BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider	)	
Refinements to and Further Development of the	)	R.05-12-013
Commission's Resource Adequacy	)	
Requirements Program	)	
	)	

CORRECTED 2007 LOCATIONAL CAPACITY TECHNICAL ANALYSIS AND ERRATA OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

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Dated: April 28, 2006

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Order Instituting Rulemaking to Consider Refinements to and Further Development of the Commission's Resource Adequacy Requirements Program	)))))	R.05-12-013

UPDATED 2007 LOCATIONAL CAPACITY TECHNICAL ANALYSIS AND ERRATA OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

I. INTRODUCTION

On April 21, 2006 the California Independent System Operator (CAISO) submitted its 2007 Locational Capacity Technical Analysis (2007 LCR Study) in this docket. A workshop was held at the offices of the CAISO on April 26, 2006 and the stakeholders raised certain issues that should be addressed in the 2007 LCR Study for consideration by the parties and the California Public Utilities Commission (CPUC). In addition, the CAISO has completed its review of the Kern load pocket, presented those results on the 26th, and would like to have the opportunity to include the results in the study. Thus, after discussions with the CPUC advisory Staff and at the recommendation of ALJ Mark Wetzell, the CAISO has attached the corrected version of the 2007 LCR Study to this Errata. A redlined version of the study has also been attached.

All of the changes that have been made to the first version of the study filed on April 21 have been explained in detail below. These modifications are either explanatory or have an insignificant effect on the results. Importantly, the procurement requirements identified in the first version of the study have either gone down or were unaffected by the changes.

II. EXPLANATION OF CHANGES

The following updates were made to the 2007 LCR Study, by page:

A. <u>Local Requirements Comparison table, page 2.</u>

1. North Coast/North Bay- the first version of the report contained single contingency (category B) results in the Lakeville sub-area based on the normal rating of the most limiting element. This corrected version reflects the 2007 LCR requirements for the Lakeville sub-area based on the emergency rating of the most limiting equipment. This change caused the requirements to decrease.

2. Greater Fresno-the first version of the report contained preliminary results based largely on data from the 2006 LCR Study. This corrected version now fully reflects the 2007 LCR Study methodology and contains the final results. These changes caused the requirements to decrease.

3. Kern- results of the Kern load pocket analysis added to the table. Adding the Kern results will not cause any additional procurement because all units are under long term contract.

4. LA Basin-the qualifying capacity numbers were reviewed on a unit-specific basis, causing minor changes to the qualifying capacity calculation. This change had no effect on the requirements.

5. San Diego- typographical error in Qualifying Capacity-Total MW" corrected.

6. Totals changed to reflect above changes.

B. Page 2, explanation.

Immediately below the table, an explanation of Gross and Net Qualifying Capacity was added in response to questions raised at the workshop.

C. Page 23, Table 2

The Kern results were added to the load forecast 1-in-5 and 1-in-10 comparison.

D. Page 24, Table 3

This is the same table that has been described in Paragraph A above.

E. Page 25, Table 4

The changes to this table reflect the changes to Table 3 set forth above.

F. Page 34, Effectiveness Factors

The DFAX numbers were converted to percentages for consistency with other areas of the study.

G. Page 39, Effectiveness Factors

The DFAX numbers were converted to percentages for consistency with other areas of the study.

H. Page 40, Effectiveness Factors

The DFAX numbers were converted to percentages for consistency with other areas of the study.

I. Page 43-Stagg Sub-area

A typographical error was corrected ("Gold Hill" removed from first line of Stagg Sub-area contingency discussion).

J. Page 51-Bay Area

Typographical errors were corrected in the narrative paragraph for consistency with the chart.

K. Pages 54-57 Greater Fresno Sub-areas

The changes on these pages were described above in paragraph A. The first version of the report contained preliminary results based largely on data from the 2006 LCR Study. This corrected version now fully reflects the 2007 LCR Study methodology and contains the final results. These changes caused the requirements to decrease.

L. Page 58-

1. Review of the Merced Sub-area was completed and added to the report.

2. Fresno requirements were changed due to further review and refinement.

M. Pages 59-61 Kern Area

All of the information about the Kern Area has been added to this corrected version of the study.

N. Pages 62-65 LA Basin

Lists of units and qualifying capacity for the Eastern and Western Sub-areas were added for consistency across the report.

O. Pages 65 and 68-LA Basin Overall

Changes were made to the narrative of the requirements to make it consistent with the rest of the report, as well as a change to reflect Qualifying Capacity, as explained above, in the narrative and in the chart.

III. CONCLUSION

The CAISO appreciates this opportunity to provide the corrected version of the 2007 LCR Study to the parties and to the CPUC.

Respectfully submitted,

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ATTACHMENT A

California ISO

2007
LOCAL CAPACITY TECHNICAL ANALYSIS

REPORT
AND STUDY RESULTS

Corrected Version April 28, 2006

Local Capacity Technical Analysis
Overview and Study Results

I. Executive Summary

At the February 3, 2006 prehearing conference in Docket R.05-12-013 (*Rulemaking to Consider Refinements to and Further Development of the Commission's Resource Adequacy Requirements Program*), the California Independent System Operator Corporation ("CAISO") advised the California Public Utilities Commission ("CPUC") that the Local Capacity Requirement ("LCR") results of its 2007 local capacity technical analysis could be made available within eight weeks after the development of the input assumptions for the study. Following a meet and confer process, Administrative Law Judge Wetzell adopted proposed study assumptions. These assumptions have been incorporated into this "Local Capacity Technical Analysis Study ("2007 LCR Study"), as discussed below. The CAISO has now completed its analysis and therefore provides this 2007 LCR Study to describe the final LCR results and the methodology and criteria used to obtain those results.

This Report provides a description of the 2007 LCR Study objectives, inputs, methodologies and assumptions, and the important policy considerations that are presented by the study results. Specifically, as requested by the Stakeholders and approved by the CPUC, the CAISO has conducted the study to produce local area capacity requirements necessary to achieve three levels of service reliability. These levels of service reliability, which are driven by the transmission grid operating standards to which the CAISO must comply, are set forth on the following table[1]:

[1] This comparison table is explained in detail at Section IV.below. The reader should be aware that the deficiencies identified for certain local areas are driven by capacity requirements in sub-area load pockets discussed at IV.B.

Local Requirements Comparison

	Qualifying Capacity			2007 LCR Requirement Based on Category B Option 1			2007 LCR Requirement Based on Category C with operating procedure Option 2			2006 Total LCR Req.
Local Area Name	**QF/ Muni (MW)**	**Market (MW)**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**(MW)**
Humboldt	73	133	206	202	0	**202**	202	0	**202**	162
North Coast / North Bay	158	861	1019	582**	0	**582****	582**	0	**582****	658
Sierra	1072	776	1848	1833	205	**2038**	1833	328	**2161**	1770*
Stockton	314	257	571	348	0	**348**	506	53	**559**	440*
Greater Bay	1314	5231	6545	4771	0	**4771**	5341	0	**5341**	6009
Greater Fresno	575	2337	2912	2530	0	**2530**	2534	68	**2602**	2837 *
Kern	978	31	1009	554	0	**554**	769	17	**786**	797*
LA Basin	3510	7012	10522	8843	0	**8843**	8843	0	**8843**	8127
San Diego	191	2741	2932	2781	0	**2781**	2781	0	**2781**	2620
Total	**8185**	**19379**	**27564**	**22444**	**205**	**22649**	**23391**	**466**	**23857**	**23420**

* Generation deficient areas (or with sub-area that are deficient) – deficiency included in LCR
** The North Coast/North Bay area requirement would have been higher by 80 MW, however a new operating procedure has been received, validated and implemented by PG&E and the CAISO.

The term "Qualifying Capacity" used in this report represents the "Gross Qualifying Capacity" (as of 1/12/2006) and it may be slightly higher, for certain generators, then the "Net Qualifying Capacity" as presented in the official list stored at:

http://www.caiso.com/1796/179694f65b9f0.xls

The difference between the terms "Qualifying Capacity" and "Net Qualifying Capacity" is that certain units have associated plant load and thus, the "Net Qualifying Capacity" represents the output from the unit after the plant load has been subtracted. However,the LCR Study incorporates the plant load from these units into the "total load" calculation.

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 and nuclear units). The second set is "market" generation. The second column, "2007 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 (Option 1, discussed in Section II.C of this Report). The third column, "2007 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 (Option 2).

The highest service reliability level, based on Performance Criteria-Category C without non-generational solutions to address operating deficiencies (Option 3), can be determined from the table by adding 80 MW to the local capacity requirements for the North Coast/North Bay area (thus raising total 2007 LCR requirements by 80 MW). This exercise removes the new operating procedure provided by PG&E from the analysis in compliance with the Category C reliability standard that relies solely on generation to address identified capacity deficiencies.

As shown on the table above, the study results have important public policy implications. These study results indicate 3 levels of capacity that are necessary to have sufficient capacity in support of 3 levels of service reliability. The reader should appreciate that the differences in levels of capacity have direct implications to the costs and expected levels of reliability that are achieved for customers located within the local areas. Thus, option 1 (performance level B) has a lower level of capacity required and will therefore have an expected lower level of reliability because less capacity is available to the CAISO. Similarly, the operational solutions underlying option 2 (performance level C) provide for less procurement of capacity than option 3 by placing load in the mix of solutions that the CAISO will use to respond to contingencies. This approach may be appropriate where all outages are expected to have short-term affects on the transmission system. Yet, long duration outages would potentially subject load to extended outages. Option 3 also NERC performance level C, results provide the quantity of capacity that would give the CAISO a full set of capacity to respond to contingencies. This level effectively reserves the load based operational solutions for major emergencies or contingencies that are not considered in the study criteria and therefore results in an expected higher level of service reliability than the two alternate options.

Public policy decision-makers must choose the appropriate level of service reliability. The information provided in the 2007 LCR Study, including the CAISO's recommendations found at Section II.E. below, can assist with this choice.

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

A. Objectives

Similar to the 2006 Local Capacity Technical Analysis ("2006 LCR Study")[2], the purpose of the2007 LCR Study is to identify specific areas within the CAISO Controlled Grid that have local reliability problems and to determine the generation capacity (MW) that would be required to mitigate these local reliability problems. However, based on input from market participants and at the direction of the CPUC, the 2007 LCR Study identifies different levels of local capacity that correspond to separate performance/reliability criteria related to grid robustness under which the CAISO must plan and operate the grid. This additional information is intended to allow the CPUC to affect the expected level of service reliability that customers of jurisdictional LSEs will receive by dictating the appropriate amount of local capacity that must be procured. In so doing, the CPUC should endeavor to make a decision that seeks to find the appropriate balance between a desired level of service reliability and the cost of installed capacity. The details of the 2007 LCR study, set forth in the following sections, will facilitate the CPUC's ability to make this important decision.

[2] The 2006 LCR Study (Locational Capacity Technical Analysis: Overview of Study Report and Final Results) dated September 23, 2005 was submitted to the CPUC as part of the CAISO's Motion to Augment the Record Regarding Resource Adequacy Phase 2 in R.04-04-003. An Addendum to the 2006 LCR Study was submitted on January 31, 2006. These documents can be found on the CAISO website at: http://www.caiso.com/1788/178883551f690.html and http://www.caiso.com/docs/2004/10/04/2004100410354511659.html

B. Key Study Assumptions

1. Inputs and Methodology

The CPUC directed the CAISO, respondents, and other interested parties to meet and confer with the objective of identifying not more than three alternative sets of input assumptions the CAISO would incorporate into the 2007 LCR Study. The meet and confer session was held on February 17, 2006 and, as noted above, the agreed-upon input scenarios were submitted by the CAISO on February 22, 2006. An errata to the February 22 filing was submitted on March 10, 2006. The following table sets forth a summary of the approved inputs and methodology that have been used in the 2007 LCR Study:

Summary Table of Inputs and Methodology Used in 2007 LCR Study:

Issue:	HOW INCORPORATED INTO THE 2007 LCR STUDY:
Input Assumptions:	
• Transmission System Configuration	The existing transmission system has been modeled, including all projects operational on or before June 1, 2007 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, 2007
• 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 historical output values for purposes of the 2007 LCR Study.
• **Maintaining Path Flows**	Path flows have been maintained below all established path ratings into the load pockets, including the 500 kV. For clarification, given the existing transmission system configuration, the only 500 kV path that flows directly into a load pocket and will, therefore, be considered in the 2007 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**	The 2007 LCR Study is being published based on Performance Level B and Performance Level C criterion, yielding the low and high range LCR scenarios. In addition, the CAISO will incorporate all new projects and other feasible and CAISO-approved operational solutions brought forth by the PTOs that can be operational on or before June 1, 2007. Any such solutions that can reduce the need for procurement to meet the Performance Level C criteria will be incorporated into the LCR Study and the resulting LCR published for this third scenario.
Load Pocket:	
• **Fixed Boundary, including limited reference to published effectiveness factors**	The 2007 LCR Study has been produced based on load pockets defined by a fixed boundary. The CAISO was initially planning to publish the effectiveness factors of the generating resources within the defined load pocket as well as the effectiveness factors of the generating resources residing outside the load pocket that had a relative effectiveness factor of no less than 5% or affect the flow on the limiting equipment by more than 5% of the equipment's applicable rating. . However, after subsequent discussions with the Commission and stakeholders, and given the comments in the CPUC Staff Report regarding the limited usefulness of effectiveness factors, the CAISO plans to only publish effectiveness factors where they are useful in facilitating procurement where excess capacity exists within a load pocket. If stakeholders want additional effectiveness factor published, the CAISO will defer to the Commission as to what further effectiveness factor data it would like the CAISO to publish.

Further details regarding the 2007 LCR Study methodology and assumptions are provided in Section III, below.

2. Operating Requirements

As was done in the 2006 LCR Study, this study incorporates specific operating requirements, needed in order to prevent voltage collapse or transient instability for the loss of a single transmission element ("N-1") followed by system readjustment and the loss of two transmission lines (common mode failure)[3]. In addition, the LCR Study addresses contingencies where the system suffers the loss of a single transmission element ("N-1"), the system is readjusted and then the loss of an additional transmission element (N-1-1). As reflected in Table 2, the capacity in columsn two (Category B) and three (Category C) are identical in at least four of the local areas. This occurs because the capacity necessary to prevent voltage collapse or transient instability for the loss of a single transmission element (N-1) is the same as that necessary for the N-1-1 scenario.

Consistent with NERC standards, after the second N-1 or immediately after the common mode failure load shedding is allowed as long as all criteria (thermal, voltage, transient, reactive margin) are respected. The CAISO planning criteria generally allows for load shedding for the double contingencies. However, the CAISO has, consistent with its Tariff, conducted planning studies that maintain the level of reliability that existed prior to its formation. This is referred in the CAISO Tariff as "Local Reliability Criteria," which, along with NERC Planning Standards discussed below, form the CAISO's "Applicable Reliability Criteria" The CAISO is under an obligation to implement Local Reliability Criteria, unless modified pursuant to agreement with the relevant Participating Transmission Owner ("PTO"). As such, to the extent a PTO's pre-CAISO standards did not allow for load shedding for common corridor and/or double circuit tower line outages, the CAISO has maintained that practice to assure that the level of reliability that prevailed before the CAISO was formed would be maintained and the CAISO remains in compliance with its obligations.

[3] These failures include a double circuit tower and the loss of two 500kv lines that are located in the same corridor.

C. Grid Reliability and Service Reliability

The 2007 LCR Study is intended to provide the CPUC with the “tools” needed to make the important threshold policy decision as to the desired level of service reliability within the CAISO Control Area, ultimately establishing the appropriate amount of local generation capacity CPUC jurisdictional LSEs must procure. The options produced by the study for consideration by the CPUC are discussed in further detail in this overview section of the report, and also in the technical discussion of the study itself. However, to assist the CPUC in analyzing the study results and the options that are being presented, it is important that the CPUC and other parties understand how the CAISO distinguishes “service reliability” from “grid reliability” and where the respective CAISO/CPUC responsibilities lie. Both service and grid reliability form the basis of the reliability standards consumers within the CAISO Control Area will receive.

1. 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 primarily apply to the bulk, interconnected electric system in the Western United States and are intended to address the reality that within an integrated network, whatever one control area does can affect the reliability of other control 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.[4] 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

[4] Pub. Utilities Code § 345

the CAISO's Participating Transmission Owners ("PTOs"), which affect a PTO's individual system.

The NERC Planning Standards define reliability on interconnected bulk 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. For instance, one category could require that the grid operator not only ensure grid integrity is maintained under certain adverse system conditions, e.g., security, but also that all customers continue to receive electric supply to meet demand, e.g., adequacy. In that case, grid reliability and service reliability would overlap. But there are other levels of performance where security can be maintained without ensuring adequacy. Here, it would be up to the regulatory agency of service reliability, i.e. the CPUC, to determine the appropriate level of service reliability under the system conditions defined by the differing levels of NERC planning standards.

Given the foregoing, one of the ambiguities identified in the recent CPUC workshops is the fact that several performance categories make up the NERC Planning Standards and, therefore, Applicable Reliability Criteria. The various parties perceived this as potentially permitting the CAISO to procure generation, in its backstop role, to satisfy all performance categories. Rather, the CAISO believes it is the role of the CPUC to determine the level of service reliability it wishes to establish for the ratepayers. To further addresses this concern, it is important to again describe the Performance Categories, which are critical to understanding how the CPUC and CAISO can work together.

a. Performance Criteria

As set forth on the Summary Table of Inputs and Methodology, the 2007 LCR is based on NERC Performance Level B and Performance Level C criterion, yielding the low and high range LCR scenarios. These Performance Levels can be described as follows:

i. Performance Criteria - Category B

Category B describes the system performance that is expected 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 a certain duration. Under this category, load cannot be shed in order to assure the Applicable Ratings are met and that facilities are returned to normal ratings when either the element that was lost is returned to service or system adjustments are made within the appropriate time limits.

However, the NERC 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, pre-contingency load-shedding, 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.[5]

ii. Performance Criteria - Category C

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 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."

2. Service Reliability

The CAISO is responsible for grid reliability in accordance with the NERC performance criteria described above. However, grid reliability can be maintained at service reliability levels that may be unacceptable to the CPUC and end user customers. The 2007 LCR Study presents the CPUC with relevant information to select a level of service reliability that also fulfills grid reliability. Specifically, the study specifies varying generation capacity levels for each local capacity area based on Performance criteria- Categories B and C, with the inclusion of suitable non-generation solutions raised by the PTOs to address contingency conditions as described under Performance Criteria- Category C.

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

As shown by the study results, where the NERC Planning Standards do not allow for load shedding, grid reliability and service reliability are the same and establish a minimum level of capacity needed to meet the CAISO's statutory obligation.[6] Where it is not possible to develop operating solutions to ensure "controlled" interruption of service, in these cases generation will also be required to meet Applicable Reliability Criteria to avoid the potential of load shedding in anticipation of a contingency. Where feasible operational solutions and/or generation procurement amounts affect the level of service to customers, service reliability is implicated and different levels of service reliability may be possible.

D. The Three Options Presented By The 2007 LCR Study

The 2007 LCR study sets forth different solution "options" with varying ranges of potential service reliability consistent with CAISO's Applicable Reliability Criteria:

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 for NERC Category B given that load cannot be removed to meet this performance standard under Applicable Reliability Criteria. However, this capacity amount implicitly relies on load interruption as the **only means** of meeting any Applicable 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 including load interruptions prior to the actual occurrence of the second contingency.[7]

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[6] The NERC Planning Standards reflect a "deterministic" analysis that captures the "robustness" of the grid. In many NERC subregions, service reliability is understood as the probability of disconnecting firm load due to a resource deficiency. Control areas in the Western Electricity Coordinating Council, including the CAISO, do not currently have sufficient information to apply a probabilistic reliability analysis to transmission or planning studies. However, the CAISO has consistently recommended that the CPUC move to a loss of load probability approach as a means by which to consider alternative solutions while still planning to a desired level of service reliability.
7 This potential for pre-contingency load shedding also occurs because real time operators must prepare for the loss of a common mode N-2 at all times.

2. Option 2- Meet 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 (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 as the CAISO operators prepare for the second contingency. However, the customer load will be interrupted in the event the second contingency occurs.

3. Option 3- Meet Performance Criteria Category C through Pure Procurement

Option 3 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 only. No load based operational solutions are incorporated into this scenario. Therefore, this results in a "pure capacity" procurement scenario.

E. The CPUC's Responsibilities and The CAISO's Recommendation

The CPUC is responsible for determination of the appropriate level of service reliability to end-use customers within each CAISO-identified local capacity area. The CPUC may meet this responsibility by exercising its jurisdiction over load serving entities to compel procurement of generation or demand resources to meet the option selected. The CPUC may also wish to allow the load serving entity to choose planned or controlled load interruption options.[8] The CPUC should impose appropriate penalties for LSEs that fail to comply with the procurement levels that are necessary to meet its established applicable reliability criteria standard. Finally, in its determination of an acceptable service reliability level, the CPUC should

[8] However, such automatic load shedding schemes or operating procedures implementing manual load shedding options must be acceptable to the CAISO, i.e., the load to be shed is demonstrable, verifiable, and appropriately dispatchable.

explicitly understand the implications associated with contingent events as well as the potential that customers will receive different levels of service reliability based on the service reliability level selected for each local capacity area.

As the grid operator, the CAISO recommends that Option 2 be selected as the service reliability standard. Option 2 identifies a potential service reliability that reflects generation capacity set forth in (2) above, adjusted for any feasible operating solution identified by a PTO prior to the study and approved by the CAISO. On a day-to-day basis the CAISO has traditionally operated the network based on the N-1-1 contingency, with operating solutions developed with the PTOs. Should the CPUC choose Option 2, and to the extent a load shedding solution proposed by a PTO is isolated solely in the service territory of a CPUC load serving entity, the CAISO has indicated the appropriateness of such operating procedure to the CPUC in this study.

III. Assumption Details: How the Study was Conducted

A. System Planning Criteria

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

Table 1: Criteria Comparison

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

1 System must be able to readjust to normal limits.

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 1. Where the specific system performance requirements were not met, generation was adjusted such that the minimum amount of generation required to meet the criteria was determined in the Local Capacity Area. The following describes how the criteria were tested for the specific type of analysis performed.

1. Power Flow Assessment:

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

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

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

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

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

[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. Methodology for Determining Zonal Requirements

A key part of the CAISO's study for determining capacity requirements in transmission-constrained areas includes **zonal requirements** to ensure that sufficient generation capacity (in MWs) exists within each large zone so that transmission constraints between zones do not threaten reliability. The analysis of zonal requirements was discussed in the CPUC workshops and the 2006 Local Capacity Technical Analysis (page 5), but the methodology for determining these zonal requirements was not explained in detail.

The CAISO's methodology for determining these zonal requirements is designed so the operating reserves within each zone meet the WECC Minimum Operating Reliability Criteria (MORC) for operating reserves.[9]

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[9] *MORC states "Prudent operating judgment shall be exercised in distributing operating reserve, taking into account effective use of capacity in an emergency, time required to be effective, transmission limitations, and local area requirements."*

The determination of these zonal requirements is dependent upon key assumptions:

- **Forecasted Load:** Consistent with CAISO Planning Standards, the CAISO proposes a forecasted zonal load level that represents the 1-in-5-year peak conditions (more specifically the zonal area "coincident" peak.) For future studies the CAISO expects to use the CEC's 1-in-5 year peak load forecasts.

- **Import Capability:** the maximum MW amount that is assumed can be imported into a zone. This can be calculated based on the maximum historical imports into a zone, plus the anticipated increase in import capability due to transmission upgrades in effect for the time period being analyzed. This includes capacity from outside the CAISO Control Area and capacity between the zones, e.g. Path 26.

- **Outages**: the amount of generation that may be unavailable within a zone due to unforeseen circumstances that require immediate maintenance. Assuming a peak load, this assumption would encompass forced outages as well as a very small amount of planned outages.

- **Recovery from a Single Worst Contingency:** enough operating reserve to recover from the most severe single contingency without relying on firm load shedding. This total reserve capacity is based on the set of assumptions for peak load conditions. Existing industry standards do not permit shedding firm load to address a single contingency.

The zonal requirement (i.e., the amount of MWs needed within each region) is determined simply by calculating the sum of the operating reserves for recovery from a single worst contingency, the historical outage data, and the 1-in-5-year peak forecast, subtracted by the import capability:

1 in 5 zonal Load forecast + Historical outage data + Recovery from single worst contingency – Import Capability = Zonal Requirement

Zonal requirements define the amount of generation (in MWs) that should exist within a region to ensure the system's ability to withstand a single worst contingency. The CAISO should focus on the 500kV system only between three major zones: NP15, NP15+ZP26, and south of Path 26 (SP26.) These are historically defined regions of the CAISO Controlled Grid where inter-zonal transmission constraints have been prone to deficiencies. Generation within all the local areas within these zones would count toward meeting a zonal requirement.

C. Load Forecast

1. System Forecast

The load forecast at the system as well as PTO levels originates from California Energy Commission (CEC). This most recent CEC forecast is then distributed across the entire system, down to the local area, division and substation level. PTO's 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 muni forecasts. The melding process consists of two parts. Part 1 deals with the PTO load. Part 2 deals with the muni 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; please refer to each PTO expansion plan for additional details.

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 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 growths projected for the divisions by the distribution planners. For example the 1-in-10 area base case, the division load growth determined for the system base case is adjusted to the 1-in-10 temperature using the load temperature relation determined from the latest peak load and temperature data of the division.

ii. Allocation of division load to transmission bus level

Since the base case loads are modeled at the various transmission buses, the division loads developed would need to be allocated to those buses. The allocation process is different depending on the load types. For the most part each PTO's 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 would be allocated to the transmission buses based on the relative magnitude of the distribution forecast. The summation of all base case loads usually is higher then the load forecast because some load like self-generation and generation-plant are load behind the meter and they need to 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 muni forecasts provided to the PTOs for the purposes of their base cases were used for this study.

3. Comparison between the 1-in 5 and 1-in-10 local load forecast

As a rule of thumb, this difference translates into a corresponding one-for-one reduction in the LCR -- (the MWs of capacity needed in that local area) -- provided that the area constraint is driven by a thermal problem AND assuming that the load and generation have roughly the same effectiveness factors.

The exact reduction in LCR results (using a less stringent 1-in-5-year instead of the 1-in-10-year load forecast) could be different due to the load growth characteristics specific to each local area. If the local area constraints are non-linear, like voltage or dynamic problems, or if the effectiveness factors between the generators and load within the same area are significantly different relative to the worst thermal constraint, then the difference in LCR results will not mirror the difference in load forecast.

Table 2: 2007 Local Area Load Forecast 1-in 5 vs 1-in-10

	Peak Load (1 in 10) (MW)	**Peak Load (1 in 5) (MW)**	**Difference (MW)**	**Difference (%)**
Humboldt	197	196	1	0.5
North Coast/North Bay	1,513	1,475	38	2.5
Sierra	1,841	1,805	36	2.0
Stockton	1,267	1,252	15	1.2
Greater Bay	9,633	9,509	124	1.3
Greater Fresno	3,154	3,004	150	4.8
Kern	1,209	1,174	35	2.9
LA Basin	19,325	18,809	516	2.7
San Diego	4,742	4,610	134	2.8
Total	**42,881***	**41,834***	**1,049**	**2.4**

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

The peak load forecast is one key variable in the determination of the LCR that meets the established criteria. In comparing the 1-in-5-year load analysis with the 1-in-10-year standard, a general conclusion that could be drawn is that the difference in required MWs for most of the local areas and sub-areas analyzed in this report would not be huge. An analysis of each local area and the unique contingencies within each area would be necessary to determine the exact difference in LCR's.

D. Power Flow Program Used in the LCR analysis

The LCR technical studies were conducted using General Electric's Power System Load Flow (GE PSLF) program version 15.2. This E PSLF program is available directly from GE or through the Western System Electricity Council (WECC) to any member.

The CAISO utilized the "2007 Heavy Summer 2A1" as the starting WECC base case for the 2007 local area power flows used in the 2007 LCR studies. To complete the local area component of this study, this 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 area as provided to the ISO by the Participating Transmission Owners ("PTOs").

Electronic contingency files provided by the PTOs were utilized to perform the numerous contingencies required to identify the LCR needs. These contingency files include remedial action and special protection schemes that are expected to be in operation during 2007. An CAISO created EPCL (a GE programming language contained within the GE PSLF package) routine was used to run the combination of contingencies; however, other routines are available from WECC with the GE PSFL package or can be developed by third parties to identify the most limiting combination of contingencies requiring the highest amount of generation within the local area to maintain power flows within applicable ratings.

IV. Locational Capacity Requirement Study Results

A. Summary of Study Results

The LCR results reflect 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 and nuclear units). The second set is "market" generation. Within this overview, LCR is defined as the amount of generating capacity that is required 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 following two tables.

Table 3: Local Requirements Comparison

	Qualifying Capacity			2007 LCR Requirement Based on Category B Option 1			2007 LCR Requirement Based on Category C with operating procedure Option 2			2006 Total LCR Req.
Local Area Name	**QF/ Muni (MW)**	**Market (MW)**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**(MW)**
Humboldt	73	133	206	202	0	**202**	202	0	**202**	162
North Coast / North Bay	158	861	1019	582**	0	**582****	582**	0	**582****	658
Sierra	1072	776	1848	1833	205	**2038**	1833	328	**2161**	1770*
Stockton	314	257	571	348	0	**348**	506	53	**559**	440*
Greater Bay	1314	5231	6545	4771	0	**4771**	5341	0	**5341**	6009
Greater Fresno	575	2337	2912	2530	0	**2530**	2534	68	**2602**	2837 *
Kern	978	31	1009	554	0	**554**	769	17	**786**	797*
LA Basin	3510	7012	10522	8843	0	**8843**	8843	0	**8843**	8127
San Diego	191	2741	2932	2781	0	**2781**	2781	0	**2781**	2620
Total	**8185**	**19379**	**27564**	**22444**	**205**	**22649**	**23391**	**466**	**23857**	**23420**

* Generation deficient areas (or with sub-area that are deficient) – deficiency included in LCR
** The North Coast/North Bay area requirement would have been higher by 80 MW, however a new operating procedure has been received, validated and implemented by PG&E and the CAISO.

The last column under "2007 LCR Requirement based on Category C with operating solution" represents the MW of generation that the ISO is proposing to be procured by all LSEs in local areas under the CPUC Local Capacity Requirements. This column includes all units needed to maintain system reliability without the potential for pre-contingency load shedding

Table 4: Local Capacity Requirements vs. Peak Load and Local Area Generation

	2007 Total LCR (MW)	Peak Load (1 in10) (MW)	2007 LCR as % of Peak Load	Total Dependable Local Area Generation (MW)	2007 LCR as % of Total Area Generation
Humboldt	202	197	103%	206	98%
North Coast/North Bay	582	1,513	38%	1,019	57%
Sierra	2,161	1,841	117%	1,848	117%**
Stockton	559	1,267	44%	571	98%**
Greater Bay	5,341	9,633	55%	6,545	82%
Greater Fresno	2,602	3,154	82%	2,912	89%**
Kern	786	1,209	65%	1,009	78%**
LA Basin	8,843	19,325	46%	10,522	84%
San Diego	2,781	4,742	59%	2,932	95%
Total	**23,857**	**42,881***	**56%***	**27,471**	**87%**

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

** Generation deficient LCA (or with sub-area that are 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.

Table 3 shows how much of the local area load is dependent on local generation and how much local generation needs to be available in order to reliably (see LCR criteria) serve the load in those Local Capacity Areas. This table also indicates where new transmission projects, new generation additions or demand side management programs would be most useful in order to reduce the dependency on existing (mostly old and inefficient) local area generation.

B. Summary of Results by Local Area

Each local 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 area is not simply a summation of the sub-area requirements. For example, some sub-areas may overlap and therefore the same units have been counted toward both sub-area requirements. Of course some sub-areas requirements are directly counted toward the total requirements of a bigger local area or the overall area.

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 115 kV
2) Humboldt 115 kV
3) Kekawaka 60 kV
4) Ridge Cabin 60 kV

Total busload within the defined area: 191 MW with 6 MW of losses resulting in total load + losses of 197 MW.

Total units and qualifying capacity available in this area:

Gen Bus	Gen Name	ID	Qualifying Capacity (MW)
31170	HMBOLDT1	1	51
31172	HMBOLDT2	1	52
31154	HUMBOLDT	1	15
31154	HUMBOLDT	2	15
31150	FAIRHAVN	1	17.2

31166	KEKAWAK	1	5.3
31158	LP SAMOA	1	25
31152	PAC.LUMB	2	12.5
31152	PAC.LUMB	1	12.5
	Total		205.5

Critical Contingency Analysis Summary

Humboldt overall:

The most critical contingency for the Humboldt area is the outage of the Bridgeville-Cottonwood 115 kV line over-lapping with an outage of one Humboldt Bay Power Plant. The local area limitation is low voltage and reactive power margin. This multiple contingency establishes a Local Capacity Requirement of 202 MW (includes 73 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. Units outside of this area are not effective.

Humboldt Overall Requirements:

	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	73	0	133	206

	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[10]	202	0	202
Category C (Multiple)[11]	202	0	202

[10] 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.

[11] 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. North Coast / North Bay Area

Area Definition

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

The transmission tie facilities coming into the Eagle Rock-Fulton sub-area are:

1) Fulton-Lakeville 230 kV line #1
2) Fulton-Ignacio 230kV line #1
3) Cortina 230/115 kV Transformer #1
4) Lakeville-Sonoma 115 kV line #1
5) Corona-Lakeville 115 kV line #1
6) Willits-Garberville 60 kV line #1

The substations that delineate the Eagle Rock-Fulton sub-area are:

1) Fulton 230 kV
2) Corona 115 kV
3) Sonoma 115 kV
4) Cortina 115 kV
5) Laytonville 60 kV

The transmission tie lines into the Lakeville sub-area are:

1) Vaca Dixon-Lakeville 230 kV line #1
2) Tulucay-Vaca Dixon 230 kV line #1
3) Lakeville-Sobrante 230 kV line #1
4) Ignacio-Sobrante 230 kV line #1
5) Ignacio-Fulton 230 kV line #1
6) Lakeville-Fulton 230 kV line #1
7) Lakeville-Corona 115 kV line #1
8) Lakeville-Sonoma 115 kV line #1

The substations that delineate the Lakeville sub-area are:

1) Lakeville 230 kV
2) Ignacio 230 kV
3) Tulucay 230 kV
4) Lakeville 115 kV

Total busload within the defined area: 1457 MW with 56 MW of losses resulting in total load + losses of 1513 MW.

Total units and qualifying capacity available in this area:

Gen Bus	Gen Name	ID	Qualifying Capacity (MW)
31433	POTTRVLY	3	2.5
31433	POTTRVLY	1	5.5
31433	POTTRVLY	4	2.5
31430	SMUDGEO1	1	38
31406	GEYSR5-6	1	36
31406	GEYSR5-6	2	36
31408	GEYSER78	1	31
31408	GEYSER78	2	31
31412	GEYSER11	1	60
31414	GEYSER12	1	41
31416	GEYSER13	1	70
31418	GEYSER14	1	63
31420	GEYSER16	1	75
31422	GEYSER17	1	51
31424	GEYSER18	1	40
31426	GEYSER20	1	40
38106	NCPA1GY1	1	59
38108	NCPA1GY2	1	59
38110	NCPA2GY1	1	60
38112	NCPA2GY2	1	60
31400	SANTA FE	2	39.1
31404	WEST FOR	2	14
31400	SANTA FE	1	39.1
31402	BEAR CAN	1	8.3
31402	BEAR CAN	2	8
31404	WEST FOR	1	14
32700	MONTICLO	1	3.3
32700	MONTICLO	2	3.4
32700	MONTICLO	3	0
31435	GEO.ENGY	1	8.6
31435	GEO.ENGY	2	8.9
31436	INDIAN V	1	3.7
31446	SONMA LF	1	7.7
	Total		1018.6

<u>Critical Contingency Analysis Summary</u>

Eagle Rock-Fulton Sub-area

The most critical overlapping contingency is the outage of the Fulton-Ignacio 230 kV line #1 and the Fulton-Lakeville 230 kV line #1. The sub-area area limitation is thermal overloading of Sonoma-Pueblo 115 kV line #1. This limiting contingency establishes a Local Capacity Requirement of 371 MW (includes 80 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area. Out of this amount, 182 MW is required among the units connected directly to the Eagle Rock substation (includes 21 MW of QF generation).

The most critical single contingency in the sub-area is the outage of Cortina 230/115 kV transformer #1. This limiting contingency establishes a Local Capacity Requirement of 245 MW (includes 80 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 within the Eagle Rock-Fulton pocket as well as units outside the pocket that are at least 5% effective to the above-mentioned constraint.

Single contingency

Gen Bus	Gen Name	Gen ID	MW Eff Fctr	Location
31404	WEST FOR	2	56	Fulton
31404	WEST FOR	1	56	Fulton
31414	GEYSER12	1	56	Fulton
31418	GEYSER14	1	56	Fulton
31420	GEYSER16	1	56	Fulton
31422	GEYSER17	1	56	Fulton
38110	NCPA2GY1	1	56	Fulton
38112	NCPA2GY2	1	56	Fulton
31406	GEYSR5-6	1	53	Eagle Rock
31406	GEYSR5-6	2	53	Eagle Rock
31408	GEYSER78	1	53	Eagle Rock
31408	GEYSER78	2	53	Eagle Rock
31412	GEYSER11	1	53	Eagle Rock

Overlapping Contingency

Gen Bus	Gen Name	Gen ID	MW Eff Fctr	Location
31404	WEST FOR	2	27	Fulton
31404	WEST FOR	1	27	Fulton
31414	GEYSER12	1	27	Fulton
31418	GEYSER14	1	27	Fulton
31420	GEYSER16	1	27	Fulton
31422	GEYSER17	1	27	Fulton

38110	NCPA2GY1	1	27	Fulton
38112	NCPA2GY2	1	27	Fulton
31406	GEYSR5-6	1	17	Eagle Rock
31406	GEYSR5-6	2	17	Eagle Rock
31408	GEYSER78	1	17	Eagle Rock
31408	GEYSER78	2	17	Eagle Rock
31412	GEYSER11	1	17	Eagle Rock

Lakeville Sub-area

Operations solutions to mitigate the most limiting constraint in the Lakeville pocket, as previously described in the LCR report, has been validated in this area in order to reduce the total LCR requirement both under single and overlapping contingency conditions. After implementing the operating solutions, the most critical contingency for Lakeville sub-area would be the outage of Vaca Dixon-Tulucay 230 kV line #1 and Geysers 13 unit. The sub-area limitation is thermal overloading of the Lakeville-Vaca-Dixon 230 kV #1. This limiting contingency establishes a Local Capacity Requirement of 582 MW for single contingency in this sub-area (includes 158 MW of QF generation). The LCR requirement for Eagle Rock/Fulton sub-area can be counted toward fulfilling the requirement of Lakeville sub-area

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	MW Eff Fctr	Location
31400	SANTA FE	2	25	Lakeville
31430	SMUDGEO1	1	25	Lakeville
31400	SANTA FE	1	25	Lakeville
31416	GEYSER13	1	25	Lakeville
31424	GEYSER18	1	25	Lakeville
31426	GEYSER20	1	25	Lakeville
38106	NCPA1GY1	1	25	Lakeville
38108	NCPA1GY2	1	25	Lakeville
31404	WEST FOR	2	22	Fulton
31404	WEST FOR	1	22	Fulton
31414	GEYSER12	1	22	Fulton
31418	GEYSER14	1	22	Fulton
31420	GEYSER16	1	22	Fulton
31422	GEYSER17	1	22	Fulton
38110	NCPA2GY1	1	22	Fulton
38112	NCPA2GY2	1	22	Eagle Rock
31406	GEYSR5-6	1	8	Eagle Rock

31406	GEYSR5-6	2	8	Eagle Rock
31408	GEYSER78	1	8	Eagle Rock
31408	GEYSER78	2	8	Eagle Rock
31412	GEYSER11	1	8	Eagle Rock

North Coast/North Bay Overall Requirements:

	QF/Seflgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	158	0	861	1019

	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[12]	582	0	582
Category C (Multiple)[13]	582	0	582

3. Sierra Area

Area Definition

The transmission tie lines into the Sierra Area are:

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

The substations that delineate the Sierra Area are:

1) Table Mountain 60 kV
2) Table Mountain 230 kV
3) Big Bend 115 kV
4) Drum 115 kV

[12] 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.
[13] 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.

5) Tamarack 60 kV
6) Brighton 230 kV
7) Rio Oso 230 kV
8) Gold Hill 230 kV

Total busload within the defined area: 1742.4 MW with 98.5 MW of losses resulting in total load + losses of 1840.9 MW.

Total units and qualifying capacity available in this area:

Gen No	Gen Name	ID	Qualifying Capacity
31888	OROVLLE	1	8.9
31890	PO POWER	2	9.8
31890	PO POWER	1	9.8
31834	KELLYRDG	1	10
31814	FORBSTWN	1	39.7
31794	WOODLEAF	1	55
31862	DEADWOOD	1	2
31832	SLY.CR.	1	13.2
32470	CMP.FARW	1	6.5
32450	COLGATE1	1	165.8
32452	COLGATE2	1	165.7
32466	NARROWS1	1	3.6
32468	NARROWS2	1	10.1
32451	FREC	1	47
32490	GRNLEAF1	2	10
32490	GRNLEAF1	1	51.1
32156	WOODLAND	1	28.6
32494	YUBA CTY	1	50.2
32496	YCEC	1	47
32492	GRNLEAF2	1	50.3
32166	UC DAVIS	1	3.5
31812	CRESTA	1	35
31812	CRESTA	2	35
31788	ROCK CK2	1	56
31820	BCKS CRK	1	33
31820	BCKS CRK	2	25
31790	POE 1	1	60
31792	POE 2	1	60
31786	ROCK CK1	1	56
31784	BELDEN	1	115
32162	RIV.DLTA	1	3.1
32502	DTCHFLT2	1	26
32476	ROLLINSF	1	11.7
32474	DEER CRK	1	5.7
32454	DRUM 5	1	49.5
32504	DRUM 1-2	1	13
32504	DRUM 1-2	2	13
32506	DRUM 3-4	1	14
32506	DRUM 3-4	2	14

32484	OXBOW F	1	6
32472	SPAULDG	1	4.4
32472	SPAULDG	2	7
32472	SPAULDG	3	5.8
32498	SPILINCF	1	13.7
32464	DTCHFLT1	1	22
32500	ULTR RCK	1	28.5
32480	BOWMAN	1	3.8
32488	HAYPRES+	1	12.3
32488	HAYPRES+	2	8.7
32462	CHI.PARK	1	38
32478	HALSEY F	1	11
32512	WISE	1	10.8
32460	NEWCSTLE	1	5.9
32510	CHILIBAR	1	7
32513	ELDRADO1	1	10
32514	ELDRADO2	1	10
32458	RALSTON	1	86
32456	MIDLFORK	1	63.4
32456	MIDLFORK	2	63.4
32486	HELLHOLE	1	0.5
32508	FRNCH MD	1	17
			1848

Critical Contingency Analysis Summary

South of Table Mountain Sub-area

The most critical 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 a Local Capacity Requirement of 1630 MW (includes 1072 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this pocket.

Effectiveness factors:

Gen No	Gen Name	ID	Qualifying Capacity	DFAX (%)
31888	OROVLLE	1	8.9	72
31890	PO POWER	2	9.8	72
31890	PO POWER	1	9.8	72
31834	KELLYRDG	1	10	72
31814	FORBSTWN	1	39.7	62
31794	WOODLEAF	1	55	62
31862	DEADWOOD	1	2	61
31832	SLY.CR.	1	13.2	61
32470	CMP.FARW	1	6.5	54
32450	COLGATE1	1	165.8	52
32452	COLGATE2	1	165.7	52

32466	NARROWS1	1	3.6	52
32468	NARROWS2	1	10.1	52
32451	FREC	1	47	42
32490	GRNLEAF1	2	10	41
32490	GRNLEAF1	1	51.1	41
32156	WOODLAND	1	28.6	28
32494	YUBA CTY	1	50.2	27
32496	YCEC	1	47	27
32492	GRNLEAF2	1	50.3	27
32166	UC DAVIS	1	3.5	26
31812	CRESTA	1	35	24
31812	CRESTA	2	35	24
31788	ROCK CK2	1	56	24
31820	BCKS CRK	1	33	24
31820	BCKS CRK	2	25	24
31790	POE 1	1	60	24
31792	POE 2	1	60	24
31786	ROCK CK1	1	56	24
31784	BELDEN	1	115	23
32162	RIV.DLTA	1	3.1	21
32502	DTCHFLT2	1	26	21
32476	ROLLINSF	1	11.7	20
32474	DEER CRK	1	5.7	20
32454	DRUM 5	1	49.5	20
32504	DRUM 1-2	1	13	20
32504	DRUM 1-2	2	13	20
32506	DRUM 3-4	1	14	20
32506	DRUM 3-4	2	14	20
32484	OXBOW F	1	6	20
32472	SPAULDG	1	4.4	20
32472	SPAULDG	2	7	20
32472	SPAULDG	3	5.8	20
32498	SPILINCF	1	13.7	20
32464	DTCHFLT1	1	22	20
32500	ULTR RCK	1	28.5	19
32480	BOWMAN	1	3.8	19
32488	HAYPRES+	1	12.3	19
32488	HAYPRES+	2	8.7	19
32462	CHI.PARK	1	38	19
32478	HALSEY F	1	11	19
32512	WISE	1	10.8	19
32460	NEWCSTLE	1	5.9	18
32510	CHILIBAR	1	7	17
32513	ELDRADO1	1	10	17
32514	ELDRADO2	1	10	17
32458	RALSTON	1	86	17
32456	MIDLFORK	1	63.4	17
32456	MIDLFORK	2	63.4	17
32486	HELLHOLE	1	0.5	16
32508	FRNCH MD	1	17	16

Colgate Sub-area
The most critical contingency is the loss of the Colgate-Smartville #1 60 kV line with one of the Narrows #2 (or Camp far West) units out of service. The area limitation is thermal overloading of the Colgate-Smartville #2 60 kV line. This limiting contingency establishes a Local Capacity Requirement of 17 MW (includes 17 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this pocket.

Effectiveness factors:

All units within this area (Narrows #2 and Camp Far West) are needed therefore no effectiveness factor is required.

Pease Sub-area
The most critical contingency is the loss of the Palermo-East Nicolaus 115 kV line with one of the Greenleaf #2 (or Yuba City) units out of service. The area limitation is thermal overloading of the Palermo-Pease 115 kV line. This limiting contingency establishes a Local Capacity Requirement of 111 MW (includes 100 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this pocket.

Effectiveness factors:

All units within this area (Greenleaf #2, Yuba City and Yuba City EC) are needed therefore no effectiveness factor is required.

Bogue Sub-area
The most critical contingency is the loss of the Pease-Rio Oso 115 kV line with one of the Greenleaf #1 (or Feather River EC) units out of service. The area limitation is thermal overloading of the Palermo-Bogue 115 kV line. This limiting contingency establishes a Local Capacity Requirement of 101 MW (includes 61 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this pocket.

Effectiveness factors:

All units within this area (Greenleaf #1 units 1&2 and Feather River EC) are needed therefore no effectiveness factor is required.

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 Palermo-East Nicolaus 115 kV line. This limiting contingency establishes a Local Capacity Requirement of 1037 MW (includes 142 MW of QF and

Muni generation as well as 250 MW of Deficiency) as the minimum capacity necessary for reliable load serving capability within this pocket.

The single most critical contingency is the loss of the Palermo-Pease 115 kV line with Belden unit out of service. The area limitation is thermal overloading of the Palermo-East Nicolaus 115 kV line. This limiting contingency establishes a Local Capacity Requirement of 980 MW (includes 142 MW of QF and Muni generation as well as 193 MW of Deficiency) as the minimum capacity necessary for reliable load serving capability within this pocket.

The Sierra case provided had a normal overload on the Palermo-East Nicolaus 115 kV line that can be resolved by changing the normal tap point for the East Marysville substation from the Palermo-East Nicolaus 115 kV line to the Pease-Rio Oso 115 kV line and by having at least 680 MW of generation on-line (from maximum 787 MW generation available – includes 142 MW of QF and Muni).

Effectiveness factors:

All units (listed below) within this area are needed therefore no effectiveness factor is required.

Gen No	Gen Name	ID	Qualifying Capacity
32476	ROLLINSF	1	11.7
32474	DEER CRK	1	5.7
32504	DRUM 1-2	1	13
32504	DRUM 1-2	2	13
32506	DRUM 3-4	1	14
32506	DRUM 3-4	2	14
32454	DRUM 5	1	49.5
32484	OXBOW F	1	6
32472	SPAULDG	1	4.4
32472	SPAULDG	2	7
32472	SPAULDG	3	5.8
32480	BOWMAN	1	3.8
32488	HAYPRES+	1	12.3
32488	HAYPRES+	2	8.7
32156	WOODLAND	1	28.6
32166	UC DAVIS	1	3.5
32502	DTCHFLT2	1	26
32464	DTCHFLT1	1	22
32162	RIV.DLTA	1	3.1
32462	CHI.PARK	1	38
31812	CRESTA	1	35
31812	CRESTA	2	35
31788	ROCK CK2	1	56
31820	BCKS CRK	1	33
31820	BCKS CRK	2	25
31790	POE 1	1	60
31792	POE 2	1	60

31786	ROCK CK1	1	56
31784	BELDEN	1	115
32478	HALSEY F	1	11
32512	WISE	1	10.8
			786.9

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 Local Capacity Requirement of 83 MW (includes 0 MW of QF and Muni generation as well as 56 MW of Deficiency) as the minimum capacity necessary for reliable load serving capability within this pocket.

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 Local Capacity Requirement of 123 MW (includes 0 MW of QF and Muni generation as well as 95 MW of Deficiency) as the minimum capacity necessary for reliable load serving capability within this pocket.

The single most critical contingency is the loss of the Drum-Higgins 115 kV line with the Wise #1 unit out of service. The area limitation is thermal overloading of the Gold Hill-Placer #1 115 kV line. This limiting contingency establishes a Local Capacity Requirement of 52 MW (includes 0 MW of QF and Muni generation as well as 24 MW of Deficiency) as the minimum capacity necessary for reliable load serving capability within this pocket.

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 a Local Capacity Requirement of 701 MW (includes 413 MW of QF and

Muni generation as well as 45 MW of Deficiency) as the minimum capacity necessary for reliable load serving capability within this pocket.

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 a Local Capacity Requirement of 352 MW (includes 413 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this pocket.

Effectiveness factors:

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

Gen No	Gen Name	ID	Qualifying Capacity	DFAX (%)
32156	WOODLAND	1	28.6	31
32490	GRNLEAF1	2	10	29
32490	GRNLEAF1	1	51.1	29
32451	FREC	1	47	28
32166	UC DAVIS	1	3.5	25
32502	DTCHFLT2	1	26	20
32476	ROLLINSF	1	11.7	19
32474	DEER CRK	1	5.7	18
32454	DRUM 5	1	49.5	18
32504	DRUM 1-2	1	13	18
32504	DRUM 1-2	2	13	18
32506	DRUM 3-4	1	14	18
32506	DRUM 3-4	2	14	18
32484	OXBOW F	1	6	18
32472	SPAULDG	1	4.4	18
32472	SPAULDG	2	7	18
32472	SPAULDG	3	5.8	18
32480	BOWMAN	1	3.8	18
32488	HAYPRES+	1	12.3	18
32488	HAYPRES+	2	8.7	18
32496	YCEC	1	47	16
32494	YUBA CTY	1	50.2	16
32492	GRNLEAF2	1	50.3	16
32464	DTCHFLT1	1	22	15
32162	RIV.DLTA	1	3.1	15
32462	CHI.PARK	1	38	12
31862	DEADWOOD	1	2	7
31814	FORBSTWN	1	39.7	7
31832	SLY.CR.	1	13.2	7
31794	WOODLEAF	1	55	7
			655.6	

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 Gold Hill-Ralston 230 kV line or vice versa. The area limitation is thermal overloading of the Rio Oso-Atlantic 230 kV line. This limiting contingency establishes a Local Capacity Requirement of 230 MW (includes 80 MW of QF and Muni generation as well as 95 MW of Deficiency) as the minimum capacity necessary for reliable load serving capability within this pocket.

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 Local Capacity Requirement of 132 MW (includes 80 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this pocket.

Effectiveness factors:

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

Gen No	Gen Name	ID	Qualifying Capacity	DFAX (%)
32498	SPILINCF	1	13.7	50
32500	ULTR RCK	1	28.5	49
32514	ELDRADO2	1	10	33
32513	ELDRADO1	1	10	33
32510	CHILIBAR	1	7	33
32460	NEWCSTLE	1	5.9	27
32478	HALSEY F	1	11	25
32512	WISE	1	10.8	25
32462	CHI.PARK	1	38	9
			134.9	

Sierra Overall Requirements:

	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	267	805	776	1848

	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single) [14]	1833	205	2038
Category C (Multiple) [15]	1833	328	2161

[14] 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.

[15] 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. 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 2
3) 30/115 kV Transformer #2
4) Tesla-Tracy 115 kV Line
5) Tesla-Salado 115 kV Line
6) Tesla-Salado-Manteca 115 kV line
7) Tesla-Shulte 115 kV Line
8) Tesla-Manteca 115 kV Line

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

1) Tesla 115 kV
2) Bellota 115 kV

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

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

The substations that delineate the Lockeford Sub-area is:

1) Lockeford 60 kV

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

1) Tesla – Stagg 230 kV Line
2) Tesla – Eight Mile Road 230 kV Line
3) Gold Hill – Eight Mile Road 230 kV Line
4) Gold Hill - Lodi Stigg 230 kV Line

The substations that delineate the Stagg Sub-area is:

1) Tesla 230 kV
2) Gold Hill 230 kV

Total busload within the defined area: 1240 MW with 27 MW of losses resulting in total load + losses of 1267 MW.

Total units and qualifying capacity available in this area:

Name	ID	Qualifying Capacity
GWFTRCY2	1	79.2
GWFTRCY1	1	79.8
FBERBORD	1	5.7
BELLTA T	1	0
CH.STN.	1	22.3
STNSLSRP	1	19.9
CPC STCN	1	62.9
CAMANCHE	1	3.7
CAMANCHE	2	3.7
CAMANCHE	3	3.7
DONNELLS	1	67.5
BEARDSLY	1	11
TULLOCH	1	9
TULLOCH	2	9
SANDBAR	1	16.8
SPRNG GP	1	6.7
STANISLS	1	91
LODI25CT	1	25.6
GEN.MILL	1	3.4
Stig CC	1	50
		570.9

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 critical contingency for the Tesla-Bellota pocket is the loss of Tesla-Tracy 115 kV and Tesla-Schulte 115 kV #1. The area limitation is thermal overloading of the Tesla-AEC section of Tesla-Kasson-Manteca 115 kV line above its emergency rating. This limiting contingency establishes a Local Capacity Requirement of 428 MW (includes 235 MW of QF and Muni generation)e minimum capacity necessary for reliable load serving capability within this area.

The single most critical contingency for the Tesla-Bellota pocket is the loss of Tesla-Tracy 115 kV line and the loss of the Stanisls unit #1. This single contingency establishes a Local Capacity Requirement of 348 MW (includes 235 MW of QF and Muni generation).

Effectiveness factors:

All units within this area are needed for the most limiting contingency 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-Colony section of the Lockeford-Lodi #1 60 kV circuit. This limiting contingency establishes a Local Capacity Requirement of 81 MW (including 28 MW of QF and Muni as well as a deficiency of 53 MW) as the minimum capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

All units within this area (Lodi CT and General Mill) are needed therefore no effectiveness factor is required.

Stagg Sub-area

The outage of the Tesla-Stagg 230 kV line and Tesla-Eight Mile 230 kV line causes low voltages at Stagg, Eight Mile Road and Lodi Stig 230 kV busses. Post-contingency steady-state voltages at these three busses are less than 0.90 pu. Lodi Stig generating unit is needed to support voltage at these three 230 kV busses. This limiting contingency establishes a Local Capacity Requirement of 50 MW as the minimum capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

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

Stockton Overall Requirements:

	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	114	200	257	571

	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[16]	348	0	348
Category C (Multiple)[17]	506	53	559

[16] 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

<u>Area Definition</u>

The transmission tie lines into the Greater Bay Area are:

1) Lakeville-Sobrante 230 kV
2) Ignacio-Sobrante 230 kV
3) Parkway-Moraga 230 kV
4) Bahia-Moraga 230 kV
5) Lambie SW Sta-Vaca Dixon 230 kV
6) Peabody-Contra Costa P.P. 230 kV
7) Kelso-Brentwood 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-Tracy #1 230 kV
14) Tesla-Tracy #2 230 kV
15) Tesla-Ravenswood 230 kV
16) Tesla-Metcalf 500 kV
17) Moss Landing-Metcalf 500 kV
18) Moss Landing-Metcalf #1 230 kV
19) Moss Landing-Metcalf #2 230 kV
20) Green Valley-Morgan Hill #1 115 kV
21) Green Valley-Morgan Hill #2 115 kV
22) Oakdale TID-Newark #1 115 kV
23) Oakdale TID-Newark #2 115 kV

The substations that delineate the Greater Bay Area are:

1) Lakeville 230 kV
2) Ignacio 230 kV
3) Moraga 230 kV
4) Lambie SW Sta 230 kV
5) Kelso 230 kV
6) Peabody 230 kV
7) Pittsburg 230 kV
8) Tesla 230 kV
9) Metcalf 500 kV
10) Moss Landing 500 kV

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[17] 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.

11) Morgan Hill 115 kV
12) Newark 115 kV

Total busload within the defined area: 9402 MW with 231 MW of losses resulting in total load + losses of 9633 MW.

Total units and qualifying capacity available in this area:

No	Name	ID	Qualifying Capacity
38118	ALMDACT1	1	25.6
38119	ALMDACT2	1	25.6
33114	C.COS 4	1	0
33115	C.COS 5	1	0
33116	C.COS 6	1	345
33117	C.COS 7	1	345
33463	CARDINAL	2	10
33463	CARDINAL	1	17.8
35863	CATALYST	1	0
36856	CCA100	1	32
33136	CCCSD	1	4.4
32921	ChevGen1	1	54
32922	ChevGen2	1	54
36854	Cogen	2	3
36854	Cogen	1	3
32900	CRCKTCOG	1	243
32175	CREEDGT1	3	47
33145	CROWN.Z.	2	5.4
33145	CROWN.Z.	1	40
33108	DEC CTG1	1	173
33109	DEC CTG2	1	173
33110	DEC CTG3	1	173
33107	DEC STG1	1	294
33161	DOWCHEM1	1	16.8
33162	DOWCHEM2	1	22
33163	DOWCHEM3	1	22
36863	DVR A GT	1	47
36865	DVR A ST	1	50
36864	DVR B GT	1	50
35318	FLOWDPTR	1	5.7
33151	FOSTER W	3	35
33151	FOSTER W	1	45.4
33151	FOSTER W	2	45.4
36858	Gia100	1	21
36895	Gia200	1	21
35850	GLRY COG	2	40
35850	GLRY COG	1	80
32174	GOOSEHGT	2	46

35851	GROYPKR1	1	45
35852	GROYPKR2	1	45
35853	GROYPKR3	1	45
33131	GWF #1	1	20
33132	GWF #2	1	20
33133	GWF #3	1	20
33134	GWF #4	1	20
33135	GWF #5	1	20
32172	HIGHWNDS	1	13
32740	HILLSIDE	1	26.2
35637	IBM-CTLE	1	50
32173	LAMBGT1	1	47
35854	LECEFGT1	1	48
35855	LECEFGT2	1	48
35856	LECEFGT3	1	48
35857	LECEFGT4	1	48
35310	LFC FIN+	1	8.9
33112	LMECCT1	1	165
33111	LMECCT2	1	165
33113	LMECST1	1	230
35881	MEC CTG1	1	184
35882	MEC CTG2	1	186
35883	MEC STG1	1	227
33121	MRAGA 1T	1	0
33122	MRAGA 2T	1	0
33123	MRAGA 3T	1	0
32901	OAKLND 1	1	55
32902	OAKLND 2	1	55
32903	OAKLND 3	1	55
35860	OLS-AGNE	1	28.5
33252	POTRERO3	1	210
33253	POTRERO4	1	52
33254	POTRERO5	1	52
33255	POTRERO6	1	52
33105	PTSB 5	1	320
33106	PTSB 6	1	325
30000	PTSB 7	1	710
33178	RVEC_GEN	1	48
35312	SEAWESTF	1	3.3
33141	SHELL 1	1	20
33142	SHELL 2	1	40
33143	SHELL 3	1	40
32176	SHILOH	1	0
35861	SJ-SCL W	1	5
33462	SMATO1SC	1	0
33460	SMATO2SC	1	0
33461	SMATO3SC	1	0
32169	SOLANOWP	1	10

33468	SRI INTL	1	3.3
33139	STAUFER	1	2.3
32920	UNION CH	1	20.4
32910	UNOCAL	1	10
32910	UNOCAL	2	10
32910	UNOCAL	3	10
33466	UNTED CO	1	27.2
35320	USW FRIC	1	3.4
35320	USW FRIC	2	0
32168	USWINDPW	2	3.4
33838	USWP_#3	1	20.5
33170	WINDMSTR	1	3.6
35316	ZOND SYS	1	6.2
			6545

Critical Contingency Analysis Summary

San Francisco Sub-area

Per the CAISO Revised Action Plan for SF, all Potrero units (360 MW) will continued to be required until completion of the plan as it is presently described.

The most critical contingency is an overlapping outage of two 115 kV cables between Martin and Hunters Point Substations. The area limitation is thermal overloading of the Martin-Bayshore-Potrero 115 kV #1 and #2 cables. This limiting contingency requires all of the existing Potrero Power plant generation (Potrero units 3-6) 360 MW be on-line.

Effectiveness factors:

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

Oakland Sub-area

The most critical contingency is an outage of the D-L 115 kV cable (with one of the Oakland CT's off-line)
The sub-area area limitation is thermal overloading of the C-X 115 kV cable This limiting contingency establishes a Local Capacity Requirement of 100 MW (includes 50 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

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 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 Local Capacity Requirement of 100 MW 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. Units outside of this area are not effective.

San Jose Sub-area

The most critical contingency is the category C outage of Evergreen 1 – Markham – San Jose B 115 kV line and the Metcalf D – IBM HR – El Patio 115 kV line. The area limitation is thermal overloading of the Baily J3 – El Patio 115 kV line.This contingency prevents the Metcalf E 115 bus from feeding the San Jose B 115 kV load. Power must flow through the remaining Metcalf D – El Patio 115 kV circuit and then to the load at San Jose B 115 kV bus. This limiting contingency establishes a Local Capacity Requirement of 457 MW (including 265 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability for this outage.

Effectiveness factors:

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

Name	ID	Qualifying Capacity
Cogen	2	3
Cogen	1	3
DVR A ST	1	51
DVR B GT	1	48.4
DVR A GT	1	48.4
Gia100	1	21
LECEFGT4	1	48
LECEFGT3	1	48
LECEFGT2	1	48
LECEFGT1	1	48
IBM-CTLE	1	50
OLS-AGNE	1	29
SJ-SCL W	1	5.5
CCA100	1	35.9
CATALYST	1	2

Gia200	1	21
		510.2

Pittsburg Sub-area

The most critical contingency is an outage of the Pittsburg-Tesla #1 or #2 230 kV line (with Delta Energy Center off-line).
The sub-area area limitation is thermal overloading of the parallel Pittsburg-Tesla 230 kV line This limiting contingency establishes a Local Capacity Requirement of 2208 MW (including 678 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 within the Pittsburg pocket as well as units outside the pocket that are at least 5% effective to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	MW Eff Fctr
33840	FLOWD3-6	1	86
33840	FLOWD3-6	2	86
33840	FLOWD3-6	3	86
33840	FLOWD3-6	4	86
33171	TRSVQ+NW	2	26
33171	TRSVQ+NW	1	26
33105	PTSB 5	1	26
33106	PTSB 6	1	26
30000	PTSB 7	1	26
33110	DEC CTG3	1	25
33109	DEC CTG2	1	25
33108	DEC CTG1	1	25
33107	DEC STG1	1	25
33113	LMECST1	1	24
33112	LMECCT1	1	24
33111	LMECCT2	1	24
33132	GWF #2	1	24
33161	DOWCHEM1	1	24
33162	DOWCHEM2	1	24
33163	DOWCHEM3	1	24
33151	FOSTER W	1	23
33151	FOSTER W	2	23
33151	FOSTER W	3	23
33141	SHELL 1	1	21
33143	SHELL 3	1	21
33142	SHELL 2	1	21
32900	CRCKTCOG	1	19
32910	UNOCAL	1	19
32910	UNOCAL	2	19
32910	UNOCAL	3	19

32920	UNION CH	1	19
32922	ChevGen2	1	18
32921	ChevGen1	1	18
32740	HILLSIDE	1	18
33135	GWF #5	1	18
38119	ALMDACT2	1	16
32903	OAKLND 3	1	16
32902	OAKLND 2	1	16
32901	OAKLND 1	1	16
38118	ALMDACT1	1	16
31404	WEST FOR	2	14
31402	BEAR CAN	1	14
31402	BEAR CAN	2	14
31404	WEST FOR	1	14
31414	GEYSER12	1	14
31416	GEYSER13	1	14
31418	GEYSER14	1	14
31420	GEYSER16	1	14
31422	GEYSER17	1	14
31424	GEYSER18	1	14
31426	GEYSER20	1	14
38110	NCPA2GY1	1	14
38112	NCPA2GY2	1	14
31400	SANTA FE	2	13
31430	SMUDGEO1	1	13
31400	SANTA FE	1	13
38106	NCPA1GY1	1	13
38108	NCPA1GY2	1	13
31406	GEYSR5-6	1	10
31406	GEYSR5-6	2	10
31408	GEYSER78	1	10
31408	GEYSER78	2	10
31412	GEYSER11	1	10
31435	GEO.ENGY	1	10
31435	GEO.ENGY	2	10
30464	EXXON_BH	1	9
33252	POTRERO3	1	7
33271	HNTRS P1	1	7
33270	HNTRS P4	1	7
33253	POTRERO4	1	7
33254	POTRERO5	1	7
33255	POTRERO6	1	7
33466	UNTED CO	1	7
35312	SEAWESTF	1	7
35316	ZOND SYS	1	7
35320	USW FRIC	1	7
32176	SHILOH	1	5
36865	DVRPPSTA	1	5

36864	DVRPPCT2	1	5
36863	DVRPPCT1	1	5
32185	WOLFSKIL	1	5
33178	RVEC_GEN	1	5
32175	CREEDGT1	3	5
32174	GOOSEHGT	2	5
32173	LAMBGT1	1	5
32150	DG_VADIX	1	5
32172	HIGHWNDS	1	5
33134	GWF #4	1	5
33116	C.COS 6	1	5
33117	C.COS 7	1	5
32154	WADHAM	1	5
33133	GWF #3	1	5
33145	CROWN.Z.	1	5
33145	CROWN.Z.	2	5
33131	GWF #1	1	5
36856	CSC_CCA	1	5
33463	CARDINAL	1	5
33463	CARDINAL	2	5
32168	USWINDPW	1	5
32168	USWINDPW	2	5
33838	USWP_#3	1	5

Bay Area overall

The most critical contingency is the loss of the Vaca Dixon 500/230 kV transformer followed by loss of the Contra Costa unit 7 or vice versa. The area limitation is thermal overloading of the Tesla-Delta Switching Yard 230 kV line. This limiting contingency establishes a Local Capacity Requirement of 5341 MW (includes 1314 MW of Wind, QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this area.

The single most critical contingency is the loss of the Vaca Dixon 500/230 kV transformer. The area limitation is thermal overloading of the Tesla-Delta Switching Yard 230 kV line. This limiting contingency establishes a Local Capacity Requirement of 4771 MW (includes 1314 MW of Wind, QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

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

Bay Area Overall Requirements:

	Wind	QF/Selfgen	Muni	Market	Max. Qualifying

	(MW)	(MW)	(MW)	(MW)	Capacity (MW)
Available generation	78	988	248	5231	6545

	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[18]	4771	0	4771
Category C (Multiple)[19]	5341	0	5341

6. Greater Fresno Area

Area Definition

The transmission facilities coming into the Greater Fresno area are:

1) Gates-Henrietta Tap 1 230 kV
2) Gates-Henrietta Tap 2 230 kV
3) Gates #1 230/115 kV Transformer Bank
4) Los Banos #3 230/70 Transformer Bank
5) Los Banos #4 230/70 Transformer Bank
6) Panoche-Gates #1 230 kV
7) Panoche-Gates #2 230 kV
8) Panoche-Coburn 230 kV
9) Panoche-Moss Landing 230 kV
10) Panoche-Los Banos #1 230 kV
11) Panoche-Los Banos #2 230 kV
12) Panoche-Dos Amigos 230 kV
13) Warnerville-Wilson 230 kV
14) Wilson-Melones 230 kV
15) Corcoran – Alpaugh - Smyrna 115 kV
16) Coalinga #1-San Miguel 70 kV

The substations that delineate the Greater Fresno area are:

1) Los Banos 230 kV
2) Gates 230 kV
3) Panoche 230 kV
4) Wilson 230 kV
5) Alpaugh 115 kV
6) Coalinga 70 kV

Total busload within the defined area: 3051 MW with 103 MW of losses resulting in total load + losses of 3154 MW.

[18] 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.
[19] 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 units and qualifying capacity available in this area:

No	Name	ID	Qualifying Capacity
34636	FRIANTDM	4	3.5
34636	FRIANTDM	3	8.7
34636	FRIANTDM	2	16.3
34608	AGRICO	2	7
34608	AGRICO	3	18.9
34608	AGRICO	4	26
34672	KRCDPCT2	1	56
34671	KRCDPCT1	1	56
34485	FRESNOWW	1	9
34142	WHD_PAN2	1	49
34553	WHD_GAT2	1	49
34179	MADERA_G	1	28.7
34433	GWF_HEP2	1	39.1
34431	GWF_HEP1	1	40
34541	GWF_GT2	1	45.1
34539	GWF_GT1	1	45.3
34186	DG_PAN1	1	49
34301	CHOWCOGN	1	52.5
34618	MCCALL1T	1	0
34621	MCCALL3T	1	0
34630	HERNDN1T	1	0
34632	HERNDN2T	1	0
38720	PINE FLT	1	75
38720	PINE FLT	2	75
38720	PINE FLT	3	75
34306	EXCHQUER	1	70.8
34658	WISHON	1	5
34658	WISHON	2	5
34658	WISHON	3	5
34658	WISHON	4	5
34344	KERCKHOF	1	8.5
34344	KERCKHOF	2	13
34344	KERCKHOF	3	12.8
34308	KERCKHOF	1	155
34600	HELMS 1	1	404
34602	HELMS 2	1	404
34604	HELMS 3	1	404
34610	HAAS	1	69.9
34610	HAAS	2	69.9
34624	BALCH 1	1	34
34612	BLCH 2-2	1	52.5
34614	BLCH 2-3	1	52.5
34616	KINGSRIV	1	52

34316	ONEILPMP	1	11
34320	MCSWAIN	1	3.9
34322	MERCEDFL	1	1.9
34658	WISHON	SJ	0.4
34631	SJ2GEN	1	3.2
34633	SJ3GEN	1	4.2
34332	JRWCOGEN	1	8.5
34334	BIO PWR	1	26.1
34640	ULTR.PWR	1	26.4
34642	KINGSBUR	1	35.3
34646	SANGERCO	1	42.9
34648	DINUBA E	1	13.5
34650	GWF-PWR.	1	25
34652	CHV.COAL	1	4.1
34652	CHV.COAL	2	14.8
34654	COLNGAGN	1	42.3
34342	INT.TURB	1	1.1
			2912

Critical Contingency Analysis Summary

Wilson Sub-area

The most critical contingency for the Wilson sub-area is the loss of the Wilson - Melones 230 kV line with one of the Helm units out of service, which would thermally overload the Wilson - Warnerville 230 kV line. This limiting contingency establishes a Local Capacity Requirement of 1381 MW (which includes 75 MW of muni generation and 215 MW of QF 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 above-mentioned constraint. All units in Fresno not listed or units outside of this area have smaller effectiveness factors.

Gen Bus	Gen Name	Gen ID	MW Eff Fctr
34332	JRWCOGEN	1	40
34322	MERCEDFL	1	33
34320	MCSWAIN	1	32
34306	EXCHQUER	1	31
34600	HELMS 1	1	31
34602	HELMS 2	1	31
34604	HELMS 3	1	31
34301	CHOWCOGN	1	29
34636	FRIANTDM	1	25
34485	FRESNOWW	1	24
34658	WISHON	1	24

34658	WISHON	2	24
34658	WISHON	3	24
34658	WISHON	4	24
34631	SJ2GEN	1	24
34633	SJ3GEN	1	23
34344	KERCKHOF	1	22
34344	KERCKHOF	2	22
34344	KERCKHOF	3	22
34308	KERCKHOF	1	22
34179	MADERA_G	1	20
34648	DINUBA E	1	19
34672	KRCDPCT2	1	18
34671	KRCDPCT1	1	18
34624	BALCH 1	1	18
34640	ULTR.PWR	1	18
34646	SANGERCO	1	18
38720	PINE FLT	1	17
38720	PINE FLT	2	17
38720	PINE FLT	3	17
34616	KINGSRIV	1	17
34642	KINGSBUR	1	17
34433	GWF_HEP2	1	14
34431	GWF_HEP1	1	14
34610	HAAS	1	14
34610	HAAS	2	14
34612	BLCH 2-2	1	14
34614	BLCH 2-3	1	14
34539	GWF_GT1	1	13
34334	BIO PWR	1	13
34541	GWF_GT2	1	12
34650	GWF-PWR.	1	12
34142	WHD_PAN2	1	11
34186	DG_PAN1	1	11
34608	AGRICO	2	10
34608	AGRICO	3	10
34608	AGRICO	4	10
34553	WHD_GAT2	1	8
34652	CHV.COAL	1	8
34652	CHV.COAL	2	8
34654	COLNGAGN	1	8
34342	INT.TURB	1	6
34316	ONEILPMP	1	6

Herndon Sub-area

The most critical contingency for the Herndon sub-area is the loss of the Herndon 230/115 kV bank 1 with Kerckhoff #2 unit out of service, which would thermally overload the parallel Herndon 230/115 kV bank 2. This limiting contingency establishes a Local Capacity Requirement of 1155 MW (which includes 149 MW of QF generation) 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 230/115 kV bank 1, which would thermally overload the parallel Herndon 230/115 kV bank 2. This limiting contingency establishes a Local Capacity Requirement of 1067 MW (which includes 149 MW of QF 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 area that have at least 5% relative effectiveness to the above-mentioned constraint. All units in Fresno not listed or units outside of this area have smaller effectiveness factors.

Gen Bus	Gen Name	Gen ID	MW Eff Fctr
34308	KERCKHOF	1	36
34344	KERCKHOF	1	35
34344	KERCKHOF	2	35
34344	KERCKHOF	3	35
34624	BALCH 1	1	33
34646	SANGERCO	1	32
34672	KRCDPCT2	1	31
34671	KRCDPCT1	1	31
34616	KINGSRIV	1	31
34640	ULTR.PWR	1	31
34648	DINUBA E	1	29
34642	KINGSBUR	1	26
38720	PINE FLT	1	22
38720	PINE FLT	2	22
38720	PINE FLT	3	22
34612	BLCH 2-2	1	22
34610	HAAS	1	21
34610	HAAS	2	21
34614	BLCH 2-3	1	21
34433	GWF_HEP2	1	14
34431	GWF_HEP1	1	14
34301	CHOWCOGN	1	9
34608	AGRICO	2	7
34608	AGRICO	3	7
34608	AGRICO	4	7
34334	BIO PWR	1	3
34652	CHV.COAL	1	3
34652	CHV.COAL	2	3
34553	WHD_GAT2	1	2
34179	MADERA_G	1	2

34654	COLNGAGN	1	2
34332	JRWCOGEN	1	-5
34485	FRESNOWW	1	-13
34600	HELMS 1	1	-15
34602	HELMS 2	1	-15
34604	HELMS 3	1	-15

McCall Sub-area

The most critical contingency for the McCall sub-area is the loss of Mc Call #3 230/115 kV transformer bank with GWF Hanford Peaker #1 unit out of service, which would thermally overload the McCall #2 230/115 kV transformer bank. This limiting contingency establishes a Local Capacity Requirement of 1,432 MW (which includes 192 MW of QF generation and 108 MW of Muni generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency for the McCall sub-area is the loss of Mc Call #3 230/115 kV transformer bank, which would thermally overload the McCall #2 230/115 kV transformer bank. This limiting contingency establishes a Local Capacity Requirement of 1,296 MW (which includes 192 MW of QF generation and 108 MW of Muni generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

See line 6 under attached link below.

Henrietta Sub-area

The most critical contingency for the Henrietta sub-area is the loss of new Henrietta 230/70 kV transformer bank with Henrietta-GWF Henrietta 70 kV line out of service, which would thermally overload the old Henrietta 230/70 kV transformer bank. This combined limit establishes a Local Capacity Requirement of 117 MW (which includes 25 MW of QF generation and 2 MW of deficiency) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency for the Henrietta sub-area is the loss of new Henrietta 230/70 kV transformer bank, which would thermally overload the old Henrietta 230/70 kV transformer bank. This combined limit establishes a Local Capacity Requirement of 34 MW (which includes 25 MW of QF generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Merced Sub-area

The most critical contingencies for the Merced sub-area is the double line outage of the Wilson – Atwater 115 kV #1 and #2 lines, which would thermally overload the Wilson – Merced 115 kV #1 and #2 lines. This limiting contingency establishes a Local Capacity Requirement of 151 MW (which includes 75 MW of muni generation, 9 MW of QF generation and 66 MW of area 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.

No	Name	ID	Qualifying Capacity
34306	EXCHQUER	1	70.8
34320	MCSWAIN	1	3.9
34322	MERCEDFL	1	1.9
34332	JRWCOGEN	1	8.5

Because of the overlapping LCR MWs requirements among the sub-areas, the total aggregate LCR requirement for the Greater Fresno Area is 2602 MW (includes 108 MW of muni generation, 222 MW of QF generation and 68 MW of deficiency).

Additional helpful effectiveness factors for Fresno area:

Please read procedure T-129Z effectiveness factors - Fresno Area at:
http://www.caiso.com/docs/2005/07/13/2005071314483315210.pdf

Fresno Area Overall Requirements:

	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	275	300	2337	2912

	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[20]	2530	0	2530
Category C (Multiple)[21]	2534	68	2602

[20] 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.

[21] 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) Temblor – San Luis Obispo 115 kV line

These sub-stations form the boundary surrounding the Kern PP sub-area:

1) Midway 115 kV
2) Kern PP 115 kV
3) Wheeler Ridge 115 kV
4) Temblor 115 kV

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

1) Wheeler Ridge 115/60 kV Bank
2) Wheeler Ridge 230/60 kV Bank

These sub-stations form the boundary surrounding the Weedpatch sub-area:

1) Wheeler Ridge 60 kV

Total busload within the defined area: 1191 MW with 18 MW of losses resulting in total load + losses of 1209 MW.

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

No	Name	ID	Qualifying Capacity
35056	TX-LOSTH	1	9
35034	MIDSUN +	1	20
35037	UNIVRSTY	1	39.9
35038	CHLKCLF+	1	49.9
35006	KERN 1	1	0
35008	KERN 2	1	0
35024	DEXEL +	1	32.1
35026	KERNFRNT	1	52.7
35029	BADGERCK	1	48.9
35027	HISIERRA	1	52.7
35023	DOUBLE C	1	51.9

35028	OILDALE	1	40.1
35032	CHV-CYMR	1	22.7
34783	TEXCO_NM	1	12
34783	TEXCO_NM	2	9
35036	MT POSO	1	56.1
35035	ULTR PWR	1	36.4
35040	KERNRDGE	1	66
35040	KERNRDGE	2	14.2
35044	TX MIDST	1	39.8
35046	SEKR	1	34.2
35048	FRITOLAY	1	7.1
35050	SLR-TANN	1	17.4
35052	CHEV.USA	1	14.4
35058	PSE-LVOK	1	49
35060	PSEMCKIT	1	50.8
35062	DISCOVRY	1	44
35064	NAVY 35R	1	31.9
35064	NAVY 35R	2	32.5
35066	PSE-BEAR	1	51.3
	Total		986

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

No	Name	ID	Qualifying Capacity
35018	KERNCNYN	1	11.2
35020	RIOBRAVO	1	12.1
	Total		23.3

<u>Critical Contingency Analysis Summary</u>

Kern PP Sub-area

The most critical contingency for the Kern PP sub-area is the outage of the Kern PP #5 230/115 kV transformer bank and the Kern PP – Kern Front 115 kV line, which would thermally overload the parallel Kern PP 230/115 kV Bank 3 and Bank 3a. This limiting contingency establishes a Local Capacity Requirement of 749 MW (which includes 749 MW of QF generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency for the Kern PP sub-area is the loss of Kern PP #5 230/115 kV transformer bank, which would thermally overload the parallel Kern PP 230/115 kV Bank 3 and Bank 3a. This limiting contingency establishes a Local Capacity Requirement of 554 MW (which includes 554 MW of QF generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area are under long-term contracts. No additional procurement needs to be done; therefore no effectiveness factor is required.

Wheedpatch Sub-area

The most critical contingency is the loss of the Wheeler Ridge – San Bernard 70 kV line and the Wheeler Ridge – Tejon 70 kV line, which would thermally overload the Wheeler Ridge – Weedparch 70 kV line and cause low voltage problem at the local 70 kV transmission system. This limiting contingency establishes a Local Capacity Requirement of 36 MW (which includes 8 MW of QF generation and 17 MW of area deficiency) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Kern Area Overall Requirements:

	QF/Selfgen (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	978	31	1009

	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[22]	554	0	554
Category C (Multiple)[23]	769	17	786

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 LA - Sylmar S #1, #2 & #3 230/230 kV Transformers
5) Sylmar S - Pardee #1 & #2 230 kV Lines
6) Vincent - Mesa Cal #1 230 kV Line

[22] 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.
[23] 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) Antelope - Mesa Cal #1 230 kV Line
8) Vincent - Rio Hondo #1 & #2 230 kV Lines
9) Eagle Rock - Pardee #1 230 kV Line
10) Devers - Valley #1 500 kV Line
11) Devers #1 & #2 500/230 kV Transformers
12) Devers - Coachelv # 1 230 kV Line
13) Mirage - Ramon # 1 230 kV Line
14) Julian Hinds-Eagle Mountain 230 kV

These sub-stations form the boundary surrounding the LA Basin area:

1) Devers 500 kV
2) Mirage 230 kV
3) Vincent 230 kV
4) San Onofre 230 kV
5) Sylmar 230 kV
6) Lugo 500 kV

Total busload within the defined area is 19055 MW with 173 MW of losses and 97 MW of pumps resulting in total load + losses of 19325 MW.

Total units and qualifying capacity available in the Eastern sub-area:

BUS-NO	NAME1	ID	Qualifying Capacity	Subarea
24052	MTNVIST3	3	319	Eastern LA Basin
24053	MTNVIST4	4	320	Eastern LA Basin
28190	WINTECX2	1	44	Eastern LA Basin
28191	WINTECX1	1	42	Eastern LA Basin
28180	WINTEC8	1	42	Eastern LA Basin
24921	MNTV-CT1	1	143.5	Eastern LA Basin
24922	MNTV-CT2	1	143.5	Eastern LA Basin
24923	MNTV-ST1	1	249	Eastern LA Basin
24924	MNTV-CT3	1	143.5	Eastern LA Basin
24925	MNTV-CT4	1	143.5	Eastern LA Basin
24926	MNTV-ST2	1	249	Eastern LA Basin
25632	TERAWND	1	1	Eastern LA Basin
25633	CAPWIND	1	1	Eastern LA Basin
25634	BUCKWND	1	1	Eastern LA Basin
25635	ALTWIND	1	2.9	Eastern LA Basin
25636	RENWIND	1	1	Eastern LA Basin
25637	TRANWND	1	2.9	Eastern LA Basin
25639	SEAWIND	1	3	Eastern LA Basin
25640	PANAERO	1	1.9	Eastern LA Basin
25645	VENWIND	1	1.9	Eastern LA Basin
25646	SANWIND	1	1	Eastern LA Basin
24826	INDIGO	1	17	Eastern LA Basin

24815	GARNET	1	1	Eastern LA Basin
28020	WINTEC6	1	1.9	Eastern LA Basin
28060	SEAWEST	1	1.9	Eastern LA Basin
28060	SEAWEST	2	1.9	Eastern LA Basin
28280	CABAZON	1	1.9	Eastern LA Basin
24030	DELGEN	1	33.1	Eastern LA Basin
24071	INLAND	1	19.7	Eastern LA Basin
24140	SIMPSON	1	34	Eastern LA Basin
24902	VSTA	1	0	Eastern LA Basin
24229	VALLEY-S	1	0	Eastern LA Basin
25991	VALYSVC2	1	0	Eastern LA Basin
25990	VALYSVC1	1	0	Eastern LA Basin
24902	VSTA	2	1.3	Eastern LA Basin
24214	SANBRDNO	2	0.5	Eastern LA Basin
24214	SANBRDNO	1	0.1	Eastern LA Basin
24055	ETIWANDA	2	34.7	Eastern LA Basin
24055	ETIWANDA	1	0.6	Eastern LA Basin
25422	ETI MWDG	1	23.7	Eastern LA Basin
28061	WHITEWTR	1	52.8	Eastern LA Basin
28260	ALTAMSA4	1	32	Eastern LA Basin
24160	VALLEYSC	1	4.2	Eastern LA Basin
24111	PADUA	2	5.8	Eastern LA Basin
24111	PADUA	1	0.5	Eastern LA Basin
24024	CHINO	1	9.9	Eastern LA Basin
25648	DVLCYN1G	1	50.7	Eastern LA Basin
25649	DVLCYN2G	2	50.7	Eastern LA Basin
25603	DVLCYN3G	1	67.7	Eastern LA Basin
25604	DVLCYN4G	2	67.7	Eastern LA Basin
	Total		2371.9	

Total units and qualifying capacity available in the Western sub-area:

BUS-NO	NAME1	ID	PMAX	Subarea
24001	ALAMT1 G	1	174.6	Western LA Basin
24002	ALAMT2 G	2	175	Western LA Basin
24003	ALAMT3 G	3	332.2	Western LA Basin
24004	ALAMT4 G	4	335.7	Western LA Basin
24005	ALAMT5 G	5	485	Western LA Basin
24161	ALAMT6 G	6	495	Western LA Basin
24162	ALAMT7 G	7	0	Western LA Basin
25203	ANAHEIMG	1	46.6	Western LA Basin
24018	BRIGEN	1	35	Western LA Basin
24020	CARBOGEN	1	29	Western LA Basin
24047	ELSEG3 G	3	335	Western LA Basin
24048	ELSEG4 G	4	335	Western LA Basin
24066	HUNT1 G	1	225.8	Western LA Basin
24067	HUNT2 G	2	225.8	Western LA Basin

24167	HUNT3 G	3	225	Western LA Basin
24168	HUNT4 G	4	227.4	Western LA Basin
24120	PULPGEN	1	40	Western LA Basin
24121	REDON5 G	5	178.9	Western LA Basin
24122	REDON6 G	6	175	Western LA Basin
24123	REDON7 G	7	493.2	Western LA Basin
24124	REDON8 G	8	486.9	Western LA Basin
24133	SANTIAGO	1	17	Western LA Basin
24062	HARBOR G	0	88.6	Western LA Basin
25510	HARBORG4	LP	5.7	Western LA Basin
24062	HARBOR G	HP	5.7	Western LA Basin
24011	ARCO 1G	1	64.7	Western LA Basin
24012	ARCO 2G	2	64.7	Western LA Basin
24013	ARCO 3G	3	64.7	Western LA Basin
24014	ARCO 4G	4	64.7	Western LA Basin
24163	ARCO 5G	5	31.2	Western LA Basin
24164	ARCO 6G	6	31.2	Western LA Basin
24022	CHEVGEN1	1	0.8	Western LA Basin
24023	CHEVGEN2	2	0.8	Western LA Basin
24026	CIMGEN	1	26.1	Western LA Basin
24063	HILLGEN	1	37.3	Western LA Basin
24070	ICEGEN	1	46.2	Western LA Basin
24139	SERRFGEN	1	25.2	Western LA Basin
24203	CENTER S	1	25.2	Western LA Basin
24075	LAGUBELL	1	11.2	Western LA Basin
24073	LA FRESA	1	5.7	Western LA Basin
24094	MOBGEN	1	45	Western LA Basin
24064	HINSON	1	25.2	Western LA Basin
24027	COLDGEN	1	28	Western LA Basin
24060	GROWGEN	1	28	Western LA Basin
24169	HUNT5 G	5	0	Western LA Basin
24213	RIOHONDO	1	0.9	Western LA Basin
24209	MESA CAL	1	0.6	Western LA Basin
24208	LCIENEGA	1	2.3	Western LA Basin
24083	LITEHIPE	1	0.3	Western LA Basin
24028	DELAMO	1	0	Western LA Basin
24157	WALNUT	1	7.9	Western LA Basin
28005	PASADNA1	1	22.5	Western LA Basin
28006	PASADNA2	1	22.5	Western LA Basin
28007	BRODWYSC	1	65	Western LA Basin
24211	OLINDA	1	2.3	Western LA Basin
24197	ELLIS	1	7.1	Western LA Basin
24129	S.ONOFR2	2	1115	Western LA Basin
24130	S.ONOFR3	3	1105	Western LA Basin
	Total		8150.4	

Critical Contingency Analysis Summary

LA Basin overall:

The combined Local Area Requirement is 8843 MW of which 3510 MW includes the San Onofre Nuclear Power Plant, QF and Muni generation. The Western and Eastern sub-area contingencies require 8843[24] MW as the minimum amount of generating capacity necessary for reliable load serving capability within these sub-areas. 2042 MW of this capacity is needed in the Eastern sub-area, and the rest (6802 MW) is needed in the Western sub-area.

The two critical contingencies in the Eastern Sub-area are: (1) Loss of Devers – Valley 500 kV line, followed by the loss of two Lugo – Mira Loma 500 kV lines #2 and #3, and (2) Loss of one San Onofre Nuclear Generator, followed by the loss of two Lugo – Mira Loma 500 kV lines #2 and #3. The sub-area area limitation is low area post-transient voltage associated with voltage collapse.

Effectiveness factors:

The area limitation is low area post-transient voltage associated with voltage collapse. The units in the Eastern area or geographically close to it are the most effective units.

The critical contingency for the in the Western Sub-area is the loss of Lugo-Victorville 500 kV, followed by loss of Sylmar-Gould 230 kV line. The sub-area area limitation is thermal overloading of the Eagle Rock-Mesa 230 kV line.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	MW Eff Fctr
24209	MESA CAL	1	19
24011	ARCO 1G	1	18
24012	ARCO 2G	2	18
24013	ARCO 3G	3	18
24014	ARCO 4G	4	18
24164	ARCO 6G	6	18
24047	ELSEG3 G	3	18
24048	ELSEG4 G	4	18
24121	REDON5 G	5	18
24122	REDON6 G	6	18
24123	REDON7 G	7	18

[24] This value is based on a potential higher South of Lugo (SOL) limit with RAS operation which needs to be determined by SCE. Based on the current 5600 MW SOL limit, the total LA Basin generation requirement would increase by an additional 900 MW for a total of 9743 MW to respect loss of a SONG unit.

24124	REDON8 G	8	18
24163	ARCO 5G	5	17
24020	CARBOGEN	1	17
24064	HINSON	1	17
24070	ICEGEN	1	17
24094	MOBGEN	1	17
24139	SERRFGEN	1	17
24062	HARBOR G	0	17
25510	HARBORG4	LP	17
24062	HARBOR G	HP	17
28005	PASADNA1	1	17
28006	PASADNA2	1	17
28007	BRODWYSC	1	17
24208	LCIENEGA	1	17
24083	LITEHIPE	1	17
24075	LAGUBELL	1	17
24073	LA FRESA	1	17
24028	DELAMO	1	17
24001	ALAMT1 G	1	16
24002	ALAMT2 G	2	16
24003	ALAMT3 G	3	16
24004	ALAMT4 G	4	16
24005	ALAMT5 G	5	16
24161	ALAMT6 G	6	16
24018	BRIGEN	1	16
24027	COLDGEN	1	16
24060	GROWGEN	1	16
24063	HILLGEN	1	16
24120	PULPGEN	1	16
24213	RIOHONDO	1	16
24203	CENTER S	1	16
24157	WALNUT	1	16
24167	HUNT3 G	3	15
24066	HUNT1 G	1	14
24067	HUNT2 G	2	14
24168	HUNT4 G	4	14
24133	SANTIAGO	1	14
24197	ELLIS	1	14
25203	ANAHEIMG	1	13
24026	CIMGEN	1	13
24030	DELGEN	1	13
24071	INLAND	1	13
24140	SIMPSON	1	13
25422	ETI MWDG	1	13
24902	VSTA	2	13
24111	PADUA	2	13
24111	PADUA	1	13

24024	CHINO	1	13
25648	DVLCYN1G	1	12
25649	DVLCYN2G	2	12
25603	DVLCYN3G	3	12
25604	DVLCYN4G	4	12
24052	MTNVIST3	3	12
24053	MTNVIST4	4	12
24129	S.ONOFR2	2	12
24130	S.ONOFR3	3	12
24921	MNTV-CT1	1	12
24922	MNTV-CT2	1	12
24923	MNTV-ST1	1	12
24924	MNTV-CT3	1	12
24925	MNTV-CT4	1	12
24926	MNTV-ST2	1	12
24214	SANBRDNO	2	12
24214	SANBRDNO	1	12
24055	ETIWANDA	2	12
24055	ETIWANDA	1	12
25632	TERAWND	1	11
25633	CAPWIND	1	11
25634	BUCKWND	1	11
25635	ALTWIND	1	11
25636	RENWIND	1	11
25637	TRANWND	1	11
25639	SEAWIND	1	11
25640	PANAERO	1	11
25645	VENWIND	1	11
25646	SANWIND	1	11
24826	INDIGO	1	11
28190	WINTECX2	1	11
28191	WINTECX1	1	11
28180	WINTEC8	1	11
24815	GARNET	1	11
24828	WINTEC9	1	11
28020	WINTEC6	1	11
28060	SEAWEST	1	11
28060	SEAWEST	2	11
28061	WHITEWTR	1	11
28260	ALTAMSA4	1	11
28280	CABAZON	1	11

LA Basin Overall Requirements:

	QF/Wind (MW)	Muni (MW)	Nuclear (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	829	461	2220	7012	10522

	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[25]	8843	0	8843
Category C (Multiple)[26]	8843	0	8843

9. 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) Miguel – 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

These sub-stations form the boundary surrounding the San Diego area:

1) Miguel 230 kV
2) San Luis Rey 230 kV
3) Talega 230 kV

Total busload within the defined area: 4637 MW with 105 MW of losses resulting in total load + losses of 4742 MW.

Total units and qualifying capacity available in this area:

No	Name	ID	Qualifying Capacity
22088	BOULEVRD	1	0.5
22092	CABRILLO	1	3.6
22172	DIVISION	1	46.9
22212	ELCAJNGT	1	15
22233	ENCINA 1	1	103.5
22234	ENCINA 2	1	104
22236	ENCINA 3	1	110
22240	ENCINA 4	1	300
22244	ENCINA 5	1	330
22248	ENCINAGT	1	15

[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.

22332	GOALLINE	1	50
22376	KEARN3CD	1	15.3
22384	KYOCERA	1	0.1
22480	MIRAMAR	1	2.7
22488	MIRAMRGT	1	18
22532	MURRAY	1	0.5
22576	NOISLMTR	1	35.3
22660	POINTLMA	1	21.8
22680	R.SNTAFE	1	0.5
22688	RINCON	1	0.5
22704	SAMPSON	1	13.6
22724	SANMRCOS	1	1.1
22776	SOUTHBGT	1	13
22780	SOUTHBY1	1	145
22784	SOUTHBY2	1	149
22788	SOUTHBY3	1	174
22792	SOUTHBY4	1	221
22820	SWEETWTR	1	0.5
22120	CARLTNHS	1	1.1
22149	CALPK_BD	1	42
22153	CALPK_ES	1	45.5
22150	CALPK_EC	1	42
22604	OTAY	1	3
22373	KEARN2AB	1	14.8
22373	KEARN2AB	2	14.8
22374	KEARN2CD	1	14.8
22374	KEARN2CD	2	14.8
22375	KEARN3AB	1	15.3
22375	KEARN3AB	2	15.3
22376	KEARN3CD	2	15.3
22377	KEARNGT1	1	16
22488	MIRAMRGT	2	18
22074	LRKSPBD1	1	46
22075	LRKSPBD2	1	46
22257	RAMCO_ES	1	40
22617	RAMCO_OY	1	42
22834	TALEGA	SC	0
22486	RAMCO_MR	1	45
22262	PEN_CT1	1	177
22263	PEN_CT2	1	177
22265	PEN_ST	1	187
22904	CAMPOGEN	1	10
22904	CAMPOGEN	2	0
			2932

Critical Contingency Analysis Summary

San Diego overall:

The most limiting contingency in the San Diego area is described by the outage of 500 kV Southwest Power Link (SWPL) between Imperial Valley and Miguel Substations over-lapping with an outage of the Palomar Combined-Cycle Power plant (541 MW) while staying within the South of San Onofre (WECC Path 44) non-simultaneous import capability rating of 2,500 MW. Therefore the 2,781 MW (includes 181 MW of QF generation and 10 MW of wind) of capacity required within this area is predicated on having sufficient generation in the San Diego Area to reduce Path 44 to its non-simultaneous rating of 2500 MW within 30 minutes.

Effectiveness factors:

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

San Diego Overall Requirements:

	QF (MW)	Wind (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	181	10	2741	2932

	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[27]	2781	0	2781
Category C (Multiple)[28]	2781	0	2781

C. Zonal Capacity Requirements

The ISO performed an assessment of the Zonal Capacity needs for year 2007 based on the methodology presented in chapter III section B. These results refer to the ISO control area only, they do not include requirements for other control areas like: LADWP, IID, SMUD-WAPA, TID or MID.

Zone	Load Forecast (MW)	Generator Outages (MW)	Single Worst Contingency (MW)	(-)Import Capability (MW)	Total Requirement (MW)
SP26	28,778	1,500	2,000	10,100	**22,178**
NP26=NP15+ZP26	21,518	2,500	1,160	5,348	**19,830**

[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.

NP15	Path 15 is not a binding constraint at this time

Units need in order to comply with the Local Area Capacity Requirements fully count toward the Zonal Requirements. San Diego and LA Basin are situated in SP26, Kern in ZP26 and the rest in NP15.

V. Future Annual Technical Analyses

For future local area capacity requirements studies, the CPUC should consider the use of the Loss of Load Probability (LOLP) methodology, used by many eastern regions. LOLP is a study methodology that can be used to establish the level of capacity required in each local area by performing a probabilistic analysis to achieve a specified probability for loss of load. Underlying this approach is an expected level of service reliability. In the established Eastern markets, a one-event in ten years LOLP methodology is used to determine LSE capacity obligations. The LOLP approach provides a potentially more uniform reliability result than the proposed deterministic approach. In the future, if the LOLP approach is determined to be a more desirable approach, then the LOLP analysis will be incorporated into the criteria if and when a criteria and methodology for applying it has been developed. Any LOLP criteria and methodology will need to be reviewed by stakeholders and approved by the CPUC. Until such time, the LOLP approach will not be used to establish LSE capacity requirements, and the deterministic approach defined above will be used.

ATTACHMENT B

California ISO

2007
LOCAL CAPACITY TECHNICAL ANALYSIS

REPORT
AND STUDY RESULTS

Corrected Version April 28~~1~~, 2006

Local Capacity Technical Analysis
Overview and Study Results

I. Executive Summary

At the February 3, 2006 prehearing conference in Docket R.05-12-013 (*Rulemaking to Consider Refinements to and Further Development of the Commission's Resource Adequacy Requirements Program*), the California Independent System Operator Corporation ("CAISO") advised the California Public Utilities Commission ("CPUC") that the Local Capacity Requirement ("LCR") results of its 2007 local capacity technical analysis could be made available within eight weeks after the development of the input assumptions for the study. Following a meet and confer process, Administrative Law Judge Wetzell adopted proposed study assumptions. These assumptions have been incorporated into this "Local Capacity Technical Analysis Study ("2007 LCR Study"), as discussed below. The CAISO has now completed its analysis and therefore provides this 2007 LCR Study to describe the final LCR results and the methodology and criteria used to obtain those results.

This Report provides a description of the 2007 LCR Study objectives, inputs, methodologies and assumptions, and the important policy considerations that are presented by the study results. Specifically, as requested by the Stakeholders and approved by the CPUC, the CAISO has conducted the study to produce local area capacity requirements necessary to achieve three levels of service reliability. These levels of service reliability, which are driven by the transmission grid operating standards to which the CAISO must comply, are set forth on the following table[1]:

[1] This comparison table is explained in detail at Section IV.below. The reader should be aware that the deficiencies identified for certain local areas are driven by capacity requirements in sub-area load pockets discussed at IV.B.

Local Requirements Comparison

	Qualifying Capacity			2007 LCR Requirement Based on Category B Option 1			2007 LCR Requirement Based on Category C with operating procedure Option 2			2006 Total LCR Req.
Local Area Name	**QF/ Muni (MW)**	**Market (MW)**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**(MW)**
Humboldt	73	133	206	202	0	**202**	202	0	**202**	162
North Coast / North Bay	158	861	1019	582**	0	**582****	582**	0	**582****	658
Sierra	1072	776	1848	1833	205	**2038**	1833	328	**2161**	1770*
Stockton	314	257	571	348	0	**348**	506	53	**559**	440*
Greater Bay	1314	5231	6545	4771	0	**4771**	5341	0	**5341**	6009
Greater Fresno	575	2337	2912	2530	0	**2530**	2534	68	**2602**	2837 *
Kern	978	31	1009	554	0	**554**	769	17	**786**	797*
LA Basin	3510	7012	10522	8843	0	**8843**	8843	0	**8843**	8127
San Diego	191	2741	2932	2781	0	**2781**	2781	0	**2781**	2620
Total	**8185**	**19379**	**27564**	**22444**	**205**	**22649**	**23391**	**466**	**23857**	**23420**

* Generation deficient areas (or with sub-area that are deficient) – deficiency included in LCR
** The North Coast/North Bay area requirement would have been higher by 80 MW, however a new operating procedure has been received, validated and implemented by PG&E and the CAISO.

The term "Qualifying Capacity" used in this report represents the "Gross Qualifying Capacity" (as of 1/12/2006) and it may be slightly higher, for certain generators, then the "Net Qualifying Capacity" as presented in the official list stored at:

http://www.caiso.com/1796/179694f65b9f0.xls

The ~~only~~ difference between the terms "Qualifying Capacity" and "Net Qualifying Capacity" is that ~~some~~certain units have associated plant load and thus, the "Net Qualifying Capacity" represents the output from the unit after the plant load has been ~~accounted for~~subtracted. However, t~~T~~he LCR Study ~~results however take~~incorporates the plant load from these units ~~into account the plant load as part of~~into the "total load" calculation. ~~as such the requirements are the same.~~

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 and nuclear units). The second set is "market" generation. The second column, "2007 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 (Option 1, discussed in Section II.C of this Report). The third column, "2007 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 (Option 2).

The highest service reliability level, based on Performance Criteria-Category C without non-generational solutions to address operating deficiencies (Option 3), can be determined from the table by adding 80 MW to the local capacity requirements for the North Coast/North Bay area (thus raising total 2007 LCR requirements by 80 MW). This exercise removes the new operating procedure provided by PG&E from the analysis in compliance with the Category C reliability standard that relies solely on generation to address identified capacity deficiencies.

As shown on the table above, the study results have important public policy implications. These study results indicate 3 levels of capacity that are necessary to have sufficient capacity in support of 3 levels of service reliability. The reader should appreciate that the differences in levels of capacity have direct implications to the costs and expected levels of reliability that are achieved for customers located within the local areas. Thus, option 1 (performance level B) has a lower level of capacity required and will therefore have an expected lower level of reliability because less capacity is available to the CAISO. Similarly, the operational solutions underlying option 2 (performance level C) provide for less procurement of capacity than option 3 by placing load in the mix of solutions that the CAISO will use to respond to contingencies. This approach may be appropriate where all outages are expected to have short-term affects on the transmission system. Yet, long duration outages would potentially subject load to extended outages. Option 3 also NERC performance level C, results provide the quantity of capacity that would give the CAISO a full set of capacity to respond to contingencies. This level effectively reserves the load based operational solutions for major emergencies or contingencies that are not considered in the study criteria and therefore results in an expected higher level of service reliability than the two alternate options.

Public policy decision-makers must choose the appropriate level of service reliability. The information provided in the 2007 LCR Study, including the CAISO's recommendations found at Section II.E. below, can assist with this choice.

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

A. Objectives

Similar to the 2006 Local Capacity Technical Analysis ("2006 LCR Study")[2], the purpose of the2007 LCR Study is to identify specific areas within the CAISO Controlled Grid that have local reliability problems and to determine the generation capacity (MW) that would be required to mitigate these local reliability problems. However, based on input from market participants and at the direction of the CPUC, the 2007 LCR Study identifies different levels of local capacity that correspond to separate performance/reliability criteria related to grid robustness under which the CAISO must plan and operate the grid. This additional information is intended to allow the CPUC to affect the expected level of service reliability that customers of jurisdictional LSEs will receive by dictating the appropriate amount of local capacity that must be procured. In so doing, the CPUC should endeavor to make a decision that seeks to find the appropriate balance between a desired level of service reliability and the cost of installed capacity. The details of the 2007 LCR study, set forth in the following sections, will facilitate the CPUC's ability to make this important decision.

[2] The 2006 LCR Study (Locational Capacity Technical Analysis: Overview of Study Report and Final Results) dated September 23, 2005 was submitted to the CPUC as part of the CAISO's Motion to Augment the Record Regarding Resource Adequacy Phase 2 in R.04-04-003. An Addendum to the 2006 LCR Study was submitted on January 31, 2006. These documents can be found on the CAISO website at: http://www.caiso.com/1788/178883551f690.html and http://www.caiso.com/docs/2004/10/04/2004100410354511659.html

B. Key Study Assumptions

1. Inputs and Methodology

The CPUC directed the CAISO, respondents, and other interested parties to meet and confer with the objective of identifying not more than three alternative sets of input assumptions the CAISO would incorporate into the 2007 LCR Study. The meet and confer session was held on February 17, 2006 and, as noted above, the agreed-upon input scenarios were submitted by the CAISO on February 22, 2006. An errata to the February 22 filing was submitted on March 10, 2006. The following table sets forth a summary of the approved inputs and methodology that have been used in the 2007 LCR Study:

Summary Table of Inputs and Methodology Used in 2007 LCR Study:

Issue:	HOW INCORPORATED INTO THE 2007 LCR STUDY:
Input Assumptions:	
• Transmission System Configuration	The existing transmission system has been modeled, including all projects operational on or before June 1, 2007 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, 2007
• 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 historical output values for purposes of the 2007 LCR Study.
• **Maintaining Path Flows**	Path flows have been maintained below all established path ratings into the load pockets, including the 500 kV. For clarification, given the existing transmission system configuration, the only 500 kV path that flows directly into a load pocket and will, therefore, be considered in the 2007 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**	The 2007 LCR Study is being published based on Performance Level B and Performance Level C criterion, yielding the low and high range LCR scenarios. In addition, the CAISO will incorporate all new projects and other feasible and CAISO-approved operational solutions brought forth by the PTOs that can be operational on or before June 1, 2007. Any such solutions that can reduce the need for procurement to meet the Performance Level C criteria will be incorporated into the LCR Study and the resulting LCR published for this third scenario.
Load Pocket:	
• **Fixed Boundary, including limited reference to published effectiveness factors**	The 2007 LCR Study has been produced based on load pockets defined by a fixed boundary. The CAISO was initially planning to publish the effectiveness factors of the generating resources within the defined load pocket as well as the effectiveness factors of the generating resources residing outside the load pocket that had a relative effectiveness factor of no less than 5% or affect the flow on the limiting equipment by more than 5% of the equipment's applicable rating. . However, after subsequent discussions with the Commission and stakeholders, and given the comments in the CPUC Staff Report regarding the limited usefulness of effectiveness factors, the CAISO plans to only publish effectiveness factors where they are useful in facilitating procurement where excess capacity exists within a load pocket. If stakeholders want additional effectiveness factor published, the CAISO will defer to the Commission as to what further effectiveness factor data it would like the CAISO to publish.

Further details regarding the 2007 LCR Study methodology and assumptions are provided in Section III, below.

2. Operating Requirements

As was done in the 2006 LCR Study, this study incorporates specific operating requirements, needed in order to prevent voltage collapse or transient instability for the loss of a single transmission element ("N-1") followed by system readjustment and the loss of two transmission lines (common mode failure)[3]. In addition, the LCR Study addresses contingencies where the system suffers the loss of a single transmission element ("N-1"), the system is readjusted and then the loss of an additional transmission element (N-1-1). As reflected in Table 2, the capacity in columsn two (Category B) and three (Category C) are identical in at least four of the local areas. This occurs because the capacity necessary to prevent voltage collapse or transient instability for the loss of a single transmission element (N-1) is the same as that necessary for the N-1-1 scenario.

Consistent with NERC standards, after the second N-1 or immediately after the common mode failure load shedding is allowed as long as all criteria (thermal, voltage, transient, reactive margin) are respected. The CAISO planning criteria generally allows for load shedding for the double contingencies. However, the CAISO has, consistent with its Tariff, conducted planning studies that maintain the level of reliability that existed prior to its formation. This is referred in the CAISO Tariff as "Local Reliability Criteria," which, along with NERC Planning Standards discussed below, form the CAISO's "Applicable Reliability Criteria" The CAISO is under an obligation to implement Local Reliability Criteria, unless modified pursuant to agreement with the relevant Participating Transmission Owner ("PTO"). As such, to the extent a PTO's pre-CAISO standards did not allow for load shedding for common corridor and/or double circuit tower line outages, the CAISO has maintained that practice to assure that the level of reliability that prevailed before the CAISO was formed would be maintained and the CAISO remains in compliance with its obligations.

[3] These failures include a double circuit tower and the loss of two 500kv lines that are located in the same corridor.

C. Grid Reliability and Service Reliability

The 2007 LCR Study is intended to provide the CPUC with the "tools" needed to make the important threshold policy decision as to the desired level of service reliability within the CAISO Control Area, ultimately establishing the appropriate amount of local generation capacity CPUC jurisdictional LSEs must procure. The options produced by the study for consideration by the CPUC are discussed in further detail in this overview section of the report, and also in the technical discussion of the study itself. However, to assist the CPUC in analyzing the study results and the options that are being presented, it is important that the CPUC and other parties understand how the CAISO distinguishes "service reliability" from "grid reliability" and where the respective CAISO/CPUC responsibilities lie. Both service and grid reliability form the basis of the reliability standards consumers within the CAISO Control Area will receive.

1. 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 primarily apply to the bulk , interconnected electric system in the Western United States and are intended to address the reality that within an integrated network, whatever one control area does can affect the reliability of other control 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.[4] 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

[4] Pub. Utilities Code § 345

the CAISO's Participating Transmission Owners ("PTOs"), which affect a PTO's individual system.

The NERC Planning Standards define reliability on interconnected bulk 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. For instance, one category could require that the grid operator not only ensure grid integrity is maintained under certain adverse system conditions, e.g., security, but also that all customers continue to receive electric supply to meet demand, e.g., adequacy. In that case, grid reliability and service reliability would overlap. But there are other levels of performance where security can be maintained without ensuring adequacy. Here, it would be up to the regulatory agency of service reliability, i.e. the CPUC, to determine the appropriate level of service reliability under the system conditions defined by the differing levels of NERC planning standards.

Given the foregoing, one of the ambiguities identified in the recent CPUC workshops is the fact that several performance categories make up the NERC Planning Standards and, therefore, Applicable Reliability Criteria. The various parties perceived this as potentially permitting the CAISO to procure generation, in its backstop role, to satisfy all performance categories. Rather, the CAISO believes it is the role of the CPUC to determine the level of service reliability it wishes to establish for the ratepayers. To further addresses this concern, it is important to again describe the Performance Categories, which are critical to understanding how the CPUC and CAISO can work together.

a. Performance Criteria

As set forth on the Summary Table of Inputs and Methodology, the 2007 LCR is based on NERC Performance Level B and Performance Level C criterion, yielding the low and high range LCR scenarios. These Performance Levels can be described as follows:

i. Performance Criteria - Category B

Category B describes the system performance that is expected 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 a certain duration. Under this category, load cannot be shed in order to assure the Applicable Ratings are met and that facilities are returned to normal ratings when either the element that was lost is returned to service or system adjustments are made within the appropriate time limits.

However, the NERC 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, pre-contingency load-shedding, 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.[5]

ii. Performance Criteria - Category C

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 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.”

2. Service Reliability

The CAISO is responsible for grid reliability in accordance with the NERC performance criteria described above. However, grid reliability can be maintained at service reliability levels that may be unacceptable to the CPUC and end user customers. The 2007 LCR Study presents the CPUC with relevant information to select a level of service reliability that also fulfills grid reliability. Specifically, the study specifies varying generation capacity levels for each local capacity area based on Performance criteria- Categories B and C, with the inclusion of suitable non-generation solutions raised by the PTOs to address contingency conditions as described under Performance Criteria- Category C.

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

As shown by the study results, where the NERC Planning Standards do not allow for load shedding, grid reliability and service reliability are the same and establish a minimum level of capacity needed to meet the CAISO's statutory obligation.[6] Where it is not possible to develop operating solutions to ensure "controlled" interruption of service, in these cases generation will also be required to meet Applicable Reliability Criteria to avoid the potential of load shedding in anticipation of a contingency. Where feasible operational solutions and/or generation procurement amounts affect the level of service to customers, service reliability is implicated and different levels of service reliability may be possible.

D. The Three Options Presented By The 2007 LCR Study

The 2007 LCR study sets forth different solution "options" with varying ranges of potential service reliability consistent with CAISO's Applicable Reliability Criteria:

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 for NERC Category B given that load cannot be removed to meet this performance standard under Applicable Reliability Criteria. However, this capacity amount implicitly relies on load interruption as the **only means** of meeting any Applicable 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

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[6] The NERC Planning Standards reflect a "deterministic" analysis that captures the "robustness" of the grid. In many NERC subregions, service reliability is understood as the probability of disconnecting firm load due to a resource deficiency. Control areas in the Western Electricity Coordinating Council, including the CAISO, do not currently have sufficient information to apply a probabilistic reliability analysis to transmission or planning studies. However, the CAISO has consistently recommended that the CPUC move to a loss of load probability approach as a means by which to consider alternative solutions while still planning to a desired level of service reliability.

overloads including load interruptions prior to the actual occurrence of the second contingency.[7]

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 (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 as the CAISO operators prepare for the second contingency. However, the customer load will be interrupted in the event the second contingency occurs.

3. Option 3- Meet Performance Criteria Category C through Pure Procurement

Option 3 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 only. No load based operational solutions are incorporated into this scenario. Therefore, this results in a "pure capacity" procurement scenario.

E. The CPUC's Responsibilities and The CAISO's Recommendation

The CPUC is responsible for determination of the appropriate level of service reliability to end-use customers within each CAISO-identified local capacity area. The CPUC may meet this responsibility by exercising its jurisdiction over load serving entities to compel procurement of generation or demand resources to meet

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7 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 option selected. The CPUC may also wish to allow the load serving entity to choose planned or controlled load interruption options.[8] The CPUC should impose appropriate penalties for LSEs that fail to comply with the procurement levels that are necessary to meet its established applicable reliability criteria standard. Finally, in its determination of an acceptable service reliability level, the CPUC should explicitly understand the implications associated with contingent events as well as the potential that customers will receive different levels of service reliability based on the service reliability level selected for each local capacity area.

As the grid operator, the CAISO recommends that Option 2 be selected as the service reliability standard. Option 2 identifies a potential service reliability that reflects generation capacity set forth in (2) above, adjusted for any feasible operating solution identified by a PTO prior to the study and approved by the CAISO. On a day-to-day basis the CAISO has traditionally operated the network based on the N-1-1 contingency, with operating solutions developed with the PTOs. Should the CPUC choose Option 2, and to the extent a load shedding solution proposed by a PTO is isolated solely in the service territory of a CPUC load serving entity, the CAISO has indicated the appropriateness of such operating procedure to the CPUC in this study.

III. Assumption Details: How the Study was Conducted

A. System Planning Criteria

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

[8] However, such automatic load shedding schemes or operating procedures implementing manual load shedding options must be acceptable to the CAISO, i.e., the load to be shed is demonstrable, verifiable, and appropriately dispatchable.

Table 1: Criteria Comparison

Contingency Component(s)	ISO Grid Planning Criteria	Existing RMR Criteria	Locational Capacity Criteria
<u>A – No Contingencies</u>	X	X	X
<u>B – Loss of a single element</u>			
1. Generator (G-1)		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 normal limits.

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 1. Where the specific system performance requirements were not met, generation was adjusted such that the minimum amount of generation required to meet the criteria was determined in the Local Capacity Area. The following describes how the criteria were tested for the specific type of analysis performed.

1. Power Flow Assessment:

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

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

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

3 Applicable Rating – Based on ISO Transmission Register or facility upgrade plans.

4 Applicable Rating – ISO Grid Planning Criteria or facility owner criteria as appropriate.

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. Methodology for Determining Zonal Requirements

A key part of the CAISO's study for determining capacity requirements in transmission-constrained areas includes **zonal requirements** to ensure that sufficient generation capacity (in MWs) exists within each large zone so that transmission constraints between zones do not threaten reliability. The analysis of zonal requirements was discussed in the CPUC workshops and the 2006 Local Capacity Technical Analysis (page 5), but the methodology for determining these zonal requirements was not explained in detail.

The CAISO's methodology for determining these zonal requirements is designed so the operating reserves within each zone meet the WECC Minimum Operating Reliability Criteria (MORC) for operating reserves.[9]

[9] *MORC states "Prudent operating judgment shall be exercised in distributing operating reserve, taking into account effective use of capacity in an emergency, time required to be effective, transmission limitations, and local area requirements."*

The determination of these zonal requirements is dependent upon key assumptions:

- **Forecasted Load:** Consistent with CAISO Planning Standards, the CAISO proposes a forecasted zonal load level that represents the 1-in-5-year peak conditions (more specifically the zonal area "coincident" peak.) For future studies the CAISO expects to use the CEC's 1-in-5 year peak load forecasts.

- **Import Capability:** the maximum MW amount that is assumed can be imported into a zone. This can be calculated based on the maximum historical imports into a zone, plus the anticipated increase in import capability due to transmission upgrades in effect for the time period being analyzed. ~~This includes capacity from outside the CAISO Control Area and capacity between the zones, e.g. Path 26.~~

- **Outages**: the amount of generation that may be unavailable within a zone due to unforeseen circumstances that require immediate maintenance. Assuming a peak load, this assumption would encompass forced outages as well as a very small amount of planned outages.

- **Recovery from a Single Worst Contingency:** enough operating reserve to recover from the most severe single contingency without relying on firm load shedding. This total reserve capacity is based on the set of assumptions for peak load conditions. Existing industry standards do not permit shedding firm load to address a single contingency.

The zonal requirement (i.e., the amount of MWs needed within each region) is determined simply by calculating the sum of the operating reserves for recovery from a single worst contingency, the historical outage data, and the 1-in-5-year peak forecast, subtracted by the import capability:

1 in 5 zonal Load forecast + Historical outage data + Recovery from single worst contingency – Import Capability = Zonal Requirement

Zonal requirements define the amount of generation (in MWs) that should exist within a region to ensure the system's ability to withstand a single worst contingency. The CAISO should focus on the 500kV system only between three major zones: NP15, NP15+ZP26, and south of Path 26 (SP26.) These are historically defined regions of the CAISO Controlled Grid where inter-zonal transmission constraints have been prone to deficiencies. Generation within all the local areas within these zones would count toward meeting a zonal requirement.

C. Load Forecast

1. System Forecast

The load forecast at the system as well as PTO levels originates from California Energy Commission (CEC). This most recent CEC forecast is then distributed across the entire system, down to the local area, division and substation level. PTO's 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 muni forecasts. The melding process consists of two parts. Part 1 deals with the PTO load. Part 2 deals with the muni 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; please refer to each PTO expansion plan for additional details.

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 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 growths projected for the divisions by the distribution planners. For example the 1-in-10 area base case, the division load growth determined for the system base case is adjusted to the 1-in-10 temperature using the load temperature relation determined from the latest peak load and temperature data of the division.

ii. Allocation of division load to transmission bus level

Since the base case loads are modeled at the various transmission buses, the division loads developed would need to be allocated to those buses. The allocation process is different depending on the load types. For the most part each PTO's 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 would be allocated to the transmission buses based on the relative magnitude of the distribution forecast. The summation of all base case loads usually is higher then the load forecast because some load like self-generation and generation-plant are load behind the meter and they need to 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 muni forecasts provided to the PTOs for the purposes of their base cases were used for this study.

3. Comparison between the 1-in 5 and 1-in-10 local load forecast

As a rule of thumb, this difference translates into a corresponding one-for-one reduction in the LCR -- (the MWs of capacity needed in that local area) -- provided that the area constraint is driven by a thermal problem AND assuming that the load and generation have roughly the same effectiveness factors.

The exact reduction in LCR results (using a less stringent 1-in-5-year instead of the 1-in-10-year load forecast) could be different due to the load growth characteristics specific to each local area. If the local area constraints are non-linear, like voltage or dynamic problems, or if the effectiveness factors between the generators and load within the same area are significantly different relative to the worst thermal constraint, then the difference in LCR results will not mirror the difference in load forecast.

Table 2~~3~~: 2007 Local Area Load Forecast 1-in 5 vs 1-in-10

	Peak Load (1 in 10) (MW)	**Peak Load (1 in 5) (MW)**	**Difference (MW)**	**Difference (%)**
Humboldt	197	196	1	0.5
North Coast/North Bay	1,513	1,475	38	2.5
Sierra	1,841	1,805	36	2.0
Stockton	1,267	1,252	15	1.2
Greater Bay	9,633	9,509	124	1.3
Greater Fresno	3,154	3,004	150	4.8
Kern	1,209	1,174	35	2.9
LA Basin	19,325	18,809	516	2.7
San Diego	4,742	4,610	134	2.8
Total	**42,881***	**41,834***	**1,049**	**2.4**

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

The peak load forecast is one key variable in the determination of the LCR that meets the established criteria. In comparing the 1-in-5-year load analysis with the 1-in-10-year standard, a general conclusion that could be drawn is that the difference in required MWs for most of the local areas and sub-areas analyzed in this report would not be huge. An analysis of each local area and the unique contingencies within each area would be necessary to determine the exact difference in LCR's.

D. Power Flow Program Used in the LCR analysis

The LCR technical studies were conducted using General Electric's Power System Load Flow (GE PSLF) program version 15.2. This E PSLF program is available directly from GE or through the Western System Electricity Council (WECC) to any member.

The CAISO utilized the "2007 Heavy Summer 2A1" as the starting WECC base case for the 2007 local area power flows used in the 2007 LCR studies. To complete the local area component of this study, this 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 area as provided to the ISO by the Participating Transmission Owners ("PTOs").

Electronic contingency files provided by the PTOs were utilized to perform the numerous contingencies required to identify the LCR needs. These contingency files include remedial action and special protection schemes that are expected to be in operation during 2007. An CAISO created EPCL (a GE programming language contained within the GE PSLF package) routine was used to run the combination of contingencies; however, other routines are available from WECC with the GE PSFL package or can be developed by third parties to identify the most limiting combination of contingencies requiring the highest amount of generation within the local area to maintain power flows within applicable ratings.

IV. Locational Capacity Requirement Study Results

A. Summary of Study Results

The LCR results reflect 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 and nuclear units). The second set is "market" generation. Within this overview, LCR is defined as the amount of generating capacity that is required 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 following two tables.

Table 3~~2~~: Local Requirements Comparison

	Qualifying Capacity			2007 LCR Requirement Based on Category B Option 1			2007 LCR Requirement Based on Category C with operating procedure Option 2			2006 Total LCR Req.
Local Area Name	**QF/ Muni (MW)**	**Market (MW)**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**(MW)**
Humboldt	73	133	206	202	0	**202**	202	0	**202**	162
North Coast / North Bay	158	861	1019	582**	0	**582****	582**	0	**582****	658
Sierra	1072	776	1848	1833	205	**2038**	1833	328	**2161**	1770*
Stockton	314	257	571	348	0	**348**	506	53	**559**	440*
Greater Bay	1314	5231	6545	4771	0	**4771**	5341	0	**5341**	6009
Greater Fresno	575	2337	2912	2530	0	**2530**	2534	68	**2602**	2837 *
Kern	978	31	1009	554	0	**554**	769	17	**786**	797*
LA Basin	3510	7012	10522	8843	0	**8843**	8843	0	**8843**	8127
San Diego	191	2741	2932	2781	0	**2781**	2781	0	**2781**	2620
Total	**8185**	**19379**	**27564**	**22444**	**205**	**22649**	**23391**	**466**	**23857**	**23420**

* Generation deficient areas (or with sub-area that are deficient) – deficiency included in LCR
** The North Coast/North Bay area requirement would have been higher by 80 MW, however a new operating procedure has been received, validated and implemented by PG&E and the CAISO.

The last column under "2007 LCR Requirement based on Category C with operating solution" represents the MW of generation that the ISO is proposing to be procured by all LSEs in local areas under the CPUC Local Capacity Requirements. This column includes all units needed to maintain system reliability without the potential for pre-contingency load shedding

Table 4~~3~~: Local Capacity Requirements vs. Peak Load and Local Area Generation

	2007 Total LCR (MW)	Peak Load (1 in10) (MW)	2007 LCR as % of Peak Load	Total Dependable Local Area Generation (MW)	2007 LCR as % of Total Area Generation
Humboldt	202	197	103%	206	98%
North Coast/North Bay	582	1,513	38%	1,019	57%
Sierra	2,161	1,841	117%	1,848	117%**
Stockton	559	1,267	44%	571	98%**
Greater Bay	5,341	9,633	55%	6,545	82%
Greater Fresno	2,602	3,154	82%	2,912	89%**
Kern	786	1,209	65%	1,009	78%**
LA Basin	8,843	19,325	46%	10,522	84%
San Diego	2,781	4,742	59%	2,932	95%
Total	**23,857**	**42,881***	**56%***	**27,471**	**87%**

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

** Generation deficient LCA (or with sub-area that are 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.

Table 3 shows how much of the local area load is dependent on local generation and how much local generation needs to be available in order to reliably (see LCR criteria) serve the load in those Local Capacity Areas. This table also indicates where new transmission projects, new generation additions or demand side management programs would be most useful in order to reduce the dependency on existing (mostly old and inefficient) local area generation.

B. Summary of Results by Local Area

Each local 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 area is not simply a summation of the sub-area requirements. For example, some sub-areas may overlap and therefore the same units have been counted toward both sub-area requirements. Of course some sub-areas requirements are directly counted toward the total requirements of a bigger local area or the overall area.

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 115 kV
2) Humboldt 115 kV
3) Kekawaka 60 kV
4) Ridge Cabin 60 kV

Total busload within the defined area: 191 MW with 6 MW of losses resulting in total load + losses of 197 MW.

Total units and qualifying capacity available in this area:

Gen Bus	Gen Name	ID	Qualifying Capacity (MW)
31170	HMBOLDT1	1	51
31172	HMBOLDT2	1	52
31154	HUMBOLDT	1	15
31154	HUMBOLDT	2	15
31150	FAIRHAVN	1	17.2

31166	KEKAWAK	1	5.3
31158	LP SAMOA	1	25
31152	PAC.LUMB	2	12.5
31152	PAC.LUMB	1	12.5
	Total		205.5

Critical Contingency Analysis Summary

Humboldt overall:

The most critical contingency for the Humboldt area is the outage of the Bridgeville-Cottonwood 115 kV line over-lapping with an outage of one Humboldt Bay Power Plant. The local area limitation is low voltage and reactive power margin. This multiple contingency establishes a Local Capacity Requirement of 202 MW (includes 73 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. Units outside of this area are not effective.

Humboldt Overall Requirements:

	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	73	0	133	206

	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single) [10]	202	0	202
Category C (Multiple) [11]	202	0	202

[10] 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.

[11] 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. North Coast / North Bay Area

Area Definition

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

The transmission tie facilities coming into the Eagle Rock-Fulton sub-area are:

1) Fulton-Lakeville 230 kV line #1
2) Fulton-Ignacio 230kV line #1
3) Cortina 230/115 kV Transformer #1
4) Lakeville-Sonoma 115 kV line #1
5) Corona-Lakeville 115 kV line #1
6) Willits-Garberville 60 kV line #1

The substations that delineate the Eagle Rock-Fulton sub-area are:

1) Fulton 230 kV
2) Corona 115 kV
3) Sonoma 115 kV
4) Cortina 115 kV
5) Laytonville 60 kV

The transmission tie lines into the Lakeville sub-area are:

1) Vaca Dixon-Lakeville 230 kV line #1
2) Tulucay-Vaca Dixon 230 kV line #1
3) Lakeville-Sobrante 230 kV line #1
4) Ignacio-Sobrante 230 kV line #1
5) Ignacio-Fulton 230 kV line #1
6) Lakeville-Fulton 230 kV line #1
7) Lakeville-Corona 115 kV line #1
8) Lakeville-Sonoma 115 kV line #1

The substations that delineate the Lakeville sub-area are:

1) Lakeville 230 kV
2) Ignacio 230 kV
3) Tulucay 230 kV
4) Lakeville 115 kV

Total busload within the defined area: 1457 MW with 56 MW of losses resulting in total load + losses of 1513 MW.

Total units and qualifying capacity available in this area:

Gen Bus	Gen Name	ID	Qualifying Capacity (MW)
31433	POTTRVLY	3	2.5
31433	POTTRVLY	1	5.5
31433	POTTRVLY	4	2.5
31430	SMUDGEO1	1	38
31406	GEYSR5-6	1	36
31406	GEYSR5-6	2	36
31408	GEYSER78	1	31
31408	GEYSER78	2	31
31412	GEYSER11	1	60
31414	GEYSER12	1	41
31416	GEYSER13	1	70
31418	GEYSER14	1	63
31420	GEYSER16	1	75
31422	GEYSER17	1	51
31424	GEYSER18	1	40
31426	GEYSER20	1	40
38106	NCPA1GY1	1	59
38108	NCPA1GY2	1	59
38110	NCPA2GY1	1	60
38112	NCPA2GY2	1	60
31400	SANTA FE	2	39.1
31404	WEST FOR	2	14
31400	SANTA FE	1	39.1
31402	BEAR CAN	1	8.3
31402	BEAR CAN	2	8
31404	WEST FOR	1	14
32700	MONTICLO	1	3.3
32700	MONTICLO	2	3.4
32700	MONTICLO	3	0
31435	GEO.ENGY	1	8.6
31435	GEO.ENGY	2	8.9
31436	INDIAN V	1	3.7
31446	SONMA LF	1	7.7
	Total		1018.6

Critical Contingency Analysis Summary

Eagle Rock-Fulton Sub-area

The most critical overlapping contingency is the outage of the Fulton-Ignacio 230 kV line #1 and the Fulton-Lakeville 230 kV line #1. The sub-area area limitation is thermal overloading of Sonoma-Pueblo 115 kV line #1. This limiting contingency establishes a Local Capacity Requirement of 371 MW (includes 80 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area. Out of this amount, 182 MW is required among the units connected directly to the Eagle Rock substation (includes 21 MW of QF generation).

The most critical single contingency in the sub-area is the outage of Cortina 230/115 kV transformer #1. This limiting contingency establishes a Local Capacity Requirement of 245 MW (includes 80 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 within the Eagle Rock-Fulton pocket as well as units outside the pocket that are at least 5% effective to the above-mentioned constraint.

Single contingency

Gen Bus	Gen Name	Gen ID	MW Eff Fctr	Location
31404	WEST FOR	2	56	Fulton
31404	WEST FOR	1	56	Fulton
31414	GEYSER12	1	56	Fulton
31418	GEYSER14	1	56	Fulton
31420	GEYSER16	1	56	Fulton
31422	GEYSER17	1	56	Fulton
38110	NCPA2GY1	1	56	Fulton
38112	NCPA2GY2	1	56	Fulton
31406	GEYSR5-6	1	53	Eagle Rock
31406	GEYSR5-6	2	53	Eagle Rock
31408	GEYSER78	1	53	Eagle Rock
31408	GEYSER78	2	53	Eagle Rock
31412	GEYSER11	1	53	Eagle Rock

Overlapping Contingency

Gen Bus	Gen Name	Gen ID	MW Eff Fctr	Location
31404	WEST FOR	2	27	Fulton
31404	WEST FOR	1	27	Fulton
31414	GEYSER12	1	27	Fulton
31418	GEYSER14	1	27	Fulton
31420	GEYSER16	1	27	Fulton
31422	GEYSER17	1	27	Fulton

38110	NCPA2GY1	1	27	Fulton
38112	NCPA2GY2	1	27	Fulton
31406	GEYSR5-6	1	17	Eagle Rock
31406	GEYSR5-6	2	17	Eagle Rock
31408	GEYSER78	1	17	Eagle Rock
31408	GEYSER78	2	17	Eagle Rock
31412	GEYSER11	1	17	Eagle Rock

Lakeville Sub-area

Operations solutions to mitigate the most limiting constraint in the Lakeville pocket, as previously described in the LCR report, has been validated in this area in order to reduce the total LCR requirement both under single and overlapping contingency conditions. After implementing the operating solutions, the most critical contingency for Lakeville sub-area would be the outage of Vaca Dixon-Tulucay 230 kV line #1 and Geysers 13 unit. The sub-area limitation is thermal overloading of the Lakeville-Vaca-Dixon 230 kV #1. This limiting contingency establishes a Local Capacity Requirement of ~~766~~ 582 MW for single contingency in this sub-area (includes 158 MW of QF generation). The LCR requirement for Eagle Rock/Fulton sub-area can be counted toward fulfilling the requirement of Lakeville sub-area

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	MW Eff Fctr	Location
31400	SANTA FE	2	25	Lakeville
31430	SMUDGEO1	1	25	Lakeville
31400	SANTA FE	1	25	Lakeville
31416	GEYSER13	1	25	Lakeville
31424	GEYSER18	1	25	Lakeville
31426	GEYSER20	1	25	Lakeville
38106	NCPA1GY1	1	25	Lakeville
38108	NCPA1GY2	1	25	Lakeville
31404	WEST FOR	2	22	Fulton
31404	WEST FOR	1	22	Fulton
31414	GEYSER12	1	22	Fulton
31418	GEYSER14	1	22	Fulton
31420	GEYSER16	1	22	Fulton
31422	GEYSER17	1	22	Fulton
38110	NCPA2GY1	1	22	Fulton
38112	NCPA2GY2	1	22	Eagle Rock

31406	GEYSR5-6	1	8	Eagle Rock
31406	GEYSR5-6	2	8	Eagle Rock
31408	GEYSER78	1	8	Eagle Rock
31408	GEYSER78	2	8	Eagle Rock
31412	GEYSER11	1	8	Eagle Rock

North Coast/North Bay Overall Requirements:

	QF/Seflgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	158	0	861	1019

	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[12]	~~766~~582	0	~~766~~582
Category C (Multiple)[13]	~~766~~582	0	~~766~~582

3. Sierra Area

Area Definition

The transmission tie lines into the Sierra Area are:

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

[12] 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.
[13] 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.

The substations that delineate the Sierra Area are:

1) Table Mountain 60 kV
2) Table Mountain 230 kV
3) Big Bend 115 kV
4) Drum 115 kV
5) Tamarack 60 kV
6) Brighton 230 kV
7) Rio Oso 230 kV
8) Gold Hill 230 kV

Total busload within the defined area: 1742.4 MW with 98.5 MW of losses resulting in total load + losses of 1840.9 MW.

Total units and qualifying capacity available in this area:

Gen No	Gen Name	ID	Qualifying Capacity
31888	OROVLLE	1	8.9
31890	PO POWER	2	9.8
31890	PO POWER	1	9.8
31834	KELLYRDG	1	10
31814	FORBSTWN	1	39.7
31794	WOODLEAF	1	55
31862	DEADWOOD	1	2
31832	SLY.CR.	1	13.2
32470	CMP.FARW	1	6.5
32450	COLGATE1	1	165.8
32452	COLGATE2	1	165.7
32466	NARROWS1	1	3.6
32468	NARROWS2	1	10.1
32451	FREC	1	47
32490	GRNLEAF1	2	10
32490	GRNLEAF1	1	51.1
32156	WOODLAND	1	28.6
32494	YUBA CTY	1	50.2
32496	YCEC	1	47
32492	GRNLEAF2	1	50.3
32166	UC DAVIS	1	3.5
31812	CRESTA	1	35
31812	CRESTA	2	35
31788	ROCK CK2	1	56
31820	BCKS CRK	1	33
31820	BCKS CRK	2	25
31790	POE 1	1	60
31792	POE 2	1	60
31786	ROCK CK1	1	56
31784	BELDEN	1	115
32162	RIV.DLTA	1	3.1
32502	DTCHFLT2	1	26

32476	ROLLINSF	1	11.7
32474	DEER CRK	1	5.7
32454	DRUM 5	1	49.5
32504	DRUM 1-2	1	13
32504	DRUM 1-2	2	13
32506	DRUM 3-4	1	14
32506	DRUM 3-4	2	14
32484	OXBOW F	1	6
32472	SPAULDG	1	4.4
32472	SPAULDG	2	7
32472	SPAULDG	3	5.8
32498	SPILINCF	1	13.7
32464	DTCHFLT1	1	22
32500	ULTR RCK	1	28.5
32480	BOWMAN	1	3.8
32488	HAYPRES+	1	12.3
32488	HAYPRES+	2	8.7
32462	CHI.PARK	1	38
32478	HALSEY F	1	11
32512	WISE	1	10.8
32460	NEWCSTLE	1	5.9
32510	CHILIBAR	1	7
32513	ELDRADO1	1	10
32514	ELDRADO2	1	10
32458	RALSTON	1	86
32456	MIDLFORK	1	63.4
32456	MIDLFORK	2	63.4
32486	HELLHOLE	1	0.5
32508	FRNCH MD	1	17
			1848

Critical Contingency Analysis Summary

South of Table Mountain Sub-area

The most critical 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 a Local Capacity Requirement of 1630 MW (includes 1072 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this pocket.

Effectiveness factors:

Gen No	Gen Name	ID	Qualifying Capacity	DFAX (%)
31888	OROVLLE	1	8.9	~~-0.7219~~72
31890	PO POWER	2	9.8	~~-0.7195~~72
31890	PO POWER	1	9.8	~~-0.7195~~72
31834	KELLYRDG	1	10	~~-0.7169~~72
31814	FORBSTWN	1	39.7	~~-0.619~~62

31794	WOODLEAF	1	55	~~-0.1556~~ 62
31862	DEADWOOD	1	2	~~-0.6088~~ 61
31832	SLY.CR.	1	13.2	~~-0.6071~~ 61
32470	CMP.FARW	1	6.5	~~-0.5425~~ 54
32450	COLGATE1	1	165.8	~~-0.5185~~ 52
32452	COLGATE2	1	165.7	~~-0.5185~~ 52
32466	NARROWS1	1	3.6	~~-0.5162~~ 52
32468	NARROWS2	1	10.1	~~-0.5162~~ 52
32451	FREC	1	47	~~-0.4229~~ 42
32490	GRNLEAF1	2	10	~~-0.4145~~ 41
32490	GRNLEAF1	1	51.1	~~-0.4145~~ 41
32156	WOODLAND	1	28.6	~~-0.2794~~ 28
32494	YUBA CTY	1	50.2	~~-0.2739~~ 27
32496	YCEC	1	47	~~-0.2735~~ 27
32492	GRNLEAF2	1	50.3	~~-0.271~~ 27
32166	UC DAVIS	1	3.5	~~-0.2569~~ 26
31812	CRESTA	1	35	~~-0.2397~~ 24
31812	CRESTA	2	35	~~-0.2397~~ 24
31788	ROCK CK2	1	56	~~-0.2396~~ 24
31820	BCKS CRK	1	33	~~-0.2395~~ 24
31820	BCKS CRK	2	25	~~-0.2395~~ 24
31790	POE 1	1	60	~~-0.2374~~ 24
31792	POE 2	1	60	~~-0.2374~~ 24
31786	ROCK CK1	1	56	~~-0.2352~~ 24
31784	BELDEN	1	115	~~-0.2346~~ 23
32162	RIV.DLTA	1	3.1	~~-0.2109~~ 21
32502	DTCHFLT2	1	26	~~-0.2092~~ 21
32476	ROLLINSF	1	11.7	~~-0.203~~ 20
32474	DEER CRK	1	5.7	~~-0.2007~~ 20
32454	DRUM 5	1	49.5	~~-0.1995~~ 20
32504	DRUM 1-2	1	13	~~-0.1993~~ 20
32504	DRUM 1-2	2	13	~~-0.1993~~ 20
32506	DRUM 3-4	1	14	~~-0.1993~~ 20
32506	DRUM 3-4	2	14	~~-0.1993~~ 20
32484	OXBOW F	1	6	~~-0.1972~~ 20
32472	SPAULDG	1	4.4	~~-0.1964~~ 20
32472	SPAULDG	2	7	~~-0.1964~~ 20
32472	SPAULDG	3	5.8	~~-0.1964~~ 20
32498	SPILINCF	1	13.7	~~-0.1962~~ 20
32464	DTCHFLT1	1	22	~~-0.1951~~ 20
32500	ULTR RCK	1	28.5	~~-0.1947~~ 19
32480	BOWMAN	1	3.8	~~-0.1941~~ 19
32488	HAYPRES+	1	12.3	~~-0.1941~~ 19
32488	HAYPRES+	2	8.7	~~-0.1941~~ 19
32462	CHI.PARK	1	38	~~-0.1924~~ 19
32478	HALSEY F	1	11	~~-0.1891~~ 19
32512	WISE	1	10.8	~~-0.1861~~ 19
32460	NEWCSTLE	1	5.9	~~-0.182~~ 18
32510	CHILIBAR	1	7	~~-0.1749~~ 17
32513	ELDRADO1	1	10	~~-0.1744~~ 17

32514	ELDRADO2	1	10	~~-0.1744~~17
32458	RALSTON	1	86	~~-0.1676~~17
32456	MIDLFORK	1	63.4	~~-0.167~~17
32456	MIDLFORK	2	63.4	~~-0.167~~17
32486	HELLHOLE	1	0.5	~~-0.1562~~16
32508	FRNCH MD	1	17	~~-0.155~~16
			1848	

Colgate Sub-area

The most critical contingency is the loss of the Colgate-Smartville #1 60 kV line with one of the Narrows #2 (or Camp far West) units out of service. The area limitation is thermal overloading of the Colgate-Smartville #2 60 kV line. This limiting contingency establishes a Local Capacity Requirement of 17 MW (includes 17 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this pocket.

Effectiveness factors:

All units within this area (Narrows #2 and Camp Far West) are needed therefore no effectiveness factor is required.

Pease Sub-area

The most critical contingency is the loss of the Palermo-East Nicolaus 115 kV line with one of the Greenleaf #2 (or Yuba City) units out of service. The area limitation is thermal overloading of the Palermo-Pease 115 kV line. This limiting contingency establishes a Local Capacity Requirement of 111 MW (includes 100 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this pocket.

Effectiveness factors:

All units within this area (Greenleaf #2, Yuba City and Yuba City EC) are needed therefore no effectiveness factor is required.

Bogue Sub-area

The most critical contingency is the loss of the Pease-Rio Oso 115 kV line with one of the Greenleaf #1 (or Feather River EC) units out of service. The area limitation is thermal overloading of the Palermo-Bogue 115 kV line. This limiting contingency establishes a Local Capacity Requirement of 101 MW (includes 61 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this pocket.

Effectiveness factors:

All units within this area (Greenleaf #1 units 1&2 and Feather River EC) are needed therefore no effectiveness factor is required.

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 Palermo-East Nicolaus 115 kV line. This limiting contingency establishes a Local Capacity Requirement of 1037 MW (includes 142 MW of QF and Muni generation as well as 250 MW of Deficiency) as the minimum capacity necessary for reliable load serving capability within this pocket.

The single most critical contingency is the loss of the Palermo-Pease 115 kV line with Belden unit out of service. The area limitation is thermal overloading of the Palermo-East Nicolaus 115 kV line. This limiting contingency establishes a Local Capacity Requirement of 980 MW (includes 142 MW of QF and Muni generation as well as 193 MW of Deficiency) as the minimum capacity necessary for reliable load serving capability within this pocket.

The Sierra case provided had a normal overload on the Palermo-East Nicolaus 115 kV line that can be resolved by changing the normal tap point for the East Marysville substation from the Palermo-East Nicolaus 115 kV line to the Pease-Rio Oso 115 kV line and by having at least 680 MW of generation on-line (from maximum 787 MW generation available – includes 142 MW of QF and Muni).

Effectiveness factors:

All units (listed below) within this area are needed therefore no effectiveness factor is required.

Gen No	Gen Name	ID	Qualifying Capacity
32476	ROLLINSF	1	11.7
32474	DEER CRK	1	5.7
32504	DRUM 1-2	1	13
32504	DRUM 1-2	2	13
32506	DRUM 3-4	1	14
32506	DRUM 3-4	2	14
32454	DRUM 5	1	49.5
32484	OXBOW F	1	6
32472	SPAULDG	1	4.4
32472	SPAULDG	2	7
32472	SPAULDG	3	5.8
32480	BOWMAN	1	3.8
32488	HAYPRES+	1	12.3
32488	HAYPRES+	2	8.7
32156	WOODLAND	1	28.6
32166	UC DAVIS	1	3.5
32502	DTCHFLT2	1	26
32464	DTCHFLT1	1	22
32162	RIV.DLTA	1	3.1
32462	CHI.PARK	1	38
31812	CRESTA	1	35

31812	CRESTA	2	35
31788	ROCK CK2	1	56
31820	BCKS CRK	1	33
31820	BCKS CRK	2	25
31790	POE 1	1	60
31792	POE 2	1	60
31786	ROCK CK1	1	56
31784	BELDEN	1	115
32478	HALSEY F	1	11
32512	WISE	1	10.8
			786.9

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 Local Capacity Requirement of 83 MW (includes 0 MW of QF and Muni generation as well as 56 MW of Deficiency) as the minimum capacity necessary for reliable load serving capability within this pocket.

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 Local Capacity Requirement of 123 MW (includes 0 MW of QF and Muni generation as well as 95 MW of Deficiency) as the minimum capacity necessary for reliable load serving capability within this pocket.

The single most critical contingency is the loss of the Drum-Higgins 115 kV line with the Wise #1 unit out of service. The area limitation is thermal overloading of the Gold Hill-Placer #1 115 kV line. This limiting contingency establishes a Local Capacity Requirement of 52 MW (includes 0 MW of QF and Muni generation as well as 24 MW of Deficiency) as the minimum capacity necessary for reliable load serving capability within this pocket.

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 a Local Capacity Requirement of 701 MW (includes 413 MW of QF and Muni generation as well as 45 MW of Deficiency) as the minimum capacity necessary for reliable load serving capability within this pocket.

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 a Local Capacity Requirement of 352 MW (includes 413 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this pocket.

Effectiveness factors:

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

Gen No	Gen Name	ID	Qualifying Capacity	DFAX (%)
32156	WOODLAND	1	28.6	~~-0.3042~~31
32490	GRNLEAF1	2	10	~~-0.2879~~29
32490	GRNLEAF1	1	51.1	~~-0.2879~~29
32451	FREC	1	47	~~-0.2787~~28
32166	UC DAVIS	1	3.5	~~-0.247~~25
32502	DTCHFLT2	1	26	~~-0.202~~20
32476	ROLLINSF	1	11.7	~~-0.1852~~19
32474	DEER CRK	1	5.7	~~-0.1797~~18
32454	DRUM 5	1	49.5	~~-0.1794~~18
32504	DRUM 1-2	1	13	~~-0.1793~~18
32504	DRUM 1-2	2	13	~~-0.1793~~18
32506	DRUM 3-4	1	14	~~-0.179~~18
32506	DRUM 3-4	2	14	~~-0.179~~18
32484	OXBOW F	1	6	~~-0.1787~~18
32472	SPAULDG	1	4.4	~~-0.1772~~18
32472	SPAULDG	2	7	~~-0.1772~~18
32472	SPAULDG	3	5.8	~~-0.1772~~18
32480	BOWMAN	1	3.8	~~-0.1769~~18
32488	HAYPRES+	1	12.3	~~-0.1769~~18
32488	HAYPRES+	2	8.7	~~-0.1769~~18
32496	YCEC	1	47	~~-0.1602~~16
32494	YUBA CTY	1	50.2	~~-0.1586~~16
32492	GRNLEAF2	1	50.3	~~-0.1573~~16
32464	DTCHFLT1	1	22	~~-0.1497~~15
32162	RIV.DLTA	1	3.1	~~-0.149~~15
32462	CHI.PARK	1	38	~~-0.1232~~12
31862	DEADWOOD	1	2	~~-0.0734~~7
31814	FORBSTWN	1	39.7	~~-0.0711~~7
31832	SLY.CR.	1	13.2	~~-0.0708~~7

31794	WOODLEAF	1	55	~~-0.0696~~7
			655.6	

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 Gold Hill-Ralston 230 kV line or vice versa. The area limitation is thermal overloading of the Rio Oso-Atlantic 230 kV line. This limiting contingency establishes a Local Capacity Requirement of 230 MW (includes 80 MW of QF and Muni generation as well as 95 MW of Deficiency) as the minimum capacity necessary for reliable load serving capability within this pocket.

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 Local Capacity Requirement of 132 MW (includes 80 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this pocket.

Effectiveness factors:

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

Gen No	Gen Name	ID	Qualifying Capacity	DFAX (%)
32498	SPILINCF	1	13.7	~~-0.4985~~50
32500	ULTR RCK	1	28.5	~~-0.4949~~49
32514	ELDRADO2	1	10	~~-0.3285~~33
32513	ELDRADO1	1	10	~~-0.3285~~33
32510	CHILIBAR	1	7	~~-0.3279~~33
32460	NEWCSTLE	1	5.9	~~-0.2659~~27
32478	HALSEY F	1	11	~~-0.2518~~25
32512	WISE	1	10.8	~~-0.2481~~25
32462	CHI.PARK	1	38	~~-0.0858~~9
			134.9	

Sierra Overall Requirements:

	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	267	805	776	1848

	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single) [14]	1833	205	2038
Category C (Multiple) [15]	1833	328	2161

[14] 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.

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 2
3) 30/115 kV Transformer #2
4) Tesla-Tracy 115 kV Line
5) Tesla-Salado 115 kV Line
6) Tesla-Salado-Manteca 115 kV line
7) Tesla-Shulte 115 kV Line
8) Tesla-Manteca 115 kV Line

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

1) Tesla 115 kV
2) Bellota 115 kV

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

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

The substations that delineate the Lockeford Sub-area is:

1) Lockeford 60 kV

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

1) Tesla – Stagg 230 kV Line
2) Tesla – Eight Mile Road 230 kV Line
3) Gold Hill – Eight Mile Road 230 kV Line
4) Gold Hill - Lodi Stigg 230 kV Line

The substations that delineate the Stagg Sub-area is:

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[15] 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.

1) Tesla 230 kV
2) Gold Hill 230 kV

Total busload within the defined area: 1240 MW with 27 MW of losses resulting in total load + losses of 1267 MW.

Total units and qualifying capacity available in this area:

Name	ID	Qualifying Capacity
GWFTRCY2	1	79.2
GWFTRCY1	1	79.8
FBERBORD	1	5.7
BELLTA T	1	0
CH.STN.	1	22.3
STNSLSRP	1	19.9
CPC STCN	1	62.9
CAMANCHE	1	3.7
CAMANCHE	2	3.7
CAMANCHE	3	3.7
DONNELLS	1	67.5
BEARDSLY	1	11
TULLOCH	1	9
TULLOCH	2	9
SANDBAR	1	16.8
SPRNG GP	1	6.7
STANISLS	1	91
LODI25CT	1	25.6
GEN.MILL	1	3.4
Stig CC	1	50
		570.9

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 critical contingency for the Tesla-Bellota pocket is the loss of Tesla-Tracy 115 kV and Tesla-Schulte 115 kV #1. The area limitation is thermal overloading of the Tesla-AEC section of Tesla-Kasson-Manteca 115 kV line above its emergency rating. This limiting contingency establishes a Local Capacity Requirement of 428 MW (includes 235 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this area.

The single most critical contingency for the Tesla-Bellota pocket is the loss of Tesla-Tracy 115 kV line and the loss of the Stanisls unit #1. This single contingency establishes a Local Capacity Requirement of 348 MW (includes 235 MW of QF and Muni generation).

Effectiveness factors:

All units within this area are needed for the most limiting contingency 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-Colony section of the Lockeford-Lodi #1 60 kV circuit. This limiting contingency establishes a Local Capacity Requirement of 81 MW (including 28 MW of QF and Muni as well as a deficiency of 53 MW) as the minimum capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

All units within this area (Lodi CT and General Mill) are needed therefore no effectiveness factor is required.

Stagg Sub-area

The outage of the Tesla-Stagg 230 kV line and Tesla-Eight Mile ~~-Gold Hill~~ 230 kV line causes low voltages at Stagg, Eight Mile Road and Lodi Stig 230 kV busses. Post-contingency steady-state voltages at these three busses are less than 0.90 pu. Lodi Stig generating unit is needed to support voltage at these three 230 kV busses. This limiting contingency establishes a Local Capacity Requirement of 50 MW as the minimum capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

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

Stockton Overall Requirements:

	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	114	200	257	571

	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[16]	348	0	348
Category C (Multiple)[17]	506	53	559

5. Greater Bay Area

<u>Area Definition</u>

The transmission tie lines into the Greater Bay Area are:

1) Lakeville-Sobrante 230 kV
2) Ignacio-Sobrante 230 kV
3) Parkway-Moraga 230 kV
4) Bahia-Moraga 230 kV
5) Lambie SW Sta-Vaca Dixon 230 kV
6) Peabody-Contra Costa P.P. 230 kV
7) Kelso-Brentwood 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-Tracy #1 230 kV
14) Tesla-Tracy #2 230 kV
15) Tesla-Ravenswood 230 kV
16) Tesla-Metcalf 500 kV
17) Moss Landing-Metcalf 500 kV
18) Moss Landing-Metcalf #1 230 kV
19) Moss Landing-Metcalf #2 230 kV
20) Green Valley-Morgan Hill #1 115 kV
21) Green Valley-Morgan Hill #2 115 kV
22) Oakdale TID-Newark #1 115 kV
23) Oakdale TID-Newark #2 115 kV

The substations that delineate the Greater Bay Area are:

1) Lakeville 230 kV
2) Ignacio 230 kV
3) Moraga 230 kV
4) Lambie SW Sta 230 kV

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[16] 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.
[17] 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.

5) Kelso 230 kV
6) Peabody 230 kV
7) Pittsburg 230 kV
8) Tesla 230 kV
9) Metcalf 500 kV
10) Moss Landing 500 kV
11) Morgan Hill 115 kV
12) Newark 115 kV

Total busload within the defined area: 9402 MW with 231 MW of losses resulting in total load + losses of 9633 MW.

Total units and qualifying capacity available in this area:

No	Name	ID	Qualifying Capacity
38118	ALMDACT1	1	25.6
38119	ALMDACT2	1	25.6
33114	C.COS 4	1	0
33115	C.COS 5	1	0
33116	C.COS 6	1	345
33117	C.COS 7	1	345
33463	CARDINAL	2	10
33463	CARDINAL	1	17.8
35863	CATALYST	1	0
36856	CCA100	1	32
33136	CCCSD	1	4.4
32921	ChevGen1	1	54
32922	ChevGen2	1	54
36854	Cogen	2	3
36854	Cogen	1	3
32900	CRCKTCOG	1	243
32175	CREEDGT1	3	47
33145	CROWN.Z.	2	5.4
33145	CROWN.Z.	1	40
33108	DEC CTG1	1	173
33109	DEC CTG2	1	173
33110	DEC CTG3	1	173
33107	DEC STG1	1	294
33161	DOWCHEM1	1	16.8
33162	DOWCHEM2	1	22
33163	DOWCHEM3	1	22
36863	DVR A GT	1	47
36865	DVR A ST	1	50
36864	DVR B GT	1	50
35318	FLOWDPTR	1	5.7
33151	FOSTER W	3	35
33151	FOSTER W	1	45.4

33151	FOSTER W	2	45.4
36858	Gia100	1	21
36895	Gia200	1	21
35850	GLRY COG	2	40
35850	GLRY COG	1	80
32174	GOOSEHGT	2	46
35851	GROYPKR1	1	45
35852	GROYPKR2	1	45
35853	GROYPKR3	1	45
33131	GWF #1	1	20
33132	GWF #2	1	20
33133	GWF #3	1	20
33134	GWF #4	1	20
33135	GWF #5	1	20
32172	HIGHWNDS	1	13
32740	HILLSIDE	1	26.2
35637	IBM-CTLE	1	50
32173	LAMBGT1	1	47
35854	LECEFGT1	1	48
35855	LECEFGT2	1	48
35856	LECEFGT3	1	48
35857	LECEFGT4	1	48
35310	LFC FIN+	1	8.9
33112	LMECCT1	1	165
33111	LMECCT2	1	165
33113	LMECST1	1	230
35881	MEC CTG1	1	184
35882	MEC CTG2	1	186
35883	MEC STG1	1	227
33121	MRAGA 1T	1	0
33122	MRAGA 2T	1	0
33123	MRAGA 3T	1	0
32901	OAKLND 1	1	55
32902	OAKLND 2	1	55
32903	OAKLND 3	1	55
35860	OLS-AGNE	1	28.5
33252	POTRERO3	1	210
33253	POTRERO4	1	52
33254	POTRERO5	1	52
33255	POTRERO6	1	52
33105	PTSB 5	1	320
33106	PTSB 6	1	325
30000	PTSB 7	1	710
33178	RVEC_GEN	1	48
35312	SEAWESTF	1	3.3
33141	SHELL 1	1	20
33142	SHELL 2	1	40
33143	SHELL 3	1	40

32176	SHILOH	1	0
35861	SJ-SCL W	1	5
33462	SMATO1SC	1	0
33460	SMATO2SC	1	0
33461	SMATO3SC	1	0
32169	SOLANOWP	1	10
33468	SRI INTL	1	3.3
33139	STAUFER	1	2.3
32920	UNION CH	1	20.4
32910	UNOCAL	1	10
32910	UNOCAL	2	10
32910	UNOCAL	3	10
33466	UNTED CO	1	27.2
35320	USW FRIC	1	3.4
35320	USW FRIC	2	0
32168	USWINDPW	2	3.4
33838	USWP_#3	1	20.5
33170	WINDMSTR	1	3.6
35316	ZOND SYS	1	6.2
			6545

<u>Critical Contingency Analysis Summary</u>

San Francisco Sub-area

Per the CAISO Revised Action Plan for SF, all Potrero units (360 MW) will continued to be required until completion of the plan as it is presently described.

The most critical contingency is an overlapping outage of two 115 kV cables between Martin and Hunters Point Substations. The area limitation is thermal overloading of the Martin-Bayshore-Potrero 115 kV #1 and #2 cables. This limiting contingency requires all of the existing Potrero Power plant generation (Potrero units 3-6) 360 MW be on-line.

Effectiveness factors:

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

Oakland Sub-area

The most critical contingency is an outage of the D-L 115 kV cable (with one of the Oakland CT's off-line). The sub-area area limitation is thermal overloading of the C-X 115 kV cable. This limiting contingency establishes a Local Capacity Requirement of 100 MW (includes 50 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

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 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 Local Capacity Requirement of 100 MW 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. Units outside of this area are not effective.

San Jose Sub-area

The most critical contingency is the category C outage of Evergreen 1 – Markham – San Jose B 115 kV line and the Metcalf D – IBM HR – El Patio 115 kV line. The area limitation is thermal overloading of the Baily J3 – El Patio 115 kV line.This contingency prevents the Metcalf E 115 bus from feeding the San Jose B 115 kV load. Power must flow through the remaining Metcalf D – El Patio 115 kV circuit and then to the load at San Jose B 115 kV bus. This limiting contingency establishes a Local Capacity Requirement of 457 MW (including 265 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability for this outage.

Effectiveness factors:

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

Name	ID	Qualifying Capacity
Cogen	2	3
Cogen	1	3
DVR A ST	1	51
DVR B GT	1	48.4
DVR A GT	1	48.4
Gia100	1	21
LECEFGT4	1	48
LECEFGT3	1	48
LECEFGT2	1	48

LECEFGT1	1	48
IBM-CTLE	1	50
OLS-AGNE	1	29
SJ-SCL W	1	5.5
CCA100	1	35.9
CATALYST	1	2
Gia200	1	21
		510.2

Pittsburg Sub-area

The most critical contingency is an outage of the Pittsburg-Tesla #1 or #2 230 kV line (with Delta Energy Center off-line). The sub-area area limitation is thermal overloading of the parallel Pittsburg-Tesla 230 kV line. This limiting contingency establishes a Local Capacity Requirement of 2208 MW (including 678 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 within the Pittsburg pocket as well as units outside the pocket that are at least 5% effective to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	MW Eff Fctr
33840	FLOWD3-6	1	86
33840	FLOWD3-6	2	86
33840	FLOWD3-6	3	86
33840	FLOWD3-6	4	86
33171	TRSVQ+NW	2	26
33171	TRSVQ+NW	1	26
33105	PTSB 5	1	26
33106	PTSB 6	1	26
30000	PTSB 7	1	26
33110	DEC CTG3	1	25
33109	DEC CTG2	1	25
33108	DEC CTG1	1	25
33107	DEC STG1	1	25
33113	LMECST1	1	24
33112	LMECCT1	1	24
33111	LMECCT2	1	24
33132	GWF #2	1	24
33161	DOWCHEM1	1	24
33162	DOWCHEM2	1	24
33163	DOWCHEM3	1	24
33151	FOSTER W	1	23
33151	FOSTER W	2	23
33151	FOSTER W	3	23
33141	SHELL 1	1	21

33143	SHELL 3	1	21
33142	SHELL 2	1	21
32900	CRCKTCOG	1	19
32910	UNOCAL	1	19
32910	UNOCAL	2	19
32910	UNOCAL	3	19
32920	UNION CH	1	19
32922	ChevGen2	1	18
32921	ChevGen1	1	18
32740	HILLSIDE	1	18
33135	GWF #5	1	18
38119	ALMDACT2	1	16
32903	OAKLND 3	1	16
32902	OAKLND 2	1	16
32901	OAKLND 1	1	16
38118	ALMDACT1	1	16
31404	WEST FOR	2	14
31402	BEAR CAN	1	14
31402	BEAR CAN	2	14
31404	WEST FOR	1	14
31414	GEYSER12	1	14
31416	GEYSER13	1	14
31418	GEYSER14	1	14
31420	GEYSER16	1	14
31422	GEYSER17	1	14
31424	GEYSER18	1	14
31426	GEYSER20	1	14
38110	NCPA2GY1	1	14
38112	NCPA2GY2	1	14
31400	SANTA FE	2	13
31430	SMUDGEO1	1	13
31400	SANTA FE	1	13
38106	NCPA1GY1	1	13
38108	NCPA1GY2	1	13
31406	GEYSR5-6	1	10
31406	GEYSR5-6	2	10
31408	GEYSER78	1	10
31408	GEYSER78	2	10
31412	GEYSER11	1	10
31435	GEO.ENGY	1	10
31435	GEO.ENGY	2	10
30464	EXXON_BH	1	9
33252	POTRERO3	1	7
33271	HNTRS P1	1	7
33270	HNTRS P4	1	7
33253	POTRERO4	1	7
33254	POTRERO5	1	7
33255	POTRERO6	1	7

33466	UNTED CO	1	7
35312	SEAWESTF	1	7
35316	ZOND SYS	1	7
35320	USW FRIC	1	7
32176	SHILOH	1	5
36865	DVRPPSTA	1	5
36864	DVRPPCT2	1	5
36863	DVRPPCT1	1	5
32185	WOLFSKIL	1	5
33178	RVEC_GEN	1	5
32175	CREEDGT1	3	5
32174	GOOSEHGT	2	5
32173	LAMBGT1	1	5
32150	DG_VADIX	1	5
32172	HIGHWNDS	1	5
33134	GWF #4	1	5
33116	C.COS 6	1	5
33117	C.COS 7	1	5
32154	WADHAM	1	5
33133	GWF #3	1	5
33145	CROWN.Z.	1	5
33145	CROWN.Z.	2	5
33131	GWF #1	1	5
36856	CSC_CCA	1	5
33463	CARDINAL	1	5
33463	CARDINAL	2	5
32168	USWINDPW	1	5
32168	USWINDPW	2	5
33838	USWP_#3	1	5

Bay Area overall

The most critical contingency is the loss of the Vaca Dixon 500/230 kV transformer followed by loss of the Contra Costa unit 7 or vice versa. The area limitation is thermal overloading of the Tesla-Delta Switching Yard 230 kV line. This limiting contingency establishes a Local Capacity Requirement of ~~5079~~ 5341 MW (includes ~~1301~~ 1314 MW of Wind, QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this area.

The single most critical contingency is the loss of the Vaca Dixon 500/230 kV transformer. The area limitation is thermal overloading of the Tesla-Delta Switching Yard 230 kV line. This limiting contingency establishes a Local Capacity Requirement of ~~4678~~ 4771 MW (includes ~~1301~~ 1314 MW of Wind, QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

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

Bay Area Overall Requirements:

	Wind (MW)	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	78	988	248	5231	6545

	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[18]	4771	0	4771
Category C (Multiple)[19]	5341	0	5341

6. Greater Fresno Area

<u>Area Definition</u>

The transmission facilities coming into the Greater Fresno area are:

1) Gates-Henrietta Tap 1 230 kV
2) Gates-Henrietta Tap 2 230 kV
3) Gates #1 230/115 kV Transformer Bank
4) Los Banos #3 230/70 Transformer Bank
5) Los Banos #4 230/70 Transformer Bank
6) Panoche-Gates #1 230 kV
7) Panoche-Gates #2 230 kV
8) Panoche-Coburn 230 kV
9) Panoche-Moss Landing 230 kV
10) Panoche-Los Banos #1 230 kV
11) Panoche-Los Banos #2 230 kV
12) Panoche-Dos Amigos 230 kV
13) Warnerville-Wilson 230 kV
14) Wilson-Melones 230 kV
15) Corcoran – Alpaugh - Smyrna 115 kV
16) Coalinga #1-San Miguel 70 kV

The substations that delineate the Greater Fresno area are:

[18] 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.

[19] 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.

1) Los Banos 230 kV
2) Gates 230 kV
3) Panoche 230 kV
4) Wilson 230 kV
5) Alpaugh 115 kV
6) Coalinga 70 kV

Total busload within the defined area: 3051 MW with 103 MW of losses resulting in total load + losses of 3154 MW.

Total units and qualifying capacity available in this area:

No	Name	ID	Qualifying Capacity
34636	FRIANTDM	4	3.5
34636	FRIANTDM	3	8.7
34636	FRIANTDM	2	16.3
34608	AGRICO	2	7
34608	AGRICO	3	18.9
34608	AGRICO	4	26
34672	KRCDPCT2	1	56
34671	KRCDPCT1	1	56
34485	FRESNOWW	1	9
34142	WHD_PAN2	1	49
34553	WHD_GAT2	1	49
34179	MADERA_G	1	28.7
34433	GWF_HEP2	1	39.1
34431	GWF_HEP1	1	40
34541	GWF_GT2	1	45.1
34539	GWF_GT1	1	45.3
34186	DG_PAN1	1	49
34301	CHOWCOGN	1	52.5
34618	MCCALL1T	1	0
34621	MCCALL3T	1	0
34630	HERNDN1T	1	0
34632	HERNDN2T	1	0
38720	PINE FLT	1	75
38720	PINE FLT	2	75
38720	PINE FLT	3	75
34306	EXCHQUER	1	70.8
34658	WISHON	1	5
34658	WISHON	2	5
34658	WISHON	3	5
34658	WISHON	4	5
34344	KERCKHOF	1	8.5
34344	KERCKHOF	2	13
34344	KERCKHOF	3	12.8

34308	KERCKHOF	1	155
34600	HELMS 1	1	404
34602	HELMS 2	1	404
34604	HELMS 3	1	404
34610	HAAS	1	69.9
34610	HAAS	2	69.9
34624	BALCH 1	1	34
34612	BLCH 2-2	1	52.5
34614	BLCH 2-3	1	52.5
34616	KINGSRIV	1	52
34316	ONEILPMP	1	11
34320	MCSWAIN	1	3.9
34322	MERCEDFL	1	1.9
34658	WISHON	SJ	0.4
34631	SJ2GEN	1	3.2
34633	SJ3GEN	1	4.2
34332	JRWCOGEN	1	8.5
34334	BIO PWR	1	26.1
34640	ULTR.PWR	1	26.4
34642	KINGSBUR	1	35.3
34646	SANGERCO	1	42.9
34648	DINUBA E	1	13.5
34650	GWF-PWR.	1	25
34652	CHV.COAL	1	4.1
34652	CHV.COAL	2	14.8
34654	COLNGAGN	1	42.3
34342	INT.TURB	1	1.1
			2912

Critical Contingency Analysis Summary

Wilson Sub-area

The most critical contingency for the Wilson sub-area is the loss of the Wilson - Melones 230 kV line with one of the Helm units out of service, which would thermally overload the Wilson - Warnerville 230 kV line. This limiting contingency establishes a Local Capacity Requirement of ~~1679~~ 1381 MW (which includes 75 MW of muni generation and ~~132~~ 215 MW of QF 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 above-mentioned constraint. All units in Fresno not listed or units outside of this area have smaller effectiveness factors.

Gen Bus	Gen Name	Gen ID	MW Eff Fctr	~~Relative effectiveness~~
34332	JRWCOGEN	1	40	~~100~~

34322	MERCEDFL	1	33	~~82.5~~
34320	MCSWAIN	1	32	~~80~~
34306	EXCHQUER	1	31	~~77.5~~
34600	HELMS 1	1	31	~~77.5~~
34602	HELMS 2	1	31	~~77.5~~
34604	HELMS 3	1	31	~~77.5~~
34301	CHOWCOGN	1	29	~~72.5~~
34636	FRIANTDM	1	25	~~62.5~~
34485	FRESNOWW	1	24	~~60~~
34658	WISHON	1	24	~~60~~
34658	WISHON	2	24	~~60~~
34658	WISHON	3	24	~~60~~
34658	WISHON	4	24	~~60~~
34631	SJ2GEN	1	24	~~60~~
34633	SJ3GEN	1	23	~~57.5~~
34344	KERCKHOF	1	22	~~55~~
34344	KERCKHOF	2	22	~~55~~
34344	KERCKHOF	3	22	~~55~~
34308	KERCKHOF	1	22	~~55~~
34179	MADERA_G	1	20	~~50~~
34648	DINUBA E	1	19	~~47.5~~
34672	KRCDPCT2	1	18	~~45~~
34671	KRCDPCT1	1	18	~~45~~
34624	BALCH 1	1	18	~~45~~
34640	ULTR.PWR	1	18	~~45~~
34646	SANGERCO	1	18	~~45~~
38720	PINE FLT	1	17	~~42.5~~
38720	PINE FLT	2	17	~~42.5~~
38720	PINE FLT	3	17	~~42.5~~
34616	KINGSRIV	1	17	~~42.5~~
34642	KINGSBUR	1	17	~~42.5~~
34433	GWF_HEP2	1	14	~~35~~
34431	GWF_HEP1	1	14	~~35~~
34610	HAAS	1	14	~~35~~
34610	HAAS	2	14	~~35~~
34612	BLCH 2-2	1	14	~~35~~
34614	BLCH 2-3	1	14	~~35~~
34539	GWF_GT1	1	13	~~32.5~~
34334	BIO PWR	1	13	~~32.5~~
34541	GWF_GT2	1	12	~~30~~
34650	GWF-PWR.	1	12	~~30~~
34142	WHD_PAN2	1	11	~~27.5~~
34186	DG_PAN1	1	11	~~27.5~~
34608	AGRICO	2	10	~~25~~
34608	AGRICO	3	10	~~25~~
34608	AGRICO	4	10	~~25~~
34553	WHD_GAT2	1	8	~~20~~
34652	CHV.COAL	1	8	~~20~~

34652	CHV.COAL	2	8	~~20~~
34654	COLNGAGN	1	8	~~20~~
34342	INT.TURB	1	6	~~15~~
34316	ONEILPMP	1	6	~~15~~

Herndon Sub-area

The most critical contingency for the Herndon sub-area is the loss of the Herndon 230/115 kV bank 1 with Kerckhoff #2 unit out of service, which would thermally overload the parallel Herndon 230/115 kV bank 2. This limiting contingency establishes a Local Capacity Requirement of ~~1115~~ 1155 MW (which includes ~~67~~ 149 MW of QF generation) 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 230/115 kV bank 1, which would thermally overload the parallel Herndon 230/115 kV bank 2. This limiting contingency establishes a Local Capacity Requirement of ~~961~~ 1067 MW (which includes ~~67~~ 149 MW of QF 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 area that have at least 5% relative effectiveness to the above-mentioned constraint. All units in Fresno not listed or units outside of this area have smaller effectiveness factors.

Gen Bus	Gen Name	Gen ID	MW Eff Fctr	~~Rel Effectiveness~~
34308	KERCKHOF	1	36	~~100.00~~
34344	KERCKHOF	1	35	~~97.22~~
34344	KERCKHOF	2	35	~~97.22~~
34344	KERCKHOF	3	35	~~97.22~~
34624	BALCH 1	1	33	~~91.67~~
34646	SANGERCO	1	32	~~88.89~~
34672	KRCDPCT2	1	31	~~86.11~~
34671	KRCDPCT1	1	31	~~86.11~~
34616	KINGSRIV	1	31	~~86.11~~
34640	ULTR.PWR	1	31	~~86.11~~
34648	DINUBA E	1	29	~~80.56~~
34642	KINGSBUR	1	26	~~72.22~~
38720	PINE FLT	1	22	~~61.11~~
38720	PINE FLT	2	22	~~61.11~~
38720	PINE FLT	3	22	~~61.11~~
34612	BLCH 2-2	1	22	~~61.11~~
34610	HAAS	1	21	~~58.33~~
34610	HAAS	2	21	~~58.33~~
34614	BLCH 2-3	1	21	~~58.33~~
34433	GWF_HEP2	1	14	~~38.89~~
34431	GWF_HEP1	1	14	~~38.89~~

34301	CHOWCOGN	1	9	~~25.00~~
34608	AGRICO	2	7	~~19.44~~
34608	AGRICO	3	7	~~19.44~~
34608	AGRICO	4	7	~~19.44~~
34334	BIO PWR	1	3	~~8.33~~
34652	CHV.COAL	1	3	~~8.33~~
34652	CHV.COAL	2	3	~~8.33~~
34553	WHD_GAT2	1	2	~~5.56~~
34179	MADERA_G	1	2	~~5.56~~
34654	COLNGAGN	1	2	~~5.56~~
34332	JRWCOGEN	1	-5	~~-13.89~~
34485	FRESNOWW	1	-13	~~-36.11~~
34600	HELMS 1	1	-15	~~-41.67~~
34602	HELMS 2	1	-15	~~-41.67~~
34604	HELMS 3	1	-15	~~-41.67~~

McCall Sub-area

The most critical contingency for the McCall sub-area is the loss of Mc Call #3 230/115 kV transformer bank with GWF Hanford Peaker #1 unit out of service, which would thermally overload the McCall #2 230/115 kV transformer bank. This limiting contingency establishes a Local Capacity Requirement of ~~1,605~~1,432 MW (which includes ~~109~~ 192 MW of QF generation and ~~478~~ 108 MW of Muni generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency for the McCall sub-area is the loss of Mc Call #3 230/115 kV transformer bank, which would thermally overload the McCall #2 230/115 kV transformer bank. This limiting contingency establishes a Local Capacity Requirement of ~~1,561~~1,296 MW (which includes ~~109~~ 192 MW of QF generation and ~~478~~ 108 MW of Muni generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

See line 6 under attached link below.

Henrietta Sub-area

The most critical contingency for the Henrietta sub-area is the loss of new ~~Henrietta 230/70 kV transformer bank with GWF Hanford out of service, which would thermally overload the old Henrietta 230/70 kV transformer bank. Another limiting contingency is the loss of new~~ Henrietta 230/70 kV transformer bank with Henrietta-GWF Henrietta 70 kV line out of service, which would thermally overload the old Henrietta 230/70 kV transformer bank. This combined limit establishes a Local Capacity Requirement of ~~64~~ 117 MW (which includes ~~29~~ 25 MW of QF generation and ~~4~~ 2 MW of deficiency) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency for the Henrietta sub-area is the loss of new Henrietta 230/70 kV transformer bank, which would thermally overload the old Henrietta 230/70 kV transformer bank. This combined limit establishes a Local Capacity Requirement of ~~27~~ 34 MW (which includes ~~29~~ 25 MW of QF generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Merced Sub-area

The most critical contingencies for the Merced sub-area is the double line outage of the Wilson – Atwater 115 kV #1 and #2 lines, which would thermally overload the Wilson – Merced 115 kV #1 and #2 lines. This limiting contingency establishes a Local Capacity Requirement of 151 MW (which includes 75 MW of muni generation, 9 MW of QF generation and 66 MW of area 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.

No	Name	ID	Qualifying Capacity
34306	EXCHQUER	1	70.8
34320	MCSWAIN	1	3.9
34322	MERCEDFL	1	1.9
34332	JRWCOGEN	1	8.5

Because of the overlapping LCR MWs requirements among the sub-areas, the total aggregate LCR requirement for the Greater Fresno Area is ~~2797~~ 2602 MW (includes ~~478~~ 108 MW of muni generation, ~~137~~ 222 MW of QF generation and ~~4~~ 68 MW of deficiency).

Additional helpful effectiveness factors for Fresno area:

Please read procedure T-129Z effectiveness factors - Fresno Area at: http://www.caiso.com/docs/2005/07/13/2005071314483315210.pdf

Fresno Area Overall Requirements:

	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	~~185~~275	~~542~~300	~~2185~~2337	2912

	Existing Generation	Deficiency	Total MW

	Capacity Needed (MW)	(MW)	Requirement
Category B (Single)[20]	~~2760~~2530	0	~~2760~~2530
Category C (Multiple)[21]	~~2797~~2534	468	~~2797~~2602

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) Temblor – San Luis Obispo 115 kV line

These sub-stations form the boundary surrounding the Kern PP sub-area:

1) Midway 115 kV
2) Kern PP 115 kV
3) Wheeler Ridge 115 kV
4) Temblor 115 kV

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

1) Wheeler Ridge 115/60 kV Bank
2) Wheeler Ridge 230/60 kV Bank

These sub-stations form the boundary surrounding the Weedpatch sub-area:

1) Wheeler Ridge 60 kV

Total busload within the defined area: 1191 MW with 18 MW of losses resulting in total load + losses of 1209 MW.

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

No	Name	ID	Qualifying Capacity
35056	TX-LOSTH	1	9
35034	MIDSUN +	1	20

[20] 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.
[21] 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.

35037	UNIVRSTY	1	39.9
35038	CHLKCLF+	1	49.9
35006	KERN 1	1	0
35008	KERN 2	1	0
35024	DEXEL +	1	32.1
35026	KERNFRNT	1	52.7
35029	BADGERCK	1	48.9
35027	HISIERRA	1	52.7
35023	DOUBLE C	1	51.9
35028	OILDALE	1	40.1
35032	CHV-CYMR	1	22.7
34783	TEXCO_NM	1	12
34783	TEXCO_NM	2	9
35036	MT POSO	1	56.1
35035	ULTR PWR	1	36.4
35040	KERNRDGE	1	66
35040	KERNRDGE	2	14.2
35044	TX MIDST	1	39.8
35046	SEKR	1	34.2
35048	FRITOLAY	1	7.1
35050	SLR-TANN	1	17.4
35052	CHEV.USA	1	14.4
35058	PSE-LVOK	1	49
35060	PSEMCKIT	1	50.8
35062	DISCOVRY	1	44
35064	NAVY 35R	1	31.9
35064	NAVY 35R	2	32.5
35066	PSE-BEAR	1	51.3
	Total		986

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

No	Name	ID	Qualifying Capacity
35018	KERNCNYN	1	11.2
35020	RIOBRAVO	1	12.1
	Total		23.3

Critical Contingency Analysis Summary

Kern PP Sub-area

The most critical contingency for the Kern PP sub-area is the outage of the Kern PP #5 230/115 kV transformer bank and the Kern PP – Kern Front 115 kV line, which would thermally overload the parallel Kern PP 230/115 kV Bank 3 and Bank 3a. This limiting contingency establishes a Local Capacity Requirement of 749 MW (which includes 749 MW of QF generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency for the Kern PP sub-area is the loss of Kern PP #5 230/115 kV transformer bank, which would thermally overload the parallel Kern PP 230/115 kV Bank 3 and Bank 3a. This limiting contingency establishes a Local Capacity Requirement of 554 MW (which includes 554 MW of QF generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area are under long-term contracts. No additional procurement needs to be done; therefore no effectiveness factor is required.

Wheedpatch Sub-area

The most critical contingency is the loss of the Wheeler Ridge – San Bernard 70 kV line and the Wheeler Ridge – Tejon 70 kV line, which would thermally overload the Wheeler Ridge – Weedparch 70 kV line and cause low voltage problem at the local 70 kV transmission system. This limiting contingency establishes a Local Capacity Requirement of 36 MW (which includes 8 MW of QF generation and 17 MW of area deficiency) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Kern Area Overall Requirements:

	QF/Selfgen (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	978	31	1009

	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[22]	554	0	554
Category C (Multiple)[23]	769	17	786

~~This area is under review.~~

8. LA Basin Area

[22] 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.
[23] 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.

Area Definition

The transmission tie lines into the LA Basin Area are:

1) San Onofre - San Luis Rey #1, #2, & #3 230 kV Lines
2) San Onofre - Talega #1 & #2 230 kV Lines
3) Lugo - Mira Loma #1, #2 & #3 500 kV Lines
4) Sylmar LA - Sylmar S #1, #2 & #3 230/230 kV Transformers
5) Sylmar S - Pardee #1 & #2 230 kV Lines
6) Vincent - Mesa Cal #1 230 kV Line
7) Antelope - Mesa Cal #1 230 kV Line
8) Vincent - Rio Hondo #1 & #2 230 kV Lines
9) Eagle Rock - Pardee #1 230 kV Line
10) Devers - Valley #1 500 kV Line
11) Devers #1 & #2 500/230 kV Transformers
12) Devers - Coachelv # 1 230 kV Line
13) Mirage - Ramon # 1 230 kV Line
14) Julian Hinds-Eagle Mountain 230 kV

These sub-stations form the boundary surrounding the LA Basin area:

1) Devers 500 kV
2) Mirage 230 kV
3) Vincent 230 kV
4) San Onofre 230 kV
5) Sylmar 230 kV
6) Lugo 500 kV

Total busload within the defined area is 19055 MW with 173 MW of losses and 97 MW of pumps resulting in total load + losses of 19325 MW.

Total units and qualifying capacity available in the Eastern sub-area:

BUS-NO	NAME1	ID	Qualifying Capacity	Subarea
24052	MTNVIST3	3	319	Eastern LA Basin
24053	MTNVIST4	4	320	Eastern LA Basin
28190	WINTECX2	1	44	Eastern LA Basin
28191	WINTECX1	1	42	Eastern LA Basin
28180	WINTEC8	1	42	Eastern LA Basin
24921	MNTV-CT1	1	143.5	Eastern LA Basin
24922	MNTV-CT2	1	143.5	Eastern LA Basin
24923	MNTV-ST1	1	249	Eastern LA Basin
24924	MNTV-CT3	1	143.5	Eastern LA Basin
24925	MNTV-CT4	1	143.5	Eastern LA Basin
24926	MNTV-ST2	1	249	Eastern LA Basin
25632	TERAWND	1	1	Eastern LA Basin

25633	CAPWIND	1	1	Eastern LA Basin
25634	BUCKWND	1	1	Eastern LA Basin
25635	ALTWIND	1	2.9	Eastern LA Basin
25636	RENWIND	1	1	Eastern LA Basin
25637	TRANWND	1	2.9	Eastern LA Basin
25639	SEAWIND	1	3	Eastern LA Basin
25640	PANAERO	1	1.9	Eastern LA Basin
25645	VENWIND	1	1.9	Eastern LA Basin
25646	SANWIND	1	1	Eastern LA Basin
24826	INDIGO	1	17	Eastern LA Basin
24815	GARNET	1	1	Eastern LA Basin
28020	WINTEC6	1	1.9	Eastern LA Basin
28060	SEAWEST	1	1.9	Eastern LA Basin
28060	SEAWEST	2	1.9	Eastern LA Basin
28280	CABAZON	1	1.9	Eastern LA Basin
24030	DELGEN	1	33.1	Eastern LA Basin
24071	INLAND	1	19.7	Eastern LA Basin
24140	SIMPSON	1	34	Eastern LA Basin
24902	VSTA	1	0	Eastern LA Basin
24229	VALLEY-S	1	0	Eastern LA Basin
25991	VALYSVC2	1	0	Eastern LA Basin
25990	VALYSVC1	1	0	Eastern LA Basin
24902	VSTA	2	1.3	Eastern LA Basin
24214	SANBRDNO	2	0.5	Eastern LA Basin
24214	SANBRDNO	1	0.1	Eastern LA Basin
24055	ETIWANDA	2	34.7	Eastern LA Basin
24055	ETIWANDA	1	0.6	Eastern LA Basin
25422	ETI MWDG	1	23.7	Eastern LA Basin
28061	WHITEWTR	1	52.8	Eastern LA Basin
28260	ALTAMSA4	1	32	Eastern LA Basin
24160	VALLEYSC	1	4.2	Eastern LA Basin
24111	PADUA	2	5.8	Eastern LA Basin
24111	PADUA	1	0.5	Eastern LA Basin
24024	CHINO	1	9.9	Eastern LA Basin
25648	DVLCYN1G	1	50.7	Eastern LA Basin
25649	DVLCYN2G	2	50.7	Eastern LA Basin
25603	DVLCYN3G	1	67.7	Eastern LA Basin
25604	DVLCYN4G	2	67.7	Eastern LA Basin
	Total		2371.9	

Total units and qualifying capacity available in the Western sub-area:

BUS-NO	NAME1	ID	~~PMAX~~Qualifying Capacity	Subarea
24001	ALAMT1 G	1	174.6	Western LA Basin
24002	ALAMT2 G	2	175	Western LA Basin
24003	ALAMT3 G	3	332.2	Western LA Basin
24004	ALAMT4 G	4	335.7	Western LA Basin

24005	ALAMT5 G	5	485	Western LA Basin
24161	ALAMT6 G	6	495	Western LA Basin
24162	ALAMT7 G	7	0	Western LA Basin
25203	ANAHEIMG	1	46.6	Western LA Basin
24018	BRIGEN	1	35	Western LA Basin
24020	CARBOGEN	1	29	Western LA Basin
24047	ELSEG3 G	3	335	Western LA Basin
24048	ELSEG4 G	4	335	Western LA Basin
24066	HUNT1 G	1	225.8	Western LA Basin
24067	HUNT2 G	2	225.8	Western LA Basin
24167	HUNT3 G	3	225	Western LA Basin
24168	HUNT4 G	4	227.4	Western LA Basin
24120	PULPGEN	1	40	Western LA Basin
24121	REDON5 G	5	178.9	Western LA Basin
24122	REDON6 G	6	175	Western LA Basin
24123	REDON7 G	7	493.2	Western LA Basin
24124	REDON8 G	8	486.9	Western LA Basin
24133	SANTIAGO	1	17	Western LA Basin
24062	HARBOR G	0	88.6	Western LA Basin
25510	HARBORG4	LP	5.7	Western LA Basin
24062	HARBOR G	HP	5.7	Western LA Basin
24011	ARCO 1G	1	64.7	Western LA Basin
24012	ARCO 2G	2	64.7	Western LA Basin
24013	ARCO 3G	3	64.7	Western LA Basin
24014	ARCO 4G	4	64.7	Western LA Basin
24163	ARCO 5G	5	31.2	Western LA Basin
24164	ARCO 6G	6	31.2	Western LA Basin
24022	CHEVGEN1	1	0.8	Western LA Basin
24023	CHEVGEN2	2	0.8	Western LA Basin
24026	CIMGEN	1	26.1	Western LA Basin
24063	HILLGEN	1	37.3	Western LA Basin
24070	ICEGEN	1	46.2	Western LA Basin
24139	SERRFGEN	1	25.2	Western LA Basin
24203	CENTER S	1	25.2	Western LA Basin
24075	LAGUBELL	1	11.2	Western LA Basin
24073	LA FRESA	1	5.7	Western LA Basin
24094	MOBGEN	1	45	Western LA Basin
24064	HINSON	1	25.2	Western LA Basin
24027	COLDGEN	1	28	Western LA Basin
24060	GROWGEN	1	28	Western LA Basin
24169	HUNT5 G	5	0	Western LA Basin
24213	RIOHONDO	1	0.9	Western LA Basin
24209	MESA CAL	1	0.6	Western LA Basin
24208	LCIENEGA	1	2.3	Western LA Basin
24083	LITEHIPE	1	0.3	Western LA Basin
24028	DELAMO	1	0	Western LA Basin
24157	WALNUT	1	7.9	Western LA Basin

28005	PASADNA1	1	22.5	Western LA Basin
28006	PASADNA2	1	22.5	Western LA Basin
28007	BRODWYSC	1	65	Western LA Basin
24211	OLINDA	1	2.3	Western LA Basin
24197	ELLIS	1	7.1	Western LA Basin
24129	S.ONOFR2	2	1115	Western LA Basin
24130	S.ONOFR3	3	1105	Western LA Basin
	Total		8150.4	

Critical Contingency Analysis Summary

LA Basin overall:

The combined Local Area Requirement is 8843 MW of which ~~3355~~ 3510 MW includes the San Onofre Nuclear Power Plant, QF and Muni generation. The Western and Eastern sub-area contingencies require ~~5488~~8843[24] MW as the minimum amount of generating capacity necessary for reliable load serving capability within these sub-areas. ~~1700~~ 2042 MW of this capacity is needed in the Eastern sub-area, and the rest (~~3788~~ 6802 MW) is needed in the Western sub-area.

The two critical contingencies in the Eastern Sub-area are: (1) Loss of Devers – Valley 500 kV line, followed by the loss of two Lugo – Mira Loma 500 kV lines #2 and #3, and (2) Loss of one San Onofre Nuclear Generator, followed by the loss of two Lugo – Mira Loma 500 kV lines #2 and #3. The sub-area area limitation is low area post-transient voltage associated with voltage collapse.

Effectiveness factors:

The area limitation is low area post-transient voltage associated with voltage collapse. The units in the Eastern area or geographically close to it are the most effective units.

The critical contingency for the in the Western Sub-area is the loss of Lugo-Victorville 500 kV, followed by loss of Sylmar-Gould 230 kV line. The sub-area area limitation is thermal overloading of the Eagle Rock-Mesa 230 kV line.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	MW Eff Fctr
24209	MESA CAL	1	19

[24] This value is based on a potential higher South of Lugo (SOL) limit with RAS operation which needs to be determined by SCE. Based on the current 5600 MW SOL limit, the total LA Basin ~~market~~ generation requirement would increase by an additional 900 MW for a total of ~~6390~~ 9743 MW to respect loss of a SONG unit.

24011	ARCO 1G	1	18
24012	ARCO 2G	2	18
24013	ARCO 3G	3	18
24014	ARCO 4G	4	18
24164	ARCO 6G	6	18
24047	ELSEG3 G	3	18
24048	ELSEG4 G	4	18
24121	REDON5 G	5	18
24122	REDON6 G	6	18
24123	REDON7 G	7	18
24124	REDON8 G	8	18
24163	ARCO 5G	5	17
24020	CARBOGEN	1	17
24064	HINSON	1	17
24070	ICEGEN	1	17
24094	MOBGEN	1	17
24139	SERRFGEN	1	17
24062	HARBOR G	0	17
25510	HARBORG4	LP	17
24062	HARBOR G	HP	17
28005	PASADNA1	1	17
28006	PASADNA2	1	17
28007	BRODWYSC	1	17
24208	LCIENEGA	1	17
24083	LITEHIPE	1	17
24075	LAGUBELL	1	17
24073	LA FRESA	1	17
24028	DELAMO	1	17
24001	ALAMT1 G	1	16
24002	ALAMT2 G	2	16
24003	ALAMT3 G	3	16
24004	ALAMT4 G	4	16
24005	ALAMT5 G	5	16
24161	ALAMT6 G	6	16
24018	BRIGEN	1	16
24027	COLDGEN	1	16
24060	GROWGEN	1	16
24063	HILLGEN	1	16
24120	PULPGEN	1	16
24213	RIOHONDO	1	16
24203	CENTER S	1	16
24157	WALNUT	1	16
24167	HUNT3 G	3	15
24066	HUNT1 G	1	14
24067	HUNT2 G	2	14
24168	HUNT4 G	4	14
24133	SANTIAGO	1	14

24197	ELLIS	1	14
25203	ANAHEIMG	1	13
24026	CIMGEN	1	13
24030	DELGEN	1	13
24071	INLAND	1	13
24140	SIMPSON	1	13
25422	ETI MWDG	1	13
24902	VSTA	2	13
24111	PADUA	2	13
24111	PADUA	1	13
24024	CHINO	1	13
25648	DVLCYN1G	1	12
25649	DVLCYN2G	2	12
25603	DVLCYN3G	3	12
25604	DVLCYN4G	4	12
24052	MTNVIST3	3	12
24053	MTNVIST4	4	12
24129	S.ONOFR2	2	12
24130	S.ONOFR3	3	12
24921	MNTV-CT1	1	12
24922	MNTV-CT2	1	12
24923	MNTV-ST1	1	12
24924	MNTV-CT3	1	12
24925	MNTV-CT4	1	12
24926	MNTV-ST2	1	12
24214	SANBRDNO	2	12
24214	SANBRDNO	1	12
24055	ETIWANDA	2	12
24055	ETIWANDA	1	12
25632	TERAWND	1	11
25633	CAPWIND	1	11
25634	BUCKWND	1	11
25635	ALTWIND	1	11
25636	RENWIND	1	11
25637	TRANWND	1	11
25639	SEAWIND	1	11
25640	PANAERO	1	11
25645	VENWIND	1	11
25646	SANWIND	1	11
24826	INDIGO	1	11
28190	WINTECX2	1	11
28191	WINTECX1	1	11
28180	WINTEC8	1	11
24815	GARNET	1	11
24828	WINTEC9	1	11
28020	WINTEC6	1	11
28060	SEAWEST	1	11

28060	SEAWEST	2	11
28061	WHITEWTR	1	11
28260	ALTAMSA4	1	11
28280	CABAZON	1	11

LA Basin Overall Requirements:

	QF/Wind (MW)	Muni (MW)	Nuclear (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	829	~~376~~461	2220	~~7033~~7012	~~10458~~ 10522

	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[25]	8843	0	8843
Category C (Multiple)[26]	8843	0	8843

9. 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) Miguel – 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

These sub-stations form the boundary surrounding the San Diego area:

1) Miguel 230 kV
2) San Luis Rey 230 kV
3) Talega 230 kV

Total busload within the defined area: 4637 MW with 105 MW of losses resulting in total load + losses of 4742 MW.

Total units and qualifying capacity available in this area:

[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.

No	Name	ID	Qualifying Capacity
22088	BOULEVRD	1	0.5
22092	CABRILLO	1	3.6
22172	DIVISION	1	46.9
22212	ELCAJNGT	1	15
22233	ENCINA 1	1	103.5
22234	ENCINA 2	1	104
22236	ENCINA 3	1	110
22240	ENCINA 4	1	300
22244	ENCINA 5	1	330
22248	ENCINAGT	1	15
22332	GOALLINE	1	50
22376	KEARN3CD	1	15.3
22384	KYOCERA	1	0.1
22480	MIRAMAR	1	2.7
22488	MIRAMRGT	1	18
22532	MURRAY	1	0.5
22576	NOISLMTR	1	35.3
22660	POINTLMA	1	21.8
22680	R.SNTAFE	1	0.5
22688	RINCON	1	0.5
22704	SAMPSON	1	13.6
22724	SANMRCOS	1	1.1
22776	SOUTHBGT	1	13
22780	SOUTHBY1	1	145
22784	SOUTHBY2	1	149
22788	SOUTHBY3	1	174
22792	SOUTHBY4	1	221
22820	SWEETWTR	1	0.5
22120	CARLTNHS	1	1.1
22149	CALPK_BD	1	42
22153	CALPK_ES	1	45.5
22150	CALPK_EC	1	42
22604	OTAY	1	3
22373	KEARN2AB	1	14.8
22373	KEARN2AB	2	14.8
22374	KEARN2CD	1	14.8
22374	KEARN2CD	2	14.8
22375	KEARN3AB	1	15.3
22375	KEARN3AB	2	15.3
22376	KEARN3CD	2	15.3
22377	KEARNGT1	1	16
22488	MIRAMRGT	2	18
22074	LRKSPBD1	1	46
22075	LRKSPBD2	1	46
22257	RAMCO_ES	1	40

22617	RAMCO_OY	1	42
22834	TALEGA	SC	0
22486	RAMCO_MR	1	45
22262	PEN_CT1	1	177
22263	PEN_CT2	1	177
22265	PEN_ST	1	187
22904	CAMPOGEN	1	10
22904	CAMPOGEN	2	0
			~~2933~~2932

Critical Contingency Analysis Summary

San Diego overall:

The most limiting contingency in the San Diego area is described by the outage of 500 kV Southwest Power Link (SWPL) between Imperial Valley and Miguel Substations over-lapping with an outage of the Palomar Combined-Cycle Power plant (541 MW) while staying within the South of San Onofre (WECC Path 44) non-simultaneous import capability rating of 2,500 MW. Therefore the 2,781 MW (includes 181 MW of QF generation and 10 MW of wind) of capacity required within this area is predicated on having sufficient generation in the San Diego Area to reduce Path 44 to its non-simultaneous rating of 2500 MW within 30 minutes.

Effectiveness factors:

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

San Diego Overall Requirements:

	QF (MW)	Wind (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	181	10	2741	~~2933~~2932

	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[27]	2781	0	2781
Category C (Multiple)[28]	2781	0	2781

[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.

C. Zonal Capacity Requirements

The ISO performed an assessment of the Zonal Capacity needs for year 2007 based on the methodology presented in chapter III section B. These results refer to the ISO control area only, they do not include requirements for other control areas like: LADWP, IID, SMUD-WAPA, TID or MID.

Zone	Load Forecast (MW)	Generator Outages (MW)	Single Worst Contingency (MW)	(-)Import Capability (MW)	Total Requirement (MW)
SP26	28,778	1,500	2,000	10,100	**22,178**
NP26=NP15+ZP26	21,518	2,500	1,160	5,348	**19,830**
NP15	Path 15 is not a binding constraint at this time				

Units need in order to comply with the Local Area Capacity Requirements fully count toward the Zonal Requirements. San Diego and LA Basin are situated in SP26, Kern in ZP26 and the rest in NP15.

V. Future Annual Technical Analyses

For future local area capacity requirements studies, the CPUC should consider the use of the Loss of Load Probability (LOLP) methodology, used by many eastern regions. LOLP is a study methodology that can be used to establish the level of capacity required in each local area by performing a probabilistic analysis to achieve a specified probability for loss of load. Underlying this approach is an expected level of service reliability. In the established Eastern markets, a one-event in ten years LOLP methodology is used to determine LSE capacity obligations. The LOLP approach provides a potentially more uniform reliability result than the proposed deterministic approach. In the future, if the LOLP approach is determined to be a more desirable approach, then the LOLP analysis will be incorporated into the criteria if and when a criteria and methodology for applying it has been developed. Any LOLP criteria and methodology will need to be reviewed by stakeholders and approved by the CPUC. Until such time, the LOLP approach will not be used to establish LSE capacity requirements, and the deterministic approach defined above will be used.

CERTIFICATE OF SERVICE

I hereby certify that I have served, by electronic and United States mail, a Corrected 2007 Locational Capacity Technical Analysis and Errata of the California Independent System Operator Corporation in Docket No. R.05-12-013.

Executed on April 28, 2006, at Folsom, California.

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