. Certain categories require that the grid operator not only ensure that grid integrity is maintained under certain adverse system conditions (e.g., security), but also that all customers continue to receive electric supply to meet demand

[3] Pub. Utilities Code § 345

(e.g., adequacy). In that case, grid reliability and service reliability would overlap. But there are other levels of performance where security can be maintained without ensuring adequacy.

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

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

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

E. Performance Criteria

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

a. Performance Criteria- Category B

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

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

b. Performance Criteria- Category C

The NERC Planning Standards require system operators to "look forward" to make sure they safely prepare for the "next" N-1 following the loss of the "first" N-1 (stay within Applicable Ratings after the "next" N-1). This is commonly referred to as N-1-1. Because it is assumed that some time exists between the "first" and "next" element losses, operating personnel may make any reasonable and feasible adjustments to the system to prepare for the loss of the second element, including, operating procedures, dispatching generation, moving load from one substation to another to reduce equipment loading, dispatching operating personnel to specific station locations to manually adjust load from the substation site, or installing a "Special Protection Scheme" that would remove pre-identified load from service upon the loss of the "next " element.[4] All Category C requirements in this report refer to situations when in real time

[4] A Special Protection Scheme is typically proposed as an operational solution that does not require additional generation and permits operators to effectively prepare for the next event as well as ensure security should the next event occur. However, these systems have their own risks, which limit the extent to which they could be deployed as a solution for grid reliability augmentation. While they provide the

(N-0) or after the first contingency (N-1) the system requires additional readjustment in order to prepare for the next worst contingency. In this time frame, load drop is not allowed per existing planning criteria.

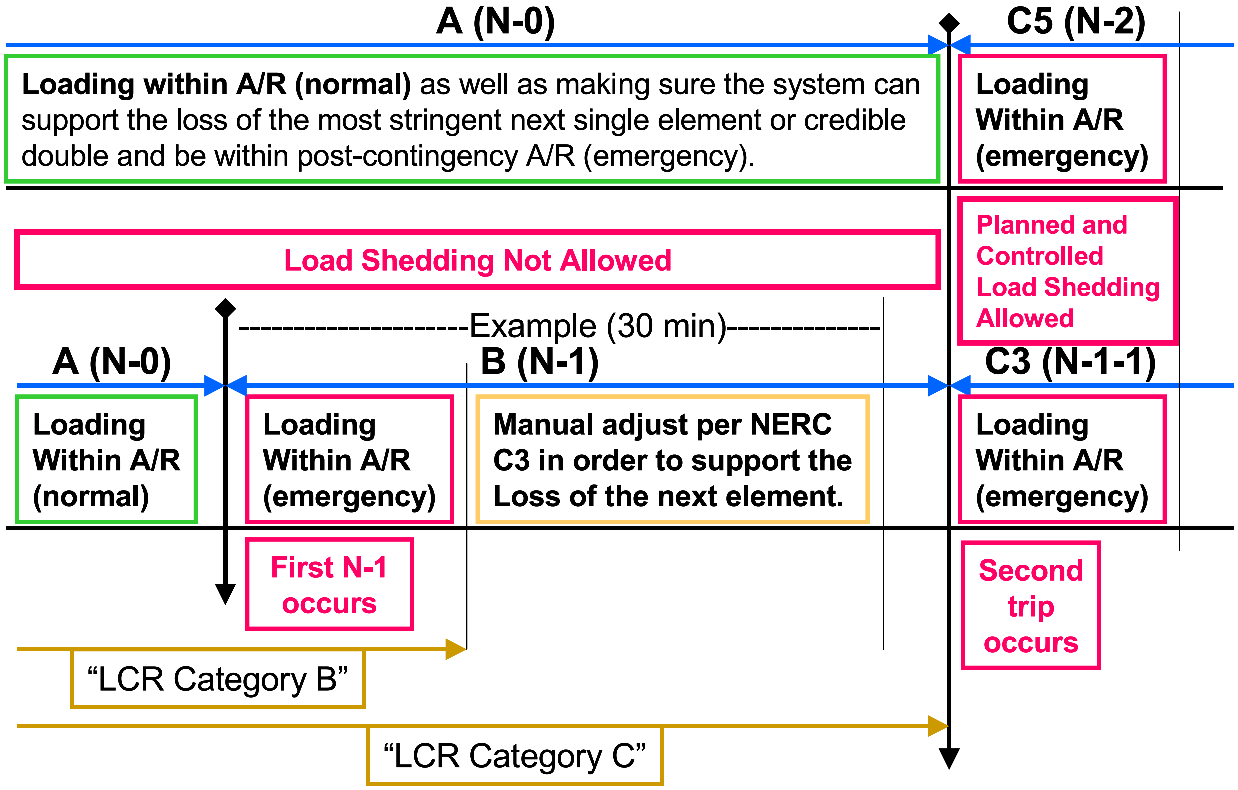
Generally, Category C describes system performance that is expected following the loss of two or more system elements. This loss of two elements is generally expected to happen simultaneously, referred to as N-2. It should be noted that once the "next" element is lost after the first contingency, as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

c. CAISO Statutory Obligation Regarding Safe Operation

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

---

value of protecting against the next event without the need for pre-contingency load shedding, they add points of potential failure to the transmission network. This increases the potential for load interruptions because sometimes these systems will operate when not required and other times they will not operate when needed.



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

Applicable Rating:

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

Normal rating is to be used under normal conditions.

Long-term emergency ratings, if available, will be used in all emergency conditions as long as "system readjustment" is provided in the amount of time given (specific to each element) to reduce the flow to within the normal ratings. If not available normal rating is to be used.

Short-term emergency ratings, if available, can be used as long as "system readjustment" is provided in the "short-time" available in order to reduce the flow to within the long-term emergency ratings where the element can be kept for another

length of time (specific to each element) before the flow needs to be reduced the below the normal ratings. If not available long-term emergency rating should be used.
Temperature-adjusted ratings shall not be used because this is a year-ahead study not a real-time tool, as such the worst-case scenario must be covered. In case temperature-adjusted ratings are the only ratings available then the minimum rating (highest temperature) given the study conditions shall be used.
CAISO Transmission Register is the only official keeper of all existing ratings mentioned above.
Ratings for future projects provided by PTO and agree upon by the CAISO shall be used.
Other short-term ratings not included in the CAISO Transmission Register may be used as long as they are engineered, studied and enforced through clear operating procedures that can be followed by real-time operators.
Path Ratings need to be maintained in order for these studies to comply with the Minimum Operating Reliability Criteria and assure that proper capacity is available in order to operate the system in real-time.

Controlled load drop:

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

Planned load drop:

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

Special Protection Scheme:

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

System Readjustment:

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

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

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

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

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

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

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

Time allowed for manual readjustment:

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

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

F. The Two Options Presented In This LCT Report

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

1. Option 1- Meet Performance Criteria Category B

Option 1 is a service reliability level that reflects generation capacity that must be available to comply with reliability standards immediately after a NERC Category B given that load cannot be removed to meet this performance standard under Reliability Criteria. However, this capacity amount implicitly relies on load interruption as the **only means** of meeting any Reliability Criteria that is beyond the loss of a single transmission element (N-1). These situations will likely require substantial load interruptions in order to maintain system continuity and alleviate equipment overloads prior to the actual occurrence of the second contingency.[5]

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

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

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

III. Assumption Details: How the Study was Conducted

A. System Planning Criteria

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 NERC performance standards, used in the study:

Table 4: Criteria Comparison

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

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

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

1. Power Flow Assessment:

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

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

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

3 Applicable Rating – Based on 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.

[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 then 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 16.2. This GE PSLF program is available directly from GE or through the Western System Electricity Council (WECC) to any member.

To evaluate Local Capacity Areas, the starting base case was adjusted to reflect the latest generation and transmission projects as well as the one-in-ten-year peak load forecast for each Local Capacity Area as provided to the CAISO by the PTOs.

Electronic contingency files provided by the PTOs were utilized to perform the numerous contingencies required to identify the LCR. These contingency files include remedial action and special protection schemes that are expected to be in operation during the year of study. An CAISO created EPCL (a GE programming language contained within the GE PSLF package) routine was used to run the combination of contingencies; however, other routines are available from WECC with the GE PSFL package or can be developed by third parties to identify the most limiting combination of contingencies requiring the highest amount of generation within the local area to maintain power flows within applicable ratings.

IV. Local Capacity Requirement Study Results

A. Summary of Study Results

LCR is defined as the amount of 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: 2010 Local Capacity Needs vs. Peak Load and Local Area Generation

	2010 Total LCR (MW)	Peak Load (1 in10) (MW)	2010 LCR as % of Peak Load	Total Dependable Local Area Generation (MW)	2010 LCR as % of Total Area Generation
Humboldt	176	203	87%	183	96%
North Coast/North Bay	790	1614	49%	885	89%**
Sierra	2102	2126	99%	1835	115%**
Stockton	681	959	71%	495	138%**
Greater Bay	4651	10276	45%	6704	69%
Greater Fresno	2640	3377	78%	2941	90%
Kern	404	1240	33%	665	61%**
LA Basin	9735	20058	49%	12130	80%
Big Creek/Ventura	3334	5033	66%	5093	65%
San Diego	3214	5127	63%	3707	87%**
Total	**27,727**	**50,013***	**55%***	**34,638**	**80%**

Table 6: 2009 Local Capacity Needs vs. Peak Load and Local Area Generation

	2009 Total LCR (MW)	Peak Load (1 in10) (MW)	2009 LCR as % of Peak Load	Total Dependable Local Area Generation (MW)	2009 LCR as % of Total Area Generation
Humboldt	177	207	86%	183	97%
North Coast/North Bay	766	1596	48%	945	81%
Sierra	2320	2126	109%	1780	130%**
Stockton	726	1436	51%	541	134%**
Greater Bay	4791	10294	47%	6773	71%
Greater Fresno	2680	3381	79%	2829	95%
Kern	422	1316	32%	677	62%**
LA Basin	9728	19836	49%	12164	80%
Big Creek/Ventura	3178	4937	64%	5132	62%
San Diego	3127	5052	62%	3663	85%**
Total	**27,915**	**50,181***	**56%***	**34,687**	**80%**

* 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 must 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 6/1/2010 have been included in this 2010 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, “2010 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, “2010 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	28864	4330	-8094	-3750	**21350**
NP26=NP15+ZP26	22236	3335	-4514	-2902	**18155**

Where:

Load Forecast is the most recent 1 in 2 CEC forecast for year 2010.

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

Allocated Imports are the actual 2009 numbers that are not expected to change much by 2010 because there are no additional transmission additions to the grid between now and summer of 2010.

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

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

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

Changes compared to last year's results:

- The load forecast went down in Southern California by about 200 MW and up in Northern California by about 300 MW.
- The Import Allocations went up in Southern California by about 400 MW and down in Northern California by about 700 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 2009. 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 derated 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

Area Definition

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

Total 2010 busload within the defined area: 197 MW with 6 MW of losses resulting in total load + losses of 203 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BRDGVL_7_BAKER				0.00		None	Not modeled	QF/Selfgen
FAIRHV_6_UNIT	31150	FAIRHAVN	13.8	14.03	1	Humboldt 60 kV		QF/Selfgen
FTSWRD_7_QFUNTS				0.70		Humboldt 60 kV	Not modeled	QF/Selfgen
HUMBPP_1_MOBLE2	31154	HUMBOLDT	13.2	15.00	2	None		Market
HUMBPP_1_MOBLE3	31154	HUMBOLDT	13.2	15.00	1	None		Market
HUMBPP_7_UNIT 1	31170	HMBOLDT1	13.8	52.00	1	Humboldt 60 kV		Market
HUMBPP_7_UNIT 2	31172	HMBOLDT2	13.8	53.00	1	Humboldt 60 kV		Market
HUMBSB_1_QF				0.00		None	Not modeled - Monthly NQC - used August for LCR	QF/Selfgen
KEKAWK_6_UNIT	31166	KEKAWAK	9.1	0.00	1	Humboldt 60 kV		QF/Selfgen

PACLUM_6_UNIT	31152	PAC.LUMB	13.8	8.31	1	Humboldt 60 kV		QF/Selfgen
PACLUM_6_UNIT	31152	PAC.LUMB	13.8	8.30	2	Humboldt 60 kV		QF/Selfgen
PACLUM_6_UNIT	31153	PAC.LUMB	2.4	4.98	3	Humboldt 60 kV		QF/Selfgen
WLLWCR_6_CEDRFL				0.00		Humboldt 60 kV	Not modeled - Monthly NQC - used August for LCR	QF/Selfgen
LAPAC_6_UNIT	31158	LP SAMOA	12.5	12.00	1	Humboldt 60 kV	No NQC - historical data	QF/Selfgen
ULTPBL_6_UNIT 1	31156	ULTRAPWR	12.5	0.00	1	Humboldt 60 kV	No NQC - historical data	Market

Major new projects modeled:

1. Humboldt Reactive Support

<u>Critical Contingency Analysis Summary</u>

Humboldt overall:

The most critical contingency for the Humboldt area is the outage of the Bridgeville-Cottonwood 115 kV line with one of the Humboldt #1 or #2 units out of service. The area limitation is low voltage and reactive power margin. This contingency establishes a LCR of 176 MW in 2010 (includes 48 MW of QF/Selfgen generation) as the minimum capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

All units within this area have the same effectiveness factor.

Changes compared to the last stakeholder meeting:

The Humboldt Reactive Support project was modeled an on-line during both the 2010 LCR studies as well as the 2009 LCR studies. The difference in results from our last stakeholder meeting is given by the removal of load (~3 MW) associated with the Humboldt Bay Power Plant; because this project has been delayed past winter of 2010.

Changes compared to last year's results:

Reactive margin is a non-liner function. The load forecast went down by 4 MW and this results in a decrease of the LCR need by 1 MW.

Humboldt Overall Requirements:

2010	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	48	0	135	183

2010	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[9] 176		0	176
Category C (Multiple)[10] 176		0	176

2. North Coast / North Bay Area

Area Definition

The North Coast/North Bay Area is composed of three sub-areas and the generation requirements within them.

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 Kekawaka are in Garberville is 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 then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

[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 MORC.

Total 2010 busload within the defined area: 1549 MW with 65 MW of losses resulting in total load + losses of 1614 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	7.00	1	Fulton, Lakeville		Market
BEARCN_2_UNITS	31402	BEAR CAN	13.8	7.00	2	Fulton, Lakeville		Market
FULTON_1_QF				0.02		Fulton, Lakeville	Not modeled	QF/Selfgen
GEYS11_7_UNIT11	31412	GEYSER11	13.8	59.00	1	Eagle Rock, Fulton, Lakeville	Monthly NQC - used August for LCR	Market
GEYS12_7_UNIT12	31414	GEYSER12	13.8	49.00	1	Fulton, Lakeville	Monthly NQC - used August for LCR	Market
GEYS13_7_UNIT13	31416	GEYSER13	13.8	55.00	1	Lakeville	Monthly NQC - used August for LCR	Market
GEYS14_7_UNIT14	31418	GEYSER14	13.8	49.00	1	Fulton, Lakeville	Monthly NQC - used August for LCR	Market
GEYS16_7_UNIT16	31420	GEYSER16	13.8	50.00	1	Fulton, Lakeville	Monthly NQC - used August for LCR	Market
GEYS17_2_BOTRCK	31421	BOT TLERK	13.8	14.70	1	Fulton, Lakeville		Market
GEYS17_7_UNIT17	31422	GEYSER17	13.8	50.00	1	Fulton, Lakeville	Monthly NQC - used August for LCR	Market
GEYS18_7_UNIT18	31424	GEYSER18	13.8	47.00	1	Lakeville	Monthly NQC - used August for LCR	Market
GEYS20_7_UNIT20	31426	GEYSER20	13.8	42.00	1	Lakeville	Monthly NQC - used August for LCR	Market
GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	40.00	1	Eagle Rock, Fulton, Lakeville	Monthly NQC - used August for LCR	Market
GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	40.00	2	Eagle Rock, Fulton, Lakeville	Monthly NQC - used August for LCR	Market
GYS7X8_7_UNITS	31408	GEYSER78	13.8	35.00	1	Eagle Rock, Fulton, Lakeville	Monthly NQC - used August for LCR	Market
GYS7X8_7_UNITS	31408	GEYSER78	13.8	35.00	2	Eagle Rock, Fulton, Lakeville	Monthly NQC - used August for LCR	Market
GYSRVL_7_WSPRNG				2.00		Fulton, Lakeville	Not modeled	QF/Selfgen
HIWAY_7_ACANYN				1.29		Lakeville	Not modeled	QF/Selfgen
IGNACO_1_QF				0.00		Lakeville	Not modeled	QF/Selfgen
INDVLY_1_UNITS	31436	INDIAN V	9.1	1.52	1	Eagle Rock, Fulton, Lakeville	QF	/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	2.50	1	Fulton, Lakeville	Monthly NQC - used August for LCR	QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	2.50	2	Fulton, Lakeville	Monthly NQC - used August for LCR	QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	0.59	3	Fulton, Lakeville	Monthly NQC - used August for LCR	QF/Selfgen
NAPA_2_UNIT				0.01		Lakeville	Not modeled	QF/Selfgen
NCPA_7_GP1UN1	38106	NCPA1GY1	13.8	35.00	1	Lakeville		MUNI

NCPA_7_GP1UN2 381	08	NCPA1GY2	13.8	32.00 1	Lakeville		MUNI
NCPA_7_GP2UN3 381	10	NCPA2GY1	13.8	33.00 1	Fulton, Lakeville		MUNI
NCPA_7_GP2UN4 381	12	NCPA2GY2	13.8	29.00 1	Fulton, Lakeville		MUNI
POTTER_6_UNITS 314	33	POTTRVLY	2.4	4.70 1	Eagle Rock, Fulton, Lakeville	Market	
POTTER_6_UNITS 314	33	POTTRVLY	2.4	2.25 3	Eagle Rock, Fulton, Lakeville	Market	
POTTER_6_UNITS 314	33	POTTRVLY	2.4	2.25 4	Eagle Rock, Fulton, Lakeville	Market	
POTTER_7_VECINO				0.01	Eagle Rock, Fulton, Lakeville	Not modeled	QF/Selfgen
SANTFG_7_UNITS 314	00	SANTA FE	13.8	33.50 1	Lakeville		Market
SANTFG_7_UNITS 314	00	SANTA FE	13.8	33.50 2	Lakeville		Market
SMUDGO_7_UNIT 1	31430	SMUDGEO 1	13.8	39.00 1	Lakeville	Monthly NQC - used August for LCR	Market
SNMALF_6_UNITS 314	46	SONMA LF	9.1	7.70 1	Fulton, Lakeville		QF/Selfgen
UKIAH_7_LAKEMN				1.70	Eagle Rock, Fulton, Lakeville	Not modeled	MUNI
WDFRDF_2_UNITS 314	04	WEST FOR	13.8	12.51 1	Fulton, Lakeville		Market
WDFRDF_2_UNITS 314	04	WEST FOR	13.8	12.49 2	Fulton, Lakeville		Market

Major new projects modeled:

1. None

Critical Contingency Analysis Summary

Eagle Rock Sub-area

The most critical overlapping contingency is the outage of the Eagle Rock-Silverado-Fulton 115 kV line and the Cortina #4 230/115 kV bank. The sub-area area limitation is thermal overloading of Fulton-Hopland 60 kV. This limiting contingency establishes a LCR of 240 MW in 2010 (includes 3 MW of QF/MUNI generation as well as 3 MW of deficiency) 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 #4 230/115 kV bank. The sub-area area limitation is thermal overloading of Fulton-Hopland 60 kV. This limiting contingency establishes a LCR of 120 MW in 2010 (includes 3 MW of QF/MUNI generation).

Effectiveness factors:

All the units within the Eagle-Rock sub-area are needed therefore no effectiveness factor is needed. Units outside this area are not effective.

Fulton Sub-area

The most critical overlapping contingency is the outage of the Lakeville-Ignacio 230 kV line #1 and the Crocket-Sobrante 230 kV line #1. The sub-area area limitation is thermal overloading of Fulton-Lakeville 230 kV line #1. This limiting contingency establishes a LCR of 559 MW (includes 17 MW of QF and 64 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area. All of the resources needed to meet the Eagle Rock sub-area count towards the Fulton sub-area LCR need.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31404	WEST FOR	2	73
31402	BEAR CAN	1	73
31402	BEAR CAN	2	73
31404	WEST FOR	1	73
31414	GEYSER12	1	73
31418	GEYSER14	1	73
31420	GEYSER16	1	73
31422	GEYSER17	1	73
38110	NCPA2GY1	1	73
38112	NCPA2GY2	1	73
31421	BOTTLERK	1	72
31406	GEYSR5-6	1	38
31406	GEYSR5-6	2	38
31408	GEYSER78	1	38
31408	GEYSER78	2	38
31412	GEYSER11	1	38
31435	GEO.ENGY	1	38
31435	GEO.ENGY	2	38

Lakeville Sub-area

The most limiting contingency is the outage of Vaca Dixon-Lakeville 230 kV line with DEC power plant out of service. The sub-area limitation is thermal overloading of the

Vaca Dixon-Tulucay 230 kV. This limiting contingency establishes a LCR of 787 MW (includes 18 MW of QF and 131 MW of MUNI generation) as the minimum capacity necessary for reliable load serving capability within this sub-area. The LCR resources needed for Eagle Rock and Fulton sub-areas can be counted toward fulfilling the requirement of Lakeville sub-area.

Effectiveness factors:

The following table has units within the North Coast/North Bay area at least 5% effective to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31400	SANTA FE	2	37
31430	SMUDGEO1	1	37
31400	SANTA FE	1	37
31416	GEYSER13	1	37
31424	GEYSER18	1	37
31426	GEYSER20	1	37
38106	NCPA1GY1	1	37
38108	NCPA1GY2	1	37
31421	BOTTLERK	1	35
31404	WEST FOR	2	35
31402	BEAR CAN	1	35
31402	BEAR CAN	2	35
31404	WEST FOR	1	35
31414	GEYSER12	1	35
31418	GEYSER14	1	35
31420	GEYSER16	1	35
31422	GEYSER17	1	35
38110	NCPA2GY1	1	35
38112	NCPA2GY2	1	35
31406	GEYSR5-6	1	19
31406	GEYSR5-6	2	19
31408	GEYSER78	1	19
31408	GEYSER78	2	19
31412	GEYSER11	1	19
31435	GEO.ENGY	1	19
31435	GEO.ENGY	2	19

Changes compared to the last stakeholder meeting:

The 2010 LCR need for the Pittsburg/Oakland sub-area (part the Greater Bay Area) has decrease by 400 MW. As a result the Lakeville LCR need has increased by 87 MW.

Changes compared to last year's results:

Overall the load forecast went up by 18 MW and that drives the LCR need up by about 24 MW.

North Coast/North Bay Overall Requirements:

2010	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	18	131	736	885

2010	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[11]	787	0	787
Category C (Multiple)[12]	787	3	790

3. Sierra Area

<u>Area Definition</u>

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

[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 then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

[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 MORC.

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 2010 busload within the defined area: 2009 MW with 117 MW of losses resulting in total load + losses of 2126 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
BELDEN_7_UNIT 1	31784	BELDEN	13.8	115.00 1		South of Palermo, South of Table Mountain	Market	
BIOMAS_1_UNIT 1	32156	WOODLAND	9.1	20.78 1		Drum-Rio Oso, South of Palermo, South of Table Mountain		QF/Self gen
BNNIEN_7_ALTAPH 323	76	BONNIE N	60	0.58		Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled - Monthly NQC - used August for LCR	Market
BOGUE_1_UNITA1 324	51	FREC	13.8	45.00 1		Bogue, Drum-Rio Oso, South of Table Mountain	Market	
BOWMN_6_UNIT 324	80	BOWMAN	9.1	1.37 1		Drum-Rio Oso, South of Palermo, South of Table Mountain	MUNI	
BUCKCK_7_OAKFL T				1.30		South of Palermo, South of Table Mountain	Not modeled	Market
BUCKCK_7_PL1X2 318	20	BCKS CRK	11	29.00 1		South of Palermo, South of Table Mountain	Market	
BUCKCK_7_PL1X2 318	20	BCKS CRK	11	29.00 2		South of Palermo, South of Table Mountain	Market	
CHICPK_7_UNIT 1	32462	CHI.PARK	11.5	38.00 1		Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	MUNI	
COLGAT_7_UNIT 1	32450	COLGAT E1	13.8	165.80	1	South of Table Mountain		MUNI
COLGAT_7_UNIT 2	32452	COLGAT E2	13.8	161.68	1	South of Table Mountain	Monthly NQC - used August for LCR	MUNI
CRESTA_7_PL1X2 318	12	CRESTA	11.5	35.00 1		South of Palermo, South of Table Mountain	Market	
CRESTA_7_PL1X2 318	12	CRESTA	11.5	35.00 2		South of Palermo, South of Table Mountain	Market	
DAVIS_7_MNMETH				1.78		Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled	Market

DEADCK_1_UNIT 318	62	DEADWOOD	9.1	0.00 1	Drum-Rio Oso, South of Table Mountain		MUNI
DEERCR_6_UNIT 1	32474	DEER CRK	9.1	5.70 1	Drum-Rio Oso, South of Palermo, South of Table Mountain		Market
DRUM_7_PL1X2 325	04	DRUM 1-2	6.6	13.00 1	Drum-Rio Oso, South of Palermo, South of Table Mountain		Market
DRUM_7_PL1X2 325	04	DRUM 1-2	6.6	13.00 2	Drum-Rio Oso, South of Palermo, South of Table Mountain		Market
DRUM_7_PL3X4 325	06	DRUM 3-4	6.6	14.00 1	Drum-Rio Oso, South of Palermo, South of Table Mountain		Market
DRUM_7_PL3X4 325	06	DRUM 3-4	6.6	14.00 2	Drum-Rio Oso, South of Palermo, South of Table Mountain		Market
DRUM_7_UNIT 5	32454	DRUM 5	13.8	49.50 1	Drum-Rio Oso, South of Palermo, South of Table Mountain		Market
DUTCH1_7_UNIT 1	32464	DTCHFLT1	11	22.00 1	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain		Market
DUTCH2_7_UNIT 1	32502	DTCHFLT2	6.9	26.00 1	Drum-Rio Oso, South of Palermo, South of Table Mountain		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_HELLH L	32486 HELL	HOLE	9.1	0.35 1	South of Rio Oso, South of Palermo, South of Table Mountain		MUNI
FMEADO_7_UNIT 325	08	FRNCH MD	4.2	16.01 1	South of Rio Oso, South of Palermo, South of Table Mountain	Monthly NQC - used August for LCR	MUNI
FORBST_7_UNIT 1 318	14	FORBSTWN 11.5		39.00 1	Drum-Rio Oso, South of Table Mountain		MUNI
GOLDHL_1_QF				0.00	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled	QF/Self gen
GRNLF1_1_UNITS 324	90	GRNLEAF1	13.8	8.08 1	Bogue, Drum-Rio Oso, South of Table Mountain		QF/Self gen
GRNLF1_1_UNITS 324	90	GRNLEAF1	13.8	41.28 2	Bogue, Drum-Rio Oso, South of Table Mountain		QF/Self gen
GRNLF2_1_UNIT 324	92	GRNLEAF2	13.8	48.09 1	Pease, Drum-Rio Oso, South of Table Mountain		QF/Self gen
HALSEY_6_UNIT 324	78 HALSEY	F	9.1	11.00 1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain		Market

HAYPRS_6_QFUNTS	32488	HAYPRES+	9.1	0.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		QF/Self gen
HAYPRS_6_QFUNTS	32488	HAYPRES+	9.1	0.00	2	Drum-Rio Oso, South of Palermo, South of Table Mountain		QF/Self gen
HIGGNS_7_QFUNTS				0.10		Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled	QF/Self gen
KANAKA_1_UNIT				0.00		Drum-Rio Oso, South of Table Mountain	Not modeled	MUNI
KELYRG_6_UNIT 318	34	KELLYRDG	9.1	10.00	1	Drum-Rio Oso, South of Table Mountain	MUNI	
MDFKRL_2_PROJCT	32456	MIDLF ORK	13.8	62.18	1	South of Rio Oso, South of Palermo, South of Table Mountain	Monthly NQC - used August for LCR	MUNI
MDFKRL_2_PROJCT	32458	RALST ON	13.8	84.32	1	South of Rio Oso, South of Palermo, South of Table Mountain	Monthly NQC - used August for LCR	MUNI
MDFKRL_2_PROJCT	32456	MIDLF ORK	13.8	62.18	2	South of Rio Oso, South of Palermo, South of Table Mountain	Monthly NQC - used August for LCR	MUNI
NAROW1_2_UNIT 324	66	NARROWS1	9.1	0.00	1	Colgate, South of Table Mountain	Monthly NQC - used August for LCR	Market
NAROW2_2_UNIT 324	68	NARROWS2	9.1	34.88	1	Colgate, South of Table Mountain	Monthly NQC - used August for LCR	MUNI
NWCSTL_7_UNIT 1	32460	NEWCSTLE	13.2	1.30	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Monthly NQC - used August for LCR	Market
OROVIL_6_UNIT 318	88	OROVLLE	9.1	6.91	1	Drum-Rio Oso, South of Table Mountain		QF/Self gen
OXBOW_6_DRUM	32484	OXBOW F	9.1	6.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	MUNI	
PACORO_6_UNIT 318	90	PO POWER	9.1	8.01	1	Drum-Rio Oso, South of Table Mountain		QF/Self gen
PACORO_6_UNIT 318	90	PO POWER	9.1	8.01	2	Drum-Rio Oso, South of Table Mountain		QF/Self gen
PLACVL_1_CHILIB 325	10	CHILIBAR	4.2	7.00	1	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Market	
PLACVL_1_RCKCRE				0.00		Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled - Monthly NQC - used August for LCR	Market
POEPH_7_UNIT 1	31790	POE 1	13.8	60.00	1	South of Palermo, South of Table Mountain	Market	
POEPH_7_UNIT 2	31792	POE 2	13.8	60.00	1	South of Palermo, South of Table Mountain	Market	
RCKCRK_7_UNIT 1	31786	ROCK CK1	13.8	56.00	1	South of Palermo, South of Table Mountain	Market	

RCKCRK_7_UNIT 2	31788	ROCK CK2	13.8	56.00	1	South of Palermo, South of Table Mountain	Market	
RIOOSO_1_QF				0.56		Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled	QF/Self gen
ROLLIN_6_UNIT 324	76 ROLLINSF		9.1	11.70	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	MUNI	
SLYCRK_1_UNIT 1	31832	SLY.CR.	9.1	13.00	1	Drum-Rio Oso, South of Table Mountain	MUNI	
SPAULD_6_UNIT 3	32472	SPAULDG	9.1	5.80	3	Drum-Rio Oso, South of Palermo, South of Table Mountain	Market	
SPAULD_6_UNIT12	32472	SPAULDG	9.1	4.78	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Monthly NQC - used August for LCR	Market
SPAULD_6_UNIT12	32472	SPAULDG	9.1	4.78	2	Drum-Rio Oso, South of Palermo, South of Table Mountain	Monthly NQC - used August for LCR	Market
SPI LI_2_UNIT 1	32498 SPILINCF		12.5	8.44	1	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain		QF/Self gen
STIGCT_2_LODI 381	14	Stig CC	13.8	49.50	1	South of Rio Oso, South of Palermo, South of Table Mountain	MUNI	
ULTRCK_2_UNIT 325	00	ULTR RCK	9.1	21.28	1	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain		QF/Self gen
WDLEAF_7_UNIT 1	31794	WOODLEAF	13.8	55.00	1	Drum-Rio Oso, South of Table Mountain	MUNI	
WISE_1_UNIT 1	32512	WISE	12	9.20	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Monthly NQC - used August for LCR	Market
WISE_1_UNIT 2	32512	WISE	12	2.79	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Monthly NQC - used August for LCR	Market
YUBACT_1_SUNS WT	32494 YUBA	CTY	9.1	43.62	1	Pease, Drum-Rio Oso, South of Table Mountain		QF/Self gen
YUBACT_6_UNITA1 324	96	YCEC	13.8	46.00	1	Pease, Drum-Rio Oso, South of Table Mountain	Market	
CAMPFW_7_FARW ST	32470 CMP.F	ARW	9.1	6.50	1	Colgate, South of Table Mountain	No NQC - historical data	MUNI
NA 321	62	RIV.DLTA	9.11	3.10	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		QF/Self gen
UCDAVS_1_UNIT 321	66	UC DAVIS	9.1	3.50	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	No NQC - historical data	QF/Self gen

Major new projects modeled:

1. Table Mountain-Rio Oso Reconductor and Tower Upgrade
2. Gold Hill-Missouri Flat #1 and #2 115 kV line Reconductoring
3. South of Palermo 115 kV Reconductoring
4. Atlantic-Lincoln 115 kV Transmission Upgrade
5. Colgate 230/60 kV transformer reinforcement
6. Pease-Marysville #2 60 kV Line
7. Palermo 115 kV Circuit Breaker and Switch Replacement

<u>Critical Contingency Analysis Summary</u>

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 2010 a LCR of 1717 MW (includes 222 MW of QF and 844 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this area.

The most critical single contingency is the loss of the Table Mountain-Rio Oso 230 kV line with one of the Colgate Units out of service. The area limitation is thermal overloading of the Table Mt-Palermo 230 kV line. This limiting contingency establishes in 2010 a LCR of 1133 MW (includes 222 MW of QF and 844 MW of Muni generation).

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	FORBST WN	1	8
31794	WOO DLEAF	1	8
31832	SLY.CR.	1	7
31862	DEADWOO D	1	7
31888	OROV LLE	1	6
31890	PO POWER	2	6
31890	PO POWER	1	6

31834 KELLYRDG	1	6
32452 COL GATE2	1	5
32450 COL GATE1	1	5
32466 NARRO WS1	1	5
32468 NARRO WS2	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 WOO DLAND	1	3
31820 BCKS CRK	1	2
31820 BCKS CRK	2	2
31788 RO CK CK2	1	2
31812 CRESTA	1	2
31812 CRESTA	2	2
31792 POE 2	1	2
31790 POE 1	1	2
31786 RO CK CK1	1	2
31784 BELDEN	1	2
32166 UC DAVIS	1	2
32500 ULT R RCK	1	2
32498 SPILINCF	1	2
32162 RIV.DLTA	1	2
32510 CHILIBAR	1	2
32514 ELDRA DO2	1	2
32513 ELDRA DO1	1	2
32478 HALSEY F	1	2
32458 RALSTO N	1	2
32456 MIDLFO RK	1	2
32456 MIDLFO RK	2	2
38114 Stig CC	1	2
32460 NEWCSTLE	1	2
32512 WISE	1	2
32486 HELL HOLE	1	2
32508 FRNCH MD	1	2
32502 DTCHF LT2	1	2
32462 CHI.PARK	1	2
32464 DTCHF LT1	1	1
32454 DRUM 5	1	1
32476 ROL LINSF	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 BOWMA	N	1	1
32472 SPAULDG		1	1
32472 SPAULDG		2	1
32472 SPAULDG		3	1

Colgate Sub-area

No requirements due to the addition of the Atlantic-Lincoln 115 kV transmission upgrade, Colgate 230/60 kV transformer reinforcement and Pease-Marysville #2 60 kV line projects.

If any one of these project are delayed all units within this area (Narrows #1 & #2 and Camp Far West) are needed.

Pease Sub-area

The most critical contingency is the loss of the Palermo-East Nicolaus 115 kV line with Green Leaf II Cogen unit out of service. The area limitation is thermal overloading of the Palermo-Pease 115 kV line. This limiting contingency establishes a LCR of 137 MW (includes 92 MW of QF generation) in 2010 as the minimum capacity necessary for reliable load serving capability within this sub-area. It is assumed that Oliverhurst is normally served from Palermo-Bogue 115 kV line and East Marysville is normally served from Palermo-East Nicolaus 115 kV line not from Pease-Rio Oso 115 kV line.

Effectiveness factors:

All units within this area (Greenleaf #2, Yuba City and Yuba City EC) are needed therefore no effectiveness factor is required. LCR need is 1 MW less then NQC.

Bogue Sub-area

No requirements due to the addition of the South of Palermo 115 kV 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 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 (most limiting) as well as Bogue-Rio Oso and East Nicolaus-Rio Oso 115 kV lines. This limiting contingency establishes a LCR of 1402 MW (includes 465 MW of QF and Muni generation as well as 213 MW of deficiency) in 2010 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 (most limiting) and Palermo-Pease 115 kV lines. This contingency establishes in 2010 a LCR of 875 MW (includes 465 MW of QF and Muni generation).

Effectiveness factors:

All units within the South of Palermo and Bogue sub-areas are needed therefore no effectiveness factor is required.

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 100 MW (includes 0 MW of QF and Muni generation as well as 71 MW of deficiency) in 2010 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 Drum-Higgins 115 kV line followed by loss of the Gold Hill-Placer #2 115 kV line. The area limitation is thermal overloading of the Gold Hill-Placer #1 115 kV line. This limiting contingency establishes a LCR of 122 MW (includes 0 MW of QF and Muni generation as well as 97 MW of deficiency) in 2010 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency is the loss of the Drum-Higgins 115 kV line with the Halsey unit out of service. The area limitation is thermal overloading of the Gold Hill-Placer #1 115 kV line. This limiting contingency establishes a LCR of 17 MW (includes 0 MW of QF and Muni generation) in 2010.

Effectiveness factors:

All units within this area (Wise units 1&2, Newcastle and Halsey) are needed therefore no effectiveness factor is required.

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 2010 a LCR of 829 MW (includes 422 MW of QF and Muni generation as well as 143 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 2010 a LCR of 493 MW (includes 422 MW of QF and Muni generation).

Effectiveness factors:

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

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 643 MW (includes 343 MW of QF and Muni generation as well as 224 MW of deficiency) in 2010 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 521 MW (includes 343 MW of QF and Muni generation as well as 102 MW of deficiency) in 2010.

Effectiveness factors:

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

Changes compared to last year's results:

Overall the load is constant between 2009 and 2010 with no load growth. The existing generation capacity needed is fairly constant between years; small changes are due to the massive number of new transmission projects in this area as well as the inclusion of Lodi STIG within this LCR Area (previously in the Stockton LCR area). The magnitude of the deficiency has significantly decrease along with some of the sub-area LCRs needs (Colgate and Bogue being eliminated) because new transmission project are due to become operational before summer of 2010.

Sierra Overall Requirements:

2010	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	222	844	769	1835

2010	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[13]	1133	102	1235
Category C (Multiple)[14]	1717	385	2102

4. Stockton Area

Area Definition

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

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

---

[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 then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.
[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 MORC.

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

Total 2010 busload within the defined area: 943 MW with 16 MW of losses resulting in total load + losses of 959 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	Monthly NQC - used August for LCR	MUNI
CURIS_1_QF				0.87		Tesla-Bellota	Not modeled	QF/Selfgen
DONNLS_7_UNIT 340	58	DONNELLS	13.8	72.00 1		Tesla-Bellota	Monthly NQC - used August for LCR	MUNI
LODI25_2_UNIT 1	38120	LODI25CT	9.11	22.70	1	Lockeford	No NQC - historical data	MUNI
PHOENX_1_UNIT				1.45		Tesla-Bellota	Not modeled - Monthly NQC - used August for LCR	Market
SCHLTE_1_UNITA1 338	05	GWFTRCY1	13.8	83.56 1		Tesla-Bellota		Market
SCHLTE_1_UNITA2 338	07	GWFTRCY2	13.8	82.88 1		Tesla-Bellota		Market
SNDBAR_7_UNIT 1	34060	SANDBAR	13.8	9.82 1		Tesla-Bellota		MUNI
SPRGAP_1_UNIT 1	34078	SPRNG GP	6	6.70 1		Tesla-Bellota		Market
STANIS_7_UNIT 1	34062	STANISLS	13.8	91.00 1		Tesla-Bellota		Market
STNRES_1_UNIT 340	56	STNSLSRP	13.8	16.56 1		Tesla-Bellota		QF/Selfgen
STOKCG_1_UNIT 1	33814	CPC STCN	12.5	48.07 1		Tesla-Bellota		QF/Selfgen
TULLCK_7_UNITS 340	76	TULLOCH	6.9	8.23 1		Tesla-Bellota	Monthly NQC - used August for LCR	MUNI
TULLCK_7_UNITS 340	76	TULLOCH	6.9	8.24 2		Tesla-Bellota	Monthly NQC - used August for LCR	MUNI
ULTPCH_1_UNIT 1	34050	CH.STN.	13.8	17.78 1		Tesla-Bellota		QF/Selfgen
VLYHOM_7_SSJID				1.33		Tesla-Bellota	Not modeled	QF/Selfgen
CAMCHE_1_PL1X3 338	50	CAMANCHE	4.2	3.50	1	Tesla-Bellota	No NQC - historical data	MUNI
CAMCHE_1_PL1X3 338	50	CAMANCHE	4.2	3.50	2	Tesla-Bellota	No NQC - historical data	MUNI
CAMCHE_1_PL1X3 338	50	CAMANCHE	4.2	3.50	3	Tesla-Bellota	No NQC - historical data	MUNI
NA 338	30	GEN.MILL	9.11	2.50	1	Lockeford	No NQC - historical data	QF/Selfgen
SPIFBD_1_PL1X2 339	17	FBERBORD	115	3.20	1	Tesla-Bellota	No NQC - historical data	QF/Selfgen

Major new projects modeled:

1. Tesla 115 kV Capacity Increase
2. Reconductor Tesla-Salado-Manteca 115 kV
3. Stagg #1 and #2 230/60 kV transformer replacement
4. Stagg Under Voltage Load Shedding scheme

Critical Contingency Analysis Summary

Stockton overall

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

Tesla-Bellota Sub-area

The two most critical contingencies listed below together establish a local capacity need of 609 MW (includes 88 MW of QF and 117 MW of Muni generation as well as 197 MW of deficiency) in 2010 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 Tesla-Tracy 115 kV and Schulte-Lammers 115 kV. The area limitation is thermal overload of the Tesla-Kasson-Manteca 115 kV line above its emergency rating. This limiting contingency establishes a local capacity need of 501 MW (includes 88 MW of QF and 117 MW of Muni generation as well as 197 MW of deficiency) in 2010.

The second most critical contingency for the Tesla-Bellota pocket is the loss of Tesla-Tracy 115 kV and Tesla-Kasson-Manteca 115 kV. The area limitation is thermal overload of the Tesla-Schulte 115 kV line. This limiting contingency establishes a 2010 local capacity need of 405 MW (includes 88 MW of QF and 117 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 Stanislaus unit #1. The area limitation is thermal overload of the Tesla-Schulte 115 kV line. This single contingency establishes a local capacity need of 357 MW (includes 205 MW of QF and Muni generation) in 2010.

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 2010 local capacity need of 72 MW (including 2 MW of QF and 23 MW of Muni generation as well as 52 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.

Stagg Sub-area

No requirements due to the addition of the addition of the Stagg Under Voltage Load Shedding scheme.

Changes compared to last year's results:

Overall the load forecast went down by 101 MW. Overall the total LCR has decreased by 45 MW however the existing generation capacity needed has decreased by 109 MW mostly because of the following new transmission projects: Stagg UVLS and the reconductoring of Tesla-Salado-Manteca 115 kV line.

Stockton Overall Requirements:

2010	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	90	139	266	495

2010	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[15] 357		0	357
Category C (Multiple)[16] 432		249	681

[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 then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

5. Greater Bay Area

Area Definition

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
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

[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 MORC.

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 2010 bus load within the defined area is 9,879 MW with 240 MW of losses and 157 MW of pumps resulting in total load + losses + pumps of 10,276 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ALMEGT_1_UNIT 1	38118	ALMDACT1	13.8	23.80	1	Oakland		MUNI
ALMEGT_1_UNIT 2	38119	ALMDACT2	13.8	24.00	1	Oakland		MUNI
BLHVN_7_MENLOP				1.57		None	Not modeled	QF/Selfgen
BRDSLD_2_HIWIND	32172	HIGHWINDS	34.5	78.64	1	None	Monthly NQC - used August for LCR	Wind
BRDSLD_2_SHILO1	32176	SHILOH	34.5	34.00	1	None	Monthly NQC - used August for LCR	Wind
CALPIN_1_AGNEW	35860	OLS-AGNE	9.11	26.10	1	San Jose		QF/Selfgen
CARDCG_1_UNITS	33463	CARDINAL	12.47	11.95	1	None		QF/Selfgen
CARDCG_1_UNITS	33463	CARDINAL	12.47	11.95	2	None		QF/Selfgen
CLRMTK_1_QF				0.00		Oakland	Not modeled	QF/Selfgen
COCOPP_7_UNIT 6	33116	C.COS 6	18	337.00	1	None		Market
COCOPP_7_UNIT 7	33117	C.COS 7	18	337.00	1	None		Market
CONTAN_1_UNIT	36856	CCA100	13.8	16.45	1	San Jose		QF/Selfgen
CROKET_7_UNIT	32900	CRCKTCOG	18	240.00	1	Pittsburg		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	Monthly NQC - used August for LCR	Market
DELTA_2_PL1X4	33108	DEC CTG1	18	181.13	1	Pittsburg	Monthly NQC - used August for LCR	Market
DELTA_2_PL1X4	33109	DEC CTG2	18	181.13	1	Pittsburg	Monthly NQC - used August for LCR	Market
DELTA_2_PL1X4	33110	DEC CTG3	18	181.13	1	Pittsburg	Monthly NQC - used August for LCR	Market
DOWCHM_1_UNITS	33161	DOWCHEM1	13.8	4.56	1	Pittsburg		QF/Selfgen
DOWCHM_1_UNITS	33162	DOWCHEM2	13.8	6.02	1	Pittsburg		QF/Selfgen
DOWCHM_1_UNITS	33163	DOWCHEM3	13.8	6.02	1	Pittsburg		QF/Selfgen
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
FLOWD2_2_UNIT 1	35318	FLOWDPTR	9.11	6.93	1	None	Monthly NQC - used August for LCR	Wind
GILROY_1_UNIT	35850	GLRY COG	13.8	69.30	1	Llagas	Monthly NQC - used August for LCR	Market
GILROY_1_UNIT	35850	GLRY COG	13.8	35.70	2	Llagas	Monthly NQC - used August for LCR	Market
GILRPP_1_PL1X2	35851	GROYPKR1	13.8	45.50	1	Llagas	Monthly NQC - used August for LCR	Market
GILRPP_1_PL1X2	35852	GROYPKR2	13.8	45.50	1	Llagas	Monthly NQC - used August for LCR	Market

GILRPP_1_PL3X4 358	53	GROYPKR3	13.8	46.00	1	Llagas	Monthly NQC - used August for LCR	Market
GRZZLY_1_BERKLY 327	40	HILLSIDE	115	26.30	1	None		QF/Selfgen
GWFPW1_6_UNIT 331	31	GWF #1	9.11	19.44	1	Pittsburg		QF/Selfgen
GWFPW2_1_UNIT 1	33132	GWF #2	13.8	18.78	1	Pittsburg		QF/Selfgen
GWFPW3_1_UNIT 1	33133	GWF #3	13.8	19.30	1	Pittsburg		QF/Selfgen
GWFPW4_6_UNIT 1	33134	GWF #4	13.8	19.09	1	Pittsburg		QF/Selfgen
GWFPW5_6_UNIT 1	33135	GWF #5	13.8	18.98	1	Pittsburg		QF/Selfgen
HICKS_7_GUADLP				2.05		None	Not modeled	QF/Selfgen
LECEF_1_UNITS 358	54	LECEFGT1	13.8	46.50	1	San Jose	Monthly NQC - used August for LCR	Market
LECEF_1_UNITS 358	55	LECEFGT2	13.8	46.50	1	San Jose	Monthly NQC - used August for LCR	Market
LECEF_1_UNITS 358	56	LECEFGT3	13.8	46.50	1	San Jose	Monthly NQC - used August for LCR	Market
LECEF_1_UNITS 358	57	LECEFGT4	13.8	46.50	1	San Jose	Monthly NQC - used August for LCR	Market
LFC 51_2_UNIT 1	35310	LFC FIN+	9.11	4.05	1	None	Monthly NQC - used August for LCR	Wind
LMBEPK_2_UNITA1 32173		LAMBGT1	13.8	47.00	1	None	Monthly NQC - used August for LCR	Market
LMBEPK_2_UNITA2 32174		GOOSEHGT	13.8	46.00	2	None	Monthly NQC - used August for LCR	Market
LMBEPK_2_UNITA3 32175		CREEDGT1	13.8	47.00	3	None	Monthly NQC - used August for LCR	Market
LMEC_1_PL1X3 331	11	LMECCT2	18	163.20	1	Pittsburg	Monthly NQC - used August for LCR	Market
LMEC_1_PL1X3 331	12	LMECCT1	18	163.20	1	Pittsburg	Monthly NQC - used August for LCR	Market
LMEC_1_PL1X3 331	13	LMECST1	18	229.60	1	Pittsburg	Monthly NQC - used August for LCR	Market
MARKHM_1_CATLST	35863 CAT	ALYST	9.11	0.00	1	San Jose		QF/Selfgen
MEDOLN_7_CHEVCP				0.79		Pittsburg	Not modeled	QF/Selfgen
METCLF_1_QF				0.37		None	Not modeled	QF/Selfgen
METEC_2_PL1X3 358	81	MEC CTG1	18	178.43	1		Monthly NQC - used August for LCR	Market
METEC_2_PL1X3 358	82	MEC CTG2	18	178.43	1		Monthly NQC - used August for LCR	Market
METEC_2_PL1X3 358	83	MEC STG1	18	213.14	1		Monthly NQC - used August for LCR	Market
MISSIX_1_QF				0.01		San Francisco	Not modeled	QF/Selfgen
MLPTAS_7_QFUNTS				0.50		San Jose	Not modeled	QF/Selfgen
MNTAGU_7_NEWBYI				3.45		None	Not modeled	QF/Selfgen
NEWARK_1_QF				0.02		None	Not modeled	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				0.92		Oakland	Not modeled	MUNI
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
POTRPP_7_UNIT 3	33252	POTRERO3	20	206.00	1	San Francisco		Market
POTRPP_7_UNIT 4	33253	POTRERO4	13.8	52.00	1	San Francisco		Market
POTRPP_7_UNIT 5	33254	POTRERO5	13.8	52.00	1	San Francisco		Market

POTRPP_7_UNIT 6	33255	POTRERO6	13.8	52.00	1	San Francisco		Market
RICHMN_7_BAYENV				2.00		None	Not modeled	QF/Selfgen
RVRVEW_1_UNITA1	33178	RVEC_GEN	13.8	46.00	1	None	Monthly NQC - used August for LCR	Market
SEAWST_6_LAPOS	35312	SEAWESTF	9.11	1.09	1	None	Monthly NQC - used August for LCR	Wind
SRINTL_6_UNIT	33468	SRI INTL	9.11	0.75	1	None		QF/Selfgen
STAUFF_1_UNIT	33139	STAUFER	9.11	0.03	1	None		QF/Selfgen
STOILS_1_UNITS	32921	CHEVGEN1	13.8	0.10	1	Pittsburg		QF/Selfgen
STOILS_1_UNITS	32922	CHEVGEN2	13.8	0.10	1	Pittsburg		QF/Selfgen
TIDWTR_2_UNITS	33151	FOSTER W	12.47	5.53	1	Pittsburg		QF/Selfgen
TIDWTR_2_UNITS	33151	FOSTER W	12.47	5.53	2	Pittsburg		QF/Selfgen
TIDWTR_2_UNITS	33151	FOSTER W	12.47	5.53	3	Pittsburg		QF/Selfgen
UNCHEM_1_UNIT	32920	UNION CH	9.11	18.00	1	Pittsburg		QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.22	1	Pittsburg		QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.22	2	Pittsburg		QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.21	3	Pittsburg		QF/Selfgen
UNTDQF_7_UNITS	33466	UNTED CO	9.11	27.96	1	None		QF/Selfgen
USWNDR_2_UNITS	32168	EXNCO	9.11	12.07	1	None	Monthly NQC - used August for LCR	Wind
USWPFK_6_FRICK	35320	USW FRIC	12	0.75	1	None	Monthly NQC - used August for LCR	Wind
USWPFK_6_FRICK	35320	USW FRIC	12	0.75	2	None	Monthly NQC - used August for LCR	Wind
USWPJR_2_UNITS	33838	USWP_#3	9.11	7.92	1	None	Monthly NQC - used August for LCR	Wind
WNDMAS_2_UNIT 1	33170	WINDMSTR	9.11	1.91	1	None	Monthly NQC - used August for LCR	Wind
ZOND_6_UNIT	35316	ZOND SYS	9.11	3.40	1	None	Monthly NQC - used August for LCR	Wind
GATWAY_2_PL1X3	33118	GATEWAY1	18	179.66	1	None		Market
GATWAY_2_PL1X3	33119	GATEWAY2	18	175.17	1	None		Market
GATWAY_2_PL1X3	33120	GATEWAY3	18	175.17	1	None		Market
IBMCTL_1_UNIT 1	35637	IBM-CTLE	115	0.00	1	San Jose	No NQC - historical data	Market
IMHOFF_1_UNIT 1	33136	CCCSD	12.47	4.40	1	Pittsburg	No NQC - historical data	QF/Selfgen
BRDSLD_2_SHILO2	32177	SHILO	34.5	35.24	2	None	No NQC - estimated data	Wind
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.90	1	None	No NQC - Pmax	Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.90	2	None	No NQC - Pmax	Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.90	3	None	No NQC - Pmax	Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.90	4	None	No NQC - Pmax	Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.90	5	None	No NQC - Pmax	Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.90	6	None	No NQC - Pmax	Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.90	7	None	No NQC - Pmax	Market
SHELRF_1_UNITS	33141	SHELL 1	12.47	19.60	1	Pittsburg		QF/Selfgen
SHELRF_1_UNITS	33142	SHELL 2	12.47	39.20	1	Pittsburg		QF/Selfgen
SHELRF_1_UNITS	33143	SHELL 3	12.47	39.20	1	Pittsburg		QF/Selfgen
USWNDR_2_SMUD	32169	SOLANOWP	21	20.00	1	None	No NQC - historical data	Wind
ZANKER_1_UNIT 1	35861	SJ-SCL W	9.11	2.10	1	San Jose	No NQC - historical data	QF/Selfgen
New unit	32171	HIGHWND3	34.5	10.00	1	None	No NQC - estimated data	Wind

Major new projects modeled:

1. Metcalf-Moss Landing 230 kV Lines Reconductoring
2. Vaca Dixon-Birds Landing 230 kV Lines Reconductoring
3. New Martin-H-P #4 115 kV Cable
4. Contra Costa-Las Positas 230 kV Reconductoring
5. TransBay DC cable
6. Pittsburg-Tesla 230 kV Lines Reconductoring
7. New Oakland underground Cable
8. Re-rate of Tesla #4 and #6 500/230 kV Transformer Banks
9. A-H-W #2 Recabling

<u>Critical Contingency Analysis Summary</u>

San Francisco Sub-area

During 2010, Potrero units #3, #4, #5 and #6 (360 MW) will continue to be required until the Trans Bay DC cable is placed in operation. Until this time, the San Francisco sub-area will be deficient without the operation of Potrero.

Before Trans Bay DC cable is operational, all Potrero units are required to meet local reliability needs. Once the Trans Bay DC cable is placed in service, the ISO estimates that, at minimum, 150 MW of San Francisco generation will be required in order to allow clearances, in off-peak conditions, for the remaining three re-cabling projects within San Francisco as well as clearances for the Newark-Ravenswood 230 kV reconductoring. The exact quantity can only be established once all clearance requests are received and processed. Tentative schedules are set for the beginning of 2011 and the end of 2010 respectively.

After the Trans A-H-W #2 115 kV re-cabling project and the Bay DC cable are operational, the LCR needs (at peak) for San Francisco will be based on an outage of the Trans Bay DC cable and A-H-W #1 115 kV cable. The area limitation is thermal overloading of the A-H-W #2 115 kV cable (at the current projected rating). This limiting contingency establishes a LCR of 25 MW in 2010 (includes 0 MW of Muni generation).

Based on these needs, peak and off-peak, all Bay Area results rely on 150 MW of San Francisco generation being available throughout the year 2010. This assumption is done in order to prepare for the cancelation of the RMR contract for Potrero #3 in mid-year, if feasible, as long as all parties involved agree.

The long-term need for generation in San Francisco will be evaluated during May through September as part of the ISO's 2010 planning process.

Effectiveness factors:

Units within this sub-area have the same effectiveness factor.

Oakland Sub-area

The most critical contingency is an outage of the Claremont K- Oakland D #1 and #2 115 kV lines. The area limitation is thermal overloading of the Moraga-Oakland X #1-4 115 kV lines. This limiting contingency establishes a LCR of 50 MW in 2010 (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. Units outside of this area are not effective.

Llagas Sub-area

The most critical contingency is an outage between Metcalf D and Morgan Hill 115 kV (with one of the Gilroy Peaker off-line). The area limitation is thermal overloading of the Metcalf-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 135 MW in 2010 (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. Units outside of this area are not effective.

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 #2 115 kV line. This limiting contingency establishes a LCR of 386 MW in 2010 (includes 45 MW of QF and 202 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
35863	CATALYST	1	20
36856	CCCA10 0	1	6
36854	Cog en	1	6
36854	Cog en	2	6
36863	DVRa GT1	1	6
36864	DVRb GT2	1	6
36865	DVRaST 3	1	6
35860	OLS-AG NE	1	5
36858	Gia10 0	1	5
36859	Gia20 0	2	5
35854	LECEFGT 1	1	5
35855	LECEFGT 2	2	5
35856	LECEFGT 3	3	5
35857	LECEFGT 4	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 2848 MW in 2010 (including 540 MW of QF/MUNI generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is 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 2418 MW in 2010 (including 540 MW of QF/MUNI generation).

Effectiveness factors:

Please see Bay Area overall.

Bay Area overall

The most critical contingency is the loss of the Tesla-Metcalf 500 kV followed by Tesla-Newark #1 230 kV line or vice versa. The area limitation is thermal overload of the ADCC-Newark 230 kV section of the Tesla-Newark #2 230 kV line. This limiting contingency establishes a LCR of 4651 MW in 2010 (includes 624 MW of QF, 217 MW of Wind and 255 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this area.

The most critical single contingency is the loss of the Tesla-Metcalf 500 kV followed by Delta Energy Center or vice versa. The area limitation is reactive margin within the Bay Area. This limiting contingency establishes a LCR of 4224 MW in 2010 (includes 624 MW of QF, 217 MW of Wind and 255 MW of Muni generation).

Effectiveness factors:

For most helpful procurement information please read procedure T-133Z effectiveness factors at: http://www.caiso.com/docs/2004/11/01/2004110116234011719.pdf

Changes compared to the last stakeholder meeting:

The ISO has reevaluated the Pittsburg/Oakland sub-area with the Trans Bay cable in manual runback mode (effectively having a flow of 0 MW). A new operating procedure will be developed such that anytime one of the Moraga 230/115 kV banks and/or Delta Energy Center are out of service the Trans Bay will be manually runback to mitigate the Pittsburg/Oakland sub-area constraints. The Pittsburg/Oakland LCR needs have decreased by 400 MW as a result the Greater Bay Area overall LCR needs have decreased by 400 MW and the North Coast/North Bay LCR needs have increased by 87 MW.

Changes compared to last year's results:

Overall the load forecast went down by 175 MW and that drives an LCR decrease. Only one new small resource was installed in this area. The reactive margin needs have decreased due to the use of the Metcalf 500 kV capacitors in automatic mode. The new overall constraint is heavily influenced by the Pittsburg and Oakland combined LCR needs that have resulted in higher dispatch in this sub-area than in the past. Combined with the fact that these units are not effective in mitigating the Tesla-Newark #2 230 kV line. As a result many more units not required for the sub-area LCR needs have to satisfy the overall LCR need. All the factors mentioned above have an overall effect of decreasing the overall area LCR by 140 MW.

Bay Area Overall Requirements:

2010	Wind (MW)	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	217	624	255	5608	6704

2010	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[17]	4224	0	4224
Category C (Multiple)[18]	4651	0	4651

[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 then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

6. Greater Fresno Area

<u>Area Definition</u>

The transmission facilities coming into the Greater Fresno area are:

1) Gates-Gregg 230 kV Line
2) Gates-McCall 230 kV Line
3) Gates #1 230/115 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 115 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

2010 total busload within the defined area is 3260 MW with 117 MW of losses resulting in a total (load plus losses) of 3377 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	21.00	3	Wilson, Herndon		Market

[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 MORC.

AGRICO_7_UNIT 346	08	AGRICO	13.8	42.62 2	Wilson, Herndon		Market
AGRICO_7_UNIT 346	08	AGRICO	13.8	7.38 4	Wilson, Herndon		Market
BALCHS_7_UNIT 1	34624	BALCH	13.2	34.00 1	Wilson, Herndon		Market
BALCHS_7_UNIT 2	34612	BLCH	13.8	52.50 1	Wilson, Herndon		Market
BALCHS_7_UNIT 3	34614	BLCH	13.8	52.50 1	Wilson, Herndon		Market
BORDEN_2_QF 308	05	BORDEN	230	1.26	Wilson	Not modeled	QF/Selfgen
BULLRD_7_SAGNES				0.00	Wilson	Not modeled	QF/Selfgen
CAPMAD_1_UNIT 1	34179	MADERA_G	13.8	15.77 1	Wilson		Market
CHEVCO_6_UNIT 1	34652	CHV.COAL	9.11	8.84 1	Wilson		QF/Selfgen
CHEVCO_6_UNIT 2	34652	CHV.COAL	9.11	1.46 2	Wilson		QF/Selfgen
CHWCHL_1_UNIT 343	01	CHOWCOGN	13.8	48.00 1	Wilson, Herndon		Market
COLGA1_6_SHELLW 346	54	COLNGAGN	9.11	35.79 1	Wilson		QF/Selfgen
CRESSY_1_PARKER 341	40	CRESSEY	115	1.76	Wilson	Not modeled	MUNI
CRNEVL_6_CRNVA				0.71	Wilson	Not modeled - Monthly NQC - used August for LCR	Market
CRNEVL_6_SJQN 2	34631	SJ2GEN	9.11	3.20 1	Wilson		Market
CRNEVL_6_SJQN 3	34633	SJ3GEN	9.11	4.20 1	Wilson		Market
DINUBA_6_UNIT 346	48	DINUBA E	13.8	9.87 1	Wilson, Herndon		Market
EXCHEC_7_UNIT 1	34306	EXCHQUER	13.8	61.77 1	Wilson	Monthly NQC - used August for LCR	MUNI
FRIANT_6_UNITS 346	36	FRIANTDM	6.6	9.53 2	Wilson		QF/Selfgen
FRIANT_6_UNITS 346	36	FRIANTDM	6.6	5.09 3	Wilson		QF/Selfgen
FRIANT_6_UNITS 346	36	FRIANTDM	6.6	1.35 4	Wilson		QF/Selfgen
GATES_6_PL1X2 345	53	WHD_GAT2	13.8	38.00 1	Wilson		Market
GWFPWR_1_UNITS 344	31	GWF_HEP1	13.8	42.20 1	Wilson, Herndon		Market
GWFPWR_1_UNITS 344	33	GWF_HEP2	13.8	42.20 1	Wilson, Herndon		Market
GWFPWR_6_UNIT 346	50	GWF-PWR.	9.11	24.34 1	Wilson, Henrietta	QF	/Selfgen
HAASPH_7_PL1X2 34610		HAAS	13.8	68.15 1	Wilson, Herndon	Monthly NQC - used August for LCR	Market
HAASPH_7_PL1X2 34610		HAAS	13.8	68.15 2	Wilson, Herndon	Monthly NQC - used August for LCR	Market
HELMPG_7_UNIT 1	34600	HELMS	18	404.00 1	Wilson		Market
HELMPG_7_UNIT 2	34602	HELMS	18	404.00 2	Wilson		Market
HELMPG_7_UNIT 3	34604	HELMS	18	404.00 3	Wilson		Market
HENRTA_6_UNITA1 345	39	GWF_GT1	13.8	45.33 1	Wilson, Henrietta	Market	
HENRTA_6_UNITA2 345	41	GWF_GT2	13.8	45.23 1	Wilson, Henrietta	Market	
INTTRB_6_UNIT 343	42	INT.TURB	9.11	3.52 1	Wilson	Monthly NQC - used August for LCR	QF/Selfgen
JRWOOD_1_UNIT 1	34332	JRWCOGEN	9.11	7.85 1	Wilson		QF/Selfgen
KERKH1_7_UNIT 1	34344	KERCKHOF	6.6	13.00 1	Wilson, Herndon		Market
KERKH1_7_UNIT 2	34344	KERCKHOF	6.6	8.50 2	Wilson, Herndon		Market
KERKH1_7_UNIT 3	34344	KERCKHOF	6.6	12.80 3	Wilson, Herndon		Market
KERKH2_7_UNIT 1	34308	KERCKHOF	13.8	153.90 1 W	ilson, Herndon		Market
KINGCO_1_KINGBR 346	42	KINGSBUR	9.11	30.91 1	Wilson, Herndon		QF/Selfgen
KINGRV_7_UNIT 1	34616	KINGSRIV	13.8	51.20 1	Wilson, Herndon		Market
MALAGA_1_PL1X2 346	71	KRCDPCT1	13.8	48.00 1	Wilson, Herndon		Market
MALAGA_1_PL1X2 346	72	KRCDPCT2	13.8	48.00 1	Wilson, Herndon		Market
MCCALL_1_QF				0.72	Wilson, Herndon	Not modeled	QF/Selfgen

MCSWAN_6_UNITS 343	20	MCSWAIN	9.11	5.04	1	Wilson	Monthly NQC - used August for LCR	MUNI
MENBIO_6_UNIT 343	34	BIO PWR	9.11	21.63	1	Wilson		QF/Selfgen
MERCFL_6_UNIT 343	22	MERCEDFL	9.11	2.20	1	Wilson	Monthly NQC - used August for LCR	Market
PINFLT_7_UNITS 387	20	PINEFLAT	13.8	70.00	1	Wilson, Herndon		MUNI
PINFLT_7_UNITS 387	20	PINEFLAT	13.8	70.00	2	Wilson, Herndon		MUNI
PINFLT_7_UNITS 387	20	PINEFLAT	13.8	70.00	3	Wilson, Herndon		MUNI
PNOCHE_1_PL1X2 341	42	WHD_PAN2	13.8	40.00	1	Wilson, Herndon		Market
PNOCHE_1_UNITA1 341	86	DG_PAN1	13.8	42.78	1	Wilson		Market
SGREGY_6_SANGER 346	46	SANGERCO	9.11	38.12	1	Wilson		QF/Selfgen
STOREY_7_MDRCHW				1.26		Wilson	Not modeled	QF/Selfgen
ULTPFR_1_UNIT 1	34640	ULTR.PWR	9.11	21.68	1	Wilson, Herndon		QF/Selfgen
WISHON_6_UNITS 346	58	WISHON	2.3	4.51	1	Wilson		Market
WISHON_6_UNITS 346	58	WISHON	2.3	4.51	2	Wilson		Market
WISHON_6_UNITS 346	58	WISHON	2.3	4.51	3	Wilson		Market
WISHON_6_UNITS 346	58	WISHON	2.3	4.51	4	Wilson		Market
WISHON_6_UNITS 346	58	WISHON	2.3	0.36	5	Wilson		Market
WRGHTP_7_AMENGY				0.67		Wilson	Not modeled	QF/Selfgen
CHWCHL_1_BIOMAS 343	05	CHWCHLA2	13.8	12.50	1	Wilson, Herndon	No NQC - Pmax	Market
ELNIDP_6_BIOMAS 343	30	ELNIDO	13.8	12.50	1	Wilson	No NQC - Pmax	Market
NA 344	85	FRESNOWW	12.5	9.00	1	Wilson	No NQC - historical data	QF/Selfgen
ONLLPP_6_UNIT 1	34316	ONEILPMP	9.11	0.50	1	Wilson	No NQC - historical data	MUNI
PNCHPP_1_CTG1 343	28	P0504GT1	13.8	60.90	1	Wilson	No NQC - Pmax	Market
PNCHPP_1_CTG2 343	29	P0504GT2	13.8	60.90	1	Wilson	No NQC - Pmax	Market

Major new projects modeled:

1. Two new small peakers

Critical Contingency Analysis Summary

Wilson Sub-area

The Wilson sub-area largely defines the Fresno area import constraints. The main constrained spot is located at Wanerville-Wilson-Gregg 230 kV transmission corridor. Other constrained spots are located at the Gates-McCall, Gates-Gregg, Panoche-McCall and Panoche-Gregg 230 kV transmission corridors.

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 2063 MW in 2010 (includes

223 MW of QF and 279 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	JRWCOGE N	1	40%
34330	ELNIDO	1	37%
34322	MERCE DFL	1	35%
34320	MCSWAI N	1	34%
34306	EXCHQ UER	1	34%
34305	CHWCHLA2	1	32%
34301	CHOWCO GN	1	32%
34658	WISHO N	1	28%
34658	WISHO N	1	28%
34658	WISHO N	1	28%
34658	WISHO N	1	28%
34658	WISHO N	1	28%
34631	SJ2GE N	1	28%
34633	SJ3GE N	1	27%
34636	FRIANT DM	2	27%
34636	FRIANT DM	3	27%
34636	FRIANT DM	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	KRCDPCT 1	1	21%
34672	KRCDPCT 2	1	21%
34640	ULT R.PWR	1	21%
34646	SANGERCO	1	21%
34642	KINGSBUR	1	19%
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%
34608	AGRICO	2	14%
34608	AGRICO	3	14%
34608	AGRICO	4	14%
34539	GWF _GT1	1	14%
34541	GWF _GT2	1	14%
34650	GWF -PWR.	1	13%
34186	DG_PA N1	1	11%
34142	WHD_PA N2	1	11%
34652	CHV.COAL	1	10%
34652	CHV.COAL	2	10%
34553	WHD_ GAT2	1	9%
34654	COL NGAGN	1	9%
34342	INT.TURB	1	6%
34316	ONEILPMP	1	6%

Herndon Sub-area

The most critical contingency is the loss of the Herndon #1 230/115 kV transformer overlapped with Kerckhoff II generator out of service. This contingency could thermally overload the parallel Herndon #2 230/115 kV transformer. This limiting contingency establishes a LCR of 1175 MW (includes 53 MW of QF and 210 MW of Muni generation) in 2010 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency for the Herndon sub-area is the loss of the Herndon #1 230/115 kV transformer, which could thermally overload the parallel Herndon #2 230/115 kV transformer. This limiting contingency establishes a LCR of 845 MW (includes 53 MW of QF and 210 MW of Muni generation) in 2010.

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 (%)
34308	KERCKHOF	1	34%
34344	KERCKHOF	1	34%
34344	KERCKHOF	2	34%
34344	KERCKHOF	3	34%
34624	BALCH 1	1	33%

34646 SANGERCO	1	31%
34616 KINGSRIV	1	31%
34671 KRCDPCT 1	1	31%
34672 KRCDPCT 2	1	31%
34640 ULT R.PWR	1	30%
34648 DINUBA E	1	28%
34642 KINGSBUR	1	25%
38720 PINE FLT	1	23%
38720 PINE FLT	2	23%
38720 PINE FLT	3	23%
34610 HAAS	1	23%
34610 HAAS	2	23%
34614 BLCH 2-3	1	23%
34612 BLCH 2-2	1	23%
34431 GWF _HEP1	1	14%
34433 GWF _HEP2	1	14%
34301 CHOWCO GN	1	9%
34305 CHWCHLA2	1	9%
34608 AGRICO	2	7%
34608 AGRICO	3	7%
34608 AGRICO	4	7%
34332 JRWCOGE N	1	-6%
34600 HELMS 1	1	-12%
34602 HELMS 2	1	-12%
34604 HELMS 3	1	-12%
34485 FRESNOWW	1	-14%

Henrietta Sub-area

The two most critical contingencies listed below together establish a local capacity need of 33 MW (includes 24 MW of QF) in 2010 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical contingency is the loss of Henrietta 230/70 kV transformer bank #4 and GWF Power unit. This contingency could thermally overload the Henrietta 230/70 kV transformer bank #2. This limiting contingency establishes a LCR of 18 MW in 2010 (includes 0 MW of QF generation).

The second most critical contingency is the loss of Henrietta 230/70 kV transformer bank #4 and one of the Henrietta-GWF Henrietta 70 kV line. This contingency could thermally overload the Henrietta 230/70 kV transformer bank #2. This limiting contingency establishes a LCR of 15 MW in 2010 (includes 24 MW of QF generation).

The most critical single contingency is the loss of Henrietta 230/70 kV transformer bank #4. This contingency could thermally overload the Henrietta 230/70 kV transformer bank #2. This limiting contingency establishes a LCR of 15 MW in 2010 (includes 24 MW of QF generation).

Effectiveness factors:

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

Changes compared to last year's results:

Overall the load forecast is steady (down by 4 MW). Path 15 flow is 1275 MW N-S the same as last year. Due to small re-dispatch between sub-areas the total overall effect is that LCR has decreased by 40 MW.

Fresno Area Overall Requirements:

2010	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	223	279	2439	2941

2010	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single) [19]	2310	0	2310
Category C (Multiple) [20]	2640	0	2640

[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 then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

[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 MORC.

7. Kern Area

Area Definition

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 & 3A
3) Kern PP 230/115 kV Bank # 4
4) Kern PP 230/115 kV Bank # 5
5) Midway 230/115 Bank # 1
6) Midway 230/115 Bank # 2 & 2a
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

The transmission facilities coming into the Weedpatch sub-area are:

1) Wheeler Ridge-Tejon 60 kV line
2) Wheeler Ridge-Weedpach 60 kV line
3) Wheeler Ridge-San Bernard 60 kV line

The substations that delineate the Weedpatch sub-area are:

1) Wheeler Ridge is out Tejon is in
2) Wheeler Ridge is out Weedpach is in
3) Wheeler Ridge is out San Bernard is in

2010 total busload within the defined area: 1228 MW with 12 MW of losses resulting in a total (load plus losses) of 1240 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
BDGRCK_1_UNITS	35029	BADGERCK	9.11	42.34	1	Kern PP		QF/Selfgen
BEARMT_1_UNIT	35066	PSE-BEAR	9.11	44.91	1	Kern PP		QF/Selfgen
CHALK_1_UNIT	35038	CHLKCLF+	9.11	44.00	1	Kern PP		QF/Selfgen
CHEVCD_6_UNIT	35052	CHEV.USA	9.11	0.48	1	Kern PP		QF/Selfgen
CHEVCY_1_UNIT	35032	CHV-CYMR	9.11	6.58	1	Kern PP		QF/Selfgen

DEXZEL_1_UNIT 350	24	DEXEL +	9.11	29.59	1	Kern PP		QF/Selfgen
DISCOV_1_CHEVRN 350	62	DISCOVRY	9.11	4.05	1	Kern PP		QF/Selfgen
DOUBLC_1_UNITS 350	23	DOUBLE C	9.11	46.85	1	Kern PP		QF/Selfgen
FELLOW_7_QFUNTS				2.17		Kern PP	Not modeled	QF/Selfgen
FRITO_1_LAY 350	48	FRITOLAY	9.11	0.09	1	Kern PP		QF/Selfgen
KERNFT_1_UNITS 350	26	KERNFRNT	9.11	47.02	1	Kern PP		QF/Selfgen
KERNRG_1_UNITS 350	40	KERNRDGE	9.11	0.44	1	Kern PP		QF/Selfgen
KERNRG_1_UNITS 350	40	KERNRDGE	9.11	0.46	2	Kern PP		QF/Selfgen
KRNCNY_6_UNIT 350	18	KERNCNYN	9.11	9.22	1	Weedpatch	Monthly NQC - used August for LCR	Market
KRNOIL_7_TEXEXP				11.88		Kern PP	Not Modeled	QF/Selfgen
LIVOAK_1_UNIT 1	35058	PSE-LVOK	9.11	44.18	1	Kern PP		QF/Selfgen
MIDSET_1_UNIT 1	35044	TX MIDST	9.11	34.33	1	Kern PP		QF/Selfgen
MIDWAY_1_QF				0.03		Kern PP	Not modeled	QF/Selfgen
MKTRCK_1_UNIT 1	35060	PSEMCKIT	9.11	43.92	1	Kern PP		QF/Selfgen
MTNPOS_1_UNIT 350	36	MT POSO	9.11	51.31	1	Kern PP		QF/Selfgen
NAVY35_1_UNITS 35064		NAVY 35R	9.11	0.00	1	Kern PP		QF/Selfgen
NAVY35_1_UNITS 35064		NAVY 35R	9.11	0.00	2	Kern PP		QF/Selfgen
OILDAL_1_UNIT 1	35028	OILDALE	9.11	39.41	1	Kern PP		QF/Selfgen
RIOBRV_6_UNIT 1	35020	RIOBRAVO	9.11	7.59	1	Weedpatch		QF/Selfgen
SIERRA_1_UNITS 350	27	HISIERRA	9.11	47.10	1	Kern PP		QF/Selfgen
TANHIL_6_SOLART 350	50	SLR-TANN	9.11	8.75	1	Kern PP		QF/Selfgen
TEMBLR_7_WELLPT				0.57		Kern PP	Not modeled	QF/Selfgen
TXMCKT_6_UNIT				2.61		Kern PP	Not modeled	QF/Selfgen
TXNMID_1_UNIT 2	34783	TEXCO_NM	9.11	0.00	1	Kern PP		QF/Selfgen
TXNMID_1_UNIT 2	34783	TEXCO_NM	9.11	0.00	2	Kern PP		QF/Selfgen
ULTOGL_1_POSO 350	35	ULTR PWR	9.11	34.97	1	Kern PP		QF/Selfgen
UNVRSY_1_UNIT 1	35037	UNIVRSTY	9.11	32.59	1	Kern PP		QF/Selfgen
VEDDER_1_SEKERN 350	46	SEKR	9.11	18.44	1	Kern PP		QF/Selfgen
NA 350	56	TX-LOSTH	4.16	9.00	1	Kern PP	No NQC - historical data	QF/Selfgen

Major new projects modeled:

1. None

Critical Contingency Analysis Summary

Kern PP Sub-area

The most critical contingency is the outage of the Kern PP #5 230/115 kV transformer bank followed by the Kern PP – Kern Front 115 kV line, which could thermally overload the parallel Kern PP #3 and #3a 230/115 kV transformers. This limiting contingency establishes a LCR of 386 MW in 2010 (includes 648 MW of QF generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the loss of Kern PP #5 230/115 kV transformer bank, which could thermally overload the parallel Kern PP #3 and #3a 230/115 kV transformers. This limiting contingency establishes a LCR of 187 MW in 2010 (includes 648 MW of QF generation).

Effectiveness factors:

The following table shows units that are at least 5% effective to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
35066	PSE-BEAR	1	22%
35029	BADGERCK	1	22%
35023	DO UBLE C	1	22%
35027	HISIERRA	1	22%
35026	KERNF RNT	1	21%
35058	PSE-LVOK	1	21%
35028	OILDALE	1	21%
35062	DISCOV RY	1	21%
35046	SEKR	1	21%
35024	DEXEL +	1	21%
35036	MT POSO	1	15%
35035	ULT R PWR	1	15%
35052	CHEV.USA	1	6%

Weedpatch Sub-area

The most critical contingency is the loss of the Wheeler Ridge – San Bernard 70 kV line followed by the Wheeler Ridge – Tejon 70 kV line, which could thermally overload the Wheeler Ridge – Weedpatch 70 kV line and cause low voltage problem at the local 70 kV transmission system. This limiting contingency establishes a LCR of 18 MW in 2010 (includes 8 MW of QF generation and 1 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.

Changes compared to last year's results:

Overall the load forecast went down by 76 MW and that drives the LCR down as well. Also this area is comprised heavily of QF facilities, which had an increase in NQC of 10 MW. As a result, following the LCR manual, the CAISO was able to decrease output from units less effective at resolving the contingency. The overall effect is that LCR has decreased by 18 MW.

Kern Area Overall Requirements:

2010	QF/Selfgen (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	656	9	665

2010	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[21] 187		0	187
Category C (Multiple)[22] 40	3	1	404

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 #1, #2 & #3 500 kV Lines
4) Sylmar - Eagle Rock 230 kV Line
5) Sylmar - Gould 230 kV Line
6) Vincent - Mesa Cal 230 kV Line
7) Antelope - Mesa Cal 230 kV Line
8) Vincent - Rio Hondo #1 & #2 230 kV Lines
9) Eagle Rock - Pardee 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 then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.
[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 MORC.

10) Devers - Palo Verde 500 kV Line
11) Devers – Harquahala 500 kV Line
12) Mirage - Coachelv 230 kV Line
13) Mirage - Ramon 230 kV Line
14) Mirage - Julian Hinds 230 kV Line

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) Eagle Rock is in Sylmar is out
5) Gould is in Sylmar is out
6) Mesa Cal is in Vincent is out
7) Mesa Cal is in Antelope 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) Devers is in Harquahala is out
12) Mirage is in Coachelv is out
13) Mirage is in Ramon is out
14) Mirage is in Julian Hinds is out

Total 2010 busload within the defined area is 19,527 MW with 517 MW of losses and 14 MW pumps resulting in total load + losses + pumps of 20,058 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_7_CT 252	03	ANAHEIMG	13.8	46.00	1	Western		MUNI
ARCOGN_2_UNITS	24011	ARCO 1G	13.8	62.71	1	Western		QF/Selfgen
ARCOGN_2_UNITS	24012	ARCO 2G	13.8	62.71	2	Western		QF/Selfgen
ARCOGN_2_UNITS	24013	ARCO 3G	13.8	62.71	3	Western		QF/Selfgen
ARCOGN_2_UNITS	24014	ARCO 4G	13.8	62.71	4	Western		QF/Selfgen
ARCOGN_2_UNITS	24163	ARCO 5G	13.8	31.36	5	Western		QF/Selfgen
ARCOGN_2_UNITS	24164	ARCO 6G	13.8	31.36	6	Western		QF/Selfgen
BARRE_2_QF 240	16	BARRE	230	0.00		Western	Not modeled	QF/Selfgen
BARRE_6_PEAKER 28309		BARPKGEN	13.8	45.38	1	Western		Market
BRDWAY_7_UNIT 3	28007	BRODWYSC	13.8	65.00	1	Western		MUNI

BUCKWD_7_WINTCV 256	34	BUCKWIND	115	0.24	W	5	Eastern		Wind
CABZON_1_WINDA1 282	80	CABAZON	33	12.55	1		Eastern	Monthly NQC - used August for LCR	Wind
CENTER_2_QF 242	03	CENTER S	66	24.81			Western	Not Modeled	QF/Selfgen
CENTER_2_RHONDO 242	03	CENTER S	66	1.91			Western	Not Modeled	QF/Selfgen
CENTER_6_PEAKER 283	08	CTRPKGEN	13.8	44.57	1		Western		Market
CENTRY_6_PL1X4				36.00			Eastern	Not Modeled	Market
CHEVMN_2_UNITS 240	22	CHEVGEN1	13.8	1.47	1		Western		QF/Selfgen
CHEVMN_2_UNITS 240	23	CHEVGEN2	13.8	1.50	2		Western		QF/Selfgen
CHINO_2_QF 240	24	CHINO	66	7.46			Western	Not modeled	QF/Selfgen
CHINO_6_CIMGEN 240	26	CIMGEN	13.8	24.83	1		Western		QF/Selfgen
CHINO_6_SMPPAP 241	40	SIMPSON	13.8	38.67	1		Western		QF/Selfgen
CHINO_7_MILIKN 240	24	CHINO	66	1.90			Western	Not modeled	Market
COLTON_6_AGUAM1				43.00			Eastern	Not Modeled	MUNI
CORONS_6_CLRWTR 242	10	MIRALOMA	66	14.00			Eastern	Not modeled	MUNI
CORONS_6_CLRWTR 242	10	MIRALOMA	66	14.00			Eastern	Not modeled	MUNI
DEVERS_1_QF 256	45	VENWIND	115	2.85	EU		Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF 256	35	ALTWIND	115	5.55	Q1		Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF 256	36	RENWIND	115	1.06	Q1		Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF 256	45	VENWIND	115	3.26	Q1		Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF 256	46	SANWIND	115	4.72	Q1		Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF 256	35	ALTWIND	115	2.55	Q2		Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF 256	36	RENWIND	115	1.11	Q2		Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF 256	45	VENWIND	115	4.30	Q2		Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF 256	46	SANWIND	115	0.51	Q2		Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF 248	15	GARNET	115	12.59	QF		Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF 256	32	TERAWND	115	3.80	QF		Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF 256	33	CAPWIND	115	3.38	QF		Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF 256	34	BUCKWIND	115	2.89	QF		Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF 256	37	TRANWIND	115	6.75	QF		Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF 256	39	SEAWIND	115	4.55	QF		Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF 256	40	PANAERO	115	5.06	QF		Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF 256	36	RENWIND	115	1.51	W	1	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DMDVLY_1_UNITS 254	25	ESRP P2	6.9	21.00			Eastern	Not modeled	QF/Selfgen
DREWS_6_PL1X4				36.00			Eastern	Not modeled	Market
DVLCYN_1_UNITS 256	48	DVLCYN1G	13.8	50.74	1		Eastern		MUNI
DVLCYN_1_UNITS 256	49	DVLCYN2G	13.8	50.74	2		Eastern		MUNI
DVLCYN_1_UNITS 256	03	DVLCYN3G	13.8	67.66	3		Eastern		MUNI
DVLCYN_1_UNITS 256	04	DVLCYN4G	13.8	67.66	4		Eastern		MUNI
ELLIS_2_QF 241	97	ELLIS	66	0.48			Western	Not modeled	QF/Selfgen
ELSEGN_7_UNIT 3	24047	ELSEG3 G	18	335.00	3		Western		Market

ELSEGN_7_UNIT 4	24048	ELSEG4 G	18	335.00	4	Western		Market
ETIWND_2_FONTNA 240	55	ETIWANDA	66	0.82		Eastern	Not modeled	QF/Selfgen
ETIWND_2_QF 240	55	ETIWANDA	66	16.07		Eastern	Not modeled	QF/Selfgen
ETIWND_6_GRPLND 283	05	ETWPKGEN	13.8	42.53	1	Eastern		Market
ETIWND_6_MWDETI 254	22	ETI MWDG	13.8	21.19	1	Eastern		Market
ETIWND_7_MIDVLY 240	55	ETIWANDA	66	2.10		Eastern	Not modeled	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 248	15	GARNET	115	0.64	G1	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
GARNET_1_UNITS 248	15	GARNET	115	0.23	G2	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
GARNET_1_UNITS 248	15	GARNET	115	0.46	G3	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
GARNET_1_UNITS 248	15	GARNET	115	0.23	PC	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
GLNARM_7_UNIT 1	28005	PASADNA1	13.8	22.30	1	Western		MUNI
GLNARM_7_UNIT 2	28006	PASADNA2	13.8	22.30	1	Western		MUNI
GLNARM_7_UNIT 3	28005	PASADNA1	13.8	44.83		Western	Not modeled	MUNI
GLNARM_7_UNIT 4	28006	PASADNA2	13.8	42.42		Western	Not modeled	MUNI
HARBGN_7_UNITS 240	62	HARBOR G	13.8	76.28	1	Western		Market
HARBGN_7_UNITS 240	62	HARBOR G	13.8	11.86	HP	Western		Market
HARBGN_7_UNITS 255	10	HARBORG4	4.16	11.86	LP	Western		Market
HINSON_6_CARBGN 240	20	CARBOGEN	13.8	29.00	1	Western		Market
HINSON_6_LBECH1	24078	LBEACH1G	13.8	65.00	1	Western		Market
HINSON_6_LBECH2	24170	LBEACH2G	13.8	65.00	2	Western		Market
HINSON_6_LBECH3	24171	LBEACH3G	13.8	65.00	3	Western		Market
HINSON_6_LBECH4	24172	LBEACH4G	13.8	65.00	4	Western		Market
HINSON_6_SERRGN 241	39	SERRFGEN	13.8	25.74	1	Western		QF/Selfgen
HNTGBH_7_UNIT 1	24066	HUNT1 G	13.8	225.75	1	Western		Market
HNTGBH_7_UNIT 2	24067	HUNT2 G	13.8	225.80	2	Western		Market
HNTGBH_7_UNIT 3	24167	HUNT3 G	13.8	225.00	3	Western		Market
HNTGBH_7_UNIT 4	24168	HUNT4 G	13.8	227.00	4	Western		Market
INDIGO_1_UNIT 1	28190	WINTECX2	13.8	42.00	1	Eastern		Market
INDIGO_1_UNIT 2	28191	WINTECX1	13.8	42.00	1	Eastern		Market
INDIGO_1_UNIT 3	28180	WINTEC8	13.8	42.00	1	Eastern		Market
JOHANN_6_QFA1 240	72	JOHANNA	230	0.00		Western	Not Modeled	QF/Selfgen
LACIEN_2_VENICE 242	08	LCIENEGA	66	3.68		Western	Not modeled	QF/Selfgen
LAFRES_6_QF	24073	LA FRESA	66	3.58		Western	Not modeled	QF/Selfgen
LAGBEL_6_QF 240	75	LAGUBELL	66	10.03		Western	Not modeled	QF/Selfgen
LGHTHP_6_ICEGEN 240	70	ICEGEN	13.8	47.97	1	Western		QF/Selfgen
LGHTHP_6_QF 240	83	LITEHIPE	66	0.70		Western	Not modeled	QF/Selfgen
MESAS_2_QF 242	09	MESA CAL	66	0.69		Western	Not modeled	QF/Selfgen
MIRLOM_2_CORONA				1.94		Eastern	Not modeled	QF/Selfgen
MIRLOM_2_TEMESC				2.18		Eastern	Not modeled	QF/Selfgen
MIRLOM_6_DELGEN 240	30	DELGEN	13.8	37.94	1	Eastern		QF/Selfgen
MIRLOM_6_PEAKER 283	07	MRLPKGEN	13.8	43.18	1	Eastern		Market
MOJAVE_1_SIPHON				14.00		Eastern	Not modeled	Market
MTWIND_1_UNIT 1				14.03		Eastern	Not modeled - Monthly NQC - used August for LCR	Wind
MTWIND_1_UNIT 2				6.57		Eastern	Not modeled - Monthly NQC - used August for LCR	Wind
MTWIND_1_UNIT 3				6.74		Eastern	Not modeled - Monthly NQC - used	Wind

								August for LCR	
OLINDA_2_COYCRK 242	11	OLINDA	66	3.13			Western	Not modeled	QF/Selfgen
OLINDA_2_QF 242	11	OLINDA	66	0.13	1		Western		QF/Selfgen
OLINDA_7_LNDFIL 242	01	BARRE	66	4.85			Western	Not modeled	QF/Selfgen
PADUA_2_ONTARO 241	11	PADUA	66	1.09			Eastern	Not modeled	QF/Selfgen
PADUA_6_QF 241	11	PADUA	66	6.05			Eastern	Not modeled	QF/Selfgen
PADUA_7_SDIMAS 241	11	PADUA	66	1.05			Eastern	Not modeled Monthly NQC - used August for LCR	QF/Selfgen
PWEST_1_UNIT				0.60			Western	Not modeled	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	493.24	7		Western		Market
REDOND_7_UNIT 8	24124	REDON8 G	20	495.90	8		Western		Market
RHONDO_2_QF 242	13	RIOHONDO	66	0.00			Western	Not modeled	QF/Selfgen
RVSIDE_6_RERCU1 242	42	RERC1G	13.8	48.50	1		Eastern		MUNI
RVSIDE_6_RERCU2 242	43	RERC2G	13.8	48.50	1		Eastern		MUNI
RVSIDE_6_SPRING 242	44	SPRINGEN	13.8	38.00	1		Eastern		Market
SANTGO_6_COYOTE 241	33	SANTIAGO	66	9.99	1		Western		Market
SBERDO_2_PSP3 249	21	MNTV-CT1	18	129.71	1		Eastern		Market
SBERDO_2_PSP3 249	22	MNTV-CT2	18	129.71	1		Eastern		Market
SBERDO_2_PSP3 249	23	MNTV-ST1	18	225.08	1		Eastern		Market
SBERDO_2_PSP4 249	24	MNTV-CT3	18	129.71	1		Eastern		Market
SBERDO_2_PSP4 249	25	MNTV-CT4	18	129.71	1		Eastern		Market
SBERDO_2_PSP4 249	26	MNTV-ST2	18	225.08	1		Eastern		Market
SBERDO_2_QF 242	14	SANBRDNO	66	0.11			Eastern	Not modeled	QF/Selfgen
SBERDO_2_SNTANA 242	14	SANBRDNO	66	1.02			Eastern	Not modeled	QF/Selfgen
SBERDO_6_MILLCK 242	14	SANBRDNO	66	1.75			Eastern	Not modeled	QF/Selfgen
SONGS_7_UNIT 2	24129	S.ONOFR2	22	1122.00	2		Western		Nuclear
SONGS_7_UNIT 3	24130	S.ONOFR3	22	1124.00	3		Western		Nuclear
TIFFNY_1_DILLON				8.20			Western	Not modeled	Wind
VALLEY_5_PERRIS 241	60	VALLEYSC	115	7.94	1		Eastern	Not modeled	QF/Selfgen
VALLEY_5_REDMTN 241	60	VALLEYSC	115	3.00			Eastern	Not modeled	QF/Selfgen
VALLEY_7_BADLND 241	60	VALLEYSC	115	1.30			Eastern	Not modeled	Market
VALLEY_7_UNITA1 241	60	VALLEYSC	115	1.46			Eastern	Not modeled	Market
VERNON_6_GONZL1				5.50			Western	Not modeled	MUNI
VERNON_6_GONZL2				5.50			Western	Not modeled	MUNI
VERNON_6_MALBRG 242	39	MALBRG1G	13.8	42.37	C1		Western		MUNI
VERNON_6_MALBRG 242	40	MALBRG2G	13.8	42.37	C2		Western		MUNI
VERNON_6_MALBRG 242	41	MALBRG3G	13.8	49.26	S3		Western		MUNI
VILLPK_2_VALLYV				4.10			Eastern	Not modeled	QF/Selfgen
VISTA_6_QF 249	02	VSTA	66	0.05	1		Eastern		QF/Selfgen
WALNUT_6_HILLGEN 240	63	HILLGEN	13.8	46.69	1		Western		QF/Selfgen
WALNUT_7_WCOVCT 241	57	WALNUT	66	1.96			Western	Not modeled	Market
WALNUT_7_WCOVST 241	57	WALNUT	66	3.19			Western	Not modeled	Market
WHTWTR_1_WINDA1 280	61	WHITEWTR	33	15.58	1		Eastern	Monthly NQC - used August for LCR	Wind
ARCOGN_2_UNITS 240	18	BRIGEN	13.8	35.00	1		Western	No NQC - historical data	Market
GARNET_1_WIND 248	15	GARNET	115	1.00	W	2	Eastern	No NQC - historical data	Wind
GARNET_1_WIND 248	15	GARNET	115	1.00	W	3	Eastern	No NQC - historical data	Wind
HINSON_6_QF 240	64	HINSON	66	0.00	1		Western	No NQC - historical data	QF/Selfgen

INLAND_6_UNIT	24071	INLAND	13.8	30.00	1	Eastern	No NQC - historical data	QF/Selfgen
INLDEM_5_UNIT 1	28041	IEEC-G1	19.5	376.20	1	Eastern		Market
INLDEM_5_UNIT 2	28042	IEEC-G2	19.5	336.70	1	Eastern		Market
MOBGEN_6_UNIT 1	24094	MOBGEN	13.8	45.00	1	Western	No NQC - historical data	QF/Selfgen
NA	24027	COLDGEN	13.8	0.00	1	Western	No NQC - historical data	Market
NA	24060	GROWGEN	13.8	0.00	1	Western	No NQC - historical data	Market
NA	28023	WINTEC4	12	0.00	1	Eastern	No NQC - historical data	Wind
NA	28260	ALTAMSA4	115	0.00	1	Eastern		Wind
NA	28060	SEAWEST	115	0.00	S1	Eastern		Wind
NA	28060	SEAWEST	115	0.00	S2	Eastern		Wind
NA	28060	SEAWEST	115	0.00	S3	Eastern		Wind
PULPGN_6_UNIT	24120	PULPGEN	13.8	35.00	1	Western	No NQC - historical data	Market
NA	28020	WINTEC6	115	0.00	1	Eastern	No NQC - historical data	Wind
New unit	28951	REFUSE	13.8	12.00	1	Western	No NQC - Pmax	Market
New unit	28953	SIGGEN	13.8	25.00	1	Western	No NQC - Pmax	Market

Major new projects modeled:

1. Two new peakers

Critical Contingency Analysis Summary

LA Basin Overall:

The most critical contingency for LA Basin is the loss of one Songs 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 9,735 MW in 2010 (includes 813 MW of QF, 66 MW of Wind, 793 MW of MUNI and 2246 MW of Nuclear generation) as the minimum generation capacity necessary for reliable load serving capability within this area.

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	35

24053	MTNVIST4	4	35
24071	INLAND	1	33
25422	ETI MWDG	1	33
28305 ETWPKGEN		1	33
24921	MNTV-CT1	1	29
24922	MNTV-CT2	1	29
24924	MNTV-CT3	1	29
24925	MNTV-CT4	1	29
24926	MNTV-ST2	1	29
24923	MNTV-ST1	1	28
24244	SPRINGEN	1	28
24905	RVCANAL1	1	27
24906	RVCANAL2	2	27
24907	RVCANAL3	3	27
24908	RVCANAL4	4	27
28041	IEEC-G1	1	27
28042	IEEC-G2	2	27
25648	DVLCYN1G	1	26
25649	DVLCYN2G	2	26
25603	DVLCYN3G	3	26
25604	DVLCYN4G	4	26
25632	TERAWND	QF	26
25633	CAPWIND	QF	26
28021	WINTEC6	1	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
28190	WINTECX2	1	26
28191	WINTECX1	1	26
28180	WINTEC8	1	26
24815	GARNET	QF	26
24815	GARNET	W3	26
24815	GARNET	W2	26
28023	WINTEC4	1	26
28060	SEAWEST	S1	26
28060	SEAWEST	S3	26
28060	SEAWEST	S2	26
28061	WHITEWTR	1	26
28260	ALTAMSA4	1	26
28280	CABAZON	1	26
24242	RERC1G	1	24
24243	RERC2G	1	24
25203	ANAHEIMG	1	22

24026	CIMGEN	1	20
24030	DELGEN	1	20
24140	SIMPSON	1	20
28309	BARPKGEN	1	20
28307	MRLPKGEN	1	18
24005	ALAMT5 G	5	17
24161	ALAMT6 G	6	17
24001	ALAMT1 G	1	16
24002	ALAMT2 G	2	16
24003	ALAMT3 G	3	16
24004	ALAMT4 G	4	16
24162	ALAMT7 G	7	16
24063	HILLGEN	1	15
24129	S.ONOFR2	2	15
24130	S.ONOFR3	3	15
24066	HUNT1 G	1	14
24067	HUNT2 G	2	14
24167	HUNT3 G	3	14
24168	HUNT4 G	4	14
28953 SIGGEN		13.8	13
28308	CTRPKGEN	1	13
24011	ARCO 1G	1	12
24012	ARCO 2G	2	12
24013	ARCO 3G	3	12
24014	ARCO 4G	4	12
24163	ARCO 5G	5	12
24164	ARCO 6G	6	12
24018	BRIGEN	1	12
24020 CARBO	GEN	1	12
24064	HINSON	1	12
24070	ICEGEN	1	12
24078	LBEACH1G	1	12
24170	LBEACH2G	2	12
24171	LBEACH3G	3	12
24172	LBEACH4G	4	12
24173	LBEACH5G	5	12
24174	LBEACH6G	6	12
24079	LBEACH7G	7	12
24080	LBEACH8G	8	12
24081	LBEACH9G	9	12
24139	SERRFGEN	1	12
24062	HARBOR G	1	12
25510	HARBORG4	LP	12
24062	HARBOR G	HP	12
24047	ELSEG3 G	3	11
24048	ELSEG4 G	4	11
24094	MOBGEN	1	11
24121	REDON5 G	5	11
24122	REDON6 G	6	11
24123	REDON7 G	7	11

24124	REDON8 G	8	11
24241	MALBRG3G	S3	10
24240	MALBRG2G	C2	10
28951	REFUSE	13.8	10
24027	COLDGEN	1	10
24060	GROWGEN	1	10
24120	PULPGEN	1	10
24239	MALBRG1G	C1	9
28005	PASADNA1	1	7
28006	PASADNA2	1	7
28007	BRODWYS C	1	7

Western Sub-Area:

The most critical contingency for the Western sub-area is the loss of Serrano-Villa Park #1 or #2 230 kV line followed by the loss of the Serrano-Lewis 230 kV line or vice versa, which would result in thermal overload of the remaining Serrano-Villa Park #1 or #2 230 kV line. This limiting contingency establishes a LCR of 4909 MW (which includes 607 MW of QF, 8 MW of Wind, 388 MW of MUNI and 2246 MW of nuclear generation) in 2010 as the generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

There are numerous (about 40) other combinations of contingencies in the area that could overload a significant number of 230 kV lines in this sub-area and have slightly less LCR need. As such, anyone of them (combination of contingencies) could become binding for any given set of procured resources. As a result, effectiveness factors are not given since they would most likely not facilitate more informed procurement.

Changes compared to last year's results:

Overall the load forecast went up by 222 MW, resulting in an increase in LCR. A few new relatively small resources were installed. The decrease in LCR for the Western (Barre) sub-area has resulted in slightly more units dispatched in the Eastern sub-area during this year studies. The difference in effectiveness factors has resulted in a decrease to the overall LCR need. The combination of these two facts has resulted in a total increase of 8 MW between the two years.

LA Basin Overall Requirements:

2010	QF/Wind (MW)	Muni (MW)	Nuclear (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	879	793	2246	8212	12130

2010	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[23]	9,735	0	9,735
Category C (Multiple)[24]	9,735	0	9,735

9. Big Creek/Ventura Area

Area Definition

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

1) Vincent-Antelope #1 230 kV Line
2) Vincent-Antelope #2 230 kV Line
3) Mesa-Antelope 230 kV Line
4) Sylmar-Pardee #1 230 kV Line
5) Sylmar-Pardee #2 230 kV Line
6) Eagle Rock-Pardee #1 230 kV Line
7) Vincent-Pardee 230 kV Line
8) Vincent-Santa Clara 230 kV Line

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

1) Vincent is out Antelope is in
2) Vincent is out Antelope is in
3) Mesa is out Antelope is in
4) Sylmar is out Pardee is in
5) Sylmar is out Pardee is in
6) Eagle Rock is out Pardee is in
7) Vincent is out Pardee is in
8) Vincent is out Santa Clara is in

[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 then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.
[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 MORC.

Total 2010 busload within the defined area is 4,734 MW with 143 MW of losses and 156 MW of pumps resulting in total load + losses + pumps of 5033 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	18.00	1	Big Creek		Market
ANTLPE_2_QF	24457	ARBWIND	66	5.42	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	24458	ENCANWND	66	28.08	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	24459	FLOWIND	66	10.15	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	24460	DUTCHWND	66	3.48	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	24465	MORWIND	66	13.93	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	24491	OAKWIND	66	4.48	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	28501	MIDWIND	12	4.48	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	28502	SOUTHWND	12	1.64	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	28503	NORTHWND	12	4.82	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	28504	ZONDWND1	12	3.28	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	28505	ZONDWND2	12	3.18	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	28506	BREEZE1	12	1.12	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	28507	BREEZE2	12	1.99	1	Big Creek	Monthly NQC - used August for LCR	Wind
BIGCRK_2_PROJCT	24306	B CRK1-1	7.2	19.33	1	Big Creek, Rector, Vestal	Market	
BIGCRK_2_PROJCT	24308	B CRK2-1	13.8	49.35	1	Big Creek, Rector, Vestal	Market	
BIGCRK_2_PROJCT	24311	B CRK3-1	13.8	34.00	1	Big Creek, Rector, Vestal	Market	
BIGCRK_2_PROJCT	24317	MAMOTH1G	13.8	90.83	1	Big Creek, Rector, Vestal	Market	
BIGCRK_2_PROJCT	24319	EASTWOOD	13.8	201.09	1	Big Creek, Rector, Vestal	Market	
BIGCRK_2_PROJCT	24323	PORTAL	4.8	9.33	1	Big Creek, Rector, Vestal	Market	
BIGCRK_2_PROJCT	24306	B CRK1-1	7.2	20.98	2	Big Creek, Rector, Vestal	Market	
BIGCRK_2_PROJCT	24308	B CRK2-1	13.8	50.51	2	Big Creek, Rector, Vestal	Market	
BIGCRK_2_PROJCT	24311	B CRK3-1	13.8	34.00	2	Big Creek, Rector, Vestal	Market	
BIGCRK_2_PROJCT	24318	MAMOTH2G	13.8	90.83	2	Big Creek, Rector, Vestal	Market	
BIGCRK_2_PROJCT	24307	B CRK1-2	13.8	20.98	3	Big Creek, Rector, Vestal	Market	
BIGCRK_2_PROJCT	24309	B CRK2-2	7.2	18.17	3	Big Creek, Rector, Vestal	Market	

BIGCRK_2_PROJCT 243	12	B CRK3-2	13.8	34.00	3	Big Creek, Rector, Vestal		Market
BIGCRK_2_PROJCT 243	07	B CRK1-2	13.8	30.31	4	Big Creek, Rector, Vestal		Market
BIGCRK_2_PROJCT 243	09	B CRK2-2	7.2	19.14	4	Big Creek, Rector, Vestal		Market
BIGCRK_2_PROJCT 243	12	B CRK3-2	13.8	39.83	4	Big Creek, Rector, Vestal		Market
BIGCRK_2_PROJCT 243	10	B CRK2-3	7.2	16.51	5	Big Creek, Rector, Vestal		Market
BIGCRK_2_PROJCT 243	13	B CRK3-3	13.8	37.89	5	Big Creek, Rector, Vestal		Market
BIGCRK_2_PROJCT 243	10	B CRK2-3	7.2	17.97	6	Big Creek, Rector, Vestal		Market
BIGCRK_2_PROJCT	24314	B CRK 4	11.5	48.96	41	Big Creek, Rector, Vestal		Market
BIGCRK_2_PROJCT	24314	B CRK 4	11.5	49.15	42	Big Creek, Rector, Vestal		Market
BIGCRK_2_PROJCT	24315	B CRK 8	13.8	23.70	81	Big Creek, Rector, Vestal		Market
BIGCRK_2_PROJCT	24315	B CRK 8	13.8	42.74	82	Big Creek, Rector, Vestal		Market
GOLETA_2_QF 240	57	GOLETA	66	1.68		Ventura	Not modeled	QF/Selfgen
GOLETA_6_ELLWOD 280	04	ELLWOOD	13.8	54.00	1	Ventura		Market
GOLETA_6_EXGEN 240	57	GOLETA	66	1.22		Ventura	Not modeled	QF/Selfgen
GOLETA_6_GAVOTA 240	57	GOLETA	66	9.90		Ventura	Not modeled	QF/Selfgen
GOLETA_6_TAJIGS 240	57	GOLETA	66	1.78		Ventura	Not modeled	Market
KERRGN_1_UNIT 1	24437	KERNRVR	66	23.51	1	Big Creek		Market
LEBECS_2_UNITS	28051 PST	RIAG1	18	157.90	G1	Big Creek	Monthly NQC - used August for LCR	Market
LEBECS_2_UNITS	28052 PST	RIAG2	18	157.90	G2	Big Creek	Monthly NQC - used August for LCR	Market
LEBECS_2_UNITS	28054 PST	RIAG3	18	157.90	G3	Big Creek	Monthly NQC - used August for LCR	Market
LEBECS_2_UNITS	28053 PST	RIAS1	18	162.40	S1	Big Creek	Monthly NQC - used August for LCR	Market
LEBECS_2_UNITS	28055 PST	RIAS2	18	78.90	S2	Big Creek	Monthly NQC - used August for LCR	Market
MNDALY_7_UNIT 1	24089	MANDLY1G	13.8	215.00	1	Ventura		Market
MNDALY_7_UNIT 2	24090	MANDLY2G	13.8	215.29	2	Ventura		Market
MNDALY_7_UNIT 3	24222	MANDLY3G	16	130.00	3	Ventura		Market
MONLTH_6_BOREL 244	56	BOREL	66	9.24	1	Big Creek		QF/Selfgen
MOORPK_6_QF 240	98	MOORPARK	66	26.43		Ventura	Not modeled	QF/Selfgen
MOORPK_7_UNITA1 240	98	MOORPARK	66	1.13		Ventura	Not modeled	QF/Selfgen
OMAR_2_UNITS	24102	OMAR 1G	13.8	77.25	1	Big Creek		QF/Selfgen
OMAR_2_UNITS	24103	OMAR 2G	13.8	77.25	2	Big Creek		QF/Selfgen
OMAR_2_UNITS	24104	OMAR 3G	13.8	77.25	3	Big Creek		QF/Selfgen
OMAR_2_UNITS	24105	OMAR 4G	13.8	77.25	4	Big Creek		QF/Selfgen
ORMOND_7_UNIT 1	24107	ORMOND1G	26	741.27	1	Ventura		Market
ORMOND_7_UNIT 2	24108	ORMOND2G	26	775.00	2	Ventura		Market
PANDOL_6_UNIT 241	13	PANDOL	13.8	18.18	1	Big Creek, Vestal		QF/Selfgen
PANDOL_6_UNIT 241	13	PANDOL	13.8	14.82	2	Big Creek, Vestal		QF/Selfgen
RECTOR_2_KAWEAH 242	12	RECTOR	66	5.63		Big Creek, Rector, Vestal	Not modeled	Market
RECTOR_2_KAWH 1	24212	RECTOR	66	1.83		Big Creek, Rector, Vestal	Not modeled	Market
RECTOR_2_QF 242	12	RECTOR	66	5.70		Big Creek, Rector, Vestal	Not modeled	QF/Selfgen
RECTOR_7_TULARE 242	12	RECTOR	66	1.51		Big Creek, Rector,	Not modeled	QF/Selfgen

							Vestal		
SAUGUS_6_PTCHGN 241	18	PITCHGEN	13.8	20.85	1		Big Creek		MUNI
SAUGUS_6_QF 24135		SAUGUS	66	5.99			Big Creek	Not modeled	QF/Selfgen
SAUGUS_7_LOPEZ 24135		SAUGUS	66	6.10			Big Creek	Not modeled	QF/Selfgen
SNCLRA_6_OXGEN 241	10	OXGEN	13.8	44.32	1		Ventura		QF/Selfgen
SNCLRA_6_PROCGN 241	19	PROCGEN	13.8	44.34	1		Ventura		Market
SNCLRA_6_QF 241	27	S.CLARA	66	2.67	1		Ventura		QF/Selfgen
SNCLRA_6_WILLMT 241	59	WILLAMET	13.8	13.95	1		Ventura		QF/Selfgen
SPRGVL_2_QF 242	15	SPRINGVL	66	0.51			Big Creek, Rector, Vestal	Not modeled	QF/Selfgen
SPRGVL_2_TULE 242	15	SPRINGVL	66	1.11			Big Creek, Rector, Vestal	Not modeled Monthly NQC - used August for LCR	Market
SPRGVL_2_TULESC 242	15	SPRINGVL	66	1.74			Big Creek, Rector, Vestal	Not modeled	Market
SYCAMR_2_UNITS 241	43	SYCCYN1G	13.8	75.53	1		Big Creek		QF/Selfgen
SYCAMR_2_UNITS 241	44	SYCCYN2G	13.8	75.53	2		Big Creek		QF/Selfgen
SYCAMR_2_UNITS 241	45	SYCCYN3G	13.8	75.53	3		Big Creek		QF/Selfgen
SYCAMR_2_UNITS 241	46	SYCCYN4G	13.8	75.55	4		Big Creek		QF/Selfgen
TENGEN_6_UNIT 1	24148	TENNGEN1	13.8	19.22	1		Big Creek		Market
TENGEN_6_UNIT 2	24149	TENNGEN2	13.8	16.08	2		Big Creek		Market
VESTAL_2_KERN 241	52	VESTAL	66	22.67		1	Big Creek, Vestal		QF/Selfgen
VESTAL_6_QF 241	52	VESTAL	66	1.97			Big Creek, Vestal	Not modeled	QF/Selfgen
VESTAL_6_ULTRGN 241	50	ULTRAGEN	13.8	34.24		1	Big Creek, Vestal		QF/Selfgen
VESTAL_6_WDFIRE 280	08	LAKEGEN	13.8	6.65		1	Big Creek, Vestal		QF/Selfgen
WARNE_2_UNIT 256	51	WARNE1	13.8	39.00	1		Big Creek		Market
WARNE_2_UNIT 256	52	WARNE2	13.8	39.00	1		Big Creek		Market
MNDALY_6_MCGRTH 283	06	MCGPKGEN	13.8	47.20	1		Ventura	No NQC - Pmax	Market
NA 244	22	PALMDALE	66	1.00	1		Big Creek	No NQC - historical data	Market
NA 244	36	GOLDTOWN	66	13.00	1		Big Creek	No NQC - historical data	Market
New unit	28952	CAMGEN	13.8	28.00	1		Ventura	No NQC - Pmax	Market

Major new projects modeled:

1. Antelope Transmission Project (Segments 1, 2 and 3)
2. One new peaker

Critical Contingency Analysis Summary

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 #1 or #2 230 kV line. This limiting contingency establishes a LCR of 3334 MW in 2010 (includes 840 MW of QF, 21 MW of MUNI and 86 MW of Wind generation) as the minimum generation capacity necessary for reliable load serving capability within this area.

The most critical 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 #1 or #2 230 kV line. This limiting contingency establishes a LCR of 3212 MW in 2010 (includes 840 MW of QF, 21 MW of MUNI and 86 MW of Wind 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. (%)
24009	APPGEN1G	1	29
24010	APPGEN2G	2	29
24107	ORMOND1G	1	29
24108	ORMOND2G	2	29
24118	PITCHGEN	1	28
24148	TENNGEN1	1	28
24149	TENNGEN2	2	28
24089	MANDLY1G	1	27
24090	MANDLY2G	2	27
24110	OXGEN	1	27
24119	PROCGEN	1	27
24159	WILLAMET	1	27
25651	WARNE1	1	27
25652	WARNE2	1	27
28004	ELLWOOD	1	27
28051	PSTRIAG1	G1	26
25606	EDMON2AP	2	26
25607	EDMON3AP	3	26
25607	EDMON3AP	4	26
25608	EDMON4AP	5	26
25608	EDMON4AP	6	26
25609	EDMON5AP	7	26
25609	EDMON5AP	8	26
25610	EDMON6AP	9	26
25610	EDMON6AP	10	26
25611	EDMON7AP	11	26
25611	EDMON7AP	12	26
25612	EDMON8AP	13	26
25612	EDMON8AP	14	26
28054	PSTRIAG3	G3	25

25615	OSO B P	7	25	
25615	OSO B P	8	25	
28952	CAMGE N	13.8		25
24127	S.CLARA	1	25	
28055	PSTRIAS2	S2	24	
28053	PSTRIAS1	S1	24	
28052	PSTRIAG2	G2	24	
25605	EDMON1AP	1	24	
24143	SYCCYN1G	1	24	
24144	SYCCYN2G	2	24	
24145	SYCCYN3G	3	24	
24146	SYCCYN4G	4	24	
24102	OMAR 1G	1	23	
24103	OMAR 2G	2	23	
24104	OMAR 3G	3	23	
24105	OMAR 4G	4	23	
25614	OSO A P	1	23	
25614	OSO A P	2	23	
25653	ALAMO SC	1	23	
24222	MANDLY3G	3	20	
28008	LAKEGEN	1	20	
24150	ULTRAGEN	1	20	
24152	VESTAL	1	20	
24319	EASTWOOD	1	20	
24306	B CRK1-1	1	20	
24306	B CRK1-1	2	20	
24307	B CRK1-2	3	20	
24307	B CRK1-2	4	20	
24308	B CRK2-1	1	20	
24308	B CRK2-1	2	20	
24309	B CRK2-2	3	20	
24309	B CRK2-2	4	20	
24310	B CRK2-3	5	20	
24310	B CRK2-3	6	20	
24311	B CRK3-1	1	20	
24311	B CRK3-1	2	20	
24312	B CRK3-2	3	20	
24312	B CRK3-2	4	20	
24313	B CRK3-3	5	20	
24314	B CRK 4	41	20	
24314	B CRK 4	42	20	
24315	B CRK 8	81	20	
24315	B CRK 8	82	20	
24317	MAMOTH1G	1	20	
24318	MAMOTH2G	2	20	
24113	PANDOL	1	19	
24113	PANDOL	2	19	
24437	KERNRVR	1	18	
24459	FLOWIND	1	14	
24436	GOLDTOWN	1	14	

28501	MIDWIND	1 14
24457	ARBWIND	1 13
24456	BOREL	1 12
24458	ENCANWND	1 12
24460	DUTCHWND	1 12
24465	MORWIND	1 12
28503	NORTHWND	1 12
28504	ZONDWND1	1 12
28505	ZONDWND2	1 12
25618	PEARBMBP	5 6
25618	PEARBMBP	6 6
25619	PEARBMCP	7 6
25619	PEARBMCP	8 6
25617	PEARBMAP	1 5
25617	PEARBMAP	2 5
25620	PEARBMDP	9 5
24136	SEAWEST	1 5

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 687 MW (includes 8 MW of QF generation) in 2010 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 (%)
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 810 MW in 2010 (which includes 107 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	ULT RAGEN	1	45
24152	VESTAL	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

Changes compared to last year's results:

Overall the load forecast went up by 96 MW. One new relatively small resource was installed. The overall effect is that the LCR has increased by 156 MW.

Big Creek Overall Requirements:

2010	QF/Wind (MW)	MUNI (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	926	21	4146	5093

2010	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[25]	3212	0	3212
Category C (Multiple)[26]	3334	0	3334

10. San Diego Area

<u>Area Definition</u>

The transmission tie lines forming a boundary around San Diego include:

1) Imperial Valley – Miguel 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

The substations that delineate the San Diego Area are:

1) Imperial Valley is out Miguel is in

[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 then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

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

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

Total 2010 busload within the defined area: 5006 MW with 121 MW of losses resulting in total load + losses of 5127 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 221	49	CALPK_BD	13.8	43.80 1		Border 69, South Bay 69	Market	
CBRLLO_6_PLSTP1 220	92	CABRILLO	69	2.91 1		None		QF/Selfgen
CCRITA_7_RPPCHF 221	24	CHCARITA	138	5.25 1		None		QF/Selfgen
CHILLS_1_SYCLFL 221	20	CARLTNHS	138	0.80 1		None		QF/Selfgen
CHILLS_7_UNITA1 221	20	CARLTNHS	138	2.50 2		None		QF/Selfgen
CPSTNO_7_PRMADS 221	12	CAPSTRNO	138	2.81 1		None		QF/Selfgen
CRSTWD_6_KUMYAY 229	15	KUMEYAAY	34.5	8.69 1		None	Monthly NQC - used August for LCR	Wind
DIVSON_6_NSQF 221	72	DIVISION	69	47.00	1	South Bay 69		QF/Selfgen
EGATE_7_NOCITY 222	04	EASTGATE	69	0.63 1		None		QF/Selfgen
ELCAJN_6_UNITA1 221	50	CALPK_EC	13.8	42.20 1		El Cajon		Market
ELCAJN_7_GT1 222	12	ELCAJNGT	12.5	16.00 1		El Cajon		Market
ENCINA_7_EA1 222	33	ENCINA 1	14.4	106.00 1		None		Market
ENCINA_7_EA2 222	34	ENCINA 2	14.4	103.00 1		None		Market
ENCINA_7_EA3 222	36	ENCINA 3	14.4	109.00 1		None		Market
ENCINA_7_EA4 222	40	ENCINA 4	22	299.00 1		None		Market
ENCINA_7_EA5 222	44	ENCINA 5	24	329.00 1		None		Market
ENCINA_7_GT1 222	48	ENCINAGT	12.5	14.00 1		None		Market
ESCNDO_6_PL1X2 222	57	MMC_ES	13.8	35.50 1		None		Market
ESCNDO_6_UNITB1 221	53	CALPK_ES	13.8	45.50 1		None		Market
ESCO_6_GLMQF 223	32	GOALLINE	69	47.09 1		None		QF/Selfgen
KEARNY_7_KY1 223	77	KEARNGT1	12.5	16.00 1		Rose Canyon		Market
KEARNY_7_KY2 223	73	KEARN2AB	12.5	15.02 1		Rose Canyon		Market
KEARNY_7_KY2 223	74	KEARN2CD	12.5	15.02 1		Rose Canyon		Market
KEARNY_7_KY2 223	73	KEARN2AB	12.5	15.02 2		Rose Canyon		Market
KEARNY_7_KY2 223	74	KEARN2CD	12.5	13.95 2		Rose Canyon		Market
KEARNY_7_KY3 223	75	KEARN3AB	12.5	14.98 1		Rose Canyon		Market
KEARNY_7_KY3 223	76	KEARN3CD	12.5	14.98 1		Rose Canyon		Market
KEARNY_7_KY3 223	75	KEARN3AB	12.5	16.05 2		Rose Canyon		Market
KEARNY_7_KY3 223	76	KEARN3CD	12.5	14.98 2		Rose Canyon		Market
LARKSP_6_UNIT 1	22074	LRKSPBD1	13.8	46.00 1		Border 69, South Bay 69	Market	
LARKSP_6_UNIT 2	22075	LRKSPBD2	13.8	46.00 1		Border 69, South Bay 69	Market	
MRGT_6_MMAREF 224	86	MFE_MR1 13.8		46.60 1		None		Market
MRGT_7_UNITS 224	88	MIRAMRGT	12.5	18.55 1		None		Market

MRGT_7_UNITS 224	88	MIRAMRGT	12.5	17.45 2		None		Market
MSHGTS_6_MMARLF 22448		MESAHGTS	69	3.00 1		None		QF/Selfgen
MSSION_2_QF 224	96	MISSION	69	1.04 1		None		QF/Selfgen
NIMTG_6_NIQF 225	76	NOISLMTR	69	35.66	1	South Bay 69		QF/Selfgen
OTAY_6_PL1X2 226	17	MMC_OY	13.8	35.50	1	South Bay 69		Market
OTAY_6_UNITB1 226	04	OTAY	69	1.49	1	South Bay 69		QF/Selfgen
OTAY_6_UNITB1 226	04	OTAY	69	1.48	2	South Bay 69		QF/Selfgen
OTAY_7_UNITC1 226	04	OTAY	69	3.40	3	South Bay 69		QF/Selfgen
PALOMR_2_PL1X3 222	62	PEN_CT1	18	162.17 1		None		Market
PALOMR_2_PL1X3 222	63	PEN_CT2	18	162.17 1		None		Market
PALOMR_2_PL1X3 222	65	PEN_ST	18	240.66 1		None		Market
PTLOMA_6_NTCCGN 226	60	POINTLMA	69	2.25 2		None		QF/Selfgen
PTLOMA_6_NTCQF 226	60	POINTLMA	69	22.27 1		None		QF/Selfgen
SAMPSN_6_KELCO1 227	04	SAMPSON	12.5	13.57 1		None		QF/Selfgen
SMRCOS_6_UNIT 1	22724	SANMRCOS	69	0.98 1		None		QF/Selfgen
SOBAY_7_GT1 227	76	SOUTHBGT	12.5	15.00	1	South Bay 69		Market
SOBAY_7_SY1 227	80	SOUTHBY1	15	146.00	1	South Bay 69		Market
SOBAY_7_SY2 227	84	SOUTHBY2	15	149.60 1		None		Market
SOBAY_7_SY3 227	88	SOUTHBY3	20	175.00 1		None		Market
SOBAY_7_SY4 227	92	SOUTHBY4	20	222.00 1		None		Market
KYCORA_7_UNIT 1	22384	KYOCERA	69	0.00 1		None	No NQC - historical data	QF/Selfgen
OGROVE_6_PL1X2 226	28	Q201U1	13.8	47.00	1	None	No NQC - Pmax	Market
OGROVE_6_PL1X2 226	29	Q201U2	13.8	47.00	2	None	No NQC - Pmax	Market
MRGT_6_MMAREF2 224	87	MFE_MR2	13.8	46.60	1	None	No NQC - Pmax	Market
NA 220	08	ASH	69	0.90 1		None	No NQC - historical data	QF/Selfgen
NA 225	32	MURRAY	69	0.20 1		None	No NQC - historical data	QF/Selfgen
NA 226	80	R.SNTAFE	69	0.40 1		None	No NQC - historical data	QF/Selfgen
NA 227	60	SHADOWR	138	0.10 1		None	No NQC - historical data	QF/Selfgen
NA 229	16	PFC-AVC	0.6	0.00 1		None	No NQC - historical data	QF/Selfgen
NA 226	80	R.SNTAFE	69	0.30 2		None	No NQC - historical data	QF/Selfgen
OTMESA_2_PL1X3 226	05	OTAYMGT1	18	155.00	1	None	No NQC - Pmax	Market
OTMESA_2_PL1X3 226	06	OTAYMGT2	18	155.00	1	None	No NQC - Pmax	Market
OTMESA_2_PL1X3 226	07	OTAYMST1	16	263.00	1	None	No NQC - Pmax	Market
New unit	23120	BULLMOOS	13.8	27.00 1		Border 69, South Bay 69	No NQC - Pmax	Market

Major new projects modeled:

1. Otay Mesa Power Plant (573 MW)
2. New peaker at Miramar 69 kV substation (49 MW)
3. New biomass unit at Border 69 kV substation (27 MW)
4. New peaker units at Pala 69 kV substation (94 MW)

Critical Contingency Analysis Summary

El Cajon Sub-area:

The most critical contingency for the El Cajon sub-area is the loss of the El Cajon-Jamacha 69 kV line (TL624) followed by the loss of Miguel-Granite-Los Coches 69 kV line (TL632), which would thermally overload the Garfield-Murray 69 kV line. This limiting contingency establishes a LCR of 72 MW (including 0 MW of QF generation and 14 MW of deficiency) in 2010 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area (El Cajon Peaker and El Cajon GT) are needed therefore no effectiveness factor is required.

Rose Canyon Sub-area

The most critical contingency for the Rose Canyon Sub-area is the loss of Old Town-Pacific Beach 69 kV line (TL613) followed by the loss of Rose Canyon-Penasquitos 69 kV line (TL661), which would thermally overload the Eastgate–Rose Canyon 69 kV line (TL6927). This limiting contingency establishes a LCR of 100 MW (including 0 MW of QF generation) in 2010 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area (Kearny GTs) have the same effectiveness factors.

Border 69 kV Sub-area

The most critical contingency for the Border Sub-area is the loss of Border – Miguel 69 kV line (TL6910) followed by the loss of Imperial Beach-Otay-San Ysidro 69 kV line (TL623), which would thermally overload Otay-Otay Lake Tap (TL649). This limiting contingency establishes a local capacity need of 15 MW (includes 0 MW of QF generation) in 2010 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units in this sub-area (Border Cal Peak, Larkspur and Bullmoos) have the same effectiveness factors.

South Bay 69 kV Sub-area

The most critical contingency for the South Bay 69 kV Sub-area is the loss of South Bay-Los Coches 138 kV line followed by the loss of South Bay-Grant Hill 138 kV line, which would thermally overload the South Bay #50 138/69 kV transformer bank. Using the 30-minute emergency of the bank, the limiting contingency establishes a LCR of 440 MW (including 89 MW of QF) in 2010 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Dispatching all of the needed generation to mitigate the overload on South Bay 138/69 kV bank causes other overloads in the South Bay area.

In order to eliminate the sub-area, the generation from South Bay Units 2, 3, and 4 needs to be limited to 302 MW. In order to eliminate just the South Bay Unit 1 and South Bay GT requirement from the sub-area, the generation from Units 2, 3 and 4 needs to be limited to 397 MW.

Effectiveness factors:

The following table has units that have at least 5% effectiveness to the above-mentioned constraint within the South Bay 69 kV sub-area:

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
22776	SOUTHBGT	1	36
22780	SOUTHBY1	1	36
22617	MMC_OY	1	35
22149	CALPK_BD	1	22
22074	LRKSPBD1	1	22
22075	LRKSPBD2	1	22
23120	BULLMOOS	1	22

22172	DIVISION	1	18
22576	NOISLMTR	1	13

San Diego overall:

The most limiting contingency in the San Diego area is described by the outage of the 500 kV Southwest Power Link (SWPL) between Imperial Valley and Miguel Substations over-lapping with an outage of the Otay Mesa Combined-Cycle Power plant (573 MW) while staying within the South of San Onofre (WECC Path 44) non-simultaneous import capability rating of 2,500 MW. This contingency establishes a LCR of 3200 MW in 2010 (includes 196 MW of QF generation and 9 MW of Wind) as the minimum generation capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

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

Changes compared to the last stakeholder meeting:

1. San Diego Gas & Electric with Calpine's concurrence has supplied a new 2010 NQC value for Otay Mesa at 573 MW (155 MW each CT and 263 MW ST).
2. Lake Hodges has confirmed delay for the in service date past June 1, 2010 therefore these units will be removed from the 2010 case, along with the Bernardo sub-area where these units are the only available resources.
3. Orange Grove peakers, have received CEC license after the start of the LCR studies and they have a confirmed in service date of October 2009, as such they will be modeled in the 2010 case.

Changes compared to last year's results:

Overall the load forecast went up by 75 MW and that lead to an increase in the LCR by same amount. Also the new Otay Mesa Power Plant replaces Palomar as the biggest single generator contingency and as a result the LCR need increases by another 12 MW.

San Diego Overall Requirements:

2010	QF (MW)	Wind (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	196	9	3502	3707

2010	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[27]	3200	0	3200
Category C (Multiple)[28]	3200	14	3214

[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 then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

[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 MORC.

CERTIFICATE OF SERVICE

I hearby certify that I have served, by electronic and United States mail, a Notice of Availability of the California Independent system Operator Corporation's Updated 2010 Local Capacity Technical Analysis to each party in Docket No. R.08-01-025.

Executed on May 1, 2009, at Folsom, California

/s/Anna Pascuzzo

Anna Pascuzzo
An Employee of the California
Independent System Operator