R.12-03-014

Table of Contents - Reply Testimony and Exhibits

Rulemaking	12-03-014
Exhibit No.:	ISO-03
Witness:	Robert Sparks

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 12-03-014

REPLY TESTIMONY OF ROBERT SPARKS
ON BEHALF OF THE CALIFORNIA INDEPENDENT
SYSTEM OPERATOR CORPORATION

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 12-03-014

REPLY TESTIMONY OF ROBERT SPARKS
ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Q. What is your name and by whom are you employed?

A. My name is Robert Sparks. I am employed by the California Independent System Operator Corporation (ISO), 250 Outcropping Way, Folsom, California as Manager, Regional Transmission.

Q. Have you previously submitted testimony in this proceeding?

A. Yes, I have. On May 23, 2012, I submitted initial testimony addressing the need for local area generating resources in the LA Basin and Big Creek/Ventura areas and on June 19, 2012 I submitted supplemental testimony describing modifications to an OTC sensitivity study for these areas that I discussed at the May 3, 2012 workshop. The changes to the sensitivity study and the study results were provided publicly in an addendum to the 2011/2012 transmission plan that was posted to the ISO website on June 12, 2012.

Q. What is the purpose of your reply testimony?

A. I will respond to specific technical issues raised by DRA, CEJA and TURN regarding the ISO's OTC study methodology and local capacity deficiency recommendations. Mr. Millar will address broader policy issues raised in the initial testimony, including those portions of my supplemental testimony regarding the ISO's incremental demand response, uncommitted energy efficiency, distributed generation, uncommitted combined heat and power and energy storage study assumptions.

Q. **DRA witness Fagan, at pages 7-9 of his testimony, discusses the ISO's power flow analysis and concludes that it would be reasonable to consider the use of a "simpler" loads and resource table to determine local area needs. Do you agree?**

A. Absolutely not. Mr. Fagan's unfounded conclusion, in response to question 7- that power flow simulations tools are too "imprecise" for use over a 10 year planning horizon- completely fly in the face of the NERC planning standards (See ISO Ex. 13). These planning standards require Transmission Planners (public utility transmission owners) and Planning Coordinators (the ISO) to conduct 10 year planning studies testing the reliability of the grid under stressed conditions. This contingency testing requires the use of power flow studies and cannot be done using a simple spreadsheet tool. Furthermore, it is impossible to analyze a transmission option using a resource balance approach. It certainly makes no sense to use one tool to analyze transmission options and a different tool to analyze non-transmission to solve the same problem. Given that the effectiveness of generation in some areas were shown to range from 32% to 7%, large errors are introduced by the spreadsheet assumption that all resources are electrically equivalent in a given LCR area. In other words a spreadsheet analysis is grossly inaccurate in many LCR areas and should not be used to make procurement decisions in this proceeding.

Q. **On page 23 of his testimony, Mr. Fagan concludes that there is no need for procurement authorization at this time because the ISO's local capacity need assessment is based on "number of 'worst case' assumptions. Is this a valid conclusion?**

A. No, not at all. As both Mr. Millar and I have explained, the OTC study was conducted using a study methodology consistent with NERC planning standards requiring the use of contingency analyses. However, the OTC study does contain one very optimistic assumption: that the SONGS nuclear unit is online. The lack of certainty regarding the availability of that generation resource heightens the ISO's concerns with Mr. Fagan's "wait and see" recommendation. Delaying procurement decisions reduces the options that are available, and if we find out that some of the shorter lead time options are not effective, then we put ourselves into an emergency shortage situation.

Q. Mr. Fagan testifies, on page 3 of his testimony, that his load and resource deficiency analysis produces a surplus for both the overall LA Basin local area and the Big Creek/Ventura local areas based on information from CAISO's OTC studies, and recent demand-side assumptions for the SCE portion of these local areas. Have you reviewed Mr. Fagan's analysis?

A. Yes, I have. It is my understanding that the conclusions on page 3 describe the "Range of Resource Deficiency/Surplus" Table RF-2 on pages 18 and 19 of the testimony.

Q. Do you have concerns with Table RF-2?

A. Yes. In addition to the assumptions about demand response, uncommitted EE and CHP that are addressed by Mr. Millar, I note that Sentinel CPV unit (included in row K) has an effectiveness factor of less than 5% which is considered a very negligible contribution to local area needs. In addition, the amount of existing supply set forth on row I includes many other units that are not effective and are not equivalent to the generation being retired. As I discussed in response to a previous question, a spreadsheet analysis does not reflect the effectiveness of existing generation and generic capacity that could address local capacity needs, and therefore makes a spreadsheet tool unreliable for determining LCR needs.

Q. CEJA witness May, at page 34 of her testimony, refers to potential transmission mitigation solutions for bottleneck areas, in particular a possible load transfer arrangement that would address the Chino-Mira Loma East # 500 kV line and Mira Loma West 500/230 kV bank #2 contingency. She then describes the ISO's response to CEJA data request No. 9 as identifying another possible transmission "fix." Did Ms. May correctly understand the ISO's response to data request No. 9?

A. No, it appears that CEJA misunderstood our response. The ISO is continuing to discuss with SCE the potential distribution system upgrades at Rancho Vista substation that would allow the approximately 600 MW load transfer from Mira Loma substation. However, the ISO response to CEJA data request No. 9 is a reference to this same distribution system upgrade. The potential 600 MW load transfer could reduce the overall LA Basin need by 2000-3000 MW, but there is no additional 2000-3000 "fix" as Ms. May suggests at that section of her testimony.

Q. Ms. May recommends, at Section I. of her testimony (pages 32-35), that the ISO should conduct a "comprehensive assessment" to determine whether there are more transmission options that could, in combination with other assumption changes such as EE, DR, DG etc. reduce the need for local generation resources. Do you believe that additional studies should be conducted before the Commission makes a decision in Track I regarding the need for procurement to meet local capacity needs?

A. No, I do not. The ISO conducts a comprehensive analysis of the grid, including the local areas, each year in the transmission planning process. As Ms. May correctly states on page 34: "Based on the fixes that CAISO has identified, which were shown by CAISO to reduce need by thousands of MW, and in some cases to eliminate need in sub-areas…" In addition, over the last 14 years the ISO has worked with the Participating TOs to identify transmission upgrades that would reduce the need for local generation capacity. Numerous reconductorings, transformer additions, and thousands of MVAR of reactive support have been added to the transmission system for the sole purpose of minimizing the reliance on local generation capacity for local reliability. Out of the existing 5000 MW of existing OTC generation capacity in the LA Basin, the ISO has identified the need for as little as 2370 MW, representing less than half. At one time, all of this 5000 MW of generation was required for local capacity, and yet the ISO has determined that after 10 years of load growth, we can still eliminate the need for over half of it. Additional studies would not produce any significant changes in the need for local generation capacity.

Q. TURN witness Kevin Woodruff, at pages 7-9 of his testimony, describes the ISO's LCR studies as a "moving target" and suggests that the potential for actual local deficiency needs to vary from the forecast is "quite significant (page 8)." How does Mr. Woodruff come to this conclusion?

A. Mr. Woodruff bases his conclusion on the differences between the OTC deficiency range for the LA Basin LCR and the deficiency for that area in the 2013-2015 Local Capacity Technical Study, portions of which he attached to his testimony. He notes that on page 73 of that study, the ISO predicted that in the 2015 timeframe, the Western LA Basin sub-area would become the most stringent and binding local constraint, and that the LA Basin could be eliminated and the Western LA Basin become the new local area. As a result, the resource needs for the LA Basin in 2015 dropped to 5988 MW from 11,304 MW in 2013. Based on this phenomenon, Mr. Woodruff states that authorization of new capacity to meet LCRs is a "financially risky proposition for customers."

Q. Do you agree with Mr. Woodruff's observations with respect to substantial deviations in LCR results?

A. No, not all. It appears that Mr. Woodruff has overlooked an important piece of information from the 2013-2015 LCR study. The entire study has been submitted as ISO Ex. 14. On page 76, the ISO provides the reason that the Western LA Basin was predicted to be the most binding constraint in 2015:

> The study has run out of generation in the 'other SCE/SDG&E areas' without being able to reach a limit in the LA Basin local area. It is estimated that about 10,800 MW of the LA Basin capacity is needed to serve load and reserves in the southern system will reach its zonal limits before reaching the local area limits. Further detailed analysis will be done at a later date [as] part of the CAISO grid expansion process.

In the OTC study, the ISO included a substantial amount of renewable generation so the amount of resources outside the LA Basin was much higher than in the 2015 LCR study, thus replacing the generation that the "other SCE/SDG&E areas" had run out of. In the OTC study 10,743 MW of LCR was identified as needed in the trajectory portfolio case, which is similar to the 10,800 MW number described in the 2015 LCR study. Although LCR needs can vary from year to year, the results are not nearly as dramatic as Mr. Woodruff suggests. In addition, past variations between yearly LCR amounts have been due to ISO and Participating TO efforts to identify all opportunities to build incremental transmission constraints and reduce the need for local generation. However, these opportunities have been exhausted, as I discussed above, and changes to LCR forecasts going forward are expected to be more predictable.

Q. At pages 10-13 of his testimony, Mr. Woodruff argues that the ISO appears to be adopting more stringent LCR standards than those previously approved by the Commission in the annual resource adequacy proceedings. Can you

respond to Mr. Woodruff's concerns with the performance criteria underlying the resource deficiencies identified in the ISO's OTC study?

A. Yes. In his testimony, Mr. Woodruff points to the limiting contingencies identified for the Ellis and Moorpark areas and data request responses provided by the ISO wherein these contingencies are identified as Category D. It is true that for both of these sub-areas, the limiting contingency is a category B contingency followed by a common mode outage of two transmission lines that resulted in voltage collapse or dynamic instability. The contingencies were identified in my initial testimony in Tables 2-5 and 7-10 as well as the 2013 Local Capacity Technical Analysis described in Mr. Woodruff's testimony.

In contrast to thermal overloads, which allow time for operators to respond to the impact on the grid, voltage collapse is instantaneous and widespread. Under the NERC reliability and planning standards, following an N-1 contingency, the ISO must take steps to ensure that the system can withstand a Category C common mode outage that would otherwise lead to voltage collapse. In the identified subareas, if generation redispatch were not an available option, then the ISO would need to interrupt electric supply to customers following a single contingency. Although this particular overlapping contingency is classified as Category D, it is a resource planning requirement that has been included in the LCR criteria approved by the Commission in D.06-06-064 and in every other approved LCR study since that time. Specifically, the system planning criteria can be found at page 17 of the 2013 Local Capacity Technical Analysis in Attachment 5 to Mr. Woodruff's testimony.[1] In the bottom row, footnote 3 clarifies that for local capacity studies, this particular type of Category D contingency must be evaluated for risks and consequences, and in the case of voltage collapse or dynamic instability, a local requirement must be created.

[1] The LCR planning criteria in this table is also in the ISO's tariff at Section 40.3.1.1.

The N-1/N-2 limiting contingencies for the El Nido and Moorpark sub-areas were first identified in the 2011 Local Capacity Technical Analysis, and then again in 2012 and 2013 (see ISO Ex. 15 at page 78 and ISO Ex. 16 at page 88). The LCR studies are vetted with stakeholders in a process outside the ISO's transmission planning process and then approved by the Commission each year for use in the annual resource adequacy proceeding.

Since these contingencies have been used by the ISO to establish LCR requirements for the El Nido and Moorpark areas in the past three studies, using planning criteria reviewed by the Commission in Docket 05-12-013, I disagree with Mr. Woodruff's conclusion that the ISO has "deviated from Commission policy" by establishing local capacity needs for these sub-areas.

Q. **Does this conclude your reply testimony?**

A. Yes, it does.

Rulemaking	12-03-014
Exhibit No.:	ISO - 05
Witness:	Mark Rothleder

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 12-03-014

REPLY TESTIMONY OF MARK ROTHLEDER
ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 12-03-014

REPLY TESTIMONY OF MARK ROTHLEDER ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Q. What is your name and by whom are you employed?

A. My name is Mark Rothleder. I am employed by the California Independent System Operator Corporation (ISO), 250 Outcropping Way, Folsom, California as Executive Director Market Analysis and Development.

Q. Have you previously submitted testimony in this proceeding?

A. Yes, I have. On May 23, 2012, I submitted initial testimony discussing the need for flexible generation in the LA Basin and Big Creek/Ventura areas. I also provided updated information about the renewable integration studies at a workshop held on June 4, 2012.

Q. What is the purpose of your reply testimony?

A. I will respond to concerns raised by CEERT and TURN regarding my recommendations that generation procured in the local areas should have flexibility characteristics.

Q. At page 19 of his testimony, TURN witness Woodruff argues that the high load scenario, which he calls the 4600 study, from the renewable integration study should not be used to make procurement decisions based on renewable integration needs in Track 1. Does the ISO expect the Commission to make a finding of need for system flexible resources for 2020 at this time based on these study results?

A. No, and that was not the point of my testimony. For the purpose of this Track 1 proceeding, I am providing support for making a local capacity decision, and evidence that if the local resources that are procured have the flexibility characteristics needed to integrate renewable resources, the quantity of potential need for system capacity is reduced. As the testimony indicates, the ISO is continuing its study work and believes the ultimate system decision can be taken up in 2013 after being informed by the Commission's decision on local capacity needs at the end of this year.

Q. Mr. Woodruff also states that the ISO's references to the 4600 study, both in your testimony and in other venues, is not consistent with the settlement agreement in R.10-05-006 and constitutes bad faith. What is your response to these statements?

A. The settlement agreement in that proceeding quite clearly states that there were some scenarios showing no need but that an additional scenario studied by the ISO did show a need for additional resources. As Mr. Woodruff and the other parties know, this additional case is the high load scenario (the 4600 study) which the ISO views as an operationally relevant case indicating the potential for needs and identifying potential shortages. As I discuss below, this higher load case was identified in the Scoping Memo in the R. 10-05-006 LTPP case and is compliant with the 33% RPS goals. In the settlement the ISO also agreed that further study of local resource needs and alternatives was needed. My testimony, and ISO comments in other venues based on the results of this operationally relevant scenario, are consistent with these statements in the settlement agreement.

Q. CEERT witness Caldwell, at pages 2-3 of his testimony, takes issue with your statements about the potential need for 1200 MW of incremental system generation, arguing that the ISO's use of the high load scenario reflects the ISO's "hunch" that the 33% RPS goals will not be met. What is your response to these assertions?

A. Mr. Caldwell's conclusion in this regard is inaccurate. The high load scenario (referred to by Mr. Woodruff as the "4600 study") uses a 10% higher load assumption than the trajectory scenario and was developed to reflect a scenario that Commission requested in R.10-05-006 at Section 3.1.2.3.3 of the December 3, 2010, Scoping Memo.[1] The assumptions in that Memo stated that a high load sensitivity study shall be performed to account for future uncertainties.

The ISO agreed with the Commission that it is operationally prudent to consider such uncertainties. Importantly, the high load scenario is still a 33% RPS compliant scenario. In fact 1,497 MW of additional renewable capacity was added to maintain compliance with the 33% RPS goals.

Q. At page 5 of his testimony, Mr. Caldwell argues that the need for flexible resources in the local areas is not supported by the study you described in your testimony because the new local resources modeled in the study were running

[1] Specifically, Section 3.1.2.3.3 provides:

> In the sensitivity analysis for demand levels for both gigawatt hour (GWh) and MW, the IOUs shall use high and low demand levels that reflect a 10% variance from the demand forecast value for each year. This value is reflective of any combination of future uncertainties (e.g., increased or decreased load growth or programmatic performance).

at baseload or near baseload capacity. Do your studies show that only baseload resources are needed in local areas?

A. No. While the study results I discussed in my initial testimony and at the workshop did show the local resources with high capacity factors, the resources provided flexibility in that they were dispatched up and down to meet the net load. Furthermore the CCGT resources modeled in the local areas did provide reserves, including load following.

The ISO also realized that outages were not being modeled on the local CCGT. As a result the resources reflected higher capacity factors. Therefore, as part of the ISO's work with the Air Resources Board (ARB), the ISO updated the studies to reflect the forced and maintenance outages. These updated results, in which these outages have been modeled, are contained in ISO Ex. 21, which is a draft report provided for use by ARB in their AB 1318 planning and report. The conclusion from these new results indicates the LCR resources assumed in the study are not just baseloaded. The CCGT resource capacity factors range from 57% - 66%.   The results also indicate that the local CCGT do provide significant amount of load following and spin reserves.   A base load resource would not dispatch to follow load or provide such reserves.

Regarding the need for flexible local resources, while energy from inflexible resources may be able to unload other flexible resources, further study is needed to determine to what degree this trade (inflexible for flexible) can occur or is economic.   Furthermore, Mr. Sparks' testimony indicates that local resources may need to be flexible for local reliability reasons in addition to system needs.   Finally, making the local resources flexible may provide additional options when it comes to other non-OTC retirements that may arise over time.

Q. Does this conclude your reply testimony?

A. Yes, it does.

Rulemaking	12-03-014
Exhibit No.:	ISO - 06
Witness:	Neil Millar

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 12-03-014

REPLY TESTIMONY OF NEIL MILLAR
ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 12-03-014

REPLY TESTIMONY OF NEIL MILLAR ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Q. What is your name and by whom are you employed?

A. My name is Neil Millar. I am employed by the California Independent System Operator Corporation (ISO), 250 Outcropping Way, Folsom, California as the Executive Director, Infrastructure Development.

Q. Please briefly describe your employment and educational background.

A. I received a Bachelor of Science in Electrical Engineering degree at the University of Saskatchewan, Canada, and am a registered professional engineer in the province of Alberta.

I have been employed for over 28 years in the electricity industry, primarily with a major Canadian investor-owned utility, TransAlta Utilities, and with the Alberta Electric System Operator and its predecessor organizations. Within those organizations, I have held management and executive roles responsible for preparing, overseeing and providing testimony for numerous transmission planning and regulatory tariff applications. I have appeared before the Alberta Energy and Utilities Board, the Alberta Utilities Commission, and the British Columbia Utilities Commission. Since November, 2010, I have been employed at the ISO, leading the Transmission Planning and Grid Asset departments.

Q. What is the purpose of your reply testimony?

A. I will address the fundamental issue of whether the ISO's planning assumptions are overly conservative, and whether it is reasonable for the Commission to use the OTC study results as a basis for authorizing procurement in the LA Basin and Big Creek/Ventura areas. Specifically, my testimony will provide details about the appropriateness of the ISO's study methodology for determining local capacity requirements (LCR) and the load forecast and levels of demand response, energy efficiency, combined heat and power and energy storage modeled in the ISO's once through cooling (OTC) study. Mr. Sparks provided some information about these assumptions in his supplemental testimony, submitted in this docket on June 19, 2012. I am adopting that portion of his supplemental testimony, pages 4-7, as part of this reply testimony. Finally, I will respond to criticism that the ISO is not supporting state renewable energy policy goals.

Transmission Planning for Local Area Needs

Q. Several parties to this proceeding, including CEJA witness May and DRA witness Fagan, have questioned the fundamental principles of the ISO's local capacity study methodology, the use of power flow tools for analyzing local needs and the planning standards and assumptions used by the ISO. Can you address these arguments and concerns?

A. Yes, I can. The following sections of my testimony will describe the basic elements of local capacity studies and the studies the ISO conducts for the purposes of its annual transmission planning process. I will also describe the differences between these studies and the studies being conducted by Mr. Rothleder for system procurement purposes.

Q. Please describe how the ISO conducts a local capacity technical study.

A. As Mr. Sparks set out in his testimony, local capacity technical studies are reliability assessments conducted to identify areas within the ISO controlled grid that have local reliability needs and to determine the minimum generation capacity that would be required to satisfy these local reliability requirements.

Further, they are conducted applying a detailed methodology set out in the ISO's tariff and Business Practice Manual for Reliability Requirements. Each year, before the commencement of the study work, a detailed Local Capacity Requirements Manual is prepared to address the specifics of the study year being examined. (see ISO Ex. 18)

The study itself consists of modeling the power system and simulating contingencies in both steady-state powerflow and dynamic stability analysis to identify areas within the ISO controlled grid that have local reliability needs and to determine the minimum generation capacity that would be required to satisfy these local reliability requirements. A copy of the 2013 Local Capacity Technical Study has been provided as ISO Ex. 14, and is discussed in Mr. Sparks' reply testimony in more detail.

The contingencies and required system performance levels that are applied are based on the NERC transmission planning reliability criteria, as augmented by WECC regional standards and California-specific standards. These mandatory standards are deterministic. Assumptions are made regarding load levels and system conditions prior to a disturbance and then specific disturbances are simulated to test modeled performance against performance requirement scales. In general, a broader range of system impacts are permissible for more extreme, and less likely, types of contingencies.

The deterministic test is exactly that – a test. It is not an assessment of every possible operating condition and the anticipated system response to each possible operating condition. This is an important distinction, as the probabilistic methodologies that are more common in system-wide resource adequacy analysis, but the two types of analyses have fundamental differences for which the lines must not be blurred.

Q. What is the difference between a deterministic study and a probabilistic analysis?

A. A deterministic transmission planning study, used by the ISO for the OTC/LCR studies and all of its transmission planning studies, makes a number of idealized assumptions, and then tests the system performance following simulated contingencies, whether in the steady-state power flow analysis or dynamic stability analysis. The required performance for each level of contingency is established through years of industry-wide experience and stakeholder input, resulting in a testing methodology that has been adopted by NERC and FERC and provides consistent and acceptable system performance across the United States, Canada, and the interconnected portions of Mexico. Those performance levels differ for different broad categories of contingencies, recognizing the significantly different likelihood of occurrence for those categories of contingencies.

Probabilistic analysis, in contrast, sums the probabilities of a number of events, each with its own probability of occurring, occurring at a particular time or in combination and assesses the anticipated impacts of all of the potential events. System-wide resource adequacy analysis lends itself to this type of approach. Individual generators each have their unique performance characteristics, including the probability of forced outages, and the combined effect of the individual performance characteristics can be considered on a probabilistic basis.

Studying a transmission system on a probabilistic basis has not replaced deterministic assessments for a number of reasons. These include the complexity of needing to consider the individual performance of a significantly larger number of transmission and generation components, considering the interaction on the transmission system between those components, and also the wide range of operating conditions that could exist at any point in time. Also, and to some extent because of these complexities, there is no meaningful industry standard to compare forecast performance against, unlike the deterministic criteria adopted by NERC and WECC. Probabilistic techniques are emerging that can be applied to transmission system planning working in conjunction with deterministic analysis. To this point, these techniques have been utilized more frequently to assist in the selection of the optional alternative to address a reliability issue, or to consider the merits of transmission reinforcement to address economic or policy-related issues. However, haphazardly or selectively applying probabilities of a particular event occurring in the midst of a deterministic analysis is not a probabilistic analysis – it is neither. Arbitrary adjustments to exclude certain contingencies from analysis as suggested in the referenced testimony simply result in weakening and undermining the test being applied in the deterministic analysis.

Applying probabilities selectively to weaken the deterministic test would be analogous to a medical student seeking to have his or her grades improved, by pointing out that the likelihood of being confronted with a particular disease or condition that was the subject of a test question is quite low, and therefore should be removed from the grading. It defeats the entire purpose of testing the integrity of the transmission system through a deterministic analysis, yet fails to provide the comprehensive view of risk under a wide range of operating conditions that probabilistic analysis would provide.

Q. Has the Commission addressed the ISO's LCR study methodology?

A. Yes. The Commission made determinations in D.06-06-064 regarding the criteria and test contingencies. Furthermore, the Commission approves the ISO's annual LCR study each year for purposes of resource adequacy. Mr. Sparks addresses specific issues regarding the LCR study methodology in his reply testimony.

Q. Do the OTC/local capacity studies differ from other transmission planning studies that the ISO conducts as part of its annual transmission planning process?

A. Transmission planning studies include a range of analysis, and different input assumptions are used for the different types of analysis such as local area studies. In studying local capacity needs whether in the annual local capacity studies, OTC studies, or the ISO's annual transmission planning process, a one-in-ten load forecast is employed for a number of reasons as set out below. Regional studies on the bulk transmission system are more generally conducted using a one-in-five load forecast, recognizing that there is a higher probability of load diversity over a larger area; simultaneous coincident peak loads in most or all areas within the ISO footprint are unlikely. In studying potential economic-driven transmission projects, the ISO uses a one-in-two load forecast, to provide a more modest estimate of economic benefits associated with a potential transmission upgrade.

In assessing reliability needs, the relevant NERC planning requirements call upon the system to be planned "at all demand levels over the range of forecast system demands" [NERC Standard TPL-002; ISO Ex. 13]. As explained earlier, the tests applied to examine system performance test the boundary conditions under certain assumptions, not only including highest anticipated load levels, but also idealized conditions with the rest of the system in service.

Local capacity analysis utilizes the most conservative set of assumptions, including the highest level of conservatism in the load forecast studied, as there is less opportunity for load diversity and generally fewer operational options in a smaller local area to manage shortages. As these load pockets or local capacity areas tend to be urban areas of high population density (which makes additional transmission into the areas challenging, prohibitively expensive or altogether not viable) there is also less tolerance for outages on an unplanned or rotating outage basis. These local areas contain approximately half of the total load of the ISO controlled grid, and are particularly sensitive to electricity outages.

The local capacity technical study methodology that was used in the OTC analysis followed this traditional approach used in transmission planning studies. As Mr. Sparks explains in more detail in his reply testimony, there are subtle adjustments to the specific contingency analysis embedded in the ISO tariff for determining local capacity requirements from the more complete analysis performed in annual transmission planning studies, such as excluding certain types of contingencies from testing and clarifying the acceptable level of system performance for certain Category D outages for LCR purposes.

Q. How do the ISO's local area capacity studies compare to the system studies that are being conducted by Mr. Rothleder for the purposes of determining incremental needs for new resources?

A. As I explained earlier, the local capacity studies focus on the need to provide an adequate transmission system that will be capable of being operated on a day to day basis providing acceptable levels of reliability of supply, augmented with local generation capacity as necessary.

Mr. Rothleder's analysis focuses on the overall system requirements to maintain the load and generation balance across the entire ISO balancing authority area, recognizing the increased variability that dispatchable generation resources will need to manage as additional non-dispatchable variable renewable resources are added to the grid. In performing this analysis, he considers relatively few transmission limitations in adjusting resources to match changing load and non-dispatchable generation levels, and considered lower system-wide load assumptions recognizing the effects of diversity across the system and the broader range of options available to address shortfalls than exist in local capacity areas. This difference in study approach is entirely appropriate, and the methodology and assumptions are tailored to the purpose of the study.

Q. How does the ISO use the Commission's planning assumptions in its transmission planning studies?

A. The ISO relies upon the renewable generation portfolios developed by the Commission, working with the ISO and the CEC, for the development of policy-driven transmission plans necessary to enable the state to meet its 33% RPS objectives. As I discuss above, the ISO's planning requirements regarding reliability requirements are based on its FERC-approved tariff and the NERC reliability standards and WECC regional criteria.

Q. CEJA witness Julia May, in her testimony at pages 36-43, argues that the ISO's LCR study methodology uses "extreme" reliability criteria beyond NERC/WECC standards that favors over-procurement of fossil fuel generation. How do you respond to these assertions?

A. These assertions are simply not correct. As indicated earlier, the ISO employs the NERC and WECC standards in its planning activities. Much of the criticism appears to be drawn from three issues that I will address in turn.

First, on page 39 of Ms. May's testimony, Ms. May quotes Ms. Firooz: " in my experience long term **resource planning** was done using a one-year-in-two (expected) load forecast plus 10% adder to provide an installed capacity cushion to account for unexpected generator outages and load forecast error at time of peak. Later, the cushion was raised to 15% to 17%." [Emphasis added]

These comments are not applicable to the studies under consideration. Local reliability analysis and the application of WECC and NERC planning standards are not system-wide resource planning exercises. To the contrary, transmission planning standards set the requirements for a reliable transmission system to deliver electricity from generation to loads, with local capacity requirements being determined necessary when the transmission system cannot be reasonably reinforced to serve the local load solely from system-wide generating resources.

Secondly, Ms. Firooz is quoted on page 38 as calculating the probabilities of particular multiple contingency events such as an "N-1-1" contingency, presumably to argue that considering these contingencies is unreasonable. However, as I explained earlier, the deterministic analysis assumes other idealized system conditions, and watering down the deterministic criteria through haphazard application of probabilities misses the point of deterministic planning studies, and the application of deterministic standards entirely.

Thirdly, Ms. May quotes a number of sources regarding the potential to drop load in lieu of system reinforcements for category C and other more extreme contingencies. I note that the actual quote [NERC Standard TPL-003] applicable to category C contingencies including the N-1-1 contingency referred to earlier is:

> "Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding) the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers **may be necessary** to maintain the overall reliability of the interconnected transmission systems." [emphasis added]

This is permissive under qualified conditions – not an expectation that if one is not relying on load shedding, that one is automatically exceeding the minimum standards.

Mr. Sparks' testimony addresses the specific assertions regarding the ISO's development of transmission reinforcements to eliminate or reduce the local capacity needs in these and other local capacity areas; I will not address those issues in my testimony as well.

Q. At pages 37-38 of CEJA witness May's testimony, citing testimony presented by CEJA in A.11-05-023, she notes that load drop is available as a "safety net" and that it is "more reliable than a generating unit." What is the ISO's position on controlled load shedding as a mitigation solution in local areas where resource deficiencies have been identified?

A. Controlled load shedding can be an acceptable mitigation for Category C outages subject to careful review of the specifics of the situation. In general, the amount and particular sensitivity of the load, the type of reliability issue being addressed, and possible restoration considerations must be considered, as well as the reliability and complexity of the means by which the load would be shed. If the load shedding is to occur under a special protection system, then the special protection system must be considered to ensure that it does not compromise system reliability

To provide more transparency to industry, guidance to transmission planners, and consistency across the ISO controlled grid, guidelines have been developed by the ISO and documented in the California ISO Planning Standards [June 23, 2011] (see ISO Ex. 19), setting out the considerations that must be given on a case by case basis. These planning standards are attached to my testimony as Exhibit 3. These include, among other considerations, the number of potential contingencies that would cause the SPS to operate, the number of elements that need to be monitored, and the consequences if the SPS failed to operate properly.

Planning for Incremental Demand Response, Uncommitted Energy Efficiency, Uncommitted Combined Heat and Power, and Energy Storage

Q. DRA witness Kevin Woodruff at page 9 of his testimony, other parties, and interveners have expressed concern that the levels of incremental demand response (DR), uncommitted energy efficiency (EE), uncommitted combined heat and power (CHP) and energy storage assumed in the ISO's OTC study do not comply with the state's energy policy goals. Do you agree?

A. No, I don't. The ISO fully supports these energy policy goals and the loading order and has been working diligently with state agencies to ensure that those goals are met while maintaining system reliability. I would note that the state goals include maintaining a reliable electricity system.

As I will explain below, the ISO's objectives in ensuring adequate system reliability, including reliability within local capacity-constrained areas that constitute a significant portion of the ISO controlled grid, is not inconsistent with the state's energy policy goals. Nothing in these reliability requirements precludes advancement of the state goals.

Q. Do you believe that the state's goals for these preferred resources will be thwarted if the ISO does not modify its planning assumptions to recognize more aggressive development forecasts?

A. No, not at all. I will comment on each of these issues in turn.

Demand Response: The ISO agrees that demand response can be a valuable asset, with its usefulness in addressing different needs being largely driven by the characteristics of the demand response program itself. The characteristics of a particular program may not lend itself to addressing all possible needs on a transmission system. However, that does not reduce the benefit for the needs that the particular program does meet. In particular, the most demanding requirements would be to address specific contingency-driven needs in a local capacity area – where the exact timing of response, amount of response, and assurance of response have the tightest specifications and the least margin for variance. In contrast, demand response programs assisting with broad system adequacy issues have the most latitude regarding responsiveness while still providing value to customers.

Energy Efficiency and (behind the meter) Combined Heat and Power: These programs again provide broad system benefits. They can also provide local capacity requirements to the extent they can be reliably forecast and included in demand forecasts on a timely basis. Even if they cannot be reliably forecast to incorporate reliability benefits in local capacity areas on a timely basis, they provide the energy savings necessary to offset other forms of generation in both the local area and on a system basis.

Combined Heat and Power (sales to grid): These assets are treated as resources, rather than being incorporated into demand forecasts. To the extent these generators can provide the performance necessary in the local capacity areas, these generators can compete with other generation to provide local capacity needs.

Distributed Generation: As set out in the supplemental testimony of Mr. Sparks that I adopted, the ISO analysis includes a reasonable level of distributed generation for the purposes of the reliability assessment. Increased levels of DG will continue to benefit both system needs as well as reducing the potential need to operate other generation in the local capacity areas.

In short, ensuring adequate local capacity to address the uncertainty of the location, timing and impact of these programs does not impede their development, and, through the assurance of reliable system operation, enables the state to more confidently move forward to encourage these programs.

Q. Why didn't the ISO model demand response?

A. The ISO does not agree that Demand Response can be relied upon to address local capacity needs, unless the DR can provide equivalent characteristics and response to that of a dispatchable generator. Demand Response programs have generally been considered an alternative to generation resources in meeting system-wide load and supply balances. Spread over a larger system, the exact amount of DR that materializes, and the location, is not relevant (within certain bounds). However, to ensure that DR does not materialize in an area that compounds a system problem (and in particular, a system problem that drove the need for reliance on DR), the ISO strongly supports DR being location-based and dispatchable – in the past, the ISO has referred to this as "generation substitutable". Further, if it is being relied upon instead of construction of new generating plants, the DR programs must be dependable over a significant period of time equivalent to the service that would be provided by new generation resources – which the ISO has referred to in the past as "durable."[1] However, these characteristics at a broad system-wide level are not sufficient to enable inclusion of the resources to address local capacity requirements triggered by transmission-related contingencies. The system must be positioned to withstand any single contingency. Typically, following a contingency event, the ISO is faced with restoring the system to a state positioned for the next, worst

---

[1] The ISO recently discussed the importance of durability in comments submitted in CPUC Proceeding A.11-03-001. *See* Comments of the California Independent System Operator Corporation on the Alternate Proposed Decision Adopting Demand Response Activities and Budgets for 2012 through 2014, at 7-8 (April 9, 2012) (ISO Ex. 20).

contingency within 30 minutes. These types of requirements are location specific and time specific. Unlike the system needs (where DR resources are helpful as part of a range of mitigations even without certainty about the resource characteristics and it is sufficient to simply avoid DR resources that could compound a problem), addressing local capacity requirement issues that are contingency-driven requires prompt and dependable response – operators simply cannot wait to see what materializes, and still have time to respond to address a shortfall.

In the past, and in unique circumstances, the ISO has counted on a small amount of large DR programs; these exceptions should not be taken to be the rule.

Q. Enernoc witnesses Hoffman and Tierny-Lloyd submitted testimony addressing DR programs in other ISO/RTO regions as well as other parts of the world. Does this information provide a reasonable basis for the inclusion of incremental demand response in the ISO's local capacity studies?

A. No. The ISO has reviewed the characteristics of the various demand response programs in place within the ISO controlled grid, in the course of preparing for the anticipated summer season without SONGS. The ISO has not been able to identify a material amount of demand response that has the characteristics to address contingency-driven local capacity requirements, in keeping with the characteristics I set out above. While this does not negate the value of demand response programs in addressing other system-wide operational needs, it also does not encourage further reliance on programs that have not yet produced material amounts that address the specific needs in the local capacity areas.

The ISO will continue to work with the Commission on demand response, as well as participating with the various related FERC dockets. The possibility of demand response programs in other jurisdictions that may have the characteristics necessary to address local capacity needs is encouraging, but it is premature to assume that

that these types of resources will become available for reliability purposes. There is simply no evidence in the California experience to support assumptions that material levels will emerge with the necessary characteristics.

Q. **DRA, NRDC and other interveners have presented materials and reports about forecasted levels of EE much higher than those used in the OTC study. Would this information support changes to the EE levels embedded in the CEC forecast?**

A. As I explained earlier, the ISO is required to consider the entire range of load forecast possibilities in its deterministic reliability assessments. The base forecast adopted by the CEC included various ranges of impacts within the forecast period of all existing programs. The CEC further recognized that there was considerable uncertainty as to the timing, location, and impact of the uncommitted programs – these are the very parameters that make it difficult to further adjust the load forecast downward in local capacity areas with specific needs in specific time frames. Given the inherent risks in adjusting a comprehensive load forecast on a piecemeal basis, I do not see sufficient reason to shift from the adopted forecast. Further, the ISO has provided some accommodation for uncertainty in future adjustments to the load forecast by requesting that procurement of local capacity needs at this time be based on the lower end of the identified ranges, assuming that resources will be procured at the most effective locations in each area.

Q: **Clean Coalition witness Janice Lin recommends, among other things, that the Commission should adopt a multi-year procurement mechanism that includes energy storage. What is your response to these comments and the other witnesses addressing energy storage?**

A. Having reviewed the testimony of Ms. Lin, I am not sure if there is an area of disagreement. Storage resources should not be excluded from resource procurement providing that they can deliver the necessary characteristics for local capacity. However, and I have not seen this suggested, it would be a different issue if delays in procurement are being sought in the hope that technological advances may occur such that storage can provide the necessary characteristics in the future. The ISO would strongly discourage this approach, as a reasonable level of procurement must commence now, in our view, to ensure reliable service in the future.

Q. California Cogeneration Council witness Beach, on page 11 of his testimony, recommends that the ISO should join the other agencies in encouraging CHP. Has Mr. Beach correctly stated the ISO's position with respect to CHP?

A. No, I do not agree with Mr. Beach's representations that the ISO is not encouraging CHP. The base forecast provided by the CEC included a reasonable amount of "behind the meter" CHP. Further, the ISO assumed that the amount of CHP currently in place would remain; that new resources would appear to replace retiring resources and that existing resources with contracts nearing termination would remain in place. Further, I note that we have set out in this proceeding the ideal characteristics of the generation we believe should be procured to maintain reliable service in the local capacity areas. I anticipate that additional CHP will compete in the procurement processes. So, with the opportunity to participate in procurement processes for the generation that we are recommending be procured, and the modeling of a reasonable set of assumptions recognizing the uncertainties identified in the CEC forecast at the time the forecast was prepared, there is ample opportunity for CHP to develop.

<u>OTC Compliance Dates (DRA- SIAO testimony)</u>

Q. The testimony presented by DRA witness Siao and incorporated into witness Fagan's load and resource table set forth on pages 18-19 suggests that compliance dates for the generators affected by OTC requirements may vary

greatly and that some plants may continue to operate beyond compliance dates. Do you believe that this information should be incorporated into the ISO's OTC studies?

A. The ISO is committed to working with the state agencies and the industry to achieve state policy goals, and to ensure that reliability is maintained through the transitions taking place to meet those goals. This commitment to policy goals is not exclusive to renewable energy, but also to the goals regarding reducing impacts on coastal marine life of OTC coastal generation. Making decisions now assuming those goals will not be achieved in effect ensures that that the goals will not be met. For this reason, this is not a tenable position and should not be taken into account by the Commission without considerable supporting evidence that the goals will in fact not be met.

<u>Procurement Characteristics for Non-Generation Alternatives</u>

Q. The July 13, 2012 Assigned Commissioner Ruling asked the parties to this proceeding to comment on non-generation resource characteristics required to ensure that incremental resources can compete in the procurement process to fill local capacity deficiencies. What are the ISO's recommendations in this regard?

A. Given the importance of having resources available in local areas to reliably operate the system and serve load under stressed conditions, resources participating in an RFO must have a high net qualifying capacity commitment. In addition, as I explain earlier in this testimony, resources must be substitutable for conventional (thermal) generation and must be location specific. Such resources should be able to respond to dispatch instructions and should have sufficient durability to remain in service over the needed period of operation. Finally, to successfully bid into the procurement process, these resources must be capable of reacting in the time frames necessary to address transmission system issues. Relying on resources without these characteristics to meet local needs under stressed system conditions will leave operators with few options to meet reliability standards.

<u>ISO Recommendations</u>

Q. TURN witness Woodruff and other intervener witnesses have taken issue with the ISO's cautionary statements, in Mr. Spark's supplemental testimony, that the risks of under-procurement are greater than the risks of over-procurement ("asymmetric risk). What is your response?

A. Reiterating earlier comments, I believe a fundamental threat to achieving the state's goals is to fail to provide reliable service in the transition. Over-reaching in attributing potential benefits to resources that provide other benefits, and failing to take appropriate action to ensure reliable system operation will jeopardize reliability as well as continued progress in advancing state goals. Contrary to assurances provided in other testimony in this proceeding, in particular Ms. May's and Mr. Spencer's, rotating outages due to lack of local capacity are noticed by the public, and declining system reliability will not an acceptable consequence of transitioning to a more sustainable energy future.

Mr. Sparks' supplemental testimony drew considerable acrimony in referring to the asymmetrical risk of over-supply versus under-supply. The asymmetrical risk is, in my view, is a statement of fact, not an attempt to encourage decisions based on fear. To the contrary, this is a time for pragmatic decisions enabling the electric system in California to move forward in addressing the complex issues.

Q. Please summarize the ISO's recommendations in this proceeding.

A. Based on the 2009 IEPR and the non-generation resource assumptions embedded in that forecast, the ISO's OTC study has identified capacity deficiencies in the LA Basin and Big Creek/Ventura local areas starting as early as 2018. As Mr. Sparks describes in his testimony, the Commission should authorize the LSEs to procure the resources required to fill the needs identified in the base case scenario by the time frames identified in the study. Procurement should not be limited to conventional resources- in particular storage and CHP should be taken into account- but resources must meet the characteristics described in my testimony. In addition, flexibility attributes should be given considerable weight in the procurement process, as described in Mr. Rothleder's testimony. Consistent with the procedural schedule established for Track 1, the Commission should issue a decision on local capacity needs by the end of 2012 so that RFOs for new resources can begin in 2013.

It is important that the Commission take action this year, not only because of the lead times required for permitting and constructing new generation and the pending OTC compliance dates, but because of the additional uncertainty caused by the current SONGS outage. Future capacity needs that are driven by SONGS can be assessed in the later stages of this docket.

Q. Does this conclude your reply testimony?

A. Yes, it does.

Rulemaking: 12-03-014

Exhibit No.: ISO-13

Witness: ____________

NERC Transmission Planning Standards

Standard TPL-001-0.1 — System Performance Under Normal Conditions

Standard TPL-002-0b — System Performance Following Los s of a Single BES Element

Standard TPL-003-0a — System Performance Following Loss of Two or More BES Elements

Standard TPL-004-0 — System Performance Following Extreme BES Events

A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)
2. **Number:** TPL-001-0.1
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
4. **Applicability:**
   - **4.1.** Planning Authority
   - **4.2.** Transmission Planner
5. **Effective Date:** May 13, 2009

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-0_R1 and TPL-001-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

A. Introduction

1. Title: **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. Number: TPL-002-0b

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: Immediately after approval of applicable regulatory authorities.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories,, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 and TPL-002-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0a	July 30, 2008	Adopted by NERC Board of Trustees	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Interpretation
0b	September 15, 2011	FERC Order issued approving the Interpretation of R1.3.10 (FERC Order becomes effective October 24, 2011)	Interpretation

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section - 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) - 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
Background Information for Interpretation
Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations: 1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)." 2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)." 3. "Include the effects of existing and planned protection systems, including any backup or redundant systems." *Category B of Table 1 (single Contingencies) specifies:* Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault. Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line *Note e specifies*: e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay. The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."
Conclusion
TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations. This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-0a

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** April 23, 2010

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-0_R1 and TPL-003-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item “e” on page 8.	Errata
0a	July 30, 2008	Adopted by NERC Board of Trustees	
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0a	April 23, 2010	FERC approval of interpretation of TPL-003-0 R1.3.12	Interpretation

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

A. Introduction

1. **Title:** System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. **Number**: TPL-004-0

3. **Purpose**: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability**:

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-0_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-0_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

B. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	**Contingencies**	**System Limits or Impacts**		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D[d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Rulemaking: 12-03-014

Exhibit No.: ISO-14

Witness: ______________________

2013 -2015 Local Capacity Technical Analysis

Final Report and Study Results

2013
LOCAL CAPACITY TECHNICAL ANALYSIS

FINAL REPORT
AND STUDY RESULTS

April 30, 2012

Local Capacity Technical Study
Overview and Results

I. Executive Summary

This Report documents the results and recommendations of the 2013 Local Capacity Technical (LCT) Study. The LCT Study assumptions, processes, and criteria were discussed and recommended through the 2013 Local Capacity Technical Study Criteria, Methodology and Assumptions Stakeholder Meeting held on November 10, 2011. On balance, the assumptions, processes, and criteria used for the 2013 LCT Study mirror those used in the 2007-2012 LCT Studies, which were previously discussed and recommended through the LCT Study Advisory Group ("LSAG")[1], an advisory group formed by the CAISO to assist the CAISO in its preparation for performing prior LCT Studies.

The 2013 LCT study results are provided to the CPUC for consideration in its 2013 resource adequacy requirements program. These results will also be used by the CAISO as "Local Capacity Requirements" or "LCR" (minimum quantity of local capacity necessary to meet the LCR criteria) and for assisting in the allocation of costs of any CAISO procurement of capacity needed to achieve the Reliability Standards notwithstanding the resource adequacy procurement of Load Serving Entities (LSEs).[2]

Please note that these studies assume that SONGS will be fully operational in 2013. At the time this study was completed, SONGS was on an extended forced outage and the expected date that it would return to service was unknown. The ISO will continue to monitor the status of SONGS and reassess the 2013 LCR values, as needed.

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

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

Below is a comparison of the 2013 vs. 2012 total LCR:

2013 Local Capacity Requirements

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

2012 Local Capacity Requirements

	Qualifying Capacity			2012 LCR Need Based on Category B			2012 LCR Need Based on Category C with operating procedure		
Local Area Name	**QF/ Muni (MW)**	**Market (MW)**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**Existing Capacity Needed****	**Deficiency**	**Total (MW)**
Humboldt	54	168	222	159	0	**159**	190	22*	**212**
North Coast / North Bay	131	728	859	613	0	**613**	613	0	**613**
Sierra	1277	760	2037	1489	36*	**1525**	1685	289*	**1974**
Stockton	246	259	505	145	0	**145**	389	178*	**567**
Greater Bay	1312	5276	6588	3647	0	**3647**	4278	0	**4278**
Greater Fresno	356	2414	2770	1873	0	**1873**	1899	8*	**1907**
Kern	602	9	611	180	0	**180**	297	28*	**325**
LA Basin	4029	8054	12083	10865	0	**10865**	10865	0	**10865**
Big Creek/ Ventura	1191	4041	5232	3093	0	**3093**	3093	0	**3093**
San Diego	162	2925	3087	2849	0	**2849**	2849	95*	**2944**
Total	**9360**	**24634**	**33994**	**24913**	**36**	**24949**	**26158**	**620**	**26778**

* No local area is “overall deficient”. Resource deficiency values result from a few deficient sub-areas; and since there are no resources that can mitigate this deficiency the numbers are carried forward into the total area needs. Resource deficient sub-area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.
** Since “deficiency” cannot be mitigated by any available resource, the “Existing Capacity Needed” will be split among LSEs on a load share ratio during the assignment of local area resource responsibility.

Overall, the LCR needs have decreased by more than 1000 MW or about 4% from 2012 to 2013. The LCR needs have decreased in the following areas: Sierra, Fresno and LA Basin due to downward trend for load; Big Creek/Ventura due to downward trend for load, new transmission projects as well as load allocation change among substations. The LCR needs are steady in Humboldt and Stockton. The LCR needs have slightly increased in North Coast/North Bay, Bay Area and Kern due to load growth; San Diego due to load growth as well as deficiency increase in two small sub-areas however the total resource capacity needed for San Diego decreased slightly mainly due to changes to the WECC Regional Criteria[3] related to the definition of adjacent circuits resulting in the performance requirements for the simultaneous loss of the Sunrise Power Link and South West Power Link being classified as Category D as to compared to a category C event as well as elimination of WECC 1000 MW path rating on Sunrise Power Link. However, over the longer-term, there are expected LCR deficiencies in San Diego area due to the 2017 OTC compliance date for the Encina power plant and to the most restrictive contingency for this area limiting the pool of resources (qualifying capacity) effective in addressing the local area needs. Furthermore the San Diego local area has been expanded to include the Imperial Valley substation because the newly formed local area has higher requirements than the existing San Diego local area alone. The write-up for each Local Capacity Area lists important new projects included in the base cases as well as a description of reason for changes between 2013 and 2012 LCRs.

The ISO has undertaken an LCR assessment of the Valley Electric service area. There are no LCR needs in this new local area due to unavailability of local resources; however there are two constraints that may require local area resources in the future. Detailed results can be found in the Valley Electric section at the end of this report.

[3] TPL-001-WECC-CRT-2 System Performance Criterion – Effective April 1 2012

The ISO has undertaken a non-summer season LCR assessment of the San Diego area at stakeholder request. These results are for information purposes only and they will not be used to alter the 2013 LSE local resource allocation. The LSE local resource allocation is done based on the summer peak study as required by the ISO Tariff. Detailed results can be found at the end of the San Diego - Imperial Valley area section in this report.

Table of Contents

II. Study Overview: Inputs, Outputs and Options

A. Objectives

As was the objective of the five previous annual LCT Studies, the intent of the 2013 LCT Study is to identify specific areas within the CAISO Balancing Authority Area that have limited import capability and determine the minimum generation capacity (MW) necessary to mitigate the local reliability problems in those areas.

B. Key Study Assumptions

1. Inputs and Methodology

The CAISO incorporated into its 2013 LCT study the same criteria, input assumptions and methodology that were incorporated into its previous years LCR studies. These inputs, assumptions and methodology were discussed and agreed to by stakeholders at the 2013 LCT Study Criteria, Methodology and Assumptions Stakeholder Meeting held on November 10, 2011.

The following table sets forth a summary of the approved inputs and methodology that have been used in the previous LCT studies as well as this 2013 LCT Study:

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

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

Further details regarding the 2013 LCT Study methodology and assumptions are provided in Section III, below.

C. Grid Reliability

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

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

---

[4] Pub. Utilities Code § 345

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

The CAISO will maintain the system in a safe operating mode at all times. This obligation translates into respecting the Reliability Criteria at all times, for example during normal operating conditions Category A (N-0) the CAISO must protect for all single contingencies Category B (N-1) and common mode Category C5 (N-2) double line outages. Also, after a single contingency, the CAISO must re-adjust the system to support the loss of the next most stringent contingency. This is referred to as the N-1-1 condition.

The N-1-1 vs N-2 terminology was introduced only as a mere temporal differentiation between two existing NERC Category C events. N-1-1 represents NERC Category C3 ("category B contingency, manual system adjustment, followed by another category B contingency"). The N-2 represents NERC Category C5 ("any two circuits of a multiple circuit tower line") as well as requirement R1.1 of the WECC Regional Criteria[3] ("two adjacent circuits") with no manual system adjustment between the two contingencies.

E. Performance Criteria

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

a. LCR Performance Criteria- Category B

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

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

b. LCR Performance Criteria- Category C

The Reliability Standards require system operators to "look forward" to make sure they safely prepare for the "next" N-1 following the loss of the "first" N-1 (stay within Applicable Ratings after the "next" N-1). This is commonly referred to as N-1-1. Because it is assumed that some time exists between the "first" and "next" element losses, operating personnel may make any reasonable and feasible adjustments to the system to prepare for the loss of the second element, including, operating procedures, dispatching generation, moving load from one substation to another to reduce equipment loading, dispatching operating personnel to specific station locations to manually adjust load from the substation site, or installing a "Special Protection Scheme" that would remove pre-identified load from service upon the loss of the "next " element.[5] All Category C requirements in this report refer to situations when in real time

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

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

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

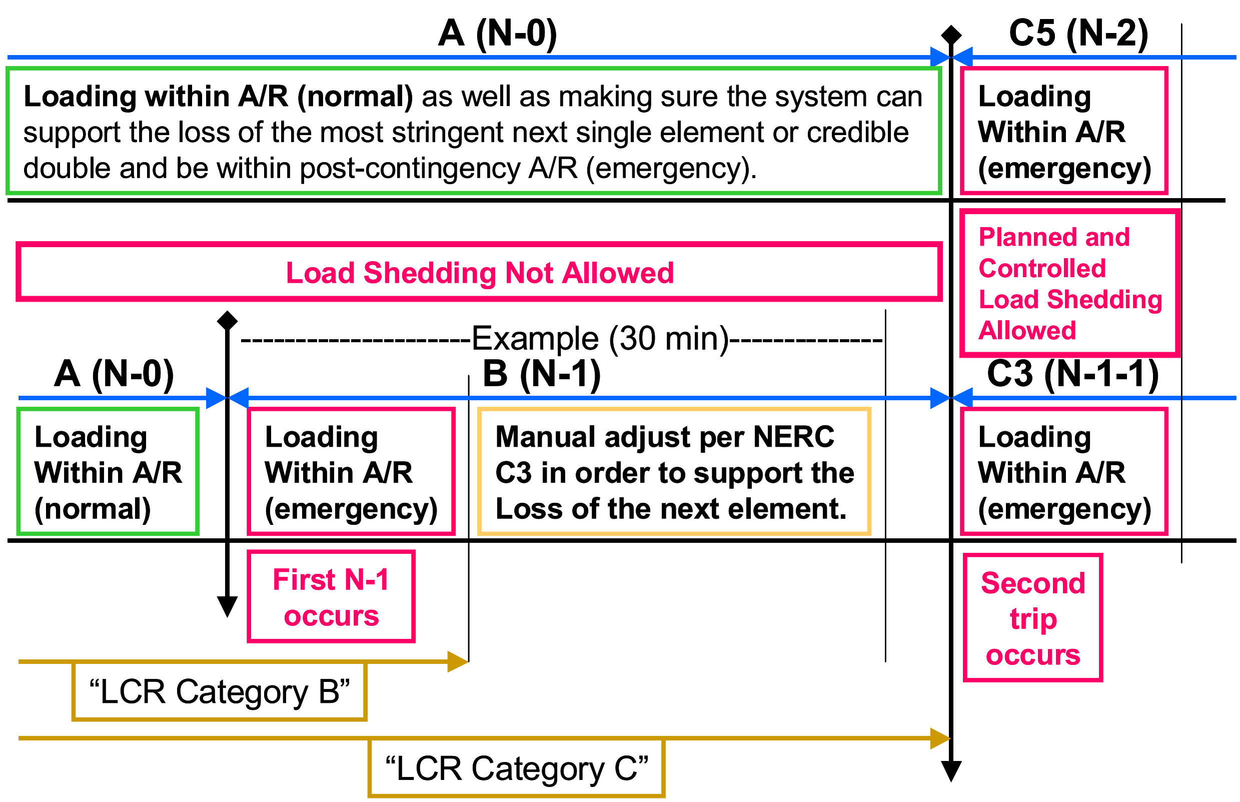
c. <u>CAISO Statutory Obligation Regarding Safe Operation</u>

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

---

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

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



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

Applicable Rating:

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

Normal rating is to be used under normal conditions.

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

Short-term emergency ratings, if available, can be used as long as “system readjustment” is provided in the “short-time” available in order to reduce the flow to within the long-term emergency ratings where the element can be kept for another length of time (specific to each element) before the flow needs to be reduced the below the normal ratings. If not available long-term emergency rating should be used.

Temperature-adjusted ratings shall not be used because this is a year-ahead study not a real-time tool, as such the worst-case scenario must be covered. In case temperature-adjusted ratings are the only ratings available then the minimum rating (highest temperature) given the study conditions shall be used.

CAISO Transmission Register is the only official keeper of all existing ratings mentioned above.

Ratings for future projects provided by PTO and agree upon by the CAISO shall be used.

Other short-term ratings not included in the CAISO Transmission Register may be used as long as they are engineered, studied and enforced through clear operating procedures that can be followed by real-time operators.

Path Ratings need to be maintained within their limits in order to assure that proper capacity is available in order to operate the system in real-time in a safe operating zone.

Controlled load drop:

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

Planned load drop:

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

Special Protection Scheme:

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

System Readjustment:

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

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

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

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

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

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

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

Time allowed for manual readjustment:

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

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

F. The Two Options Presented In This LCT Report

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

1. Option 1- Meet LCR Performance Criteria Category B

Option 1 is a service reliability level that reflects generation capacity that must be available to comply with reliability standards immediately after a NERC Category B given that load cannot be removed to meet this performance standard under Reliability Criteria. However, this capacity amount implicitly relies on load interruption as the **only means** of meeting any Reliability Standard that is beyond the loss of a single transmission element (N-1). These situations will likely require substantial load interruptions in order to maintain system continuity and alleviate equipment overloads prior to the actual occurrence of the second contingency.[6]

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

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

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

III. Assumption Details: How the Study was Conducted

A. System Planning Criteria

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

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

Table 4: Criteria Comparison

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

1 System must be able to readjust to a safe operating zone in order to be able to support the loss of the next contingency.

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

3 Evaluate for risks and consequence, per NERC standards. No voltage collapse or dynamic instability allowed.

4 Evaluate for risks and consequence, per NERC standards.

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

1. Power Flow Assessment:

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

1. All single contingency outages (i.e. generating unit, transmission line or transformer) will be simulated on Participating Transmission Owners' local area systems.
2. Key generating unit out, system readjusted, followed by a line outage. This overlapping outage is considered a single contingency within the ISO Grid Planning Criteria. Therefore, load dropping for an overlapping G-1, L-1 scenario is not permitted.
3. Applicable Rating – Based on ISO Transmission Register or facility upgrade plans including established Path ratings.
4. Applicable Rating – ISO Grid Planning Criteria or facility owner criteria as appropriate including established Path ratings.
5. A thermal or voltage criterion violation resulting from a transformer outage may not be cause for a local area reliability requirement if the violation is considered marginal (e.g. acceptable loss of facility life or low voltage), otherwise, such a violation will necessitate creation of a requirement.
6. Following the first contingency (N-1), the generation must be sufficient to allow the operators to bring the system back to within acceptable (normal) operating range (voltage and loading) and/or appropriate OTC following the studied outage conditions.
7. During normal operation or following the first contingency (N-1), the generation must be sufficient to allow the operators to prepare for the next worst N-1 or common mode N-2 without pre-contingency interruptible or firm load shedding. SPS/RAS/Safety Nets may be utilized to satisfy the criteria after the second N-1

or common mode N-2 except if the problem is of a thermal nature such that short-term ratings could be utilized to provide the operators time to shed either interruptible or firm load. T-2s (two transformer bank outages) would be excluded from the criteria.

2. Post Transient Load Flow Assessment:

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

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

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

3. Stability Assessment:

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

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

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

B. Load Forecast

1. System Forecast

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

2. Base Case Load Development Method

The method used to develop the base case loads is a melding process that extracts, adjusts and modifies the information from the system, distribution and municipal utility forecasts. The melding process consists of two parts: Part 1 deals with the PTO load and Part 2 deals with the municipal utility load. There may be small differences between the methodologies used by each PTO to disaggregate the CEC load forecast to their level of local area as well as bar-bus model.

a. PTO Loads in Base Case

The methods used to determine the PTO loads are, for the most part, similar. One part of the method deals with the determination of the division[7] loads that would meet the requirements of 1-in-5 or 1-in-10 system or area base cases and the other part deals with the allocation of the division load to the transmission buses.

i. Determination of division loads

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

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

ii. Allocation of division load to transmission bus level

Since the base case loads are modeled at the various transmission buses, the division loads developed must be allocated to those buses. The allocation process is different depending on the load types. For the most part, each PTO classifies its loads into four types: conforming, non-conforming, self-generation and generation-plant loads. Since the non-conforming and self-generation loads are assumed to not vary with temperature, their magnitude would be the same in the system or area base cases of the same year. The remaining load (the total division load developed above, less the quantity of non-conforming and self-generation load) is the conforming load. The remaining load is allocated to the transmission buses based on the relative magnitude of the distribution forecast. The summation of all base case loads is generally higher than the load forecast because some load, i.e., self-generation and generation-plant, are behind the meter and must be modeled in the base cases. However, for the most part, metered or aggregated data with telemetry is used to come up with the load forecast.

b. Municipal Loads in Base Case

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

C. Power Flow Program Used in the LCT analysis

The technical studies were conducted using General Electric's Power System Load Flow (GE PSLF) program version 17.0. This GE PSLF program is available directly from GE or through the Western System Electricity Council (WECC) to any member.

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

Electronic contingency files provided by the PTOs were utilized to perform the numerous contingencies required to identify the LCR. These contingency files include remedial action and special protection schemes that are expected to be in operation

during the year of study. An CAISO created EPCL (a GE programming language contained within the GE PSLF package) routine was used to run the combination of contingencies; however, other routines are available from WECC with the GE PSFL package or can be developed by third parties to identify the most limiting combination of contingencies requiring the highest amount of generation within the local area to maintain power flows within applicable ratings.

IV. Local Capacity Requirement Study Results

A. Summary of Study Results

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

Table 5: 2013 Local Capacity Needs vs. Peak Load and Local Area Generation

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

Table 6: 2012 Local Capacity Needs vs. Peak Load and Local Area Generation

	2012 Total LCR (MW)	Peak Load (1 in10) (MW)	2012 LCR as % of Peak Load	Total Dependable Local Area Generation (MW)	2012 LCR as % of Total Area Generation
Humboldt	212	210	101%	222	95%**
North Coast/North Bay	613	1420	43%	859	71%
Sierra	1974	1816	109%	2037	97%**
Stockton	567	1086	52%	505	112%**
Greater Bay	4278	9954	43%	6588	65%
Greater Fresno	1907	3120	61%	2770	69%**
Kern	325	1110	29%	611	53%**
LA Basin	10865	19931	55%	12083	90%
Big Creek/Ventura	3093	4693	66%	5232	59%
San Diego	2944	4844	61%	3087	95%**
Total	**26,778**	**48184***	**56%***	**33,994**	**79%**

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

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

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

The term "Qualifying Capacity" used in this report is the latest "Net Qualifying Capacity" ("NQC") posted on the CAISO web site at:

http://www.caiso.com/1796/179688b22c970.html

The NQC list includes the area (if applicable) where each resource is located for units already operational. Neither the NQC list nor this report incorporates Demand Side Management programs and their related NQC. Units scheduled to become operational before 6/1/2013 have been included in this 2013 LCR Report and added to the total NQC values for those respective areas (see detail write-up for each area).

The first column, “Qualifying Capacity,” reflects two sets of generation. The first set is comprised of generation that would normally be expected to be on-line such as Municipal generation and Regulatory Must-take generation (state, federal, QFs, wind and nuclear units). The second set is “market” generation. The second column, “2013 LCR Requirement Based on Category B” identifies the local capacity requirements, and deficiencies that must be addressed, in order to achieve a service reliability level based on Performance Criteria- Category B. The third column, “2013 LCR Requirement Based on Category C with Operating Procedure”, sets forth the local capacity requirements, and deficiencies that must be addressed, necessary to attain a service reliability level based on Performance Criteria-Category C with operational solutions.

B. Summary of Zonal Needs

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

Zone	Load Forecast (MW)	15% reserves (MW)	(-) Allocated imports (MW)	(-) Allocated Path 26 Flow (MW)	Total Zonal Resource Need (MW)
SP26	28253	4238	-7836	-3750	**20905**
NP26=NP15+ZP26	21883	3282	-4600	-2902	**17663**

Where:

Load Forecast is the most recent 1 in 2 CEC forecast for year 2013.

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

Allocated Imports are the actual 2012 Available Import Capability for loads in the CAISO control area numbers that are not expected to change much by 2013 because there are no additional import transmission additions to the grid between now and summer of 2013.

Allocated Path 26 flow The CAISO determines the amount of Path 26 transfer capacity available for RA counting purposes after accounting for (1) Existing Transmission Contracts (ETCs) that serve load outside the CAISO Balancing Area[8] and (2) loop flow[9] from the maximum path 26 rating of 4000 MW (North-to-South) and 3000 MW (South-to-North).

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

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

Changes compared to last year's results:

- The load forecast went up in Southern California by about 800 MW and up in Northern California by about 700 MW.
- The Import Allocations went down in Southern California by about 1000 MW and down in Northern California by about 100 MW.
- The Path 26 transfer capability has not changed and is not envisioned to change in the near future. As such, the LSEs should assume that their load/share ratio allocation for path 26 will stay at the same levels as 2012. If there are any changes, they will be heavily influenced by the pre-existing "grandfathered contracts" and when they expire most of the LSEs will likely see their load share ratio going up, while the owners of these grandfathered contracts may see their share decreased to the load-share ratio.

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

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

C. Summary of Results by Local Area

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

1. Humboldt Area

Area Definition

The transmission tie lines into the area include:

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

The substations that delineate the Humboldt Area are:

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

Total 2013 busload within the defined area: 200 MW with 10 MW of losses resulting in total load + losses of 210 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BLULKE_6_BLUELK	31156	BLUELKPP	12.5	0.00	1	Humboldt 60 kV	Energy Only	Market
BRDGVL_7_BAKER				0.00		None	Not modeled Aug NQC	QF/Selfgen
FAIRHV_6_UNIT	31150	FAIRHAVN	13.8	14.69	1	Humboldt 60 kV	Aug NQC	QF/Selfgen
FTSWRD_7_QFUNTS				0.51		Humboldt 60 kV	Not modeled Aug NQC	QF/Selfgen
HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.27	1	None		Market
HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.27	2	None		Market

HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.27	3	None		Market
HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.27	4	None		Market
HUMBPP_6_UNITS1	31181	HUMB_G2	13.8	16.27	5	Humboldt 60 kV		Market
HUMBPP_6_UNITS1	31181	HUMB_G2	13.8	16.27	6	Humboldt 60 kV		Market
HUMBPP_6_UNITS1	31181	HUMB_G2	13.8	16.27	7	Humboldt 60 kV		Market
HUMBPP_6_UNITS2	31182	HUMB_G2	13.8	16.27	8	Humboldt 60 kV		Market
HUMBPP_6_UNITS2	31182	HUMB_G2	13.8	16.27	9	Humboldt 60 kV		Market
HUMBPP_6_UNITS2	31182	HUMB_G2	13.8	16.27	10	Humboldt 60 kV		Market
HUMBSB_1_QF				0.00		None	Not modeled Aug NQC	QF/Selfgen
KEKAWK_6_UNIT	31166	KEKAWAK	9.1	0.00	1	Humboldt 60 kV	Aug NQC	QF/Selfgen
LAPAC_6_UNIT	31158	LP SAMOA	12.5	20.00	1	Humboldt 60 kV		QF/Selfgen
PACLUM_6_UNIT	31152	PAC.LUMB	13.8	7.47	1	Humboldt 60 kV	Aug NQC	QF/Selfgen
PACLUM_6_UNIT	31152	PAC.LUMB	13.8	7.47	2	Humboldt 60 kV	Aug NQC	QF/Selfgen
PACLUM_6_UNIT	31153	PAC.LUMB	2.4	4.48	3	Humboldt 60 kV	Aug NQC	QF/Selfgen
WLLWCR_6_CEDRFL				0.02		Humboldt 60 kV	Not modeled Aug NQC	QF/Selfgen

Major new projects modeled:

1. Humboldt Reactive Support
2. Blue Lake generation project (energy only 0 MW NQC)
3. Garberville Reactive Support
4. Bridgeville 115/60 kV transformer replacement – PG&E maintenance project

<u>Critical Contingency Analysis Summary</u>

Humboldt 60 kV Sub-area:

The most critical contingency for the Humboldt 60 kV Sub-area area is the outage of the Humboldt 115/60 Transformer and one of the gen tie-line connecting the new Humboldt Bay units (on 60 kV side). The area limitation is the overload on the parallel Humboldt 115/60 kV Transformer. This contingency establishes a LCR of 174 MW in 2012 (includes 55 MW of QF/Selfgen generation as well as 22 MW of deficiency) as the minimum capacity necessary for reliable load serving capability within this area.

The most critical single contingency is the outage of the Humboldt 115/60 kV Transformer. The limitation is thermal overload on the parallel Humboldt 115/60 kV Transformer. This limiting contingency establishes a LCR of 125 MW in 2013 (includes 55 MW of QF/Selfgen generation).

Effectiveness factors:

The following table has units within the Humboldt 60 kV Sub-area area with at least 5% effective to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31156	BLUELKPP	1	78
31150	FAIRHAVN	1	75
31158	LP SAMOA	1	75
31182	HUMB_G3	10	69
31182	HUMB_G3	9	69
31182	HUMB_G3	8	69
31181	HUMB_G2	7	69
31181	HUMB_G2	6	69
31181	HUMB_G2	5	69
31152	PAC.LUMB	1	42
31152	PAC.LUMB	2	42
31153	PAC.LUMB	3	42
31180	HUMB_G1	4	-14
31180	HUMB_G1	3	-14
31180	HUMB_G1	2	-14
31180	HUMB_G1	1	-14

Humboldt overall:

The most critical contingency for the Humboldt area is the outage of the Bridgeville-Cottonwood 115 kV Line overlapping with an outage of one of the tie-line connecting the new Humboldt Bay units on the 115 kV side. The area limitation is the overload on the Humboldt – Trinity 115 kV Line. This contingency establishes a LCR of 190 MW in 2013 (includes 55 MW of QF/Selfgen generation) as the minimum capacity necessary for reliable load serving capability within this area.

For the single contingency, the most critical one is an outage of the Bridgeville-Cottonwood 115 kV Line when one of the Humboldt Bay Power Plant units connected to the 115 kV bus is out of service. The limitation is the overload on the Humboldt – Trinity 115 kV Line. This limiting contingency establishes a LCR of 143 MW in 2013 (includes 55 MW of QF/Selfgen generation).

Effectiveness factors:

The following table has units within the Humboldt Overall system with at least 5% effective to the above-mentioned constraint

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

Changes compared to last year's results:

The 2013 load and LCR needs remained the same as it they were in 2012.

Humboldt Overall Requirements:

2013	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	55	0	162	217

2013	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[10]	143	0	143
Category C (Multiple)[11]	190	22	212

[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 than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[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 NERC transmission operations standards.

2. North Coast / North Bay Area

Area Definition

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

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

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

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

Total 2013 busload within the defined area: 1442 MW with 37 MW of losses resulting in total load + losses of 1479 MW.

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

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ADLIN_1_UNITS	31435	GEO.ENGY	9.1	8.00	1	Eagle Rock, Fulton, Lakeville		Market
ADLIN_1_UNITS	31435	GEO.ENGY	9.1	8.00	2	Eagle Rock, Fulton, Lakeville		Market
BEARCN_2_UNITS	31402	BEAR CAN	13.8	6.50	1	Fulton, Lakeville		Market
BEARCN_2_UNITS	31402	BEAR CAN	13.8	6.50	2	Fulton, Lakeville		Market
FULTON_1_QF				0.06		Fulton, Lakeville	Not modeled Aug NQC	QF/Selfgen
GEYS11_7_UNIT11	31412	GEYSER11	13.8	65.00	1	Eagle Rock, Fulton, Lakeville		Market
GEYS12_7_UNIT12	31414	GEYSER12	13.8	50.00	1	Fulton, Lakeville		Market
GEYS13_7_UNIT13	31416	GEYSER13	13.8	56.00	1	Lakeville		Market
GEYS14_7_UNIT14	31418	GEYSER14	13.8	50.00	1	Fulton, Lakeville		Market
GEYS16_7_UNIT16	31420	GEYSER16	13.8	49.00	1	Fulton, Lakeville		Market
GEYS17_2_BOTRCK	31421	BOTTLERK	13.8	14.70	1	Fulton, Lakeville		Market
GEYS17_7_UNIT17	31422	GEYSER17	13.8	53.00	1	Fulton, Lakeville		Market

GEYS18_7_UNIT18	31424	GEYSER18	13.8	45.00	1	Lakeville		Market
GEYS20_7_UNIT20	31426	GEYSER20	13.8	40.00	1	Lakeville		Market
GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	40.00	1	Eagle Rock, Fulton, Lakeville		Market
GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	40.00	2	Eagle Rock, Fulton, Lakeville		Market
GYS7X8_7_UNITS	31408	GEYSER78	13.8	38.00	1	Eagle Rock, Fulton, Lakeville		Market
GYS7X8_7_UNITS	31408	GEYSER78	13.8	38.00	2	Eagle Rock, Fulton, Lakeville		Market
GYSRVL_7_WSPRNG				1.68		Fulton, Lakeville	Not modeled Aug NQC	QF/Selfgen
HIWAY_7_ACANYN				0.92		Lakeville	Not modeled Aug NQC	QF/Selfgen
IGNACO_1_QF				0.00		Lakeville	Not modeled Aug NQC	QF/Selfgen
INDVLY_1_UNITS	31436	INDIAN V	9.1	0.54	1	Eagle Rock, Fulton, Lakeville	Aug NQC	QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	3.88	1	Fulton, Lakeville	Aug NQC	QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	3.88	2	Fulton, Lakeville	Aug NQC	QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	0.92	3	Fulton, Lakeville	Aug NQC	QF/Selfgen
NAPA_2_UNIT				0.01		Lakeville	Not modeled Aug NQC	QF/Selfgen
NCPA_7_GP1UN1	38106	NCPA1GY1	13.8	31.00	1	Lakeville	Aug NQC	MUNI
NCPA_7_GP1UN2	38108	NCPA1GY2	13.8	28.00	1	Lakeville	Aug NQC	MUNI
NCPA_7_GP2UN3	38110	NCPA2GY1	13.8	0.00	1	Fulton, Lakeville	Aug NQC	MUNI
NCPA_7_GP2UN4	38112	NCPA2GY2	13.8	52.73	1	Fulton, Lakeville	Aug NQC	MUNI
POTTER_6_UNITS	31433	POTTRVLY	2.4	4.70	1	Eagle Rock, Fulton, Lakeville	Aug NQC	Market
POTTER_6_UNITS	31433	POTTRVLY	2.4	2.25	3	Eagle Rock, Fulton, Lakeville	Aug NQC	Market
POTTER_6_UNITS	31433	POTTRVLY	2.4	2.25	4	Eagle Rock, Fulton, Lakeville	Aug NQC	Market
POTTER_7_VECINO				0.02		Eagle Rock, Fulton, Lakeville	Not modeled Aug NQC	QF/Selfgen
SANTFG_7_UNITS	31400	SANTA FE	13.8	30.00	1	Lakeville		Market
SANTFG_7_UNITS	31400	SANTA FE	13.8	30.00	2	Lakeville		Market
SMUDGO_7_UNIT 1	31430	SMUDGEO1	13.8	37.00	1	Lakeville		Market
SNMALF_6_UNITS	31446	SONMA LF	9.1	4.60	1	Fulton, Lakeville	Aug NQC	QF/Selfgen
UKIAH_7_LAKEMN				1.70		Eagle Rock, Fulton, Lakeville	Not modeled	MUNI
WDFRDF_2_UNITS	31404	WEST FOR	13.8	12.51	1	Fulton, Lakeville		Market
WDFRDF_2_UNITS	31404	WEST FOR	13.8	12.49	2	Fulton, Lakeville		Market
New Unit	31447	S0476	4.2	0	1	Lakeville	Energy Only	Market

Major new projects modeled:

1. Lakeville-Ignacio #2 230 kV line
2. Fulton-Fitch Mountain 60 kV Line reconductoring

Critical Contingency Analysis Summary

Eagle Rock Sub-area

The most critical contingency is the outage of Cortina-Mendocino 115 kV line and Geysers #5-Geysers #3 115 kV line. The sub-area area limitation is thermal overloading of the Eagle Rock-Cortina 115 kV line. This limiting contingency establishes a LCR of 235 MW in 2013 (includes 2 MW of QF/MUNI generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the outage of the Cortina-Mendocino 115 kV line with Geysers 11 generation unit out of service. The sub-area area limitation is thermal overloading of Eagle Rock-Cortina 115 kV line. This limiting contingency establishes a LCR of 215 MW in 2013 (includes 2MW of QF/MUNI generation).

Effectiveness factors:

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

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

Fulton Sub-area

The most critical contingency is the outage of Lakeville-Fulton 230 kV line #1 and Fulton-Ignacio 230 kV line #1. The sub-area limitation is thermal overloading of Santa Rosa-Corona 115 kV line #1. This limiting contingency establishes a LCR of 301 MW in 2013 (includes 16 MW of QF and 54 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area. All of the resources needed to meet the Eagle Rock sub-area count towards the Fulton sub-area LCR need.

Effectiveness factors:

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

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

Lakeville Sub-area

The most limiting contingency is the outage of Vaca Dixon-Tulucay 230 kV line with DEC power plant out of service. The area limitation is thermal overloading of Vaca Dixon-Lakeville 230 kV. This limiting contingency establishes a LCR of 629 MW in 2013 (includes 17 MW of QF and 113 MW of MUNI generation). The LCR resources needed for Eagle Rock and Fulton sub-areas can be counted toward fulfilling the requirement of Lakeville sub-area.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31400	SANTA FE	2	38
31430	SMUDGEO1	1	38
31400	SANTA FE	1	38
31416	GEYSER13	1	38
31424	GEYSER18	1	38
31426	GEYSER20	1	38
38106	NCPA1GY1	1	38
38108	NCPA1GY2	1	38
31447	S0476	1	38
31421	BOTTLERK	1	36
31404	WEST FOR	2	36

31402	BEAR CAN	1	36
31402	BEAR CAN	2	36
31404	WEST FOR	1	36
31414	GEYSER12	1	36
31418	GEYSER14	1	36
31420	GEYSER16	1	36
31422	GEYSER17	1	36
38110	NCPA2GY1	1	36
38112	NCPA2GY2	1	36
31446	SONMA LF	1	36
32700	MONTICLO	1	31
32700	MONTICLO	2	31
32700	MONTICLO	3	31
31406	GEYSR5-6	1	18
31406	GEYSR5-6	2	18
31408	GEYSER78	1	18
31408	GEYSER78	2	18
31412	GEYSER11	1	18
31435	GEO.ENGY	1	18
31435	GEO.ENGY	2	18
31433	POTTRVLY	1	15
31433	POTTRVLY	2	15
31433	POTTRVLY	3	15

Changes compared to last year's results:

The load forecast went up by 59 MW and the LCR need went up by 16 MW.

North Coast/North Bay Overall Requirements:

2013	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	17	113	739	869

2013	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[12]	629	0	629
Category C (Multiple)[13]	629	0	629

[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 than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[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 NERC transmission operations standards.

3. Sierra Area

Area Definition

The transmission tie lines into the Sierra Area are:

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

The substations that delineate the Sierra Area are:

1) Table Mountain is out Rio Oso is in
2) Table Mountain is out Palermo is in
3) Table Mt is out Pease is in
4) Caribou is out Palermo is in
5) Drum is in Summit is out
6) Drum is in Summit is out
7) Spaulding is in Summit is out
8) Brighton is in Bellota is out
9) Rio Oso is in Lockeford is out
10) Gold Hill is in Eight Mile is out
11) Lodi STIG is in Eight Mile Road is out
12) Gold Hill is in Lake is out

Total 2013 busload within the defined area: 1639 MW with 99 MW of losses resulting in total load + losses of 1738 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BELDEN_7_UNIT 1	31784	BELDEN	13.8	115.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
BIOMAS_1_UNIT 1	32156	WOODLAN D	9.1	22.80	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen

BNNIEN_7_ALTAPH	32376	BONNIE N	60	0.67		Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
BOGUE_1_UNITA1	32451	FREC	13.8	45.00	1	Bogue, Drum-Rio Oso, South of Table Mountain	Aug NQC	Market
BOWMN_6_UNIT	32480	BOWMAN	9.1	2.68	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
BUCKCK_7_OAKFLT				0.87		South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
BUCKCK_7_PL1X2	31820	BCKS CRK	11	29.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
BUCKCK_7_PL1X2	31820	BCKS CRK	11	29.00	2	South of Palermo, South of Table Mountain	Aug NQC	Market
CHICPK_7_UNIT 1	32462	CHI.PARK	11.5	38.00	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
COLGAT_7_UNIT 1	32450	COLGATE1	13.8	161.65	1	South of Table Mountain	Aug NQC	MUNI
COLGAT_7_UNIT 2	32452	COLGATE2	13.8	161.68	1	South of Table Mountain	Aug NQC	MUNI
CRESTA_7_PL1X2	31812	CRESTA	11.5	35.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
CRESTA_7_PL1X2	31812	CRESTA	11.5	35.00	2	South of Palermo, South of Table Mountain	Aug NQC	Market
DAVIS_7_MNMETH				2.04		Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
DEADCK_1_UNIT	31862	DEADWOOD	9.1	0.00	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
DEERCR_6_UNIT 1	32474	DEER CRK	9.1	3.61	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DRUM_7_PL1X2	32504	DRUM 1-2	6.6	13.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DRUM_7_PL1X2	32504	DRUM 1-2	6.6	13.00	2	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DRUM_7_PL3X4	32506	DRUM 3-4	6.6	13.70	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market

DRUM_7_PL3X4	32506	DRUM 3-4	6.6	13.70	2	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DRUM_7_UNIT 5	32454	DRUM 5	13.8	49.50	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DUTCH1_7_UNIT 1	32464	DTCHFLT1	11	22.00	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DUTCH2_7_UNIT 1	32502	DTCHFLT2	6.9	26.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
ELDORO_7_UNIT 1	32513	ELDRADO1	21.6	11.00	1	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain		Market
ELDORO_7_UNIT 2	32514	ELDRADO2	21.6	11.00	1	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain		Market
FMEADO_6_HELLHL	32486	HELLHOLE	9.1	0.54	1	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
FMEADO_7_UNIT	32508	FRNCH MD	4.2	16.01	1	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
FORBST_7_UNIT 1	31814	FORBSTWN	11.5	39.00	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
GOLDHL_1_QF				0.00		Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled	QF/Selfgen
GRNLF1_1_UNITS	32490	GRNLEAF1	13.8	5.47	1	Bogue, Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
GRNLF1_1_UNITS	32490	GRNLEAF1	13.8	27.97	2	Bogue, Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
GRNLF2_1_UNIT	32492	GRNLEAF2	13.8	34.00	1	Pease, Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
HALSEY_6_UNIT	32478	HALSEY F	9.1	7.01	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
HAYPRS_6_QFUNTS	32488	HAYPRES+	9.1	0.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
HAYPRS_6_QFUNTS	32488	HAYPRES+	9.1	0.00	2	Drum-Rio Oso, South of Palermo, South of Table	Aug NQC	QF/Selfgen

						Mountain		
HIGGNS_7_QFUNTS				0.11		Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	QF/Selfgen
KANAKA_1_UNIT				0.00		Drum-Rio Oso, South of Table Mountain	Not modeled Aug NQC	MUNI
KELYRG_6_UNIT	31834	KELLYRDG	9.1	10.00	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
MDFKRL_2_PROJCT	32456	MIDLFORK	13.8	62.18	1	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
MDFKRL_2_PROJCT	32456	MIDLFORK	13.8	62.18	2	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
MDFKRL_2_PROJCT	32458	RALSTON	13.8	84.32	1	South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
NAROW1_2_UNIT	32466	NARROWS1	9.1	6.29	1	South of Table Mountain	Aug NQC	Market
NAROW2_2_UNIT	32468	NARROWS2	9.1	22.59	1	South of Table Mountain	Aug NQC	MUNI
NWCSTL_7_UNIT 1	32460	NEWCSTLE	13.2	0.03	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
OROVIL_6_UNIT	31888	OROVLLE	9.1	4.61	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
OXBOW_6_DRUM	32484	OXBOW F	9.1	6.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
PACORO_6_UNIT	31890	PO POWER	9.1	7.56	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
PACORO_6_UNIT	31890	PO POWER	9.1	7.57	2	Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
PLACVL_1_CHILIB	32510	CHILIBAR	4.2	2.18	1	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PLACVL_1_RCKCRE				0.00		Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
PLSNTG_7_LNCLND	32408	PLSNT GR	60	1.24		Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
POEPH_7_UNIT 1	31790	POE 1	13.8	60.00	1	South of Palermo, South of Table	Aug NQC	Market

						Mountain		
POEPH_7_UNIT 2	31792	POE 2	13.8	60.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
RCKCRK_7_UNIT 1	31786	ROCK CK1	13.8	56.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
RCKCRK_7_UNIT 2	31788	ROCK CK2	13.8	56.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
RIOOSO_1_QF				1.12		Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	QF/Selfgen
ROLLIN_6_UNIT	32476	ROLLINSF	9.1	11.09	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
SLYCRK_1_UNIT 1	31832	SLY.CR.	9.1	10.36	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
SPAULD_6_UNIT 3	32472	SPAULDG	9.1	5.80	3	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
SPAULD_6_UNIT12	32472	SPAULDG	9.1	4.96	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
SPAULD_6_UNIT12	32472	SPAULDG	9.1	4.96	2	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
SPI LI_2_UNIT 1	32498	SPILINCF	12.5	10.49	1	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
STIGCT_2_LODI	38114	Stig CC	13.8	49.50	1	South of Rio Oso, South of Palermo, South of Table Mountain		MUNI
ULTRCK_2_UNIT	32500	ULTR RCK	9.1	20.74	1	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
WDLEAF_7_UNIT 1	31794	WOODLEAF	13.8	55.00	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
WHEATL_6_LNDFIL	32350	WHEATLND	60	1.20		South of Table Mountain	Not modeled Aug NQC	Market
WISE_1_UNIT 1	32512	WISE	12	10.82	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
WISE_1_UNIT 2	32512	WISE	12	0.34	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of	Aug NQC	Market

						Table Mountain		
YUBACT_1_SUNSWT	32494	YUBA CTY	9.1	24.80	1	Pease, Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
YUBACT_6_UNITA1	32496	YCEC	13.8	46.00	1	Pease, Drum-Rio Oso, South of Table Mountain		Market
CAMPFW_7_FARWST	32470	CMP.FARW	9.1	4.60	1	South of Table Mountain	No NQC - hist. data	MUNI
NA	32162	RIV.DLTA	9.11	0.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	No NQC - hist. data	QF/Selfgen
UCDAVS_1_UNIT	32166	UC DAVIS	9.1	3.50	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	No NQC - hist. data	QF/Selfgen
STIGCT_2_LODIEC	38123	Q267CT1	18	166.00	1	South of Rio Oso, South of Palermo, South of Table Mountain	No NQC - Pmax	MUNI
STIGCT_2_LODIEC	38124	Q267ST1	18	114.00	1	South of Rio Oso, South of Palermo, South of Table Mountain	No NQC - Pmax	MUNI

Major new projects modeled:

1. Table Mountain-Rio Oso Reconductor and Tower Upgrade
2. Atlantic-Lincoln 115 kV Transmission Upgrade
3. Gold Hill – Horseshoe 115 kV line Reconductoring
4. Palermo-Rio Oso 115 kV Reconductoring
5. Lodi Energy Center

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 and Table Mountain-Palermo double circuit tower line outage. The area limitation is thermal overloading of the Caribou-Palermo 115 kV line. This limiting contingency establishes in 2013 a LCR of 1376 MW (includes 171 MW of QF and 1103 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this area.

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

Effectiveness factors:

The following table has all units in Sierra area and their effectiveness factor to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	Eff Fctr. (%)
31814	FORBSTWN	1	8
31794	WOODLEAF	1	8
31832	SLY.CR.	1	7
31862	DEADWOOD	1	7
31888	OROVLLE	1	6
31890	PO POWER	2	6
31890	PO POWER	1	6
31834	KELLYRDG	1	6
32452	COLGATE2	1	5
32450	COLGATE1	1	5
32466	NARROWS1	1	5
32468	NARROWS2	1	5
32470	CMP.FARW	1	5
32451	FREC	1	5
32490	GRNLEAF1	2	4
32490	GRNLEAF1	1	4
32496	YCEC	1	3
32494	YUBA CTY	1	3
32492	GRNLEAF2	1	3
32156	WOODLAND	1	3
31820	BCKS CRK	1	2
31820	BCKS CRK	2	2
31788	ROCK CK2	1	2
31812	CRESTA	1	2
31812	CRESTA	2	2
31792	POE 2	1	2
31790	POE 1	1	2
31786	ROCK CK1	1	2
31784	BELDEN	1	2
32166	UC DAVIS	1	2
32500	ULTR RCK	1	2
32498	SPILINCF	1	2
32162	RIV.DLTA	1	2
32510	CHILIBAR	1	2
32514	ELDRADO2	1	2
32513	ELDRADO1	1	2
32478	HALSEY F	1	2
32458	RALSTON	1	2
32456	MIDLFORK	1	2

32456	MIDLFORK	2	2
38114	Stig CC	1	2
32460	NEWCSTLE	1	2
32512	WISE	1	2
32486	HELLHOLE	1	2
32508	FRNCH MD	1	2
32502	DTCHFLT2	1	2
32462	CHI.PARK	1	2
32464	DTCHFLT1	1	1
32454	DRUM 5	1	1
32476	ROLLINSF	1	1
32484	OXBOW F	1	1
32474	DEER CRK	1	1
32506	DRUM 3-4	1	1
32506	DRUM 3-4	2	1
32504	DRUM 1-2	1	1
32504	DRUM 1-2	2	1
32488	HAYPRES+	1	1
32488	HAYPRES+	2	1
32480	BOWMAN	1	1
32472	SPAULDG	1	1
32472	SPAULDG	2	1
32472	SPAULDG	3	1
38123	Q267CT1	1	1
38124	Q267ST1	1	1

Colgate Sub-area

No requirements due to the addition of the Atlantic-Lincoln 115 kV transmission upgrade project. If this project is delayed all units within this area (Narrows #1 & #2 and Camp Far West) are needed.

Pease Sub-area

The most critical contingency is the loss of the Palermo-East Nicolaus 115 kV line with Yuba City Energy Center unit out of service. The area limitation is thermal overloading of the Palermo-Pease 115 kV line. This limiting contingency establishes a LCR of 52 MW (includes 59 MW of QF generation) in 2013 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area (Greenleaf #2, Yuba City and Yuba City EC) have the same effectiveness factor.

Bogue Sub-area

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

South of Palermo Sub-area

The most critical contingency is the loss of the Double Circuit Tower Line Table Mountain-Rio Oso and Colgate-Rio Oso 230 kV lines. The area limitation is thermal overloading of the Pease-Rio Oso 115 kV line. This limiting contingency establishes a LCR of 1568 MW (includes 59 MW of QF and 639 MW of Muni generation as well as 204 MW of deficiency) in 2013 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the loss of the Palermo- East Nicolaus 115 kV line with Belden unit out of service. The area limitation is thermal overloading of the Pease-Rio Oso 115 kV line. This contingency establishes in 2013 a LCR of 1247 MW (includes 59 MW of QF and 639 MW of Muni generation).

Effectiveness factors:

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

Placerville Sub-area

The most critical contingency is the loss of the Gold Hill-Clarksville 115 kV line followed by loss of the Gold Hill-Missouri Flat #2 115 kV line. The area limitation is thermal overloading of the Gold Hill-Missouri Flat #1 115 kV line. This limiting contingency establishes a LCR of 72 MW (includes 0 MW of QF and Muni generation as well as 48 MW of deficiency) in 2013 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area (El Dorado units 1&2 and Chili Bar) are needed therefore no effectiveness factor is required.

Placer Sub-area

The most critical contingency is the loss of the Gold Hill-Placer #1 115 kV line followed by loss of the Gold Hill-Placer #2 115 kV line. The area limitation is thermal overloading of the Drum-Higgins 115 kV line. This limiting contingency establishes a LCR of 81 MW (includes 38 MW of QF and Muni generation as well as 2 MW of deficiency) in 2013 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency is the loss of the Gold Hill-Placer #2 115 kV line with Chicago Park unit out of service. The area limitation is thermal overloading of the Drum-Higgins 115 kV line. This limiting contingency establishes a local capacity need of 59 MW (includes 38 MW of QF and Muni generation) in 2013.

Effectiveness factors:

All units within this area (Chicago Park, Dutch Flat#1, Wise units 1&2, Newcastle and Halsey) have the same effectiveness factor.

Drum-Rio Oso Sub-area

The most critical contingency is the loss of the Rio Oso #2 230/115 transformer followed by loss of the Rio Oso-Brighton 230 kV line. The area limitation is thermal overloading of the Rio Oso #1 230/115 kV transformer. This limiting contingency establishes in 2013 a LCR of 522 MW (includes 171 MW of QF and 198 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency is the loss of the Rio Oso #2 230/115 transformer. The area limitation is thermal overloading of the Rio Oso #1 230/115 kV transformer. This limiting contingency establishes in 2013 a LCR of 226 MW (includes 171 MW of QF and 198 MW of Muni generation).

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr. (%)
32156	WOODLAND	1	22
32490	GRNLEAF1	1	22
32490	GRNLEAF1	2	22
32451	FREC	1	21
32166	UC DAVIS	1	18
32498	SPILINCF	1	15
32502	DTCHFLT2	1	15
32494	YUBA CTY	1	14
32496	YCEC	1	14
32492	GRNLEAF2	1	13
32454	DRUM 5	1	13
32476	ROLLINSF	1	13
32474	DEER CRK	1	13
32504	DRUM 1-2	1	13
32504	DRUM 1-2	2	13
32506	DRUM 3-4	1	13
32506	DRUM 3-4	2	13
32484	OXBOW F	1	13
32472	SPAULDG	3	12
32472	SPAULDG	1	12
32472	SPAULDG	2	12
32488	HAYPRES+	1	12
32480	BOWMAN	1	12
32488	HAYPRES+	2	12
32464	DTCHFLT1	1	11
32162	RIV.DLTA	1	11
32462	CHI.PARK	1	9
32500	ULTR RCK	1	6
31862	DEADWOOD	1	5
31814	FORBSTWN	1	5
31832	SLY.CR.	1	5
31794	WOODLEAF	1	5
32478	HALSEY F	1	2
31888	OROVLLE	1	2
32512	WISE	1	2
31834	KELLYRDG	1	2
31890	PO POWER	1	2
31890	PO POWER	2	2
32460	NEWCSTLE	1	1

South of Rio Oso Sub-area

The most critical contingency is the loss of the Rio Oso-Gold Hill 230 line followed by loss of the Rio Oso-Lincoln 115 kV line or vice versa. The area limitation is thermal overloading of the Rio Oso-Atlantic 230 kV line. This limiting contingency establishes a LCR of 500 MW (includes 31 MW of QF and 593 MW of Muni generation) in 2013 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency is the loss of the Rio Oso-Gold Hill 230 line with the Ralston unit out of service. The area limitation is thermal overloading of the Rio Oso-Atlantic 230 kV line. This limiting contingency establishes a LCR of 333 MW (includes 31 MW of QF and 593 MW of Muni generation) in 2013.

Effectiveness factors:

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

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

Changes compared to last year's results:

The Sierra Area load forecast went down by 78 MW and the LCR need has decreased by 44 MW.

Sierra Overall Requirements:

2013	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	171	1103	765	2039

2013	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[14]	1408	0	1408
Category C (Multiple)[15]	1712	218	1930

4. Stockton Area

Area Definition

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

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

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

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

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

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

[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 than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[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 NERC transmission operations standards.

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

The substations that delineate the Lockeford Sub-area are:

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

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

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

The substations that delineate the Weber Sub-area are:

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

Total 2013 busload within the defined area: 1090 MW with 19 MW of losses resulting in total load + losses of 1109 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BEARDS_7_UNIT 1	34074	BEARDSLY	6.9	8.36	1	Tesla-Bellota	Aug NQC	MUNI
CURIS_1_QF				0.84		Tesla-Bellota	Not modeled Aug NQC	QF/Selfgen
DONNLS_7_UNIT	34058	DONNELLS	13.8	72.00	1	Tesla-Bellota	Aug NQC	MUNI
LODI25_2_UNIT 1	38120	LODI25CT	9.11	22.70	1	Lockeford		MUNI
PHOENX_1_UNIT				1.41		Tesla-Bellota	Not modeled Aug NQC	Market
SCHLTE_1_PL1X3	33805	GWFTRCY1	13.8	83.56	1	Tesla-Bellota		Market
SCHLTE_1_PL1X3	33807	GWFTRCY2	13.8	82.88	1	Tesla-Bellota		Market
SNDBAR_7_UNIT 1	34060	SANDBAR	13.8	12.02	1	Tesla-Bellota	Aug NQC	MUNI
SPIFBD_1_PL1X2	33917	FBERBORD	115	1.91	1	Tesla-Bellota	Aug NQC	QF/Selfgen
SPRGAP_1_UNIT 1	34078	SPRNG GP	6	0.04	1	Tesla-Bellota	Aug NQC	Market
STANIS_7_UNIT 1	34062	STANISLS	13.8	91.00	1	Tesla-Bellota	Aug NQC	Market
STNRES_1_UNIT	34056	STNSLSRP	13.8	15.98	1	Tesla-Bellota	Aug NQC	QF/Selfgen
STOKCG_1_UNIT 1	33814	CPC STCN	12.5	34.91	1	Tesla-Bellota	Aug NQC	QF/Selfgen
TULLCK_7_UNITS	34076	TULLOCH	6.9	8.23	1	Tesla-Bellota	Aug NQC	MUNI
TULLCK_7_UNITS	34076	TULLOCH	6.9	8.24	2	Tesla-Bellota	Aug NQC	MUNI
ULTPCH_1_UNIT 1	34050	CH.STN.	13.8	15.17	1	Tesla-Bellota	Aug NQC	QF/Selfgen
VLYHOM_7_SSJID				1.39		Tesla-Bellota	Not modeled Aug NQC	QF/Selfgen
CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	3.50	1	Tesla-Bellota	No NQC - hist. data	MUNI
CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	3.50	2	Tesla-Bellota	No NQC - hist. data	MUNI
CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	3.50	3	Tesla-Bellota	No NQC - hist. data	MUNI

NA	33687	STKTN WW	60	1.50	1	Weber	No NQC - hist. data	QF/Selfgen
NA	33830	GEN.MILL	9.11	2.50	1	Lockeford	No NQC - hist. data	QF/Selfgen
COGNAT_1_UNIT	33818	COG.NTNL	12	0.00	1	Weber	Retired	QF/Selfgen
SCHLTE_1_PL1X3	33811	GWFTRCY3	13.8	145	1	Tesla-Bellota	No NQC - Pmax	Market

Major new projects modeled:

1. Weber 230/60 kV Transformer Replacement
2. Weber-Stockton "A" #1 & #2 60 kV Reconductoring
3. GWF Tracy Expansion – Loop in Tesla-Manteca 115 kV line to Schulte switching station.
4. GWF Tracy (145 MW) connecting to Schulte 115 kV switching station.

<u>Critical Contingency Analysis Summary</u>

Stockton overall

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

Tesla-Bellota Sub-area

The two most critical contingencies listed below together establish a local capacity need of 518 MW (includes 70 MW of QF and 119 MW of Muni generation as well as 130 MW of deficiency) in 2013 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical contingency for the Tesla-Bellota pocket is the loss of Schulte-Kasson-Manteca 115 kV and Schulte-Lammers 115 kV. The area limitation is thermal overload of the Tesla-Tracy 115 kV line above its emergency rating. This limiting contingency establishes a local capacity need of 412 MW (includes 70 MW of QF and 119 MW of Muni generation as well as 130 MW of deficiency) in 2013.

The second most critical contingency for the Tesla-Bellota pocket is the loss of Tesla-Tracy 115 kV and Tesla-Schulte #2 115 kV lines. The area limitation is thermal overload of the Tesla-Schulte #1 115 kV line. This limiting contingency establishes a 2013 local capacity need of 388 MW (includes 70 MW of QF and 119 MW of Muni generation).

The single most critical contingency for the Tesla-Bellota pocket is the loss of Tesla-Tracy 115 kV line and the loss of the GWF Tracy unit #3. The area limitation is thermal overload of the Tesla-Schulte #1 115 kV line. This single contingency establishes a local capacity need of 242 MW (includes 70 MW of QF and 119 MW of Muni generation) in 2013.

Effectiveness factors:

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

Lockeford Sub-area

The critical contingency for the Lockeford area is the loss of Lockeford-Industrial 60 kV circuit and Lockeford-Lodi #2 60 kV circuit. The area limitation is thermal overloading of the Lockeford-Lodi Jct. section of the Lockeford-Lodi #3 60 kV circuit. This limiting contingency establishes a 2013 local capacity need of 49 MW (including 2 MW of QF and 23 MW of Muni generation as well as 24 MW of deficiency) as the minimum capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

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

Weber Sub-area

No requirement due to the Weber 230/60 kV transformer replacement and Weber – Stockton “A” #1 & 2 60 kV lines reconductoring projects. If these projects are delayed all units within this sub-area (Cogeneration National and Stockton Wastewater) are needed.

Changes compared to last year’s results:

Overall the Stockton area load forecast went up by 23 MW. There are a few transmission upgrade modeled and one new generation project modeled (GWF Tracy Expansion – Loop in the Tesla-Manteca 115 kV line to Schulte switching station) in the Stockton local area compared to last year studies. The Weber sub-area is eliminated because of the Weber 230/60 kV transformer upgrade and Weber – Stockton “A” #1 & 2 60 kV lines reconductoring projects. As a result, the overall requirement for the Stockton area stayed the same as last year.

Stockton Overall Requirements:

2013	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	74	142	404	620

2013	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[16]	242	0	242
Category C (Multiple)[17]	413	154	567

5. Greater Bay Area

<u>Area Definition</u>

The transmission tie lines into the Greater Bay Area are:

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

[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 than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[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 NERC transmission operations standards.

12) Tesla-Newark #2 230 kV
13) Tesla-Ravenswood 230 kV
14) Tesla-Metcalf 500 kV
15) Moss Landing-Metcalf 500 kV
16) Moss Landing-Metcalf #1 230 kV
17) Moss Landing-Metcalf #2 230 kV
18) Oakdale TID-Newark #1 115 kV
19) Oakdale TID-Newark #2 115 kV

The substations that delineate the Greater Bay Area are:

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

Total 2013 bus load within the defined area is 9770 MW with 199 MW of losses and 264 MW of pumps resulting in total load + losses + pumps of 10233 MW. This corresponds to about 9633 MW of load per CEC forecast since there are about 600 MW of loads behind the meter modeled in the base cases.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ALMEGT_1_UNIT 1	38118	ALMDACT1	13.8	23.80	1	Oakland		MUNI
ALMEGT_1_UNIT 2	38119	ALMDACT2	13.8	24.40	1	Oakland		MUNI
BANKPP_2_NSPIN	38760	DELTA E	13.2	28.00	10	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38760	DELTA E	13.2	28.00	11	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38765	DELTA D	13.2	28.00	8	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38765	DELTA D	13.2	28.00	9	Contra Costa	Pumps	MUNI

BANKPP_2_NSPIN	38770	DELTA C	13.2	28.00	6	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38770	DELTA C	13.2	28.00	7	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38815	DELTA B	13.2	28.00	4	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38815	DELTA B	13.2	28.00	5	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38820	DELTA A	13.2	9.00	1	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38820	DELTA A	13.2	9.00	2	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38820	DELTA A	13.2	22.00	3	Contra Costa	Pumps	MUNI
BLHVN_7_MENLOP				1.06		None	Not modeled Aug NQC	QF/Selfgen
BRDSLD_2_HIWIND	32172	HIGHWINDS	34.5	35.09	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_MTZUMA	32171	HIGHWND3	34.5	5.95	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_SHILO1	32176	SHILOH	34.5	36.85	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_SHILO2	32177	SHILOH 2	34.5	33.87	1	Contra Costa	Aug NQC	Wind
CALPIN_1_AGNEW	35860	OLS-AGNE	9.11	22.43	1	San Jose	Aug NQC	QF/Selfgen
CARDCG_1_UNITS	33463	CARDINAL	12.5	10.67	1	None	Aug NQC	QF/Selfgen
CARDCG_1_UNITS	33463	CARDINAL	12.5	10.68	2	None	Aug NQC	QF/Selfgen
CLRMTK_1_QF				0.00		Oakland	Not modeled	QF/Selfgen
COCOPP_7_UNIT 6	33116	C.COS 6	18	0.00	1	Contra Costa	Energy Only	Market
COCOPP_7_UNIT 7	33117	C.COS 7	18	0.00	1	Contra Costa	Energy Only	Market
CONTAN_1_UNIT	36856	CCA100	13.8	25.80	1	San Jose	Aug NQC	QF/Selfgen
CROKET_7_UNIT	32900	CRCKTCOG	18	194.00	1	Pittsburg	Aug NQC	QF/Selfgen
CSCCOG_1_UNIT 1	36854	Cogen	12	3.00	1	San Jose		MUNI
CSCCOG_1_UNIT 1	36854	Cogen	12	3.00	2	San Jose		MUNI
CSCGNR_1_UNIT 1	36858	Gia100	13.8	24.00	1	San Jose		MUNI
CSCGNR_1_UNIT 2	36895	Gia200	13.8	24.00	2	San Jose		MUNI
DELTA_2_PL1X4	33107	DEC STG1	24	269.61	1	Pittsburg	Aug NQC	Market
DELTA_2_PL1X4	33108	DEC CTG1	18	181.13	1	Pittsburg	Aug NQC	Market
DELTA_2_PL1X4	33109	DEC CTG2	18	181.13	1	Pittsburg	Aug NQC	Market
DELTA_2_PL1X4	33110	DEC CTG3	18	181.13	1	Pittsburg	Aug NQC	Market
DUANE_1_PL1X3	36863	DVRaGT1	13.8	49.27	1	San Jose		MUNI
DUANE_1_PL1X3	36864	DVRbGT2	13.8	49.27	1	San Jose		MUNI
DUANE_1_PL1X3	36865	DVRaST3	13.8	49.26	1	San Jose		MUNI
FLOWD1_6_ALTPP1	35318	FLOWDPTR	9.11	0.00	1	Contra Costa	Aug NQC	Wind
FLOWD2_2_UNIT 1				2.86		Contra Costa	Not Modeled Aug NQC	Wind
GATWAY_2_PL1X3	33118	GATEWAY1	18	189.27	1	Contra Costa	Aug NQC	Market
GATWAY_2_PL1X3	33119	GATEWAY2	18	185.36	1	Contra Costa	Aug NQC	Market
GATWAY_2_PL1X3	33120	GATEWAY3	18	185.36	1	Contra Costa	Aug NQC	Market
GILROY_1_UNIT	35850	GLRY COG	13.8	69.30	1	Llagas	Aug NQC	Market
GILROY_1_UNIT	35850	GLRY COG	13.8	35.70	2	Llagas	Aug NQC	Market
GILRPP_1_PL1X2	35851	GROYPKR1	13.8	45.50	1	Llagas	Aug NQC	Market
GILRPP_1_PL1X2	35852	GROYPKR2	13.8	45.50	1	Llagas	Aug NQC	Market
GILRPP_1_PL3X4	35853	GROYPKR3	13.8	46.00	1	Llagas	Aug NQC	Market
GRZZLY_1_BERKLY	32740	HILLSIDE	115	24.58	1	None	Aug NQC	QF/Selfgen
GWFPW1_6_UNIT	33131	GWF #1	9.11	15.73	1	Pittsburg, Contra Costa	Aug NQC	QF/Selfgen
GWFPW2_1_UNIT 1	33132	GWF #2	13.8	17.53	1	Pittsburg	Aug NQC	QF/Selfgen
GWFPW3_1_UNIT 1	33133	GWF #3	13.8	14.53	1	Pittsburg, Contra Costa	Aug NQC	QF/Selfgen
GWFPW4_6_UNIT 1	33134	GWF #4	13.8	16.51	1	Pittsburg, Contra Costa	Aug NQC	QF/Selfgen
GWFPW5_6_UNIT 1	33135	GWF #5	13.8	17.54	1	Pittsburg	Aug NQC	QF/Selfgen
HICKS_7_GUADLP				1.98		None	Not modeled Aug	QF/Selfgen

							NQC	
KIRKER_7_KELCYN	32951	KIRKER	115	3.21		Pittsburg	Not modeled	Market
LAWRNC_7_SUNYVL				0.16		None	Not modeled Aug NQC	Market
LECEF_1_UNITS	35854	LECEFGT1	13.8	46.50	1	San Jose	Aug NQC	Market
LECEF_1_UNITS	35855	LECEFGT2	13.8	46.50	1	San Jose	Aug NQC	Market
LECEF_1_UNITS	35856	LECEFGT3	13.8	46.50	1	San Jose	Aug NQC	Market
LECEF_1_UNITS	35857	LECEFGT4	13.8	46.50	1	San Jose	Aug NQC	Market
LFC 51_2_UNIT 1	35310	LFC FIN+	9.11	1.72	1	None	Aug NQC	Wind
LMBEPK_2_UNITA1	32173	LAMBGT1	13.8	47.00	1	Contra Costa	Aug NQC	Market
LMBEPK_2_UNITA2	32174	GOOSEHGT	13.8	46.00	2	Contra Costa	Aug NQC	Market
LMBEPK_2_UNITA3	32175	CREEDGT1	13.8	47.00	3	Contra Costa	Aug NQC	Market
LMEC_1_PL1X3	33111	LMECCT2	18	163.20	1	Pittsburg	Aug NQC	Market
LMEC_1_PL1X3	33112	LMECCT1	18	163.20	1	Pittsburg	Aug NQC	Market
LMEC_1_PL1X3	33113	LMECST1	18	229.60	1	Pittsburg	Aug NQC	Market
MARKHM_1_CATLST	35863	CATALYST	9.11	0.00	1	San Jose		QF/Selfgen
MARTIN_1_SUNSET				0.80		None	Not modeled Aug NQC	QF/Selfgen
METCLF_1_QF				0.08		None	Not modeled Aug NQC	QF/Selfgen
METEC_2_PL1X3	35881	MEC CTG1	18	178.43	1	None	Aug NQC	Market
METEC_2_PL1X3	35882	MEC CTG2	18	178.43	1	None	Aug NQC	Market
METEC_2_PL1X3	35883	MEC STG1	18	213.14	1	None	Aug NQC	Market
MILBRA_1_QF				0.00		None	Not modeled	QF/Selfgen
MISSIX_1_QF				0.24		None	Not modeled Aug NQC	QF/Selfgen
MLPTAS_7_QFUNTS				0.02		San Jose	Not modeled Aug NQC	QF/Selfgen
MNTAGU_7_NEWBYI				2.87		None	Not modeled Aug NQC	QF/Selfgen
NEWARK_1_QF				0.03		None	Not modeled Aug NQC	QF/Selfgen
OAK C_7_UNIT 1	32901	OAKLND 1	13.8	55.00	1	Oakland		Market
OAK C_7_UNIT 2	32902	OAKLND 2	13.8	55.00	1	Oakland		Market
OAK C_7_UNIT 3	32903	OAKLND 3	13.8	55.00	1	Oakland		Market
OAK L_7_EBMUD				0.56		Oakland	Not modeled Aug NQC	MUNI
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	1	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	2	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	3	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	4	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	5	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	6	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	7	None		Market
PALALT_7_COBUG				4.50		None	Not modeled	MUNI
PITTSP_7_UNIT 5	33105	PTSB 5	18	312.00	1	Pittsburg		Market
PITTSP_7_UNIT 6	33106	PTSB 6	18	317.00	1	Pittsburg		Market
PITTSP_7_UNIT 7	30000	PTSB 7	20	682.00	1	Pittsburg		Market
RICHMN_7_BAYENV				2.00		None	Not modeled Aug NQC	QF/Selfgen
RVRVEW_1_UNITA1	33178	RVEC_GEN	13.8	46.00	1	Contra Costa	Aug NQC	Market
SEAWST_6_LAPOS	35312	SEAWESTF	9.11	0.35	1	Contra Costa	Aug NQC	Wind
SRINTL_6_UNIT	33468	SRI INTL	9.11	0.76	1	None	Aug NQC	QF/Selfgen
STAUFF_1_UNIT	33139	STAUFER	9.11	0.01	1	None	Aug NQC	QF/Selfgen

STOILS_1_UNITS	32921	CHEVGEN1	13.8	1.41	1	Pittsburg	Aug NQC	QF/Selfgen
STOILS_1_UNITS	32922	CHEVGEN2	13.8	1.41	1	Pittsburg	Aug NQC	QF/Selfgen
TIDWTR_2_UNITS	33151	FOSTER W	12.5	5.93	1	Pittsburg	Aug NQC	QF/Selfgen
TIDWTR_2_UNITS	33151	FOSTER W	12.5	5.93	2	Pittsburg	Aug NQC	QF/Selfgen
TIDWTR_2_UNITS	33151	FOSTER W	12.5	5.93	3	Pittsburg	Aug NQC	QF/Selfgen
UNCHEM_1_UNIT	32920	UNION CH	9.11	15.94	1	Pittsburg	Aug NQC	QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.03	1	Pittsburg	Aug NQC	QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.03	2	Pittsburg	Aug NQC	QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.03	3	Pittsburg	Aug NQC	QF/Selfgen
UNTDQF_7_UNITS	33466	UNTED CO	9.11	22.81	1	None	Aug NQC	QF/Selfgen
USWNDR_2_SMUD	32169	SOLANOWP	21	17.82	1	Contra Costa	Aug NQC	Wind
USWNDR_2_UNITS	32168	EXNCO	9.11	26.27	1	Contra Costa	Aug NQC	Wind
USWPFK_6_FRICK	35320	USW FRIC	12	0.47	1	Contra Costa	Aug NQC	Wind
USWPFK_6_FRICK	35320	USW FRIC	12	0.47	2	Contra Costa	Aug NQC	Wind
USWPJR_2_UNITS	33838	USWP_#3	9.11	2.57	1	Contra Costa	Aug NQC	Wind
WNDMAS_2_UNIT 1	33170	WINDMSTR	9.11	3.30	1	Contra Costa	Aug NQC	Wind
ZOND_6_UNIT	35316	ZOND SYS	9.11	4.50	1	Contra Costa	Aug NQC	Wind
IBMCTL_1_UNIT 1	35637	IBM-CTLE	115	0.00	1	San Jose	No NQC - hist. data	Market
IMHOFF_1_UNIT 1	33136	CCCSD	12.5	4.40	1	Pittsburg	No NQC - hist. data	QF/Selfgen
SHELRF_1_UNITS	33141	SHELL 1	12.5	20.00	1	Pittsburg	No NQC - hist. data	QF/Selfgen
SHELRF_1_UNITS	33142	SHELL 2	12.5	40.00	1	Pittsburg	No NQC - hist. data	QF/Selfgen
SHELRF_1_UNITS	33143	SHELL 3	12.5	40.00	1	Pittsburg	No NQC - hist. data	QF/Selfgen
ZANKER_1_UNIT 1	35861	SJ-SCL W	9.11	5.00	1	San Jose	No NQC - hist. data	QF/Selfgen
BRDSLD_2_MTZUM2	32179	MNTZUMA2	0.69	26	1	Contra Costa	No NQC - est. data	Wind
BRDSLD_2_SHLO3A	32191	SHLH3AC2	0.58	30	1	Contra Costa	No NQC - est. data	Wind
BRDSLD_2_SHLO3B	32194	SHLH3BC2	0.58	30	1	Contra Costa	No NQC - est. data	Wind
KELSO_2_GTG6	33813	KELSOCT1	13.8	50	1	Contra Costa	No NQC - Pmax	Market
KELSO_2_GTG7	33815	KELSOCT2	13.8	50	2	Contra Costa	No NQC - Pmax	Market
KELSO_3_GTG8	33817	KELSOCT3	13.8	50	3	Contra Costa	No NQC - Pmax	Market
KELSO_3_GTG9	33819	KELSOCT4	13.8	50	4	Contra Costa	No NQC - Pmax	Market
New Unit	32186	SOLANO	34.5	42	1	Contra Costa	No NQC - est. data	Wind
New Unit	33188	T320BS1	16.4	193.5	1	Contra Costa	No NQC - Pmax	Market
New Unit	33188	T320BS1	16.4	193.5	2	Contra Costa	No NQC - Pmax	Market
New Unit	33189	T320BS2	16.4	193.5	3	Contra Costa	No NQC - Pmax	Market
New Unit	33189	T320BS2	16.4	193.5	4	Contra Costa	No NQC - Pmax	Market
New Unit	35304	Q045CTG1	15	177.50	1	None	No NQC - Pmax	Market
New Unit	35305	Q045CTG2	15	177.50	1	None	No NQC - Pmax	Market
New Unit	35306	Q067STG1	15	245.00	1	None	No NQC - Pmax	Market
New Unit	35858	T03878ST1	13.8	120.00	1	San Jose	No NQC - Pmax	Market

Major new projects modeled:

1. Replace Moraga 230/115kV Bank #1 with larger unit - 12/30/2012

2. Eastshore - San Mateo 230 kV Line Reconductor – 12/01/2011
3. Eastshore - Dumbarton 115 kV Line Reconductor - 06/01/2012
4. Four Wind farms connected to Birds Landing (~ 340 MW P max)
5. Russell City Energy Center (~ 600 MW P max) - 06/01/2013
6. Marsh Landing Generating Station (~ 774 MW P max) - 12/01/2012
7. Los Esteros Critical Energy Facility (LECEF) capacity increase by 120 MW (total 295 MW) - 05/01/2013

Critical Contingency Analysis Summary

Oakland Sub-area

The most critical contingency is an outage of the C-X #2 and #3 115 kV cables. The area limitation is thermal overloading of the D-L 115 kV lines. This limiting contingency establishes a LCR of 68 MW in 2012 (includes 49 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

This Oakland requirement does not include the need for Pittsburg/Oakland sub-area.

Effectiveness factors:

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

Llagas Sub-area

The most critical contingency is an outage between Metcalf D and Morgan Hill 115 kV (with one of the Gilroy Peaker off-line). The area limitation is thermal overloading of the Metcalf-Llagas 115 kV line as well as voltage drop (5%) at the Morgan Hill substation. As documented within a CAISO Operating Procedure, this limitation is dependent on power flowing in the direction from Metcalf to Llagas/Morgan Hill. This limiting contingency establishes a LCR of 100 MW in 2013 (includes 0 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

San Jose Sub-area

The most critical contingency is an outage of Metcalf-El Patio #1 or #2 115 kV line followed by Metcalf-Evergreen #1 115 kV line. The area limitation is thermal overloading of the Evergreen – San Jose B 115 kV line. This limiting contingency establishes a LCR of 565 MW in 2013 (includes 53 MW of QF and 202 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is an outage of the Metcalf-Evergreen #1 115 kV line with Duane PP out of service. The sub-area area limitation is thermal overloading of the Northern Receiving Station (NRS) - Southern Receiving Station (SRS) 115 kV. This limiting contingency establishes a LCR of 354 MW in 2013 (including 53 MW of QF and 202 MW of Muni generation).

Effectiveness factors:

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

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

Pittsburg and Oakland Sub-area Combined

The most critical contingency is an outage of the Moraga #3 230/115 kV transformer combined with the loss of Delta Energy Center. The sub-area area limitation is thermal overloading of Moraga #1 230/115 kV transformer. This limiting contingency establishes a LCR of 2379 MW in 2013 (including 417 MW of QF and 49 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is an outage of the Moraga #3 230/115 kV transformer. The sub-area area limitation is thermal overloading of the Moraga #1 230/115 kV transformer. This limiting contingency establishes a LCR of 1966 MW in 2013 (including 417 MW of QF and 49 MW of Muni generation).

Effectiveness factors:

Please see Bay Area overall.

Contra Costa Sub-area

The most critical contingency is an outage of Kelso-Tesla 230 kV with the Gateway off line. The area limitation is thermal overloading of the Delta Switching Yard-Tesla 230 kV line. This limiting contingency establishes a LCR of 1052 MW in 2013 (includes 47 MW of QF and 298 MW of Wind generation and 264 MW of MUNI pumps) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

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

38770	DELTA C	7	71
38815	DELTA B	4	71
38815	DELTA B	5	71
38820	DELTA A	3	71
33170	WINDMSTR	1	68
33118	GATEWAY1	1	23
33119	GATEWAY2	1	23
33120	GATEWAY3	1	23
33116	C.COS 6	1	23
33117	C.COS 7	1	23
33133	GWF #3	1	23
33134	GWF #4	1	23
33178	RVEC_GEN	1	23
33131	GWF #1	1	22
32179	T222	1	18
32188	P0611G	1	18
32190	Q039	1	18
32186	P0609	1	18
32171	HIGHWND3	1	18
32177	Q0024	1	18
32168	ENXCO	2	18
32169	SOLANOWP	1	18
32172	HIGHWNDS	1	18
32176	SHILOH	1	18
33838	USWP_#3	1	18
32173	LAMBGT1	1	14
32174	GOOSEHGT	2	14
32175	CREEDGT1	3	14
35312	SEAWESTF	1	11
35316	ZOND SYS	1	11
35320	USW FRIC	1	11

Bay Area overall

As the aggregate sub pocket LCR is not adequate to cover the overall Bay area contingency,

The most critical contingency is an overlapping outage of the Tesla-Metcalf 500 kV line and Tesla-Newark #1 230 kV line. The sub-area area limitation is thermal overload on the Tesla-Ravenswood 230 kV line. This limiting contingency establishes a LCR of 4502 MW in 2013 (including 549 MW of QF, 519 MW of MUNI and 300 MW of wind generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is an outage of the Tesla-Metcalf 500 kV line with Delta Energy Center out of service. The sub-area area limitation is reactive margin within the Bay Area. This limiting contingency establishes a LCR of 3479 MW in 2013 (including 549 MW of QF, 519 MW of MUNI and 300 MW of wind generation).

Effectiveness factors:

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

Changes compared to last year's results:

Overall the load forecast went up by 279 MW. There are many new resources and transmission projects modeled compared with last year study. As an overall result, LCR has increased by 224 MW.

Bay Area Overall Requirements:

2013	Wind (MW)	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	300	549	519	6296	7664

2013	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[18]	3479	0	3479
Category C (Multiple)[19]	4502	0	4502

[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 than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[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 NERC transmission operations standards.

6. Greater Fresno Area

Area Definition

The transmission facilities coming into the Greater Fresno area are:

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

The substations that delineate the Greater Fresno area are:

1) Gates is out Henrietta is in
2) Gates is out Henrietta is in
3) Gates 230 kV is out Gates 70 kV is in
4) Los Banos 230 kV is out Los Banos 70 kV is in
5) Los Banos 230 kV is out Los Banos 70 kV is in
6) Panoche is out Helm is in
7) Panoche is out Mc Mullin is in
8) Panoche 115 kV is in Panoche 230 kV is out
9) Panoche 115 kV is in Panoche 230 kV is out
10) Warnerville is out Wilson is in
11) Wilson is in Melones is out
12) Quebec SP is out Corcoran is in
13) Coalinga is in San Miguel is out

2013 total busload within the defined area is 3032 MW with 81 MW of losses resulting in a total (load plus losses) of 3032 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
AGRICO_6_PL3N5	34608	AGRICO	13.8	20.00	3	Wilson, Herndon		Market
AGRICO_7_UNIT	34608	AGRICO	13.8	43.05	2	Wilson, Herndon		Market
AGRICO_7_UNIT	34608	AGRICO	13.8	7.45	4	Wilson, Herndon		Market
BALCHS_7_UNIT 1	34624	BALCH	13.2	33.00	1	Wilson, Herndon	Aug NQC	Market

BALCHS_7_UNIT 2	34612	BLCH	13.8	52.50	1	Wilson, Herndon	Aug NQC	Market
BALCHS_7_UNIT 3	34614	BLCH	13.8	52.50	1	Wilson, Herndon	Aug NQC	Market
BORDEN_2_QF	34253	BORDEN D	12.5	0.98	QF	Wilson	Aug NQC	QF/Selfgen
BULLRD_7_SAGNES	34213	BULLD 12	12.5	0.00	1	Wilson	Aug NQC	QF/Selfgen
CAPMAD_1_UNIT 1	34179	MADERA_G	13.8	17.00	1	Wilson		Market
CHEVCO_6_UNIT 1	34652	CHV.COAL	9.11	6.69	1	Wilson	Aug NQC	QF/Selfgen
CHEVCO_6_UNIT 2	34652	CHV.COAL	9.11	1.40	2	Wilson	Aug NQC	QF/Selfgen
CHWCHL_1_BIOMAS	34305	CHWCHLA2	13.8	3.84	1	Wilson, Herndon	Aug NQC	Market
CHWCHL_1_UNIT	34301	CHOWCOGN	13.8	48.00	1	Wilson, Herndon		Market
COLGA1_6_SHELLW	34654	COLNGAGN	9.11	35.61	1	Wilson	Aug NQC	QF/Selfgen
CRESSY_1_PARKER	34140	CRESSEY	115	1.24		Wilson	Not modeled Aug NQC	MUNI
CRNEVL_6_CRNVA	34634	CRANEVLY	12	0.71	1	Wilson	Aug NQC	Market
CRNEVL_6_SJQN 2	34631	SJ2GEN	9.11	3.20	1	Wilson	Aug NQC	Market
CRNEVL_6_SJQN 3	34633	SJ3GEN	9.11	4.20	1	Wilson	Aug NQC	Market
DINUBA_6_UNIT	34648	DINUBA E	13.8	9.87	1	Wilson, Herndon		Market
ELNIDP_6_BIOMAS	34330	ELNIDO	13.8	3.16	1	Wilson	Aug NQC	Market
EXCHEC_7_UNIT 1	34306	EXCHQUER	13.8	61.77	1	Wilson	Aug NQC	MUNI
FRIANT_6_UNITS	34636	FRIANTDM	6.6	8.71	2	Wilson	Aug NQC	QF/Selfgen
FRIANT_6_UNITS	34636	FRIANTDM	6.6	4.65	3	Wilson	Aug NQC	QF/Selfgen
FRIANT_6_UNITS	34636	FRIANTDM	6.6	1.23	4	Wilson	Aug NQC	QF/Selfgen
GATES_6_PL1X2	34553	WHD_GAT2	13.8	46.00	1	Wilson	NQC List has 0 MW	Market
GWFPWR_1_UNITS	34431	GWF_HEP1	13.8	42.20	1	Wilson, Herndon		Market
GWFPWR_1_UNITS	34433	GWF_HEP2	13.8	42.20	1	Wilson, Herndon		Market
HAASPH_7_PL1X2	34610	HAAS	13.8	68.15	1	Wilson, Herndon	Aug NQC	Market
HAASPH_7_PL1X2	34610	HAAS	13.8	68.15	2	Wilson, Herndon	Aug NQC	Market
HELMPG_7_UNIT 1	34600	HELMS	18	404.00	1	Wilson	Aug NQC	Market
HELMPG_7_UNIT 2	34602	HELMS	18	404.00	2	Wilson	Aug NQC	Market
HELMPG_7_UNIT 3	34604	HELMS	18	404.00	3	Wilson	Aug NQC	Market
HENRTA_6_UNITA1	34539	GWF_GT1	13.8	45.33	1	Wilson, Henrietta		Market
HENRTA_6_UNITA2	34541	GWF_GT2	13.8	45.23	1	Wilson, Henrietta		Market
INTTRB_6_UNIT	34342	INT.TURB	9.11	2.50	1	Wilson	Aug NQC	QF/Selfgen
JRWOOD_1_UNIT 1	34332	JRWCOGEN	9.11	1.70	1	Wilson	Aug NQC	QF/Selfgen
KERKH1_7_UNIT 1	34344	KERCKHOF	6.6	13.00	1	Wilson, Herndon	Aug NQC	Market
KERKH1_7_UNIT 2	34344	KERCKHOF	6.6	8.50	2	Wilson, Herndon	Aug NQC	Market
KERKH1_7_UNIT 3	34344	KERCKHOF	6.6	12.80	3	Wilson, Herndon	Aug NQC	Market
KERKH2_7_UNIT 1	34308	KERCKHOF	13.8	153.90	1	Wilson, Herndon	Aug NQC	Market
KINGCO_1_KINGBR	34642	KINGSBUR	9.11	22.97	1	Wilson, Herndon	Aug NQC	QF/Selfgen
KINGRV_7_UNIT 1	34616	KINGSRIV	13.8	51.20	1	Wilson, Herndon	Aug NQC	Market
MALAGA_1_PL1X2	34671	KRCDPCT1	13.8	48.00	1	Wilson, Herndon		Market
MALAGA_1_PL1X2	34672	KRCDPCT2	13.8	48.00	1	Wilson, Herndon		Market
MCCALL_1_QF	34219	MCCALL 4	12.5	0.64	QF	Wilson, Herndon	Aug NQC	QF/Selfgen
MCSWAN_6_UNITS	34320	MCSWAIN	9.11	5.22	1	Wilson	Aug NQC	MUNI
MENBIO_6_UNIT	34334	BIO PWR	9.11	20.67	1	Wilson	Aug NQC	QF/Selfgen
MERCFL_6_UNIT	34322	MERCEDFL	9.11	2.30	1	Wilson	Aug NQC	Market
PINFLT_7_UNITS	38720	PINEFLAT	13.8	27.50	1	Wilson, Herndon	Aug NQC	MUNI
PINFLT_7_UNITS	38720	PINEFLAT	13.8	27.50	2	Wilson, Herndon	Aug NQC	MUNI
PINFLT_7_UNITS	38720	PINEFLAT	13.8	27.50	3	Wilson, Herndon	Aug NQC	MUNI
PNCHPP_1_PL1X2	34328	STARGT1	13.8	55.58	1	Wilson		Market
PNCHPP_1_PL1X2	34329	STARGT2	13.8	55.58	1	Wilson		Market
PNOCHE_1_PL1X2	34142	WHD_PAN2	13.8	45.00	1	Wilson, Herndon		Market

PNOCHE_1_UNITA1	34186	DG_PAN1	13.8	42.78	1	Wilson		Market
SGREGY_6_SANGER	34646	SANGERCO	9.11	26.47	1	Wilson	Aug NQC	QF/Selfgen
STOREY_7_MDRCHW	34209	STOREY D	12.5	1.18	1	Wilson	Aug NQC	QF/Selfgen
ULTPFR_1_UNIT 1	34640	ULTR.PWR	9.11	18.31	1	Wilson, Herndon	Aug NQC	QF/Selfgen
WISHON_6_UNITS	34658	WISHON	2.3	4.51	1	Wilson	Aug NQC	Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	2	Wilson	Aug NQC	Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	3	Wilson	Aug NQC	Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	4	Wilson	Aug NQC	Market
WISHON_6_UNITS	34658	WISHON	2.3	0.36	5	Wilson	Aug NQC	Market
WRGHTP_7_AMENGY	24207	WRIGHT D	12.5	0.52	QF	Wilson	Aug NQC	QF/Selfgen
NA	34257	SANCTY D	12	0.00	1	Wilson	No NQC - hist. data	QF/Selfgen
NA	34263	SANDDRAG	12	0.00	1	Wilson	No NQC - hist. data	QF/Selfgen
NA	34265	AVENAL P	12	0.00	1	Wilson	No NQC - hist. data	QF/Selfgen
NA	34485	FRESNOWW	12.5	4.00	1	Wilson	No NQC - hist. data	QF/Selfgen
NA	34485	FRESNOWW	12.5	4.00	2	Wilson	No NQC - hist. data	QF/Selfgen
NA	34485	FRESNOWW	12.5	1.00	3	Wilson	No NQC - hist. data	QF/Selfgen
ONLLPP_6_UNIT 1	34316	ONEILPMP	9.11	0.50	1	Wilson	No NQC - hist. data	MUNI
GWFPWR_6_UNIT	34650	GWF-PWR.	9.11	0.00	1	Wilson, Henrietta	Retired	QF/Selfgen
MENBIO_6_RENEW1	34339	CALRENEW	12.5	0.00	1	Wilson	Energy Only	Market
New Unit	34603	JQBSWLT	12.5	0.00	ST	Wilson	Energy Only	Market
New Unit	34673	Q372	0.48	20.00	1	Wilson, Henrietta	No NQC - Pmax	Market
New Unit	34674	Q470	0.48	20.00	1	Wilson, Henrietta	No NQC - Pmax	Market
New Unit	34675	Q471	0.48	20.00	1	Wilson, Henrietta	No NQC - Pmax	Market
New Unit	34696	Q478	21	20.00	1	Wilson, Herndon	No NQC - Pmax	Market

Major new projects modeled:

1. A few new small resources we added.

<u>Critical Contingency Analysis Summary</u>

Wilson Sub-area

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

The most critical contingency is the loss of the Melones - Wilson 230 kV line overlapped with one of the Helms units out of service. This contingency would thermally overload the Warnerville - Wilson 230 kV line (most stringent) and possibly also the Gates-McCall 230 kV line. This limiting contingency establishes a LCR of 1786 MW in 2013 (includes 163 MW of QF and 151 MW of Muni generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
34332	JRWCOGEN	1	40%
34330	ELNIDO	1	37%
34209	STOREY D	1	35%
34322	MERCEDFL	1	35%
34320	MCSWAIN	1	34%
34306	EXCHQUER	1	34%
34305	CHWCHLA2	1	32%
34301	CHOWCOGN	1	32%
34253	BORDEN D	1	28%
34658	WISHON	1	28%
34658	WISHON	1	28%
34658	WISHON	1	28%
34658	WISHON	1	28%
34658	WISHON	1	28%
34631	SJ2GEN	1	28%
34633	SJ3GEN	1	27%
34636	FRIANTDM	2	27%
34636	FRIANTDM	3	27%
34636	FRIANTDM	4	27%
34600	HELMS 1	1	27%
34602	HELMS 2	1	27%
34604	HELMS 3	1	27%
34308	KERCKHOF	1	26%
34344	KERCKHOF	1	26%
34344	KERCKHOF	2	26%
34344	KERCKHOF	3	26%
34485	FRESNOWW	1	24%
34648	DINUBA E	1	22%
34179	MADERA_G	1	22%
34616	KINGSRIV	1	22%
34624	BALCH 1	1	21%
34671	KRCDPCT1	1	21%
34672	KRCDPCT2	1	21%
34640	ULTR.PWR	1	21%
34646	SANGERCO	1	21%
34642	KINGSBUR	1	19%

34696	Q478	1	18%
34610	HAAS	1	18%
34610	HAAS	1	18%
34614	BLCH 2-3	1	18%
34612	BLCH 2-2	1	17%
38720	PINE FLT	1	17%
38720	PINE FLT	2	17%
38720	PINE FLT	3	17%
34431	GWF_HEP1	1	17%
34433	GWF_HEP2	1	17%
34334	BIO PWR	1	14%
34673	Q372	1	13%
34674	Q470	1	13%
34675	Q471	1	13%
34608	AGRICO	2	13%
34608	AGRICO	3	13%
34608	AGRICO	4	13%
34539	GWF_GT1	1	13%
34541	GWF_GT2	1	13%
34650	GWF-PWR.	1	13%
34186	DG_PAN1	1	11%
34142	WHD_PAN2	1	11%
34652	CHV.COAL	1	10%
34652	CHV.COAL	2	10%
34553	WHD_GAT2	1	9%
34654	COLNGAGN	1	9%
34342	INT.TURB	1	6%
34316	ONEILPMP	1	6%

Herndon Sub-area

The most critical contingency is the loss of the Helm -McCall 230 kV line along with Gates-McCall 230 kV line. This contingency could thermally overload the Herndon–Manchester 115 kV line. This limiting contingency establishes a LCR of 372 MW (includes 42 MW of QF and 83 MW of Muni generation) in 2013 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
34648	DINUBA E	1	32%
34616	KINGSRIV	1	31%
34671	KRCDPCT1	1	31%
34672	KRCDPCT2	1	31%
34624	BALCH 1	1	31%

34640	ULTR.PWR	1	30%
34646	SANGERCO	1	30%
34618	MCCALL1T	1	30%
34610	HAAS	1	30%
34614	BLCH 2-3	1	30%
34612	BLCH 2-2	1	29%
38720	PINE FLT	3	29%
38720	PINE FLT	2	29%
38720	PINE FLT	1	29%
34696	Q478	1	29%
34642	KINGSBUR	1	28%
34344	KERCKHOF	3	20%
34344	KERCKHOF	2	20%
34344	KERCKHOF	1	20%
34308	KERCKHOF	1	19%
34433	GWF_HEP2	1	15%
34431	GWF_HEP1	1	15%

Henrietta Sub-area

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

Changes compared to last year's results:

From 2012 the load forecast has decreased by 88 MW and the LCR needs by 121 MW.

Fresno Area Overall Requirements:

2013	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	163	151	2503	2817

2013	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single) [20]	1786	0	1786
Category C (Multiple) [21]	1786	0	1786

[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 than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[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 NERC transmission operations standards.

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

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

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

2013 total busload within the defined area: 1295 MW with 16 MW of losses resulting in a total (load plus losses) of 1311 MW.

Total units and qualifying capacity available in this Kern area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BDGRCK_1_UNITS	35029	BADGERCK	9.11	43.40	1	Kern PP	Aug NQC	QF/Selfgen
BEARMT_1_UNIT	35066	PSE-BEAR	9.11	45.90	1	Kern PP, West Park	Aug NQC	QF/Selfgen
CHALK_1_UNIT	35038	CHLKCLF+	9.11	44.76	1	Kern PP	Aug NQC	QF/Selfgen
CHEVCD_6_UNIT	35052	CHEV.USA	9.11	2.16	1	Kern PP	Aug NQC	QF/Selfgen
CHEVCY_1_UNIT	35032	CHV-CYMR	9.11	5.04	1	Kern PP	Aug NQC	QF/Selfgen
DEXZEL_1_UNIT	35024	DEXEL +	9.11	28.45	1	Kern PP	Aug NQC	QF/Selfgen
DISCOV_1_CHEVRN	35062	DISCOVRY	9.11	2.44	1	Kern PP	Aug NQC	QF/Selfgen
DOUBLC_1_UNITS	35023	DOUBLE C	9.11	37.50	1	Kern PP	Aug NQC	QF/Selfgen
FELLOW_7_QFUNTS	34778	FELLOWS	21	1.34	QF	Kern PP	Aug NQC	QF/Selfgen
FRITO_1_LAY	35048	FRITOLAY	9.11	0.09	1	Kern PP	Aug NQC	QF/Selfgen
KERNFT_1_UNITS	35026	KERNFRNT	9.11	37.70	1	Kern PP	Aug NQC	QF/Selfgen
KERNRG_1_UNITS	35040	KERNRDGE	9.11	0.54	1	Kern PP	Aug NQC	QF/Selfgen
KERNRG_1_UNITS	35040	KERNRDGE	9.11	0.54	2	Kern PP	Aug NQC	QF/Selfgen
LIVOAK_1_UNIT 1	35058	PSE-LVOK	9.11	44.27	1	Kern PP	Aug NQC	QF/Selfgen
MIDSET_1_UNIT 1	35044	TX MIDST	9.11	32.82	1	Kern PP	Aug NQC	QF/Selfgen
MIDWAY_1_QF	34215	MIDWY D7	12.5	0.03	QF	Kern PP	Aug NQC	QF/Selfgen
MKTRCK_1_UNIT 1	35060	PSEMCKIT	9.11	40.01	1	Kern PP	Aug NQC	QF/Selfgen

MTNPOS_1_UNIT	35036	MT POSO	9.11	34.60	1	Kern PP	Aug NQC	QF/Selfgen
OILDAL_1_UNIT 1	35028	OILDALE	9.11	38.96	1	Kern PP	Aug NQC	QF/Selfgen
SIERRA_1_UNITS	35027	HISIERRA	9.11	43.26	1	Kern PP	Aug NQC	QF/Selfgen
TANHIL_6_SOLART	35050	SLR-TANN	9.11	10.18	1	Kern PP	Aug NQC	QF/Selfgen
TEMBLR_7_WELLPT	34201	TEMBLORD	12.5	0.26	WP	Kern PP	Aug NQC	QF/Selfgen
TXMCKT_6_UNIT				4.04		Kern PP	Not modeled Aug NQC	QF/Selfgen
ULTOGL_1_POSO	35035	ULTR PWR	9.11	34.73	1	Kern PP	Aug NQC	QF/Selfgen
UNVRSY_1_UNIT 1	35037	UNIVRSTY	9.11	32.23	1	Kern PP	Aug NQC	QF/Selfgen
VEDDER_1_SEKERN	35046	SEKR	9.11	6.10	1	Kern PP	Aug NQC	QF/Selfgen
MIDSUN_1_PL1X2	35034	MIDSUN +	9.11	0.00	1	Kern PP	Retired	Market
NA	34783	TEXCO_NM	9.11	0.00	1	Kern PP	No NQC - hist. data	QF/Selfgen
NA	34783	TEXCO_NM	9.11	3.40	2	Kern PP	No NQC - hist. data	QF/Selfgen
NA	35056	TX-LOSTH	4.16	8.80	1	Kern PP	No NQC - hist. data	QF/Selfgen
New Unit	35000	Q340	21	0.00	1	Kern PP	Energy Only	Market

Major new projects modeled:

1. Transfer Navy 35 load and self-gen to the Midway-Elk Hills 230 kV lines.

Critical Contingency Analysis Summary

Kern PP Sub-area

The most critical contingency is the outage of the Kern PP #5 or #3 230/115 kV transformer followed by the Kern PP – Double C Junction 115 kV line, which could thermally overload the parallel Kern PP #4 230/115 kV transformer. This limiting contingency establishes a LCR of 483 MW in 2013 (includes 584 MW of QF generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the loss of Kern PP #5 or #3 230/115 kV transformer bank, which could thermally overload the parallel Kern PP #4 230/115 kV transformer. This limiting contingency establishes a LCR of 295 MW in 2013 (includes 584 MW of QF generation).

Effectiveness factors:

The following table shows units that are at least 5% effective:

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)

35066	PSE-BEAR	1	22%
35029	BADGERCK	1	22%
35023	DOUBLE C	1	22%
35027	HISIERRA	1	22%
35026	KERNFRNT	1	21%
35058	PSE-LVOK	1	21%
35028	OILDALE	1	21%
35062	DISCOVRY	1	21%
35046	SEKR	1	21%
35024	DEXEL +	1	21%
35036	MT POSO	1	15%
35035	ULTR PWR	1	15%
35052	CHEV.USA	1	6%

Weedpatch Sub-area

Weedpatch sub-area has been eliminated from this year's LCR analysis. Circuit breaker (CB) 42 at San Bernard substation which was normally closed for earlier year's analysis was open for this year's analysis. This results in a system configuration that by design drops the load in the area for the most critical contingency reported in previous analysis.

West Park Sub-area

The most critical contingency is the loss of common mode Kern - West Park # 1 & #2 115 kV lines, resulting in the overload of the 6/42 To Magunden section of Kern – Magunden - Witco 115 kV line. This limitation establishes a LCR of 115 MW (includes 46 MW of QF generation and 42 MW of deficiency) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Changes compared to last year's results:

From 2012 the load forecast has increased by 201 MW and the LCR by 200 MW.

Kern Area Overall Requirements:

2013	QF/Selfgen (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	584	0	584

2013	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single) [22]	295	0	295
Category C (Multiple) [23]	483	42	525

8. LA Basin Area

Area Definition

The transmission tie lines into the LA Basin Area are:

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

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

1) San Onofre is in San Luis Rey is out
2) San Onofre is in Talega is out
3) Mira Loma is in Lugo is out
4) Rancho Vista is in Lugo is out
5) Eagle Rock is in Sylmar is out
6) Gould is in Sylmar is out
7) Mesa Cal is in Vincent is out
8) Rio Hondo is in Vincent is out
9) Eagle Rock is in Pardee is out
10) Devers is in Palo Verde is out
11) Mirage is in Coachelv is out

[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 than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[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 NERC transmission operations standards.

12)Mirage is in Ramon is out
13)Mirage is in Julian Hinds is out

Total 2013 busload within the defined area is 19,300 MW with 133 MW of losses and 27 MW pumps resulting in total load + losses + pumps of 19,460 MW.

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

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ALAMIT_7_UNIT 1	24001	ALAMT1 G	18	174.56	1	Western		Market
ALAMIT_7_UNIT 2	24002	ALAMT2 G	18	175.00	2	Western		Market
ALAMIT_7_UNIT 3	24003	ALAMT3 G	18	332.18	3	Western		Market
ALAMIT_7_UNIT 4	24004	ALAMT4 G	18	335.67	4	Western		Market
ALAMIT_7_UNIT 5	24005	ALAMT5 G	20	497.97	5	Western		Market
ALAMIT_7_UNIT 6	24161	ALAMT6 G	20	495.00	6	Western		Market
ANAHM_2_CANYN1	25211	CanyonGT	13.8	49.40	1	Western		MUNI
ANAHM_2_CANYN2	25212	CanyonGT	13.8	48.00	2	Western		MUNI
ANAHM_2_CANYN3	25213	CanyonGT	13.8	48.00	3	Western		MUNI
ANAHM_2_CANYN4	25214	CanyonGT	13.8	49.40	4	Western		MUNI
ANAHM_7_CT	25203	ANAHEIMG	13.8	40.64	1	Western	Aug NQC	MUNI
ARCOGN_2_UNITS	24011	ARCO 1G	13.8	54.28	1	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24012	ARCO 2G	13.8	54.28	2	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24013	ARCO 3G	13.8	54.28	3	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24014	ARCO 4G	13.8	54.28	4	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24163	ARCO 5G	13.8	27.14	5	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24164	ARCO 6G	13.8	27.15	6	Western	Aug NQC	QF/Selfgen
BARRE_2_QF	24016	BARRE	230	0.00		Western	Not modeled	QF/Selfgen
BARRE_6_PEAKER	29309	BARPKGEN	13.8	45.38	1	Western		Market
BRDWAY_7_UNIT 3	29007	BRODWYSC	13.8	65.00	1	Western		MUNI
BUCKWD_7_WINTCV	25634	BUCKWIND	115	0.15	W5	None	Aug NQC	Wind
CABZON_1_WINDA1	29290	CABAZON	33	11.29	1	None	Aug NQC	Wind
CENTER_2_QF	24203	CENTER S	66	18.10		Western	Not modeled Aug NQC	QF/Selfgen
CENTER_2_RHONDO	24203	CENTER S	66	1.91		Western	Not modeled	QF/Selfgen
CENTER_6_PEAKER	29308	CTRPKGEN	13.8	44.57	1	Western		Market
CENTRY_6_PL1X4	25302	CLTNCTRY	13.8	36.00	1	None	Aug NQC	MUNI
CHEVMN_2_UNITS	24022	CHEVGEN1	13.8	0.00	1	Western, El Nido	Aug NQC	QF/Selfgen
CHEVMN_2_UNITS	24023	CHEVGEN2	13.8	0.00	2	Western, El Nido	Aug NQC	QF/Selfgen
CHINO_2_QF	24024	CHINO	66	7.83		Western	Not modeled Aug NQC	QF/Selfgen
CHINO_2_SOLAR	24024	CHINO	66	0.00		Western	Not modeled	Market
CHINO_6_CIMGEN	24026	CIMGEN	13.8	25.29	1	Western	Aug NQC	QF/Selfgen
CHINO_6_SMPPAP	24140	SIMPSON	13.8	27.15	1	Western	Aug NQC	QF/Selfgen
CHINO_7_MILIKN	24024	CHINO	66	1.37		Western	Not modeled Aug NQC	Market
COLTON_6_AGUAM1	25303	CLTNAGUA	13.8	43.00	1	None		MUNI
CORONS_6_CLRWTR	24210	MIRALOMA	66	14.00		None	Not modeled	MUNI
CORONS_6_CLRWTR	24210	MIRALOMA	66	14.00		None	Not modeled	MUNI
DEVERS_1_QF	24815	GARNET	115	1.51	QF	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25632	TERAWND	115	2.94	QF	None	Aug NQC	QF/Selfgen

DEVERS_1_QF	25633	CAPWIND	115	0.56	QF	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25634	BUCKWIND	115	1.73	QF	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25635	ALTWIND	115	1.35	Q1	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25635	ALTWIND	115	2.50	Q2	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	0.59	Q1	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	2.28	Q2	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	0.27	W1	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25637	TRANWIND	115	6.68	QF	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25639	SEAWIND	115	2.01	QF	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25640	PANAERO	115	1.79	QF	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25645	VENWIND	115	1.53	EU	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25645	VENWIND	115	3.58	Q1	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25645	VENWIND	115	2.41	Q2	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25646	SANWIND	115	0.80	Q1	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25646	SANWIND	115	2.68	Q2	None	Aug NQC	QF/Selfgen
DMDVLY_1_UNITS	25425	ESRP P2	6.9	1.39		None	Not modeled Aug NQC	QF/Selfgen
DREWS_6_PL1X4	25301	CLTNDREW	13.8	36.00	1	None	Aug NQC	MUNI
DVLCYN_1_UNITS	25603	DVLCYN3G	13.8	67.15	3	None	Aug NQC	MUNI
DVLCYN_1_UNITS	25604	DVLCYN4G	13.8	67.15	4	None	Aug NQC	MUNI
DVLCYN_1_UNITS	25648	DVLCYN1G	13.8	50.35	1	None	Aug NQC	MUNI
DVLCYN_1_UNITS	25649	DVLCYN2G	13.8	50.35	2	None	Aug NQC	MUNI
ELLIS_2_QF	24197	ELLIS	66	0.00		Western, Ellis	Not modeled Aug NQC	QF/Selfgen
ELSEGN_7_UNIT 3	24047	ELSEG3 G	18	335.00	3	Western, El Nido		Market
ELSEGN_7_UNIT 4	24048	ELSEG4 G	18	335.00	4	Western, El Nido		Market
ETIWND_2_FONTNA	24055	ETIWANDA	66	0.81		None	Not modeled Aug NQC	QF/Selfgen
ETIWND_2_QF	24055	ETIWANDA	66	14.86		None	Not modeled Aug NQC	QF/Selfgen
ETIWND_2_SOLAR	24055	ETIWANDA	66	0.00		None	Not modeled Aug NQC	Market
ETIWND_6_GRPLND	29305	ETWPKGEN	13.8	42.53	1	None		Market
ETIWND_6_MWDETI	25422	ETI MWDG	13.8	10.37	1	None	Aug NQC	Market
ETIWND_7_MIDVLY	24055	ETIWANDA	66	1.54		None	Not modeled Aug NQC	QF/Selfgen
ETIWND_7_UNIT 3	24052	MTNVIST3	18	320.00	3	None		Market
ETIWND_7_UNIT 4	24053	MTNVIST4	18	320.00	4	None		Market
GARNET_1_UNITS	24815	GARNET	115	0.71	G1	None	Aug NQC	QF/Selfgen
GARNET_1_UNITS	24815	GARNET	115	0.25	G2	None	Aug NQC	QF/Selfgen
GARNET_1_UNITS	24815	GARNET	115	0.51	G3	None	Aug NQC	QF/Selfgen
GARNET_1_UNITS	24815	GARNET	115	0.25	PC	None	Aug NQC	QF/Selfgen
GARNET_1_WIND	24815	GARNET	115	0.66	W2	None	Aug NQC	Wind
GARNET_1_WIND	24815	GARNET	115	0.66	W3	None	Aug NQC	Wind
GLNARM_7_UNIT 1	29005	PASADNA1	13.8	22.30	1	Western		MUNI
GLNARM_7_UNIT 2	29006	PASADNA2	13.8	22.30	1	Western		MUNI
GLNARM_7_UNIT 3	29005	PASADNA1	13.8	44.83		Western	Not modeled	MUNI
GLNARM_7_UNIT 4	29006	PASADNA2	13.8	42.42		Western	Not modeled	MUNI
HARBGN_7_UNITS	24062	HARBOR G	13.8	76.28	1	Western		Market
HARBGN_7_UNITS	24062	HARBOR G	13.8	11.86	HP	Western		Market
HARBGN_7_UNITS	25510	HARBORG4	4.16	11.86	LP	Western		Market
HINSON_6_CARBGN	24020	CARBOGEN	13.8	21.46	1	Western	Aug NQC	Market

HINSON_6_LBECH1	24078	LBEACH1G	13.8	65.00	1	Western		Market
HINSON_6_LBECH2	24170	LBEACH2G	13.8	65.00	2	Western		Market
HINSON_6_LBECH3	24171	LBEACH3G	13.8	65.00	3	Western		Market
HINSON_6_LBECH4	24172	LBEACH4G	13.8	65.00	4	Western		Market
HINSON_6_SERRGN	24139	SERRFGEN	13.8	28.38	1	Western	Aug NQC	QF/Selfgen
HNTGBH_7_UNIT 1	24066	HUNT1 G	13.8	225.75	1	Western, Ellis		Market
HNTGBH_7_UNIT 2	24067	HUNT2 G	13.8	225.80	2	Western, Ellis		Market
INDIGO_1_UNIT 1	29190	WINTECX2	13.8	42.00	1	None		Market
INDIGO_1_UNIT 2	29191	WINTECX1	13.8	42.00	1	None		Market
INDIGO_1_UNIT 3	29180	WINTEC8	13.8	42.00	1	None		Market
INLDEM_5_UNIT 1	29041	IEEC-G1	19.5	335.00	1	Valley	Aug NQC	Market
INLDEM_5_UNIT 2	29042	IEEC-G2	19.5	335.00	1	Valley	Aug NQC	Market
JOHANN_6_QFA1	24072	JOHANNA	230	0.00		Western, Ellis	Not modeled Aug NQC	QF/Selfgen
LACIEN_2_VENICE	24337	VENICE	13.8	4.45	1	Western, El Nido	Aug NQC	MUNI
LAFRES_6_QF	24073	LA FRESA	66	2.55		Western, El Nido	Not modeled Aug NQC	QF/Selfgen
LAGBEL_6_QF	24075	LAGUBELL	66	10.60		Western	Not modeled Aug NQC	QF/Selfgen
LGHTHP_6_ICEGEN	24070	ICEGEN	13.8	46.55	1	Western	Aug NQC	QF/Selfgen
LGHTHP_6_QF	24083	LITEHIPE	66	1.10		Western	Not modeled Aug NQC	QF/Selfgen
MESAS_2_QF	24209	MESA CAL	66	1.06		Western	Not modeled Aug NQC	QF/Selfgen
MIRLOM_2_CORONA				2.35		None	Not modeled Aug NQC	QF/Selfgen
MIRLOM_2_TEMESC				2.49		None	Not modeled Aug NQC	QF/Selfgen
MIRLOM_6_DELGEN	24030	DELGEN	13.8	29.78	1	None	Aug NQC	QF/Selfgen
MIRLOM_6_PEAKER	29307	MRLPKGEN	13.8	43.18	1	None		Market
MIRLOM_7_MWDLKM	24210	MIRALOMA	66	4.60		None	Not modeled Aug NQC	MUNI
MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	6.00	1	None	Aug NQC	Market
MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	6.00	2	None	Aug NQC	Market
MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	6.00	3	None	Aug NQC	Market
MTWIND_1_UNIT 1	29060	MOUNTWND	115	7.08	S1	None	Aug NQC	Wind
MTWIND_1_UNIT 2	29060	MOUNTWND	115	2.76	S2	None	Aug NQC	Wind
MTWIND_1_UNIT 3	29060	MOUNTWND	115	2.88	S3	None	Aug NQC	Wind
OLINDA_2_COYCRK	24211	OLINDA	66	3.13		Western	Not modeled	QF/Selfgen
OLINDA_2_QF	24211	OLINDA	66	0.78	1	Western	Aug NQC	QF/Selfgen
OLINDA_7_LNDFIL	24201	BARRE	66	4.50		Western	Not modeled Aug NQC	QF/Selfgen
PADUA_2_ONTARO	24111	PADUA	66	0.91		None	Not modeled Aug NQC	QF/Selfgen
PADUA_6_MWDSDM	24111	PADUA	66	7.70		None	Not modeled Aug NQC	MUNI
PADUA_6_QF	24111	PADUA	66	0.74		None	Not modeled Aug NQC	QF/Selfgen
PADUA_7_SDIMAS	24111	PADUA	66	1.05		None	Not modeled Aug NQC	QF/Selfgen
PWEST_1_UNIT				0.15		Western	Not modeled Aug NQC	Market
REDOND_7_UNIT 5	24121	REDON5 G	18	178.87	5	Western		Market
REDOND_7_UNIT 6	24122	REDON6 G	18	175.00	6	Western		Market
REDOND_7_UNIT 7	24123	REDON7 G	20	505.96	7	Western		Market

REDOND_7_UNIT 8	24124	REDON8 G	20	495.90	8	Western		Market
RHONDO_2_QF	24213	RIOHONDO	66	2.54		Western	Not modeled Aug NQC	QF/Selfgen
RHONDO_6_PUENTE	24213	RIOHONDO	66	0.00		Western	Not modeled Aug NQC	Market
RVSIDE_2_RERCU3	24299	RERC2G3	13.8	48.50	1	None		MUNI
RVSIDE_2_RERCU4	24300	RERC2G4	13.8	48.50	1	None		MUNI
RVSIDE_6_RERCU1	24242	RERC1G	13.8	48.35	1	None		MUNI
RVSIDE_6_RERCU2	24243	RERC2G	13.8	48.50	1	None		MUNI
RVSIDE_6_SPRING	24244	SPRINGEN	13.8	36.00	1	None		Market
SANTGO_6_COYOTE	24133	SANTIAGO	66	6.08	1	Western, Ellis	Aug NQC	Market
SBERDO_2_PSP3	24921	MNTV-CT1	18	129.71	1	None		Market
SBERDO_2_PSP3	24922	MNTV-CT2	18	129.71	1	None		Market
SBERDO_2_PSP3	24923	MNTV-ST1	18	225.08	1	None		Market
SBERDO_2_PSP4	24924	MNTV-CT3	18	129.71	1	None		Market
SBERDO_2_PSP4	24925	MNTV-CT4	18	129.71	1	None		Market
SBERDO_2_PSP4	24926	MNTV-ST2	18	225.08	1	None		Market
SBERDO_2_QF	24214	SANBRDNO	66	0.14		None	Not modeled Aug NQC	QF/Selfgen
SBERDO_2_SNTANA	24214	SANBRDNO	66	0.27		None	Not modeled Aug NQC	QF/Selfgen
SBERDO_6_MILLCK	24214	SANBRDNO	66	1.28		None	Not modeled Aug NQC	QF/Selfgen
SONGS_7_UNIT 2	24129	S.ONOFR2	22	1122.00	2	Western		Nuclear
SONGS_7_UNIT 3	24130	S.ONOFR3	22	1124.00	3	Western		Nuclear
TIFFNY_1_DILLON				5.63		Western	Not modeled Aug NQC	Wind
VALLEY_5_PERRIS	24160	VALLEYSC	115	7.94		Valley	Not modeled Aug NQC	QF/Selfgen
VALLEY_5_REDMTN	24160	VALLEYSC	115	2.00		Valley	Not modeled Aug NQC	QF/Selfgen
VALLEY_7_BADLND	24160	VALLEYSC	115	0.54		Valley	Not modeled Aug NQC	Market
VALLEY_7_UNITA1	24160	VALLEYSC	115	1.34		Valley	Not modeled Aug NQC	Market
VERNON_6_GONZL1				5.75		Western	Not modeled	MUNI
VERNON_6_GONZL2				5.75		Western	Not modeled	MUNI
VERNON_6_MALBRG	24239	MALBRG1G	13.8	42.37	C1	Western		MUNI
VERNON_6_MALBRG	24240	MALBRG2G	13.8	42.37	C2	Western		MUNI
VERNON_6_MALBRG	24241	MALBRG3G	13.8	49.26	S3	Western		MUNI
VILLPK_2_VALLYV	24216	VILLA PK	66	4.10		Western	Not modeled Aug NQC	QF/Selfgen
VILLPK_6_MWDYOR	24216	VILLA PK	66	0.00		Western	Not modeled Aug NQC	MUNI
VISTA_6_QF	24902	VSTA	66	0.17	1	None	Aug NQC	QF/Selfgen
WALNUT_6_HILLGEN	24063	HILLGEN	13.8	47.07	1	Western	Aug NQC	QF/Selfgen
WALNUT_7_WCOVCT	24157	WALNUT	66	3.43		Western	Not modeled Aug NQC	Market
WALNUT_7_WCOVST	24157	WALNUT	66	2.98		Western	Not modeled Aug NQC	Market
WHTWTR_1_WINDA1	29061	WHITEWTR	33	8.26	1	None	Aug NQC	Wind
ARCOGN_2_UNITS	24018	BRIGEN	13.8	0.00	1	Western	No NQC - hist. data	Market
HINSON_6_QF	24064	HINSON	66	0.00	1	Western	No NQC - hist. data	QF/Selfgen
INLAND_6_UNIT	24071	INLAND	13.8	30.30	1	None	No NQC -	QF/Selfgen

							hist. data	
MOBGEN_6_UNIT 1	24094	MOBGEN	13.8	20.20	1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24324	SANIGEN	13.8	6.80	D1	None	No NQC - hist. data	QF/Selfgen
NA	24325	ORCOGEN	13.8	0.00	1	Western, Ellis	No NQC - hist. data	QF/Selfgen
NA	24327	THUMSGEN	13.8	40.00	1	Western	No NQC - hist. data	QF/Selfgen
NA	24328	CARBGEN2	13.8	15.2	1	Western	No NQC – hist. data	Market
NA	24329	MOBGEN2	13.8	20.2	1	Western, El Nido	No NQC – hist. data	QF/Selfgen
NA	24330	OUTFALL1	13.8	0.00	1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24331	OUTFALL2	13.8	0.00	1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24332	PALOGEN	13.8	3.60	D1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24341	COYGEN	13.8	0.00	1	Western, Ellis	No NQC - hist. data	QF/Selfgen
NA	24342	FEDGEN	13.8	0.00	1	Western	No NQC - hist. data	QF/Selfgen
NA	24839	BLAST	115	45.00	1	None	No NQC – hist. data	QF/Selfgen
NA	29021	WINTEC6	115	45.00	1	None	No NQC – hist. data	Wind
NA	29023	WINTEC4	12	16.50	1	None	No NQC – hist. data	Wind
NA	29060	SEAWEST	115	44.40	S1	None	No NQC – hist. data	Wind
NA	29060	SEAWEST	115	22.20	S2	None	No NQC – hist. data	Wind
NA	29060	SEAWEST	115	22.40	S3	None	No NQC – hist. data	Wind
NA	29260	ALTAMSA4	115	40.00	1	None	No NQC – hist. data	Wind
NA	29338	CLEARGEN	13.8	0.00	1	None	No NQC - hist. data	QF/Selfgen
NA	29339	DELGEN	13.8	0.00	1	None	No NQC - hist. data	QF/Selfgen
NA	29951	REFUSE	13.8	9.90	D1	Western	No NQC - Pmax	QF/Selfgen
NA	29953	SIGGEN	13.8	24.90	D1	Western	No NQC - Pmax	QF/Selfgen
HNTGBH_7_UNIT 3	24167	HUNT3 G	13.8	0.00	3	Western, Ellis	Retired	Market
HNTGBH_7_UNIT 4	24168	HUNT4 G	13.8	0.00	4	Western, Ellis	Retired	Market
New unit	29201	EME WCG1	13.8	100	1	Western	No NQC - Pmax	Market
New unit	29202	EME WCG2	13.8	100	1	Western	No NQC - Pmax	Market
New unit	29203	EME WCG3	13.8	100	1	Western	No NQC - Pmax	Market
New unit	29204	EME WCG4	13.8	100	1	Western	No NQC - Pmax	Market
New unit	29205	EME WCG5	13.8	100	1	Western	No NQC - Pmax	Market
New unit	29901	NRG ELG5	18	175	5	Western, El Nido	No NQC - Pmax	Market
New unit	29902	NRG ELG7	18	280	7	Western, El Nido	No NQC -	Market

							Pmax	
New unit	29903	NRG ELG6	18	175	6	Western, El Nido	No NQC - Pmax	Market

Major new projects modeled:

1. 3 new resources have been modeled
2. Huntington Beach #3 and #4 have been retired
3. Del Amo – Ellis 230 kV line loops into Barre 230 kV substation
4. Recalibrate arming level for Santiago SPS

<u>Critical Contingency Analysis Summary</u>

LA Basin Overall:

The most critical contingency for LA Basin is the loss of one SONGS unit followed by Palo Verde-Devers 500 kV line, which could exceed the approved 6400 MW rating for the South of Lugo path. This limiting contingency establishes a LCR of 10,295 MW in 2013 (includes 810 MW of QF, 230 MW of Wind, 1166 MW of Muni and 2246 MW of Nuclear generation) as the minimum generation capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	MW Eff Fctr (%)
24052	MTNVIST3	3	34
24053	MTNVIST4	4	34
24071	INLAND	1	32
25422	ETI MWDG	1	32
29305	ETWPKGEN	1	32
24921	MNTV-CT1	1	28
24922	MNTV-CT2	1	28
24923	MNTV-ST1	1	28
24924	MNTV-CT3	1	28
24925	MNTV-CT4	1	28
24926	MNTV-ST2	1	28
29041	IEEC-G1	1	28

29042	IEEC-G2	2	28
24905	RVCANAL1	R1	27
24906	RVCANAL2	R2	27
24907	RVCANAL3	R3	27
24908	RVCANAL4	R4	27
29190	WINTECX2	1	27
29191	WINTECX1	1	27
29180	WINTEC8	1	27
24815	GARNET	QF	27
24815	GARNET	W3	27
29023	WINTEC4	1	27
29021	WINTEC6	1	27
24242	RERC1G	1	27
24243	RERC2G	1	27
24244	SPRINGEN	1	27
25301	CLTNDREW	1	27
25302	CLTNCTRY	1	27
25303	CLTNAGUA	1	27
24299	RERC2G3	1	27
24300	RERC2G4	1	27
24839	BLAST	1	27
25648	DVLCYN1G	1	26
25649	DVLCYN2G	2	26
25603	DVLCYN3G	3	26
25604	DVLCYN4G	4	26
25632	TERAWND	QF	26
25634	BUCKWND	QF	26
25635	ALTWIND	Q1	26
25635	ALTWIND	Q2	26
25637	TRANWND	QF	26
25639	SEAWIND	QF	26
25640	PANAERO	QF	26
25645	VENWIND	EU	26
25645	VENWIND	Q2	26
25645	VENWIND	Q1	26
25646	SANWIND	Q2	26
29060	MOUNTWND	S1	26
29060	MOUNTWND	S3	26
29060	MOUNTWND	S2	26
29061	WHITEWTR	1	26
29260	ALTAMSA4	1	26
29290	CABAZON	1	26
25633	CAPWIND	QF	25

25657	MJVSPHN1	1	25
25658	MJVSPHN2	2	25
25659	MJVSPHN3	3	25
25203	ANAHEIMG	1	23
25211	CanyonGT 1	1	22
25212	CanyonGT 2	2	22
25213	CanyonGT 3	3	22
25214	CanyonGT 4	4	22
24030	DELGEN	1	21
29309	BARPKGEN	1	21
24026	CIMGEN	D1	21
24140	SIMPSON	D1	21
29307	MRLPKGEN	1	20
29338	CLEARGEN	1	20
29339	DELGEN	1	20
24005	ALAMT5 G	5	19
24066	HUNT1 G	1	19
24067	HUNT2 G	2	19
24167	HUNT3 G	3	19
24168	HUNT4 G	4	19
24129	S.ONOFR2	2	19
24130	S.ONOFR3	3	19
24133	SANTIAGO	1	19
24325	ORCOGEN	1	19
24341	COYGEN	1	19
24001	ALAMT1 G	1	18
24002	ALAMT2 G	2	18
24003	ALAMT3 G	3	18
24004	ALAMT4 G	4	18
24161	ALAMT6 G	6	18
24162	ALAMT7 G	R7	17
24063	HILLGEN	D1	17
29201	EME WCG1	1	17
29203	EME WCG3	1	17
29204	EME WCG4	1	17
29205	EME WCG5	1	17
29202	EME WCG2	1	17
24018	BRIGEN	1	16
29308	CTRPKGEN	1	16
29953	SIGGEN	D1	16
24011	ARCO 1G	1	15
24012	ARCO 2G	2	15
24013	ARCO 3G	3	15

24014	ARCO 4G	4	15
24163	ARCO 5G	5	15
24164	ARCO 6G	6	15
24020	CARBGEN1	1	15
24022	CHEVGEN1	1	15
24023	CHEVGEN2	2	15
24064	HINSON	1	15
24070	ICEGEN	D1	15
24170	LBEACH12	2	15
24171	LBEACH34	3	15
24094	MOBGEN1	1	15
24062	HARBOR G	1	15
25510	HARBORG4	LP	15
24062	HARBOR G	HP	15
24139	SERRFGEN	D1	15
24170	LBEACH12	1	15
24171	LBEACH34	4	15
24173	LBEACH5G	R5	15
24174	LBEACH6G	R6	15
24327	THUMSGEN	1	15
24328	CARBGEN2	1	15
24330	OUTFALL1	1	15
24331	OUTFALL2	1	15
24332	PALOGEN	D1	15
24333	REDON1 G	R1	15
24334	REDON2 G	R2	15
24335	REDON3 G	R3	15
24336	REDON4 G	R4	15
24337	VENICE	1	15
24079	LBEACH7G	R7	15
24080	LBEACH8G	R8	15
24081	LBEACH9G	R9	15
24047	ELSEG3 G	3	14
24048	ELSEG4 G	4	14
24121	REDON5 G	5	14
24122	REDON6 G	6	14
24123	REDON7 G	7	14
24124	REDON8 G	8	14
24329	MOBGEN2	1	14
29901	NRG ELG5	5	14
29903	NRG ELG6	6	14
29902	NRG ELS7	7	14
29951	REFUSE	D1	13

29209	BLY1ST1	1	13
29207	BLY1CT1	1	13
29208	BLY1CT2	1	13
24342	FEDGEN	1	13
24241	MALBRG3G	S3	12
24240	MALBRG2G	C2	12
24239	MALBRG1G	C1	12
29005	PASADNA1	1	10
29006	PASADNA2	1	10
29007	BRODWYSC	1	10

Valley Sub-Area:

The most critical contingency for the Valley sub-area is the loss of Palo Verde – Devers 500 kV line and Valley – Serrano 500 kV line or vice versa, which would result in voltage collapse. This limiting contingency establishes a LCR of 670 MW (includes 10 MW of QF generation) in 2013 as the generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Western Sub-Area:

The most critical contingency for the Western sub-area is the loss of Serrano-Villa Park #2 230 kV line followed by the loss of the Serrano-Lewis 230 kV line or vice versa, which would result in thermal overload of the remaining Serrano-Villa Park 230 kV line. This limiting contingency establishes a LCR of 5540 MW (includes 623 MW of QF, 6 MW of Wind, 582 MW of Muni and 2246 MW of nuclear generation) in 2013 as the generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	MW Eff Fctr (%)
29309	BARPKGEN	1	31

25203	ANAHEIMG	1	30
25211	CanyonGT 1	1	29
25212	CanyonGT 2	2	29
25213	CanyonGT 3	3	29
25214	CanyonGT 4	4	29
24005	ALAMT5 G	5	23
24161	ALAMT6 G	6	23
24001	ALAMT1 G	1	22
24002	ALAMT2 G	2	22
24003	ALAMT3 G	3	22
24004	ALAMT4 G	4	22
24162	ALAMT7 G	R7	22
24066	HUNT1 G	1	22
24067	HUNT2 G	2	22
24167	HUNT3 G	3	22
24168	HUNT4 G	4	22
24325	ORCOGEN	1	21
24133	SANTIAGO	1	16
24341	COYGEN	1	16
24011	ARCO 1G	1	15
24012	ARCO 2G	2	15
24013	ARCO 3G	3	15
24014	ARCO 4G	4	15
24018	BRIGEN	1	15
24020	CARBGEN1	1	15
24064	HINSON	1	15
24070	ICEGEN	D1	15
24170	LBEACH12	2	15
24171	LBEACH34	3	15
24062	HARBOR G	1	15
25510	HARBORG4	LP	15
24062	HARBOR G	HP	15
24139	SERRFGEN	D1	15
24170	LBEACH12	1	15
24171	LBEACH34	4	15
24173	LBEACH5G	R5	15
24174	LBEACH6G	R6	15
24327	THUMSGEN	1	15
24328	CARBGEN2	1	15
24079	LBEACH7G	R7	15
24080	LBEACH8G	R8	15
24081	LBEACH9G	R9	15
24163	ARCO 5G	5	14

24164	ARCO 6G	6	14
24022	CHEVGEN1	1	14
24023	CHEVGEN2	2	14
24048	ELSEG4 G	4	14
24094	MOBGEN1	1	14
29308	CTRPKGEN	1	14
24329	MOBGEN2	1	14
24330	OUTFALL1	1	14
24331	OUTFALL2	1	14
24332	PALOGEN	D1	14
24333	REDON1 G	R1	14
24334	REDON2 G	R2	14
24335	REDON3 G	R3	14
24336	REDON4 G	R4	14
24337	VENICE	1	14
29953	SIGGEN	D1	14
29901	NRG ELG5	5	14
29903	NRG ELG6	6	14
29902	NRG ELS7	7	14
24047	ELSEG3 G	3	13
24121	REDON5 G	5	13
24122	REDON6 G	6	13
24123	REDON7 G	7	13
24124	REDON8 G	8	13
29951	REFUSE	D1	12
24342	FEDGEN	1	12
24241	MALBRG3G	S3	11
24240	MALBRG2G	C2	11
24239	MALBRG1G	C1	11
29005	PASADNA1	1	9
29006	PASADNA2	1	9
29007	BRODWYSC	1	9
24063	HILLGEN	D1	6
29201	EME WCG1	1	5
29203	EME WCG3	1	5
29204	EME WCG4	1	5
29205	EME WCG5	1	5
29202	EME WCG2	1	5

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

Ellis sub-area

The Del Amo – Ellis loop-in project along with recalibration of the Santiago SPS eliminates the LCR need for the Ellis sub-area.

El Nido sub-area

The most critical contingency for the El Nido sub-area is the loss of the La Fresa – Hinson 230 kV line followed by the loss of the La Fresa – Redondo #1 and #2 230 kV lines, which would cause voltage collapse. This limiting contingency establishes a LCR of 386 MW in 2013 (which includes 47 MW of QF and 4 MW of MUNI generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Changes compared to last year's results:

Overall the load forecast went down by 470 MW resulting in 570 MW decrease in LCR.

LA Basin Overall Requirements:

2013	QF/Wind (MW)	Muni (MW)	Nuclear (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	1040	1166	2246	8675	13127

2013	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[24]	10,295	0	10,295
Category C (Multiple)[25]	10,295	0	10,295

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

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

9. Big Creek/Ventura Area

Area Definition

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

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

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

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

Total 2013 busload within the defined area is 4164 MW with 77 MW of losses and 355 MW of pumps resulting in total load + losses + pumps of 4596 MW.

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

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ALAMO_6_UNIT	25653	ALAMO SC	13.8	16.00	1	Big Creek	Aug NQC	Market
ANTLPE_2_QF	24457	ARBWIND	66	2.91	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	24458	ENCANWND	66	15.09	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	24459	FLOWIND	66	5.45	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	24460	DUTCHWND	66	1.87	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	24465	MORWIND	66	7.49	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	24491	OAKWIND	66	2.41	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28501	MIDWIND	12	2.41	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28502	SOUTHWND	12	0.88	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28503	NORTHWND	12	2.59	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28504	ZONDWND1	12	1.76	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28505	ZONDWND2	12	1.71	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28506	BREEZE1	12	0.60	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28507	BREEZE2	12	1.07	1	Big Creek	Aug NQC	Wind
BIGCRK_2_EXESWD	24306	B CRK1-1	7.2	19.38	1	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24306	B CRK1-1	7.2	21.03	2	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24307	B CRK1-2	13.8	21.03	3	Big Creek, Rector, Vestal	Aug NQC	Market

BIGCRK_2_EXESWD	24307	B CRK1-2	13.8	30.39	4	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24308	B CRK2-1	13.8	49.48	1	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24308	B CRK2-1	13.8	50.64	2	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24309	B CRK2-2	7.2	18.22	3	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24309	B CRK2-2	7.2	19.19	4	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24310	B CRK2-3	7.2	16.55	5	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24310	B CRK2-3	7.2	18.02	6	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24311	B CRK3-1	13.8	34.09	1	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24311	B CRK3-1	13.8	34.09	2	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24312	B CRK3-2	13.8	34.09	3	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24312	B CRK3-2	13.8	39.93	4	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24313	B CRK3-3	13.8	37.99	5	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24314	B CRK 4	11.5	49.09	41	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24314	B CRK 4	11.5	49.28	42	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24315	B CRK 8	13.8	23.76	81	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24315	B CRK 8	13.8	42.85	82	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24317	MAMOTH1G	13.8	91.07	1	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24318	MAMOTH2G	13.8	91.07	2	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24323	PORTAL	4.8	9.35	1	Big Creek, Rector, Vestal	Aug NQC	Market
EASTWD_7_UNIT	24319	EASTWOOD	13.8	199.00	1	Big Creek, Rector, Vestal		Market
EDMONS_2_NSPIN	25605	EDMON1AP	14.4	23.27	1	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25606	EDMON2AP	14.4	23.27	2	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25607	EDMON3AP	14.4	23.27	3	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25607	EDMON3AP	14.4	23.27	4	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25608	EDMON4AP	14.4	23.27	5	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25608	EDMON4AP	14.4	23.27	6	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25609	EDMON5AP	14.4	23.27	7	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25609	EDMON5AP	14.4	23.27	8	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25610	EDMON6AP	14.4	23.27	9	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25610	EDMON6AP	14.4	23.27	10	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25611	EDMON7AP	14.4	23.26	11	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25611	EDMON7AP	14.4	23.26	12	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25612	EDMON8AP	14.4	23.26	13	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25612	EDMON8AP	14.4	23.26	14	Big Creek	Pumps	MUNI
GOLETA_2_QF	24057	GOLETA	66	0.14		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	QF/Selfgen

GOLETA_6_ELLWOD	28004	ELLWOOD	13.8	54.00	1	Ventura, S.Clara, Moorpark		Market
GOLETA_6_EXGEN	24057	GOLETA	66	1.17		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	QF/Selfgen
GOLETA_6_GAVOTA	24057	GOLETA	66	1.41		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	QF/Selfgen
GOLETA_6_TAJIGS	24057	GOLETA	66	2.90		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	Market
KERRGN_1_UNIT 1	24437	KERNRVR	66	9.03	1	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	28051	PSTRIAG1	18	157.90	G1	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	28052	PSTRIAG2	18	157.90	G2	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	28053	PSTRIAS1	18	162.40	S1	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	28054	PSTRIAG3	18	157.90	G3	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	28055	PSTRIAS2	18	78.90	S2	Big Creek	Aug NQC	Market
MNDALY_7_UNIT 1	24089	MANDLY1G	13.8	215.00	1	Ventura, Moorpark		Market
MNDALY_7_UNIT 2	24090	MANDLY2G	13.8	215.29	2	Ventura, Moorpark		Market
MNDALY_7_UNIT 3	24222	MANDLY3G	16	130.00	3	Ventura, S.Clara, Moorpark		Market
MONLTH_6_BOREL	24456	BOREL	66	8.98	1	Big Creek	Aug NQC	QF/Selfgen
MOORPK_2_CALABS	24099	MOORPARK	230	6.96		Ventura, Moorpark	Not modeled	Market
MOORPK_6_QF	24098	MOORPARK	66	26.44		Ventura, Moorpark	Not modeled Aug NQC	QF/Selfgen
MOORPK_7_UNITA1	24098	MOORPARK	66	1.24		Ventura, Moorpark	Not modeled Aug NQC	QF/Selfgen
OMAR_2_UNIT 1	24102	OMAR 1G	13.8	77.25	1	Big Creek		QF/Selfgen
OMAR_2_UNIT 2	24103	OMAR 2G	13.8	77.25	2	Big Creek		QF/Selfgen
OMAR_2_UNIT 3	24104	OMAR 3G	13.8	77.25	3	Big Creek		QF/Selfgen
OMAR_2_UNIT 4	24105	OMAR 4G	13.8	77.25	4	Big Creek		QF/Selfgen
ORMOND_7_UNIT 1	24107	ORMOND1G	26	741.27	1	Ventura, Moorpark		Market
ORMOND_7_UNIT 2	24108	ORMOND2G	26	775.00	2	Ventura, Moorpark		Market
OSO_6_NSPIN	25614	OSO A P	13.2	3.63	1	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25614	OSO A P	13.2	3.63	2	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25614	OSO A P	13.2	3.63	3	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25614	OSO A P	13.2	3.63	4	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	3.63	5	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	3.63	6	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	3.63	7	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	3.63	8	Big Creek	Pumps	MUNI
PANDOL_6_UNIT	24113	PANDOL	13.8	24.81	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
PANDOL_6_UNIT	24113	PANDOL	13.8	20.21	2	Big Creek, Vestal	Aug NQC	QF/Selfgen
RECTOR_2_KAWEAH	24212	RECTOR	66	1.45		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
RECTOR_2_KAWH 1	24212	RECTOR	66	0.71		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
RECTOR_2_QF	24212	RECTOR	66	5.34		Big Creek,	Not modeled	QF/Selfgen

						Rector, Vestal	Aug NQC	
RECTOR_7_TULARE	24212	RECTOR	66	1.60		Big Creek, Rector, Vestal	Not modeled	QF/Selfgen
SAUGUS_2_TOLAND	24135	SAUGUS	66	0.72		Big Creek	Not modeled Aug NQC	Market
SAUGUS_6_MWDFTH	24135	SAUGUS	66	7.50		Big Creek	Not modeled Aug NQC	MUNI
SAUGUS_6_PTCHGN	24118	PITCHGEN	13.8	19.12	1	Big Creek	Aug NQC	MUNI
SAUGUS_6_QF	24135	SAUGUS	66	0.92		Big Creek	Not modeled Aug NQC	QF/Selfgen
SAUGUS_7_CHIQCN	24135	SAUGUS	66	6.67		Big Creek	Not modeled Aug NQC	Market
SAUGUS_7_LOPEZ	24135	SAUGUS	66	5.39		Big Creek	Not modeled Aug NQC	QF/Selfgen
SNCLRA_6_OXGEN	24110	OXGEN	13.8	33.53	1	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SNCLRA_6_PROCGN	24119	PROCGEN	13.8	46.16	1	Ventura, S.Clara, Moorpark	Aug NQC	Market
SNCLRA_6_QF	24127	S.CLARA	66	1.09	1	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SNCLRA_6_WILLMT	24159	WILLAMET	13.8	12.63	1	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SPRGVL_2_QF	24215	SPRINGVL	66	0.25		Big Creek, Rector, Vestal	Not modeled Aug NQC	QF/Selfgen
SPRGVL_2_TULE	24215	SPRINGVL	66	0.63		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
SPRGVL_2_TULESC	24215	SPRINGVL	66	0.39		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
SYCAMR_2_UNITS	24143	SYCCYN1G	13.8	57.56	1	Big Creek	Aug NQC	QF/Selfgen
SYCAMR_2_UNITS	24144	SYCCYN2G	13.8	57.56	2	Big Creek	Aug NQC	QF/Selfgen
SYCAMR_2_UNITS	24145	SYCCYN3G	13.8	57.56	3	Big Creek	Aug NQC	QF/Selfgen
SYCAMR_2_UNITS	24146	SYCCYN4G	13.8	57.55	4	Big Creek	Aug NQC	QF/Selfgen
TENGEN_2_PL1X2	24148	TENNGEN1	13.8	18.35	1	Big Creek	Aug NQC	Market
TENGEN_2_PL1X2	24149	TENNGEN2	13.8	18.35	2	Big Creek	Aug NQC	Market
VESTAL_2_KERN	24152	VESTAL	66	6.72	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
VESTAL_6_QF	24152	VESTAL	66	5.06		Big Creek, Vestal	Not modeled Aug NQC	QF/Selfgen
VESTAL_6_ULTRGN	24150	ULTRAGEN	13.8	34.70	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
VESTAL_6_WDFIRE	28008	LAKEGEN	13.8	5.57	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
WARNE_2_UNIT	25651	WARNE1	13.8	38.00	1	Big Creek	Aug NQC	Market
WARNE_2_UNIT	25652	WARNE2	13.8	38.00	1	Big Creek	Aug NQC	Market
APPGEN_6_UNIT 1	24009	APPGEN1G	13.8	0.00	1	Big Creek	No NQC - hist. data	Market
APPGEN_6_UNIT 1	24010	APPGEN2G	13.8	0.00	2	Big Creek	No NQC - hist. data	Market
MNDALY_6_MCGRTH	29306	MCGPKGEN	13.8	47.00	1	Ventura, S.Clara, Moorpark	No NQC - hist. data	Market
NA	24326	Exgen1	13.8	0.00	S1	Ventura, S.Clara, Moorpark	No NQC - hist. data	QF/Selfgen

NA	24340	CHARMIN	13.8	15.20	1	Ventura, S.Clara, Moorpark	No NQC - hist. data	QF/Selfgen
NA	24362	Exgen2	13.8	0.00	G1	Ventura, S.Clara, Moorpark	No NQC - hist. data	QF/Selfgen
NA	24370	Kawgen	13.8	0.00	1	Big Creek, Rector, Vestal	No NQC - hist. data	Market
NA	24372	KR 3-1	13.8	0.00	1	Big Creek, Vestal	No NQC - hist. data	QF/Selfgen
NA	24373	KR 3-2	13.8	0.00	1	Big Creek, Vestal	No NQC - hist. data	QF/Selfgen
NA	24422	PALMDALE	66	0.00	1	Big Creek	No NQC - hist. data	Market
NA	24436	GOLDTOWN	66	0.00	1	Big Creek	No NQC - hist. data	Market

Major new projects modeled:

1. Segments of TRTP project

Critical Contingency Analysis Summary

Big Creek/Ventura overall:

The most critical contingency is the loss of the Lugo-Victorville 500 kV followed by Sylmar-Pardee #1 or #2 230 kV line, which could thermally overload the remaining Sylmar-Pardee 230 kV line. This limiting contingency establishes a LCR of 2241 MW in 2013 (includes 752 MW of QF, 381 MW of Muni and 46 MW of Wind generation) as the minimum generation capacity necessary for reliable load serving capability within this area.

The most critical single contingency is the loss of Sylmar-Pardee #1 (or # 2) line followed by Ormond Beach Unit #2, which could thermally overload the remaining Sylmar-Pardee 230 kV line. This limiting contingency establishes a LCR of 2161 MW in 2013 (includes 752 MW of QF, 381 MW of Muni and 46 MW of Wind generation).

Effectiveness factors:

The following table has units that have at least 5% effectiveness to any one of the Sylmar-Pardee 230 kV lines after the loss of the Lugo-Victorville 500 kV followed by one of the other Sylmar-Pardee 230 kV line in this area:

Gen Bus	Gen Name	Gen ID	MW Eff Fctr

24118	PITCHGEN	D1	35
24148	TENNGEN1	D1	35
24149	TENNGEN2	D2	35
24009	APPGEN1G	1	34
24010	APPGEN2G	2	34
24107	ORMOND1G	1	34
24108	ORMOND2G	2	34
24361	APPGEN3G	3	34
25651	WARNE1	1	33
25652	WARNE2	1	33
24090	MANDLY2G	2	32
29306	MCGPKGEN	1	32
24089	MANDLY1G	1	31
29004	ELLWOOD	1	31
29952	CAMGEN	D1	31
24326	EXGEN1	S1	31
24362	EXGEN2	G1	31
29055	PSTRIAS2	S2	30
29054	PSTRIAG3	G3	30
29053	PSTRIAS1	S1	30
29052	PSTRIAG2	G2	30
29051	PSTRIAG1	G1	30
25605	EDMON1AP	1	30
25606	EDMON2AP	2	30
25607	EDMON3AP	3	30
25607	EDMON3AP	4	30
25608	EDMON4AP	5	30
25608	EDMON4AP	6	30
25609	EDMON5AP	7	30
25609	EDMON5AP	8	30
25610	EDMON6AP	9	30
25610	EDMON6AP	10	30
25612	EDMON8AP	13	30
25612	EDMON8AP	14	30
24127	S.CLARA	1	30
24110	OXGEN	D1	30
24119	PROCGEN	D1	30
24159	WILLAMET	D1	30
24340	CHARMIN	1	30
25611	EDMON7AP	11	29
25611	EDMON7AP	12	29

24222	MANDLY3G	3	29
25614	OSO A P	1	29
25614	OSO A P	2	29
25615	OSO B P	7	29
25615	OSO B P	8	29
25653	ALAMO SC	1	29
24370	KAWGEN	1	28
24113	PANDOL	1	27
24113	PANDOL	2	27
29008	LAKEGEN	1	27
24150	ULTRAGEN	1	27
24152	VESTAL	1	27
24372	KR 3-1	1	27
24373	KR 3-2	2	27
24102	OMAR 1G	1	26
24103	OMAR 2G	2	26
24104	OMAR 3G	3	26
24105	OMAR 4G	4	26
24143	SYCCYN1G	1	26
24144	SYCCYN2G	2	26
24145	SYCCYN3G	3	26
24146	SYCCYN4G	4	26
24319	EASTWOOD	1	25
24306	B CRK1-1	1	25
24306	B CRK1-1	2	25
24307	B CRK1-2	3	25
24307	B CRK1-2	4	25
24308	B CRK2-1	1	25
24308	B CRK2-1	2	25
24309	B CRK2-2	3	25
24309	B CRK2-2	4	25
24310	B CRK2-3	5	25
24310	B CRK2-3	6	25
24311	B CRK3-1	1	25
24311	B CRK3-1	2	25
24312	B CRK3-2	3	25
24312	B CRK3-2	4	25
24313	B CRK3-3	5	25
24314	B CRK 4	41	25
24314	B CRK 4	42	25

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

Rector Sub-area

The most critical contingency for the Rector sub-area is the loss of one of the Rector-Vestal 230 kV lines with the Eastwood unit out of service, which would thermally overload the remaining Rector-Vestal 230 kV line. This limiting contingency establishes a LCR of 601 MW (includes 7 MW of QF generation) in 2013 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
24370	KAWGEN	1	45
24319	EASTWOOD	1	41
24306	B CRK1-1	1	41
24306	B CRK1-1	2	41
24307	B CRK1-2	3	41
24307	B CRK1-2	4	41
24323	PORTAL	1	41
24308	B CRK2-1	1	40
24308	B CRK2-1	2	40
24309	B CRK2-2	3	40
24309	B CRK2-2	4	40
24315	B CRK 8	81	40
24315	B CRK 8	82	40

24310	B CRK2-3	5	39
24310	B CRK2-3	6	39
24311	B CRK3-1	1	39
24311	B CRK3-1	2	39
24312	B CRK3-2	3	39
24312	B CRK3-2	4	39
24313	B CRK3-3	5	39
24317	MAMOTH1G	1	39
24318	MAMOTH2G	2	39
24314	B CRK 4	41	38
24314	B CRK 4	42	38

Vestal Sub-area

The most critical contingency for the Vestal sub-area is the loss of one of the Magunden-Vestal 230 kV lines with the Eastwood unit out of service, which would thermally overload the remaining Magunden-Vestal 230 kV line. This limiting contingency establishes a LCR of 801 MW in 2013 (which includes 104 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
28008	LAKEGEN	1	46
24113	PANDOL	1	45
24113	PANDOL	2	45
24150	ULTRAGEN	1	45
24372	KR 3-1	1	45
24373	KR 3-2	2	45
24152	VESTAL	1	45
24370	KAWGEN	1	45
24319	EASTWOOD	1	24
24306	B CRK1-1	1	24
24306	B CRK1-1	2	24
24307	B CRK1-2	3	24
24307	B CRK1-2	4	24
24308	B CRK2-1	1	24
24308	B CRK2-1	2	24
24309	B CRK2-2	3	24
24309	B CRK2-2	4	24
24310	B CRK2-3	5	24
24310	B CRK2-3	6	24

24315	B CRK 8	81	24
24315	B CRK 8	82	24
24323	PORTAL	1	24
24311	B CRK3-1	1	23
24311	B CRK3-1	2	23
24312	B CRK3-2	3	23
24312	B CRK3-2	4	23
24313	B CRK3-3	5	23
24317	MAMOTH1G	1	23
24318	MAMOTH2G	2	23
24314	B CRK 4	41	22
24314	B CRK 4	42	22

S. Clara sub-areas

The most critical contingency for the S.Clara sub-area is the loss of the Pardee to S.Clara 230 kV line followed by the loss of the Moorpark to S.Clara #1 and #2 230 kV lines, which would cause voltage collapse. This limiting contingency establishes a LCR of 264 MW in 2013 (which includes 65 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Moorpark sub-areas

The most critical contingency for the Moorpark sub-area is the loss of one of the Pardee to Moorpark 230 kV lines followed by the loss of the remaining two Moorpark to Pardee 230 kV lines, which would cause voltage collapse. This limiting contingency establishes a LCR of 422 MW in 2013 (which includes 93 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Changes compared to last year's results:

Overall the load forecast went down by 97 MW. The new Antelope 500/230 kV #1 and #2 transformers have been modeled as part of the TRTP. The overall effect is that the

LCR has decreased by 852 MW. The majority of the LCR decrease is due to load allocation change within the Big Creek Ventura.

Big Creek Overall Requirements:

2013	QF/Wind (MW)	MUNI (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	798	381	4097	5276

2013	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[26]	2161	0	2161
Category C (Multiple)[27]	2241	0	2241

10. San Diego-Imperial Valley Area

Area Definition

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

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

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

1) Imperial Valley is in North Gila is out
2) Otay Mesa is in Tijuana is out
3) San Onofre is out San Luis Rey is in

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

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

4) San Onofre is out San Luis Rey is in
5) San Onofre is out San Luis Rey is in
6) San Onofre is out Talega is in
7) San Onofre is out Talega is in
8) Imperial Valley is in El Centro is out
9) Imperial Valley is in Dixieland is out
10) Imperial Valley is in La Rosita is out

Total 2013 busload within the defined area: 4990 MW with 124 MW of losses resulting in total load + losses of 5114 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BORDER_6_UNITA1	22149	CALPK_BD	13.8	48.98	1	San Diego		Market
CBRLLO_6_PLSTP1	22092	CABRILLO	69	2.23	1	San Diego	Aug NQC	QF/Selfgen
CCRITA_7_RPPCHF	22124	CHCARITA	138	3.69	1	San Diego	Aug NQC	QF/Selfgen
CHILLS_1_SYCENG	22120	CARLTNHS	138	0.26	1	San Diego	Aug NQC	QF/Selfgen
CHILLS_7_UNITA1	22120	CARLTNHS	138	1.31	2	San Diego	Aug NQC	QF/Selfgen
CPSTNO_7_PRMADS	22112	CAPSTRNO	138	4.73	1	San Diego	Aug NQC	QF/Selfgen
CRSTWD_6_KUMYAY	22915	KUMEYAAY	34.5	6.70	1	San Diego	Aug NQC	Wind
DIVSON_6_NSQF	22172	DIVISION	69	34.41	1	San Diego	Aug NQC	QF/Selfgen
EGATE_7_NOCITY	22204	EASTGATE	69	0.21	1	San Diego	Aug NQC	QF/Selfgen
ELCAJN_6_LM6K	23320	EC GEN2	13.8	48.10	1	San Diego, El Cajon		Market
ELCAJN_6_UNITA1	22150	CALPK_EC	13.8	45.42	1	San Diego, El Cajon		Market
ELCAJN_7_GT1	22212	ELCAJNGT	12.5	16.00	1	San Diego, El Cajon		Market
ENCINA_7_EA1	22233	ENCINA 1	14.4	106.00	1	San Diego		Market
ENCINA_7_EA2	22234	ENCINA 2	14.4	104.00	1	San Diego		Market
ENCINA_7_EA3	22236	ENCINA 3	14.4	110.00	1	San Diego		Market
ENCINA_7_EA4	22240	ENCINA 4	22	300.00	1	San Diego		Market
ENCINA_7_EA5	22244	ENCINA 5	24	330.00	1	San Diego		Market
ENCINA_7_GT1	22248	ENCINAGT	12.5	14.50	1	San Diego		Market
ESCNDO_6_PL1X2	22257	ESGEN	13.8	35.50	1	San Diego		Market
ESCNDO_6_UNITB1	22153	CALPK_ES	13.8	48.04	1	San Diego		Market
ESCO_6_GLMQF	22332	GOALLINE	69	39.92	1	San Diego, Esco	Aug NQC	QF/Selfgen
KEARNY_7_KY1	22377	KEARNGT1	12.5	16.00	1	San Diego, Mission		Market
KEARNY_7_KY2	22373	KEARN2AB	12.5	15.02	1	San Diego, Mission		Market
KEARNY_7_KY2	22373	KEARN2AB	12.5	15.02	2	San Diego, Mission		Market
KEARNY_7_KY2	22374	KEARN2CD	12.5	15.02	1	San Diego, Mission		Market
KEARNY_7_KY2	22374	KEARN2CD	12.5	13.95	2	San Diego, Mission		Market
KEARNY_7_KY3	22375	KEARN3AB	12.5	14.98	1	San Diego, Mission		Market

KEARNY_7_KY3	22375	KEARN3AB	12.5	16.05	2	San Diego, Mission		Market
KEARNY_7_KY3	22376	KEARN3CD	12.5	14.98	1	San Diego, Mission		Market
KEARNY_7_KY3	22376	KEARN3CD	12.5	14.98	2	San Diego, Mission		Market
LAKHDG_6_UNIT 1	22625	LKHODG1	13.8	20.00	1	San Diego, Bernardo		Market
LARKSP_6_UNIT 1	22074	LRKSPBD1	13.8	46.00	1	San Diego		Market
LARKSP_6_UNIT 2	22075	LRKSPBD2	13.8	46.00	1	San Diego		Market
LAROA1_2_UNITA1	20187	LRP-U1	16	165	1	None		Market
LAROA2_2_UNITA1	22996	INTBST	18	157	1	None		Market
LAROA2_2_UNITA1	22997	INTBCT	16	165	1	None		Market
MRGT_6_MEF2	22487	MFE_MR2	13.8	47.90	1	San Diego, Mission, Miramar		Market
MRGT_6_MMAREF	22486	MFE_MR1	13.8	48.00	1	San Diego, Mission, Miramar		Market
MRGT_7_UNITS	22488	MIRAMRGT	12.5	18.55	1	San Diego, Mission, Miramar		Market
MRGT_7_UNITS	22488	MIRAMRGT	12.5	17.45	2	San Diego, Mission, Miramar		Market
MSHGTS_6_MMARLF	22448	MESAHGTS	69	3.19	1	San Diego, Mission	Aug NQC	QF/Selfgen
MSSION_2_QF	22496	MISSION	69	0.74	1	San Diego	Aug NQC	QF/Selfgen
NIMTG_6_NIQF	22576	NOISLMTR	69	35.59	1	San Diego	Aug NQC	QF/Selfgen
OGROVE_6_PL1X2	22628	PA99MWQ1	13.8	49.95	1	San Diego, Pala		Market
OGROVE_6_PL1X2	22629	PA99MWQ2	13.8	49.95	2	San Diego, Pala		Market
OTAY_6_PL1X2	22617	OYGEN	13.8	35.50	1	San Diego		Market
OTAY_6_UNITB1	22604	OTAY	69	2.80	1	San Diego	Aug NQC	QF/Selfgen
OTAY_7_UNITC1	22604	OTAY	69	2.65	3	San Diego	Aug NQC	QF/Selfgen
OTMESA_2_PL1X3	22605	OTAYMGT1	18	185.06	1	San Diego		Market
OTMESA_2_PL1X3	22606	OTAYMGT2	18	185.06	1	San Diego		Market
OTMESA_2_PL1X3	22607	OTAYMST1	16	233.48	1	San Diego		Market
PALOMR_2_PL1X3	22262	PEN_CT1	18	162.39	1	San Diego		Market
PALOMR_2_PL1X3	22263	PEN_CT2	18	162.39	1	San Diego		Market
PALOMR_2_PL1X3	22265	PEN_ST	18	240.83	1	San Diego		Market
PTLOMA_6_NTCCGN	22660	POINTLMA	69	1.65	2	San Diego	Aug NQC	QF/Selfgen
PTLOMA_6_NTCQF	22660	POINTLMA	69	16.70	1	San Diego	Aug NQC	QF/Selfgen
SAMPSN_6_KELCO1	22704	SAMPSON	12.5	0.72	1	San Diego	Aug NQC	QF/Selfgen
SMRCOS_6_UNIT 1	22724	SANMRCOS	69	0.47	1	San Diego	Aug NQC	QF/Selfgen
TERMEX_2_PL1X3	22981	IV GEN1	18	281	1	None		Market
TERMEX_2_PL1X3	22982	IV GEN2	18	156	1	None		Market
TERMEX_2_PL1X3	22983	IVGEN3	18	156	1	None		Market
NA	22444	MESA RIM	69	0.00	1	San Diego	No NQC - hist. data	QF/Selfgen
NA	22592	OLD TOWN	69	0.00	1	San Diego	No NQC - hist. data	QF/Selfgen
NA	22602	OMWD	69	0.00	1	San Diego	No NQC - hist. data	QF/Selfgen
NA	22708	SANLUSRY	69	0.00	1	San Diego	No NQC - hist. data	QF/Selfgen
NA	22916	PFC-AVC	0.6	0.00	1	San Diego	No NQC - hist. data	QF/Selfgen
LAKHDG_6_UNIT 2	22626	LKHODG2	13.8	20.00	2	San Diego, Bernardo	No NQC - Pmax	Market

Major new projects modeled:

1. Sunrise Power Link Project (Southern Route)
2. Eastgate – Rose Canyon 69kV (TL6927) reconductor
3. New Imperial Valley-Dixieland 230 kV line
4. East County 500 kV substation (ECO)

<u>Critical Contingency Analysis Summary</u>

El Cajon Sub-area:

The most critical contingency for the El Cajon sub-area is the loss of the El Cajon-Jamacha 69 kV line (TL624) followed by the loss of Miguel-Granite-Los Coches 69 kV line (TL632), which would thermally overload the El Cajon – Los Coches 69 kV line (TL631). This limiting contingency establishes a LCR of 83 MW (including 0 MW of QF generation) in 2013 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency for this sub-area is the loss of Miguel-Granite-Los Coches 69 kV line (TL632) with El Cajon Energy Center already out of service, which would thermally overload the El Cajon – Los Coches 69 kV line (TL631). This limiting contingency establishes a LCR of 53 MW (including 0 MW of QF generation) in 2013.

Effectiveness factors:

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

Rose Canyon Sub-area

This sub-area has been eliminated due to TL6927, Eastgate-Rose Canyon 69 kV reconductor which is already in-service.

Mission Sub-area

The most critical contingency for the Mission sub-area is the loss of Mission - Kearny 69 kV line (TL663) followed by the loss of Mission – Mesa Heights 69kV line (TL676), which would thermally overload the Mission - Clairmont 69kV line (TL670). This limiting contingency establishes a local capacity need of 126 MW (including 3 MW of QF generation) in 2013 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Bernardo Sub-area:

The most critical contingency for the Bernardo sub-area is the loss of Artesian - Sycamore 69 kV line followed by the loss of Poway-Rancho Carmel 69 kV line, which would thermally overload the Felicita Tap-Bernardo 69 kV line (TL689). This limiting contingency establishes a LCR of 110 MW (including 0 MW of QF generation and 70 MW of deficiency) in 2013 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Esco Sub-area

The most critical contingency for the Esco sub-area is the loss of Poway-Pomerado 69 kV line (TL6913) followed by the loss of Esco - Escondido 69kV line (TL6908) which would thermally overload the Bernardo – Rancho Carmel 69 kV line (TL633). This limiting contingency establishes a LCR of 114 MW (including 40 MW of QF generation and 74 MW of deficiency) in 2013 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Pala Sub-area

The most critical contingency for the Pala sub-area is the loss of Pendleton – San Luis Rey 69 kV line (TL6912) followed by the loss of Lilac - Pala 69kV line (TL6932) which would thermally overload the Melrose – Morro Hill Tap 69 kV line. This limiting contingency establishes a LCR of 43 MW (including 0 MW of QF generation) in 2013 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area (Orange Grove) have the same effectiveness factor.

Miramar Sub-area

The most critical contingency for the Miramar sub-area is the loss of Otay Mesa – Miguel Tap – Silvergate 230kV line (TL23042) followed by the loss of Sycamore 230/138 kV Bank #60, which would thermally overload the Sycamore - Scripps 69 kV line (TL6916). This limiting contingency establishes a LCR of 97 MW (including 0 MW of QF generation) in 2013 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency for this sub-area is the loss of Otay Mesa – Miguel Tap – Silvergate 230kV line (TL23042) with Miramar Energy Facility #1 or #2 out of service, which would thermally overload the Sycamore - Scripps 69 kV line (TL6916). This limiting contingency establishes a LCR of 86 MW (including 0 MW of QF generation) in 2013.

Effectiveness factors:

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

San Diego Sub-area:

The most limiting contingency for San Diego sub-area is the loss of Imperial Valley-Suncrest 500 kV line followed by the loss of ECO-Miguel 500 kV line. The limiting constraint is post-transient voltage instability. This contingency establishes a LCR of 2570 MW in 2013 (includes 151 MW of QF generation and 7 MW of Wind) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The most limiting single contingency in the San Diego sub-area is a (G-1/N-1) contingency described by the outage of ECO-Miguel 500 kV line with Otay Mesa Combined-Cycle Power Plant (603 MW) already out of service. The limiting constraint is post-transient voltage instability. This contingency establishes a LCR of 2192 MW in 2013 (includes 151 MW of QF generation and 7 MW of Wind).

Effectiveness factors:

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

San Diego Sub-area Requirements:

2013	QF (MW)	Wind (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	151	7	2911	3069

2013	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[28]	2192	0	2192
Category C (Multiple)[29]	2570	144	2714

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

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

San Diego-Imperial Valley Area Overall:

The most limiting contingency in the San Diego-Imperial Valley area is described by the outage of 500 kV Southwest Power Link (SWPL) between Imperial Valley and N. Gila Substations over-lapping with an outage of the Otay Mesa Combined-Cycle Power plant (603 MW) while staying within the South of San Onofre (WECC Path 44) non-simultaneous import capability rating of 2,500 MW. This limiting contingency establishes a local capacity need of 2938 MW in 2013 (includes 151 MW of QF generation and 7 MW of Wind) as the minimum capacity necessary for reliable load serving capability within this area.

It is worth mentioning that Imperial Valley – Dixieland 230kV line was modeled between IID and CAISO. There were no additional upgrades modeled between CFE and CAISO control areas at Imperial Valley 230 kV bus in 2013 base case. The CAISO acknowledges that the LCR needs for the San Diego-Imperial Valley area will decrease as additional transmission is constructed between the IID/CFE systems and Imperial Valley and more power is flowing in real-time from these control areas into the CAISO control area.

Effectiveness factors:

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

Changes compared to last year's results:

The load forecast went up by 270 MW and total local resource capacity needed for the San Diego-Imperial Valley increased by 89 MW overall due to a combination of factors.

Local capacity needs (Category C) for the San Diego sub-area decreased by 279 MW compared to last year mainly due to the WECC classification of Sunrise Power Link and South West Power Link as not being in the same corridor as well as elimination of WECC 1000 MW path rating on Sunrise Power Link. This shifted the most restrictive constraint to the larger area, however, resulting in an overall increase of89 MW from the

2012 requirement but drawing on a larger pool of resources.

Overall the total LCR requirements (including deficiencies that cannot be contracted for due to unavailability of resources) have actually increased by 138 MW mainly due to the deficiency increase in the Bernardo and Esco sub-areas. It should be noted that further LCR deficiencies in the San Diego sub area are expected in later years due to the 2017 OTC compliance date for the Encina power plant and to the most restrictive contingency for this sub area limiting the pool of resources (qualifying capacity) effective in addressing the San Diego local area needs.

San Diego-Imperial Valley Area Overall Requirements:

2013	QF (MW)	Wind (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	151	7	3991	4149

2013	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[30]	2938	0	2938
Category C (Multiple)[31]	2938	144	3082

For stakeholder information only

Non-summer season LCR limited analysis

These results are for information purposes only and they will not be used to alter the 2013 LSE local resource allocation. The LSE local resource allocation is done based on the summer peak study as required by the ISO Tariff.

Extra assumptions as agreed upon by stakeholders:

1. One transmission element under maintenance conditions
2. Two resources under maintenance conditions

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

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

Total 2013 busload within the defined area: 3800 MW with 71 MW of losses resulting in total load + losses of 3871 MW. This corresponds to a 1-in-10 peak for the month of October (highest among non-summer months).

San Diego Sub-area non-summer season:

Worst transmission element out on maintenance was considered to be one of the Imperial Valley-Suncrest, Imperial Valley-ECO or ECO-Miguel 500 kV lines.

The most limiting contingency for San Diego sub-area is the loss of Miguel - ECO 500 kV line with Otay Mesa out of service (Imperial Valley – Suncrest 500 kV line is out on maintenance). The limiting constraint is post-transient voltage instability. This contingency establishes a LCR of 1777 MW in 2013 (includes 151 MW of QF generation and 7 MW of Wind) as the minimum generation capacity necessary for reliable load serving capability within this sub-area in the non-summer season.

Under the current design all units with approved maintenance schedules are allowed to count towards the local requirement even when they are out of service. Maintaining these assumptions the “two units out on maintenance” can make up anywhere from 30 to 1169 MW for an average of 500-600 MW. The total local resources in the greater San Diego sub-area under an RA contract in the non-summer season should be therefore around 2277-2377 MW, a level 200-300 MW lower than the summer peak need.

San Diego-Imperial Valley Area Overall non-summer season:

Worst transmission element out on maintenance was considered to be one of the five 230 kV lines that comprise the South of SONGS path. This will reduce the import capability of South of SONGS from 2500 MW to about 1650 MW.

The most limiting contingency in the San Diego-Imperial Valley area is described by the outage of 500 kV Southwest Power Link (SWPL) between Imperial Valley and N. Gila Substations over-lapping with an outage of the Otay Mesa Combined-Cycle Power plant

(603 MW) while staying within the South of San Onofre (WECC Path 44) non-simultaneous import capability of 1,650 MW (after one element out for maintenance). This limiting contingency establishes a local capacity need of 2498 MW in 2013 (includes 151 MW of QF generation and 7 MW of Wind) as the minimum capacity necessary for reliable load serving capability within this area in the non-summer season.

Under the current design all units with approved maintenance schedules are allowed to count towards the local requirement even when they are out of service. Maintaining these assumptions the “two units out on maintenance” can make up anywhere from 30 to 1197 MW for an average of 500-600 MW. The total local resources in the greater San Diego-Imperial Valley area under an RA contract in the non-summer season should be therefore around 2998-3098 MW, a level 200-300 MW higher than the summer peak need.

11. Valley Electric Area

Area Definition

The transmission tie lines into the area include:

1) Amargosa-Sandy 138 kV line
2) Jackass Flats-Lathrop Switch 138 kV line
3) Sloan Canyon-Pahrump 230 kV line
4) Desert View-Pahrump 230 kV line

The substations that delineate the area are:

1) Amargosa is out Sandy is in
2) Jackass Flats is out Lathrop Switch is in
3) Sloan Canyon is out Pahrump is in
4) Desert View is out Pahrump is in

Total 2013 busload within the defined area was: 119 MW along with 2 MW of transmission losses resulting in total load + losses of 121 MW.

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

Major new transmission projects modeled:

1. Northwest-Desert View 230 kV Line #1 (under construction, be in service before the summer of 2013)

<u>Critical Contingency Analysis Summary</u>

Pahrump South Sub-Area

The most critical contingency for the Pahrump South Sub-Area is the loss of Pahrump-Gamebird 138 kV line with the biggest resource in the area out of service (estimated at a minimum of 7 MW). This contingency results in voltage lower than 0.90 pu at Gamebird sub (0.89 pu), Thousandaire sub (0.89 pu), and Charleston sub (0.89 pu), and establishes a local capacity need of 7 MW plus the biggest resource in the area (estimated at 7 MW) or a total of 14 MW (includes 14 MW of deficiency) in 2013 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

There is no generation available in this sub-area.

Valley Electric Association Overall Area

The most critical contingency for the Valley Electric Association Area is the loss of Mead-Sloan Canyon 230 kV line followed by the loss of Northwest-Desert View 230 kV line or vice versa. This double contingency event may result in voltage collapse in the Valley Electric Association area, and establishes a local capacity need of 37 MW (including 37 MW of deficiency) in 2013 as the minimum capacity necessary for reliable load serving capability within the area. An SPS to drop load for this N-2 could eliminate this overall local capacity need.

Effectiveness factors:

There is no generation available in this area.

Changes compared to last year's results:

There is no comparison to last year's results since this is first year to establish local capacity requirement for the Valley Electric Area.

Valley Electric Area Overall Requirements:

2013	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	0	0	0	0

2013	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single) [32]	0	14	14
Category C (Multiple) [33]	0	37	37

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

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

Rulemaking: 12-03-014
Exhibit No.: ISO-15
Witness:

2011 Local Capacity Technical Analysis

Final Report and Study Results

California Independent
System Operator

2011
LOCAL CAPACITY TECHNICAL ANALYSIS

FINAL REPORT
AND STUDY RESULTS

April 30, 2010

Local Capacity Technical Study
Overview and Results

I. Executive Summary

This Report documents the results and recommendations of the 2011 Local Capacity Technical (LCT) Study. The LCT Study assumptions, processes, and criteria were discussed and recommended through the 2011 Local Capacity Technical Study Criteria, Methodology and Assumptions Stakeholder Meeting held on November 24, 2009. On balance, the assumptions, processes, and criteria used for the 2011 LCT Study mirror those used in the 2007-2010 LCT Studies, which were previously discussed and recommended through the LCT Study Advisory Group ("LSAG")[1], an advisory group formed by the CAISO to assist the CAISO in its preparation for performing prior LCT Studies.

The 2011 LCT study results are provided to the CPUC for consideration in its 2011 resource adequacy requirements program. These results will also be used by the CAISO for identifying the minimum quantity of local capacity necessary to meet the North American Electric Reliability Corporation (NERC) Reliability Criteria used in the LCT Study (this may be referred to as "Local Capacity Requirements" or "LCR") and for assisting in the allocation of costs of any CAISO procurement of capacity needed to achieve the Reliability Criteria notwithstanding the resource adequacy procurement of Load Serving Entities (LSEs).[2] In this regard, the 2011 LCT Study also provides additional information on sub-area needs and effectiveness factors (where applicable) in order to allow LSEs to engage in more informed procurement.

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

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

Below is a comparison of the 2011 vs. 2010 total LCR:

2011 Local Capacity Requirements

	Qualifying Capacity			2011 LCR Need Based on Category B			2011 LCR Need Based on Category C with operating procedure		
Local Area Name	**QF/ Muni (MW)**	**Market (MW)**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**
Humboldt	57	166	223	147	0	**147**	188	17	**205**
North Coast / North Bay	133	728	861	734	0	**734**	734	0	**734**
Sierra	1057	759	1816	1330	313	**1643**	1510	572	**2082**
Stockton	267	259	526	374	0	**374**	459	223	**682**
Greater Bay	1210	5296	6506	4036	0	**4036**	4804	74	**4878**
Greater Fresno	485	2434	2919	2200	0	**2200**	2444	4	**2448**
Kern	699	9	708	243	0	**243**	434	13	**447**
LA Basin	4206	8103	12309	10589	0	**10589**	10589	0	**10589**
Big Creek/ Ventura	1196	4110	5306	2786	0	**2786**	2786	0	**2786**
San Diego	194	3227	3421	3146	0	**3146**	3146	61	**3207**
Total	**9504**	**25091**	**34595**	**25585**	**313**	**25898**	**27094**	**964**	**28058**

2010 Local Capacity Requirements

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

Overall, the LCR needs are steady from 2010 to 2011. The total LCR needs have increased by about 331 MW, however the existing capacity needed to meet the LCR has increased by only 19 MW. The LCR needs have decreased in the following areas: North Coast/North Bay, Sierra, Fresno, Big Creek/Ventura and San Diego due to downward trend for load. The LCR needs have slightly increased in Humboldt due to new Humboldt Bay Power Plant configuration, Greater Bay due to the Potrero Power Plant retirement, Kern due to load growth and LA Basin due to load growth and permanent retirement of the Antelope-Mesa Cal 230 kV line (as required per TRTP – in order to make room for a new 500 kV line). The Stockton LCR needs are steady. The write-up for each Local Capacity Area lists important new projects included in the base cases as well as a description of reason for changes between 2011 and 2010 LCRs.

Table of Contents

II. Study Overview: Inputs, Outputs and Options

A. Objectives

As was the objective of the four previous annual LCT Studies, the intent of the 2011 LCT Study is to identify specific areas within the CAISO Balancing Authority Area that have limited import capability and determine the minimum generation capacity (MW) necessary to mitigate the local reliability problems in those areas.

B. Key Study Assumptions

1. Inputs and Methodology

The CAISO incorporated into its 2011 LCT study the same criteria, input assumptions and methodology that were incorporated into its previous years LCR studies. These inputs, assumptions and methodology were discussed and agreed to by stakeholders at the 2011 LCT Study Criteria, Methodology and Assumptions Stakeholder Meeting held on November 24, 2009.

The following table sets forth a summary of the approved inputs and methodology that have been used in the previous LCT studies as well as this 2011 LCT Study:

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

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

Further details regarding the 2011 LCT Study methodology and assumptions are provided in Section III, below.

C. Grid Reliability

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

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

[3] Pub. Utilities Code § 345

there are other levels of performance where security can be maintained without ensuring adequacy.

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

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

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

E. Performance Criteria

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

a. Performance Criteria- Category B

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

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

b. Performance Criteria- Category C

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

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

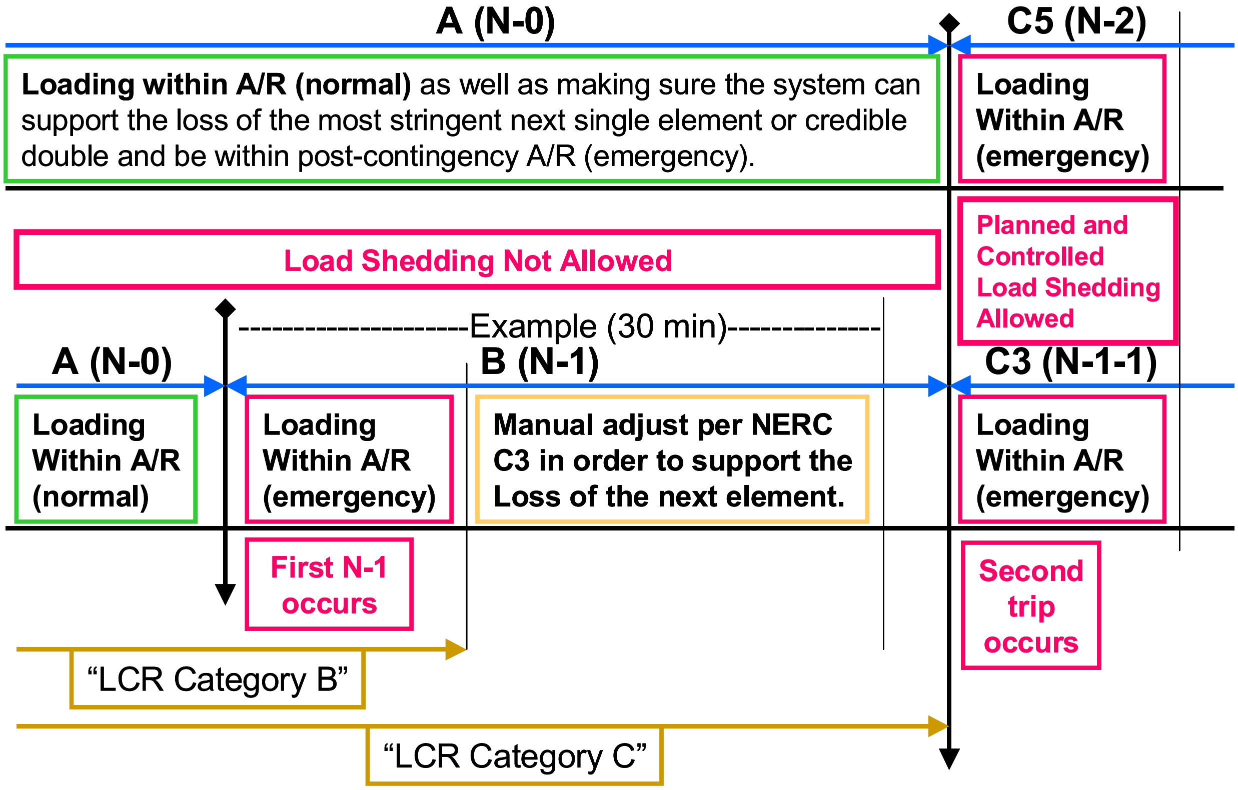
(N-0) or after the first contingency (N-1) the system requires additional readjustment in order to prepare for the next worst contingency. In this time frame, load drop is not allowed per existing planning criteria.

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

c. CAISO Statutory Obligation Regarding Safe Operation

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

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



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

<u>Applicable Rating:</u>

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

<u>Normal rating</u> is to be used under normal conditions.

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

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

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

Controlled load drop:

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

Planned load drop:

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

Special Protection Scheme:

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

System Readjustment:

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

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

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

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

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

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

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

Time allowed for manual readjustment:

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

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

F. The Two Options Presented In This LCT Report

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

1. Option 1- Meet Performance Criteria Category B

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

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

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

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

III. Assumption Details: How the Study was Conducted

A. System Planning Criteria

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

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

Table 4: Criteria Comparison

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

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

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

1. Power Flow Assessment:

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

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

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

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

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

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

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

[7] During normal operation or following the first contingency (N-1), the generation must be sufficient to allow the operators to prepare for the next worst N-1 or common mode N-2 without pre-contingency interruptible or firm load shedding.

SPS/RAS/Safety Nets may be utilized to satisfy the criteria after the second N-1 or common mode N-2 except if the problem is of a thermal nature such that short-term ratings could be utilized to provide the operators time to shed either interruptible or firm load. T-2s (two transformer bank outages) would be excluded from the criteria.

2. Post Transient Load Flow Assessment:

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

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

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

3. Stability Assessment:

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

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

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

B. Load Forecast

1. System Forecast

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

2. Base Case Load Development Method

The method used to develop the base case loads is a melding process that extracts, adjusts and modifies the information from the system, distribution and municipal utility forecasts. The melding process consists of two parts: Part 1 deals with the PTO load and Part 2 deals with the municipal utility load. There may be small differences between the methodologies used by each PTO to disaggregate the CEC load forecast to their level of local area as well as bar-bus model.

a. PTO Loads in Base Case

The methods used to determine the PTO loads are, for the most part, similar. One part of the method deals with the determination of the division[6] loads that would meet the requirements of 1-in-5 or 1-in-10 system or area base cases and the other part deals with the allocation of the division load to the transmission buses.

i. Determination of division loads

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

---

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

ii. Allocation of division load to transmission bus level

Since the base case loads are modeled at the various transmission buses, the division loads developed must be allocated to those buses. The allocation process is different depending on the load types. For the most part, each PTO classifies its loads into four types: conforming, non-conforming, self-generation and generation-plant loads. Since the non-conforming and self-generation loads are assumed to not vary with temperature, their magnitude would be the same in the system or area base cases of the same year. The remaining load (the total division load developed above, less the quantity of non-conforming and self-generation load) is the conforming load. The remaining load is allocated to the transmission buses based on the relative magnitude of the distribution forecast. The summation of all base case loads is generally higher than the load forecast because some load, i.e., self-generation and generation-plant, are behind the meter and must be modeled in the base cases. However, for the most part, metered or aggregated data with telemetry is used to come up with the load forecast.

b. Municipal Loads in Base Case

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

C. Power Flow Program Used in the LCT analysis

The technical studies were conducted using General Electric's Power System Load Flow (GE PSLF) program version 17.0. This GE PSLF program is available directly from GE or through the Western System Electricity Council (WECC) to any member.

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

Electronic contingency files provided by the PTOs were utilized to perform the numerous contingencies required to identify the LCR. These contingency files include remedial action and special protection schemes that are expected to be in operation

during the year of study. An CAISO created EPCL (a GE programming language contained within the GE PSLF package) routine was used to run the combination of contingencies; however, other routines are available from WECC with the GE PSFL package or can be developed by third parties to identify the most limiting combination of contingencies requiring the highest amount of generation within the local area to maintain power flows within applicable ratings.

IV. Local Capacity Requirement Study Results

A. Summary of Study Results

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

Table 5: 2011 Local Capacity Needs vs. Peak Load and Local Area Generation

	2011 Total LCR (MW)	Peak Load (1 in10) (MW)	2011 LCR as % of Peak Load	Total Dependable Local Area Generation (MW)	2011 LCR as % of Total Area Generation
Humboldt	205	206	100%	223	92%**
North Coast/North Bay	734	1574	47%	861	85%
Sierra	2082	1977	105%	1816	115%**
Stockton	682	1163	59%	526	130%**
Greater Bay	4878	10322	47%	6506	75%**
Greater Fresno	2448	3306	74%	2919	84%**
Kern	447	1387	32%	708	63%**
LA Basin	10589	20223	52%	12309	86%
Big Creek/Ventura	2786	4648	60%	5306	53%
San Diego	3207	5036	64%	3421	94%**
Total	**28,058**	**49842***	**56%***	**34,595**	**81%**

Table 6: 2010 Local Capacity Needs vs. Peak Load and Local Area Generation

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

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

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

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

The term "Qualifying Capacity" used in this report is the latest "Net Qualifying Capacity" ("NQC") posted on the CAISO web site at:

http://www.caiso.com/1796/179688b22c970.html

The NQC list includes the area (if applicable) where each resource is located for units already operational. Neither the NQC list nor this report incorporates Demand Side Management programs and their related NQC. Units scheduled to become operational before 6/1/2011 have been included in this 2011 LCR Report and added to the total NQC values for those respective areas (see detail write-up for each area).

The first column, "Qualifying Capacity," reflects two sets of generation. The first set is comprised of generation that would normally be expected to be on-line such as Municipal generation and Regulatory Must-take generation (state, federal, QFs, wind and nuclear units). The second set is "market" generation. The second column, "2011 LCR Requirement Based on Category B" identifies the local capacity requirements, and deficiencies that must be addressed, in order to achieve a service reliability level based on Performance Criteria- Category B. The third column, "2011 LCR Requirement Based on Category C with Operating Procedure", sets forth the local capacity requirements, and deficiencies that must be addressed, necessary to attain a service reliability level based on Performance Criteria-Category C with operational solutions.

B. Summary of Zonal Needs

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

Zone	Load Forecast (MW)	15% reserves (MW)	(-) Allocated imports (MW)	(-) Allocated Path 26 Flow (MW)	Total Zonal Resource Need (MW)
SP26	28363	4254	-8544	-3750	**20323**
NP26=NP15+ZP26	21988	3298	-4885	-2902	**17499**

Where:

Load Forecast is the most recent 1 in 2 CEC forecast for year 2011.

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

Allocated Imports are the actual 2010 numbers that are not expected to change much by 2011 because there are no additional transmission additions to the grid between now and summer of 2011.

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

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

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

Changes compared to last year's results:

- The load forecast went down in Southern California by about 500 MW and down in Northern California by about 250 MW.
- The Import Allocations went up in Southern California by about 450 MW and up in Northern California by about 370 MW.
- The Path 26 transfer capability has not changed and is not envisioned to change in the near future. As such, the LSEs should assume that their load/share ratio allocation for path 26 will stay at the same levels as 2010. If there are any changes, they will be heavily influenced by the pre-existing "grandfathered contracts" and when they expire most of the LSEs will likely see their load share ratio going up, while the owners of these grandfathered contracts may see their share decreased to the load-share ratio.

---

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

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

C. Summary of Results by Local Area

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

1. Humboldt Area

<u>Area Definition</u>

The transmission tie lines into the area include:

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

The substations that delineate the Humboldt Area are:

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

Total 2011 busload within the defined area: 197 MW with 9 MW of losses resulting in total load + losses of 206 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BRDGVL_7_BAKER				0.00		None	Not modeled	QF/Selfgen
FAIRHV_6_UNIT	31150	FAIRHAVN	13.8	14.99	1	Humboldt 60 kV		QF/Selfgen
FTSWRD_7_QFUNTS				0.64		Humboldt 60 kV	Not modeled	QF/Selfgen
HUMBPP_1_MOBLE2	31154	HUMBOLDT	13.2	15.00	2	None	Retired	Market
HUMBPP_1_MOBLE3	31154	HUMBOLDT	13.2	15.00	1	None	Retired	Market
HUMBPP_7_UNIT 1	31170	HMBOLDT1	13.8	52.00	1	Humboldt 60 kV	Retired	Market
HUMBPP_7_UNIT 2	31172	HMBOLDT2	13.8	53.00	1	Humboldt 60 kV	Retired	Market
HUMBSB_1_QF				0.00		None	Not modeled - Monthly NQC - used August for LCR	QF/Selfgen
KEKAWK_6_UNIT	31166	KEKAWAK	9.1	0.00	1	Humboldt 60 kV		QF/Selfgen

LAPAC_6_UNIT	31158	LP SAMOA	12.5	20.00	1	Humboldt 60 kV		QF/Selfgen
PACLUM_6_UNIT	31152	PAC.LUMB	13.8	8.25	1	Humboldt 60 kV		QF/Selfgen
PACLUM_6_UNIT	31152	PAC.LUMB	13.8	8.24	2	Humboldt 60 kV		QF/Selfgen
PACLUM_6_UNIT	31153	PAC.LUMB	2.4	4.95	3	Humboldt 60 kV		QF/Selfgen
WLLWCR_6_CEDRFL				0.00		Humboldt 60 kV	Not modeled - Monthly NQC - used August for LCR	QF/Selfgen
ULTPBL_6_UNIT 1	31156	ULTRAPWR	12.5	0.00	1	Humboldt 60 kV	No NQC - historical data	Market
HUMBPP_1_UNITS2	31180	HUMB_G1	13.8	16.60	1	None	No NQC - Pmax	Market
HUMBPP_1_UNITS2	31180	HUMB_G1	13.8	16.60	2	None	No NQC - Pmax	Market
HUMBPP_1_UNITS2	31180	HUMB_G1	13.8	16.60	3	None	No NQC - Pmax	Market
HUMBPP_1_UNITS2	31180	HUMB_G1	13.8	16.60	4	None	No NQC - Pmax	Market
HUMBPP_6_UNITS1	31181	HUMB_G2	13.8	16.60	5	Humboldt 60 kV	No NQC - Pmax	Market
HUMBPP_6_UNITS1	31181	HUMB_G2	13.8	16.60	6	Humboldt 60 kV	No NQC - Pmax	Market
HUMBPP_6_UNITS1	31181	HUMB_G2	13.8	16.60	7	Humboldt 60 kV	No NQC - Pmax	Market
HUMBPP_6_UNITS3	31182	HUMB_G2	13.8	16.60	8	Humboldt 60 kV	No NQC - Pmax	Market
HUMBPP_6_UNITS3	31182	HUMB_G2	13.8	16.60	9	Humboldt 60 kV	No NQC - Pmax	Market
HUMBPP_6_UNITS3	31182	HUMB_G2	13.8	16.60	10	Humboldt 60 kV	No NQC - Pmax	Market

Major new projects modeled:

1. Humboldt Bay Repower
2. Humboldt Reactive Support
3. Maple Creek Reactive Support
4. Garberville Reactive Support

<u>Critical Contingency Analysis Summary</u>

Humboldt 60 kV Sub-area:

The most critical contingency for the Humboldt 60 kV Sub-area area is the outage of the Humboldt 115/60 Transformer and one of the gen tie-line connecting the new Humboldt Bay units (on 60 kV side). The area limitation is the overload on the parallel Humboldt 115/60 kV Transformer. This contingency establishes a LCR of 174 MW in 2011 (includes 57 MW of QF/Selfgen generation as well as 17 MW of deficiency) as the minimum capacity necessary for reliable load serving capability within this area.

The most critical single contingency is the outage of the Humboldt 115/60 kV Transformer. The limitation is thermal overload on the parallel Humboldt 115/60 kV Transformer. This limiting contingency establishes a LCR of 147 MW in 2011 (includes 57 MW of QF/Selfgen generation).

Effectiveness factors:

The following table has units within the Humboldt 60 kV Sub-area area with at least 5% effective to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31150	FAIRHAVN	1	73
31158	LP SAMOA	1	73
31182	HUMB_G3	10	68
31182	HUMB_G3	9	68
31182	HUMB_G3	8	68
31181	HUMB_G2	7	68
31181	HUMB_G2	6	68
31181	HUMB_G2	5	68
31180	HUMB_G1	4	-14
31180	HUMB_G1	3	-14
31180	HUMB_G1	2	-14
31180	HUMB_G1	1	-14
31152	PAC.LUMB	1	40
31152	PAC.LUMB	2	40
31153	PAC.LUMB	3	40

Humboldt overall:

The most critical contingency for the Humboldt area is the outage of the Bridgeville-Cottonwood 115 kV Line overlapping with an outage of one of the tie-line connecting the new Humboldt Bay units. The area limitation is the overload on the Humboldt – Trinity 115 kV Line. This contingency establishes a LCR of 188 MW in 2011 (includes 57 MW of QF/Selfgen generation) as the minimum capacity necessary for reliable load serving capability within this area.

For the single contingency, generation capacity to mitigate overloading facilities identified in Humboldt 60 kV Sub-area is sufficient to mitigate potential overload for the overall system.

Effectiveness factors:

The following table has units within the Humboldt Overall system with at least 5% effective to the above-mentioned constraint

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31150	FAIRHAVN	1	58
31158	LP SAMOA	1	58
31182	HUMB_G3	10	57
31182	HUMB_G3	9	57
31182	HUMB_G3	8	57
31181	HUMB_G2	7	57
31181	HUMB_G2	6	57
31181	HUMB_G2	5	57
31180	HUMB_G1	4	59
31180	HUMB_G1	3	59
31180	HUMB_G1	2	59
31180	HUMB_G1	1	59
31152	PAC.LUMB	1	52
31152	PAC.LUMB	2	52
31153	PAC.LUMB	3	52

Changes compared to last year's results:

The Humboldt Repowering Project (HBPP) was modeled an on-line in the 2011 LCR studies. Two new transmission projects, the Maple Creek and Garberville Reactive support projects were also modeled. While the overall load is steady, the LCR need has increased due to the change in system configuration after the addition of the new Humboldt Bay Power Plant. Furthermore, new transmission projects have resulted in different type of limiting facilities as such the reactive power is no longer the biggest concern. Overall the LCR has increased by 29 MW, however the LCR resource need has only increase by 12 MW.

Humboldt Overall Requirements:

2011	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	57	0	166	223

2011	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[9]	147	0	147
Category C (Multiple)[10]	188	17	205

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

2. North Coast / North Bay Area

Area Definition

The North Coast/North Bay Area is composed of three sub-areas and the generation requirements within them. The transmission tie facilities coming into the North Coast/North Bay area are:

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

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

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

Total 2011 busload within the defined area: 1511 MW with 63 MW of losses resulting in total load + losses of 1574 MW.

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

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ADLIN_1_UNITS	31435	GEO.ENGY	9.1	8.00	1	Eagle Rock, Fulton, Lakeville		Market
ADLIN_1_UNITS	31435	GEO.ENGY	9.1	8.00	2	Eagle Rock, Fulton, Lakeville		Market
BEARCN_2_UNITS	31402	BEAR CAN	13.8	6.50	1	Fulton, Lakeville		Market
BEARCN_2_UNITS	31402	BEAR CAN	13.8	6.50	2	Fulton, Lakeville		Market
FULTON_1_QF				0.18		Fulton, Lakeville	Not modeled	QF/Selfgen
GEYS11_7_UNIT11	31412	GEYSER11	13.8	60.00	1	Eagle Rock, Fulton, Lakeville	Monthly NQC - used August for LCR	Market
GEYS12_7_UNIT12	31414	GEYSER12	13.8	50.00	1	Fulton, Lakeville	Monthly NQC - used August for LCR	Market

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

GEYS13_7_UNIT13	31416	GEYSER13	13.8	56.00	1	Lakeville	Monthly NQC - used August for LCR	Market
GEYS14_7_UNIT14	31418	GEYSER14	13.8	50.00	1	Fulton, Lakeville	Monthly NQC - used August for LCR	Market
GEYS16_7_UNIT16	31420	GEYSER16	13.8	49.00	1	Fulton, Lakeville	Monthly NQC - used August for LCR	Market
GEYS17_2_BOTRCK	31421	BOTTLERK	13.8	14.70	1	Fulton, Lakeville		Market
GEYS17_7_UNIT17	31422	GEYSER17	13.8	47.00	1	Fulton, Lakeville	Monthly NQC - used August for LCR	Market
GEYS18_7_UNIT18	31424	GEYSER18	13.8	45.00	1	Lakeville	Monthly NQC - used August for LCR	Market
GEYS20_7_UNIT20	31426	GEYSER20	13.8	40.00	1	Lakeville	Monthly NQC - used August for LCR	Market
GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	40.00	1	Eagle Rock, Fulton, Lakeville	Monthly NQC - used August for LCR	Market
GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	40.00	2	Eagle Rock, Fulton, Lakeville	Monthly NQC - used August for LCR	Market
GYS7X8_7_UNITS	31408	GEYSER78	13.8	38.00	1	Eagle Rock, Fulton, Lakeville	Monthly NQC - used August for LCR	Market
GYS7X8_7_UNITS	31408	GEYSER78	13.8	38.00	2	Eagle Rock, Fulton, Lakeville	Monthly NQC - used August for LCR	Market
GYSRVL_7_WSPRNG				1.68		Fulton, Lakeville	Not modeled	QF/Selfgen
HIWAY_7_ACANYN				1.26		Lakeville	Not modeled	QF/Selfgen
IGNACO_1_QF				0.00		Lakeville	Not modeled	QF/Selfgen
INDVLY_1_UNITS	31436	INDIAN V	9.1	0.80	1	Eagle Rock, Fulton, Lakeville		QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	2.74	1	Fulton, Lakeville	Monthly NQC - used August for LCR	QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	2.74	2	Fulton, Lakeville	Monthly NQC - used August for LCR	QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	0.65	3	Fulton, Lakeville	Monthly NQC - used August for LCR	QF/Selfgen
NAPA_2_UNIT				0.02		Lakeville	Not modeled	QF/Selfgen
NCPA_7_GP1UN1	38106	NCPA1GY1	13.8	32.00	1	Lakeville		MUNI
NCPA_7_GP1UN2	38108	NCPA1GY2	13.8	29.00	1	Lakeville		MUNI
NCPA_7_GP2UN3	38110	NCPA2GY1	13.8	28.00	1	Fulton, Lakeville		MUNI
NCPA_7_GP2UN4	38112	NCPA2GY2	13.8	27.00	1	Fulton, Lakeville		MUNI
POTTER_6_UNITS	31433	POTTRVLY	2.4	4.70	1	Eagle Rock, Fulton, Lakeville		Market
POTTER_6_UNITS	31433	POTTRVLY	2.4	2.25	3	Eagle Rock, Fulton, Lakeville		Market
POTTER_6_UNITS	31433	POTTRVLY	2.4	2.25	4	Eagle Rock, Fulton, Lakeville		Market
POTTER_7_VECINO				0.03		Eagle Rock, Fulton, Lakeville	Not modeled	QF/Selfgen
SANTFG_7_UNITS	31400	SANTA FE	13.8	30.00	1	Lakeville		Market
SANTFG_7_UNITS	31400	SANTA FE	13.8	30.00	2	Lakeville		Market

SMUDGO_7_UNIT 1	31430	SMUDGEO1	13.8	37.00	1	Lakeville	Monthly NQC - used August for LCR	Market
SNMALF_6_UNITS	31446	SONMA LF	9.1	5.52	1	Fulton, Lakeville		QF/Selfgen
UKIAH_7_LAKEMN				1.70		Eagle Rock, Fulton, Lakeville	Not modeled	MUNI
WDFRDF_2_UNITS	31404	WEST FOR	13.8	12.51	1	Fulton, Lakeville		Market
WDFRDF_2_UNITS	31404	WEST FOR	13.8	12.49	2	Fulton, Lakeville		Market

Major new projects modeled: None

<u>Critical Contingency Analysis Summary</u>

Eagle Rock Sub-area

The most critical overlapping contingency is the outage of the Eagle Rock-Silverado-Fulton 115 kV line and the Cortina #4 230/115 kV bank. The sub-area area limitation is thermal overloading of Fulton-Hopland 60 kV. This limiting contingency establishes a LCR of 217 MW in 2011 (includes 3 MW of QF/MUNI generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the outage of the Cortina #4 230/115 kV bank. The sub-area area limitation is thermal overloading of Fulton-Hopland 60 kV. This limiting contingency establishes a LCR of 93 MW in 2011 (includes 3 MW of QF/MUNI generation).

Effectiveness factors:

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

Fulton Sub-area

The most critical overlapping contingency is the outage of the Lakeville-Ignacio 230 kV line #1 and the Crocket-Sobrante 230 kV line #1. The sub-area area limitation is thermal overloading of Fulton-Lakeville 230 kV line #1. This limiting contingency establishes a LCR of 546 MW (includes 14 MW of QF and 57 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area. All of the resources needed to meet the Eagle Rock sub-area count towards the Fulton sub-area LCR need.

Effectiveness factors:

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

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

Lakeville Sub-area

The most limiting contingency is the outage of Vaca Dixon-Lakeville 230 kV line with DEC power plant out of service. The sub-area limitation is thermal overloading of the Vaca Dixon-Tulucay 230 kV. This limiting contingency establishes a LCR of 734 MW (includes 15 MW of QF and 118 MW of MUNI generation) as the minimum capacity necessary for reliable load serving capability within this sub-area. The LCR resources needed for Eagle Rock and Fulton sub-areas can be counted toward fulfilling the requirement of Lakeville sub-area.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31400	SANTA FE	2	37
31430	SMUDGEO1	1	37
31400	SANTA FE	1	37

31416	GEYSER13	1	37
31424	GEYSER18	1	37
31426	GEYSER20	1	37
38106	NCPA1GY1	1	37
38108	NCPA1GY2	1	37
31421	BOTTLERK	1	35
31404	WEST FOR	2	35
31402	BEAR CAN	1	35
31402	BEAR CAN	2	35
31404	WEST FOR	1	35
31414	GEYSER12	1	35
31418	GEYSER14	1	35
31420	GEYSER16	1	35
31422	GEYSER17	1	35
38110	NCPA2GY1	1	35
38112	NCPA2GY2	1	35
31406	GEYSR5-6	1	19
31406	GEYSR5-6	2	19
31408	GEYSER78	1	19
31408	GEYSER78	2	19
31412	GEYSER11	1	19
31435	GEO.ENGY	1	19
31435	GEO.ENGY	2	19

Changes compared to last year's results:

Overall the load forecast went down by 40 MW and the LCR need down by 56. The study results shown in this report for the overall North Coast and North Bay area assume that DC run-back can be used as a mitigation plan.

North Coast/North Bay Overall Requirements:

2011	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	15	118	728	861

2011	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[11]	734	0	734
Category C (Multiple)[12]	734	0	734

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

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

3. Sierra Area

Area Definition

The transmission tie lines into the Sierra Area are:

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

The substations that delineate the Sierra Area are:

1) Table Mountain is out Rio Oso is in
2) Table Mountain is out Palermo is in
3) Table Mt is out Pease is in
4) Caribou is out Palermo is in
5) Drum is in Summit is out
6) Drum is in Summit is out
7) Spaulding is in Summit is out
8) Brighton is in Bellota is out
9) Rio Oso is in Lockeford is out
10) Gold Hill is in Eight Mile is out
11) Lodi STIG is in Eight Mile Road is out
12) Gold Hill is in Lake is out

Total 2011 busload within the defined area: 1858 MW with 119 MW of losses resulting in total load + losses of 1977 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BELDEN_7_UNIT 1	31784	BELDEN	13.8	115.00	1	South of Palermo, South of Table Mountain		Market
BIOMAS_1_UNIT 1	32156	WOODLAND	9.1	20.78	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		QF/Selfgen

BNNIEN_7_ALTAPH	32376	BONNIE N	60	0.58		Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled - Monthly NQC - used August for LCR	Market
BOGUE_1_UNITA1	32451	FREC	13.8	45.00	1	Bogue, Drum-Rio Oso, South of Table Mountain		Market
BOWMN_6_UNIT	32480	BOWMAN	9.1	2.44	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		MUNI
BUCKCK_7_OAKFLT				1.13		South of Palermo, South of Table Mountain	Not modeled	Market
BUCKCK_7_PL1X2	31820	BCKS CRK	11	29.00	1	South of Palermo, South of Table Mountain		Market
BUCKCK_7_PL1X2	31820	BCKS CRK	11	29.00	2	South of Palermo, South of Table Mountain		Market
CHICPK_7_UNIT 1	32462	CHI.PARK	11.5	38.00	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain		MUNI
COLGAT_7_UNIT 1	32450	COLGATE1	13.8	161.65	1	South of Table Mountain		MUNI
COLGAT_7_UNIT 2	32452	COLGATE2	13.8	161.68	1	South of Table Mountain	Monthly NQC - used August for LCR	MUNI
CRESTA_7_PL1X2	31812	CRESTA	11.5	35.00	1	South of Palermo, South of Table Mountain		Market
CRESTA_7_PL1X2	31812	CRESTA	11.5	35.00	2	South of Palermo, South of Table Mountain		Market
DAVIS_7_MNMETH				2.80		Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled	Market
DEADCK_1_UNIT	31862	DEADWOOD	9.1	0.00	1	Drum-Rio Oso, South of Table Mountain		MUNI
DEERCR_6_UNIT 1	32474	DEER CRK	9.1	2.96	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		Market
DRUM_7_PL1X2	32504	DRUM 1-2	6.6	13.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		Market
DRUM_7_PL1X2	32504	DRUM 1-2	6.6	13.00	2	Drum-Rio Oso, South of Palermo, South of Table Mountain		Market
DRUM_7_PL3X4	32506	DRUM 3-4	6.6	13.70	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		Market
DRUM_7_PL3X4	32506	DRUM 3-4	6.6	13.70	2	Drum-Rio Oso, South of Palermo, South of Table Mountain		Market
DRUM_7_UNIT 5	32454	DRUM 5	13.8	49.50	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		Market

DUTCH1_7_UNIT 1	32464	DTCHFLT1	11	22.00	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain		Market
DUTCH2_7_UNIT 1	32502	DTCHFLT2	6.9	26.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		MUNI
ELDORO_7_UNIT 1	32513	ELDRADO1	21.6	11.00	1	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain		Market
ELDORO_7_UNIT 2	32514	ELDRADO2	21.6	11.00	1	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain		Market
FMEADO_6_HELLHL	32486	HELLHOLE	9.1	0.50	1	South of Rio Oso, South of Palermo, South of Table Mountain		MUNI
FMEADO_7_UNIT	32508	FRNCH MD	4.2	16.01	1	South of Rio Oso, South of Palermo, South of Table Mountain	Monthly NQC - used August for LCR	MUNI
FORBST_7_UNIT 1	31814	FORBSTWN	11.5	39.00	1	Drum-Rio Oso, South of Table Mountain		MUNI
GOLDHL_1_QF				0.00		Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled	QF/Selfgen
GRNLF1_1_UNITS	32490	GRNLEAF1	13.8	7.74	1	Bogue, Drum-Rio Oso, South of Table Mountain		QF/Selfgen
GRNLF1_1_UNITS	32490	GRNLEAF1	13.8	39.55	2	Bogue, Drum-Rio Oso, South of Table Mountain		QF/Selfgen
GRNLF2_1_UNIT	32492	GRNLEAF2	13.8	47.91	1	Pease, Drum-Rio Oso, South of Table Mountain		QF/Selfgen
HALSEY_6_UNIT	32478	HALSEY F	9.1	5.05	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain		Market
HAYPRS_6_QFUNTS	32488	HAYPRES+	9.1	0.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		QF/Selfgen
HAYPRS_6_QFUNTS	32488	HAYPRES+	9.1	0.00	2	Drum-Rio Oso, South of Palermo, South of Table Mountain		QF/Selfgen
HIGGNS_7_QFUNTS				0.05		Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled	QF/Selfgen
KANAKA_1_UNIT				0.00		Drum-Rio Oso, South of Table Mountain	Not modeled	MUNI
KELYRG_6_UNIT	31834	KELLYRDG	9.1	10.00	1	Drum-Rio Oso, South of Table Mountain		MUNI
MDFKRL_2_PROJCT	32456	MIDLFORK	13.8	62.18	1	South of Rio Oso, South of Palermo, South of Table	Monthly NQC - used August for LCR	MUNI

						Mountain		
MDFKRL_2_PROJCT	32458	RALSTON	13.8	84.32	1	South of Rio Oso, South of Palermo, South of Table Mountain	Monthly NQC - used August for LCR	MUNI
MDFKRL_2_PROJCT	32456	MIDLFORK	13.8	62.18	2	South of Rio Oso, South of Palermo, South of Table Mountain	Monthly NQC - used August for LCR	MUNI
NAROW1_2_UNIT	32466	NARROWS1	9.1	0.00	1	Colgate, South of Table Mountain	Monthly NQC - used August for LCR	Market
NAROW2_2_UNIT	32468	NARROWS2	9.1	34.88	1	Colgate, South of Table Mountain	Monthly NQC - used August for LCR	MUNI
NWCSTL_7_UNIT 1	32460	NEWCSTLE	13.2	1.30	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Monthly NQC - used August for LCR	Market
OROVIL_6_UNIT	31888	OROVLLE	9.1	6.50	1	Drum-Rio Oso, South of Table Mountain		QF/Selfgen
OXBOW_6_DRUM	32484	OXBOW F	9.1	6.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		MUNI
PACORO_6_UNIT	31890	PO POWER	9.1	8.05	1	Drum-Rio Oso, South of Table Mountain		QF/Selfgen
PACORO_6_UNIT	31890	PO POWER	9.1	8.05	2	Drum-Rio Oso, South of Table Mountain		QF/Selfgen
PLACVL_1_CHILIB	32510	CHILIBAR	4.2	2.51	1	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain		Market
PLACVL_1_RCKCRE				0.00		Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled - Monthly NQC - used August for LCR	Market
PLSNTG_7_LNCLND	32408	PLSNT GR	60	2.10		Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled	Market
POEPH_7_UNIT 1	31790	POE 1	13.8	60.00	1	South of Palermo, South of Table Mountain		Market
POEPH_7_UNIT 2	31792	POE 2	13.8	60.00	1	South of Palermo, South of Table Mountain		Market
RCKCRK_7_UNIT 1	31786	ROCK CK1	13.8	56.00	1	South of Palermo, South of Table Mountain		Market
RCKCRK_7_UNIT 2	31788	ROCK CK2	13.8	56.00	1	South of Palermo, South of Table Mountain		Market
RIOOSO_1_QF				0.77		Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled	QF/Selfgen
ROLLIN_6_UNIT	32476	ROLLINSF	9.1	11.09	1	Drum-Rio Oso, South of Palermo, South of		MUNI

						Table Mountain		
SLYCRK_1_UNIT 1	31832	SLY.CR.	9.1	10.36	1	Drum-Rio Oso, South of Table Mountain		MUNI
SPAULD_6_UNIT 3	32472	SPAULDG	9.1	4.70	3	Drum-Rio Oso, South of Palermo, South of Table Mountain		Market
SPAULD_6_UNIT12	32472	SPAULDG	9.1	4.96	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Monthly NQC - used August for LCR	Market
SPAULD_6_UNIT12	32472	SPAULDG	9.1	4.96	2	Drum-Rio Oso, South of Palermo, South of Table Mountain	Monthly NQC - used August for LCR	Market
SPI LI_2_UNIT 1	32498	SPILINCF	12.5	9.37	1	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain		QF/Selfgen
STIGCT_2_LODI	38114	Stig CC	13.8	49.50	1	South of Rio Oso, South of Palermo, South of Table Mountain		MUNI
ULTRCK_2_UNIT	32500	ULTR RCK	9.1	21.07	1	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain		QF/Selfgen
WDLEAF_7_UNIT 1	31794	WOODLEAF	13.8	55.00	1	Drum-Rio Oso, South of Table Mountain		MUNI
WHEATL_6_LNDFIL	32350	WHEATLND	60	1.30		Colgate, South of Table Mountain	Not modeled	Market
WISE_1_UNIT 1	32512	WISE	12	9.20	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Monthly NQC - used August for LCR	Market
WISE_1_UNIT 2	32512	WISE	12	2.79	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Monthly NQC - used August for LCR	Market
YUBACT_1_SUNSWT	32494	YUBA CTY	9.1	43.58	1	Pease, Drum-Rio Oso, South of Table Mountain		QF/Selfgen
YUBACT_6_UNITA1	32496	YCEC	13.8	46.00	1	Pease, Drum-Rio Oso, South of Table Mountain		Market
CAMPFW_7_FARWST	32470	CMP.FARW	9.1	6.50	1	Colgate, South of Table Mountain	No NQC - historical data	MUNI
NA	32162	RIV.DLTA	9.11	3.10	1	Drum-Rio Oso, South of Palermo, South of Table Mountain		QF/Selfgen
UCDAVS_1_UNIT	32166	UC DAVIS	9.1	3.50	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	No NQC - historical data	QF/Selfgen

Major new projects modeled:

1. Table Mountain-Rio Oso Reconductor and Tower Upgrade
2. Atlantic-Lincoln 115 kV Transmission Upgrade

3. Colgate 230/60 kV transformer reinforcement
4. Pease-Marysville #2 60 kV Line
5. Palermo 115 kV Circuit Breaker and Switch Replacement

<u>Critical Contingency Analysis Summary</u>

South of Table Mountain Sub-area

The most critical contingency is the loss of the Table Mountain-Rio Oso 230 kV and Table Mountain-Palermo double circuit tower line outage. The area limitation is thermal overloading of the Caribou-Palermo 115 kV line. This limiting contingency establishes in 2011 a LCR of 1510 MW (includes 220 MW of QF and 837 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this area.

The units required for the South of Palermo sub-area satisfy the category B requirement for this sub-area.

Effectiveness factors:

The following table has all units in Sierra area and their effectiveness factor to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	Eff Fctr. (%)
31814	FORBSTWN	1	8
31794	WOODLEAF	1	8
31832	SLY.CR.	1	7
31862	DEADWOOD	1	7
31888	OROVLLE	1	6
31890	PO POWER	2	6
31890	PO POWER	1	6
31834	KELLYRDG	1	6
32452	COLGATE2	1	5
32450	COLGATE1	1	5
32466	NARROWS1	1	5
32468	NARROWS2	1	5
32470	CMP.FARW	1	5
32451	FREC	1	5
32490	GRNLEAF1	2	4
32490	GRNLEAF1	1	4
32496	YCEC	1	3
32494	YUBA CTY	1	3
32492	GRNLEAF2	1	3

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

Colgate Sub-area

No requirements due to the addition of the Atlantic-Lincoln 115 kV transmission upgrade and Pease-Marysville #2 60 kV line projects.

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

Pease Sub-area

The most critical contingency is the loss of the Palermo-East Nicolaus 115 kV line with Green Leaf II Cogen unit out of service. The area limitation is thermal overloading of the Palermo-Pease 115 kV line. This limiting contingency establishes a LCR of 124 MW (includes 91 MW of QF generation) in 2011 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area (Greenleaf #2, Yuba City and Yuba City EC) have the same effectiveness factor.

Bogue Sub-area

The most critical contingency is the loss of the Pease-Rio Oso 115 kV line with one of the Greenleaf #1 units out of service. The area limitation is thermal overloading of the Palermo-Bogue 115 kV line. This limiting contingency establishes in 2011 a LCR of 137 MW (includes 47 MW of QF generation and 45 MW of deficiency) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area (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 LCR of 1630 MW (includes 417 MW of QF and Muni generation as well as

546 MW of deficiency) in 2011 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the loss of the Palermo-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 contingency establishes in 2011 a LCR of 1407 MW (includes 417 MW of QF and Muni generation as well as 313 MW of deficiency).

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

Placerville Sub-area
The most critical contingency is the loss of the Gold Hill-Clarksville 115 kV line followed by loss of the Gold Hill-Missouri Flat #2 115 kV line. The area limitation is thermal overloading of the Gold Hill-Missouri Flat #1 115 kV line. This limiting contingency establishes a LCR of 116 MW (includes 0 MW of QF and Muni generation as well as 91 MW of deficiency) in 2011 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:
All units within this area (El Dorado units 1&2 and Chili Bar) are needed therefore no effectiveness factor is required.

Placer Sub-area
The most critical contingency is the loss of the Drum-Higgins 115 kV line followed by loss of the Gold Hill-Placer #2 115 kV line. The area limitation is thermal overloading of the Gold Hill-Placer #1 115 kV line. This limiting contingency establishes a LCR of 111 MW (includes 0 MW of QF and Muni generation as well as 32 MW of deficiency) in 2011 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency is the loss of the Gold Hill-Placer #2 115 kV line with Chicago Park unit out of service. The area limitation is thermal overloading of the Drum-Higgins 115 kV line. This limiting contingency establishes a local capacity need of 66 MW (includes 0 MW of QF and Muni generation) in 2011 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:
All units within this area (Chicago Park, Dutch Flat#1, Wise units 1&2, Newcastle and Halsey) are needed therefore no effectiveness factor is required.

Drum-Rio Oso Sub-area
The most critical contingency is the loss of the Rio Oso #2 230/115 transformer followed by loss of the Rio Oso-Brighton 230 kV line. The area limitation is thermal overloading of the Rio Oso #1 230/115 kV transformer. This limiting contingency establishes in 2011 a LCR of 687 MW (includes 418 MW of QF and Muni generation as well as 12 MW of deficiency) as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency is the loss of the Rio Oso #2 230/115 transformer. The area limitation is thermal overloading of the Rio Oso #1 230/115 kV transformer. This limiting contingency establishes in 2011 a LCR of 296 MW (includes 418 MW of QF and Muni generation).

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

South of Rio Oso Sub-area
The most critical contingency is the loss of the Rio Oso-Gold Hill 230 line followed by loss of the Rio Oso-Lincoln 115 kV line or vice versa. The area limitation is thermal overloading of the Rio Oso-Atlantic 230 kV line. This limiting contingency establishes a LCR of 488 MW (includes 343 MW of QF and Muni generation as well as 77 MW of deficiency) in 2011 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency is the loss of the Rio Oso-Gold Hill 230 line with the Ralston unit out of service. The area limitation is thermal overloading of the Rio Oso-Atlantic 230 kV line. This limiting contingency establishes a LCR of 473 MW (includes 343 MW of QF and Muni generation as well as 62 MW of deficiency) in 2011.

Effectiveness factors:

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

Changes compared to last year's results:

Overall the Sierra Area load forecast went down by 149 MW. As such, the existing generation capacity needed is reduced by 207 MW. However, the magnitude of the deficiency has significantly increased along with some of the sub-area LCRs needs (South of Palermo and Bogue sub-areas) because of delay in implementing the Palermo-Rio Oso 115 kV reconductoring project.

Sierra Overall Requirements:

2011	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	220	837	759	1816

2011	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[13]	1330	313	1643
Category C (Multiple)[14]	1510	572	2082

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

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

4. Stockton Area

Area Definition

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

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

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

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

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

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

The substations that delineate the Lockeford Sub-area are:

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

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

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

The substations that delineate the Weber Sub-area are:

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

Total 2011 busload within the defined area: 1141 MW with 22 MW of losses resulting in total load + losses of 1163 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BEARDS_7_UNIT 1	34074	BEARDSLY	6.9	8.36	1	Tesla-Bellota	Monthly NQC - used August for LCR	MUNI
COGNAT_1_UNIT	33818	COG.NTNL	12	38.31	1	Weber		QF/Selfgen
CURIS_1_QF				0.67		Tesla-Bellota	Not modeled	QF/Selfgen
DONNLS_7_UNIT	34058	DONNELLS	13.8	72.00	1	Tesla-Bellota	Monthly NQC - used August for LCR	MUNI
LODI25_2_UNIT 1	38120	LODI25CT	9.11	22.70	1	Lockeford	No NQC - historical data	MUNI
PHOENX_1_UNIT				1.45		Tesla-Bellota	Not modeled - Monthly NQC - used August for LCR	Market
SCHLTE_1_UNITA1	33805	GWFTRCY1	13.8	83.56	1	Tesla-Bellota		Market
SCHLTE_1_UNITA2	33807	GWFTRCY2	13.8	82.88	1	Tesla-Bellota		Market
SNDBAR_7_UNIT 1	34060	SANDBAR	13.8	11.09	1	Tesla-Bellota		MUNI
SPIFBD_1_PL1X2	33917	FBERBORD	115	3.00	1	Tesla-Bellota		QF/Selfgen
SPRGAP_1_UNIT 1	34078	SPRNG GP	6	0.59	1	Tesla-Bellota		Market
STANIS_7_UNIT 1	34062	STANISLS	13.8	91.00	1	Tesla-Bellota		Market
STNRES_1_UNIT	34056	STNSLSRP	13.8	14.66	1	Tesla-Bellota		QF/Selfgen
STOKCG_1_UNIT 1	33814	CPC STCN	12.5	47.44	1	Tesla-Bellota		QF/Selfgen
TULLCK_7_UNITS	34076	TULLOCH	6.9	8.23	1	Tesla-Bellota	Monthly NQC - used August for LCR	MUNI
TULLCK_7_UNITS	34076	TULLOCH	6.9	8.24	2	Tesla-Bellota	Monthly NQC - used August for LCR	MUNI
ULTPCH_1_UNIT 1	34050	CH.STN.	13.8	15.58	1	Tesla-Bellota		QF/Selfgen
VLYHOM_7_SSJID				1.49		Tesla-Bellota	Not modeled	QF/Selfgen
CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	3.50	1	Tesla-Bellota	No NQC - historical data	MUNI
CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	3.50	2	Tesla-Bellota	No NQC - historical data	MUNI
CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	3.50	3	Tesla-Bellota	No NQC - historical data	MUNI
NA	33687	STKTN WW	60	2.00	1	Weber	No NQC - historical data	QF/Selfgen
NA	33830	GEN.MILL	9.11	2.50	1	Lockeford	No NQC - historical data	QF/Selfgen

Major new projects modeled:

1. Tesla 115 kV Capacity Increase

<u>Critical Contingency Analysis Summary</u>

Stockton overall

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

Tesla-Bellota Sub-area

The two most critical contingencies listed below together establish a local capacity need of 547 MW (includes 83 MW of QF and 118 MW of Muni generation as well as 153 MW of deficiency) in 2011 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical contingency for the Tesla-Bellota pocket is the loss of Tesla-Tracy 115 kV and Schulte-Lammers 115 kV. The area limitation is thermal overload of the Tesla-Kasson-Manteca 115 kV line above its emergency rating. This limiting contingency establishes a local capacity need of 447 MW (includes 83 MW of QF and 118 MW of Muni generation as well as 153 MW of deficiency) in 2011.

The second most critical contingency for the Tesla-Bellota pocket is the loss of Tesla-Tracy 115 kV and Tesla-Kasson-Manteca 115 kV. The area limitation is thermal overload of the Tesla-Schulte 115 kV line. This limiting contingency establishes a 2011 local capacity need of 394 MW (includes 83 MW of QF and 118 MW of Muni generation).

The single most critical contingency for the Tesla-Bellota pocket is the loss of Tesla-Tracy 115 kV line and the loss of the Stanislaus unit #1. The area limitation is thermal overload of the Tesla-Schulte 115 kV line. This single contingency establishes a local capacity need of 344 MW (includes 201 MW of QF and Muni generation) in 2011.

Effectiveness factors:

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

Lockeford Sub-area

The critical contingency for the Lockeford area is the loss of Lockeford-Industrial 60 kV circuit and Lockeford-Lodi #2 60 kV circuit. The area limitation is thermal overloading of the Lockeford-Lodi Jct. section of the Lockeford-Lodi #3 60 kV circuit. This limiting contingency establishes a 2011 local capacity need of 63 MW (including 2 MW of QF and 23 MW of Muni generation as well as 38 MW of deficiency) as the minimum capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

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

Stagg Sub-area

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

Weber Sub-area

The critical contingency for the Weber area is the loss of the Weber 230/60 kV Transformer #1 with the Cogeneration National out of service. The area limitation is thermal overloading of the remaining Weber 230/60 kV Transformers #2 & #2a. This limiting contingency establishes a local capacity need of 72 MW (including 40 MW of QF and Muni generation as well as a deficiency of 32 MW) in 2011 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency for this sub-area is the loss of Weber 230/60 kV Transformer #1. The area limitation is thermal overloading of the remaining Weber 230/60 kV Transformers #2 & #2a. This limiting contingency establishes a local capacity need of 30 MW (including 40 MW of QF and Muni generation) in 2011.

Effectiveness factors:

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

Changes compared to last year's results:

A new Weber sub-area has been added to the Stockton LCR area. Comparing the combined Tesla-Bellota and Lockeford sub-area loads, the load forecast went down by 35 MW. As a combined result of the above changes, the overall Stockton LCR has stayed fairly constant between the years.

Stockton Overall Requirements:

2011	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	126	141	259	526

2011	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[15]	374	0	374
Category C (Multiple)[16]	459	223	682

5. Greater Bay Area

Area Definition

The transmission tie lines into the Greater Bay Area are:

1) Lakeville-Sobrante 230 kV
2) Ignacio-Sobrante 230 kV
3) Parkway-Moraga 230 kV
4) Bahia-Moraga 230 kV
5) Lambie SW Sta-Vaca Dixon 230 kV
6) Peabody-Birds Landing SW Sta 230 kV
7) Tesla-Kelso 230 kV
8) Tesla-Delta Switching Yard 230 kV
9) Tesla-Pittsburg #1 230 kV
10) Tesla-Pittsburg #2 230 kV
11) Tesla-Newark #1 230 kV
12) Tesla-Newark #2 230 kV
13) Tesla-Ravenswood 230 kV
14) Tesla-Metcalf 500 kV
15) Moss Landing-Metcalf 500 kV
16) Moss Landing-Metcalf #1 230 kV
17) Moss Landing-Metcalf #2 230 kV
18) Oakdale TID-Newark #1 115 kV
19) Oakdale TID-Newark #2 115 kV

The substations that delineate the Greater Bay Area are:

1) Lakeville is out Sobrante is in

[15] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.
[16] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

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

Total 2011 bus load within the defined area is 9,885 MW with 280 MW of losses and 157 MW of pumps resulting in total load + losses + pumps of 10,322 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ALMEGT_1_UNIT 1	38118	ALMDACT1	13.8	23.80	1	Oakland		MUNI
ALMEGT_1_UNIT 2	38119	ALMDACT2	13.8	24.40	1	Oakland		MUNI
BANKPP_2_NSPIN	38820	DELTA A	13.2	14.00	1	None	Pumps	MUNI
BANKPP_2_NSPIN	38820	DELTA A	13.2	14.00	2	None	Pumps	MUNI
BANKPP_2_NSPIN	38820	DELTA A	13.2	14.00	3	None	Pumps	MUNI
BANKPP_2_NSPIN	38815	DELTA B	13.2	14.00	4	None	Pumps	MUNI
BANKPP_2_NSPIN	38815	DELTA B	13.2	14.00	5	None	Pumps	MUNI
BANKPP_2_NSPIN	38770	DELTA C	13.2	14.00	6	None	Pumps	MUNI
BANKPP_2_NSPIN	38770	DELTA C	13.2	14.00	7	None	Pumps	MUNI
BANKPP_2_NSPIN	38765	DELTA D	13.2	14.00	8	None	Pumps	MUNI
BANKPP_2_NSPIN	38765	DELTA D	13.2	15.00	9	None	Pumps	MUNI
BANKPP_2_NSPIN	38760	DELTA E	13.2	15.00	10	None	Pumps	MUNI
BANKPP_2_NSPIN	38760	DELTA E	13.2	15.00	11	None	Pumps	MUNI
BLHVN_7_MENLOP				1.51		None	Not modeled	QF/Selfgen
BRDSLD_2_HIWIND	32172	HIGHWINDS	34.5	36.54	1	None	Monthly NQC - used August for LCR	Wind
BRDSLD_2_SHILO1	32176	SHILOH	34.5	37.36	1	None	Monthly NQC - used August for LCR	Wind
BRDSLD_2_SHILO2	32177	SHILO	34.5	35.20	2	None	Monthly NQC - used August for LCR	Wind

CALPIN_1_AGNEW	35860	OLS-AGNE	9.11	26.54	1	San Jose		QF/Selfgen
CARDCG_1_UNITS	33463	CARDINAL	12.5	11.88	1	None		QF/Selfgen
CARDCG_1_UNITS	33463	CARDINAL	12.5	11.88	2	None		QF/Selfgen
CLRMTK_1_QF				0.00		Oakland	Not modeled	QF/Selfgen
COCOPP_7_UNIT 6	33116	C.COS 6	18	337.00	1	None		Market
COCOPP_7_UNIT 7	33117	C.COS 7	18	337.00	1	None		Market
CONTAN_1_UNIT	36856	CCA100	13.8	25.80	1	San Jose		QF/Selfgen
CROKET_7_UNIT	32900	CRCKTCOG	18	240.00	1	Pittsburg		QF/Selfgen
CSCCOG_1_UNIT 1	36854	Cogen	12	3.00	1	San Jose		MUNI
CSCCOG_1_UNIT 1	36854	Cogen	12	3.00	2	San Jose		MUNI
CSCGNR_1_UNIT 1	36858	Gia100	13.8	24.00	1	San Jose		MUNI
CSCGNR_1_UNIT 2	36895	Gia200	13.8	24.00	2	San Jose		MUNI
DELTA_2_PL1X4	33107	DEC STG1	24	269.61	1	Pittsburg	Monthly NQC - used August for LCR	Market
DELTA_2_PL1X4	33108	DEC CTG1	18	181.13	1	Pittsburg	Monthly NQC - used August for LCR	Market
DELTA_2_PL1X4	33109	DEC CTG2	18	181.13	1	Pittsburg	Monthly NQC - used August for LCR	Market
DELTA_2_PL1X4	33110	DEC CTG3	18	181.13	1	Pittsburg	Monthly NQC - used August for LCR	Market
DOWCHM_1_UNITS	33161	DOWCHEM1	13.8	1.54	1	Pittsburg		QF/Selfgen
DOWCHM_1_UNITS	33162	DOWCHEM2	13.8	2.03	1	Pittsburg		QF/Selfgen
DOWCHM_1_UNITS	33163	DOWCHEM3	13.8	2.03	1	Pittsburg		QF/Selfgen
DUANE_1_PL1X3	36863	DVRaGT1	13.8	49.27	1	San Jose		MUNI
DUANE_1_PL1X3	36864	DVRbGT2	13.8	49.27	1	San Jose		MUNI
DUANE_1_PL1X3	36865	DVRaST3	13.8	49.26	1	San Jose		MUNI
FLOWD2_2_UNIT 1	35318	FLOWDPTR	9.11	6.93	1	None	Monthly NQC - used August for LCR	Wind
GATWAY_2_PL1X3	33118	GATEWAY1	18	196.27	1	None		Market
GATWAY_2_PL1X3	33119	GATEWAY2	18	191.36	1	None		Market
GATWAY_2_PL1X3	33120	GATEWAY3	18	191.36	1	None		Market
GILROY_1_UNIT	35850	GLRY COG	13.8	69.30	1	Llagas	Monthly NQC - used August for LCR	Market
GILROY_1_UNIT	35850	GLRY COG	13.8	35.70	2	Llagas	Monthly NQC - used August for LCR	Market
GILRPP_1_PL1X2	35851	GROYPKR1	13.8	45.50	1	Llagas	Monthly NQC - used August for LCR	Market
GILRPP_1_PL1X2	35852	GROYPKR2	13.8	45.50	1	Llagas	Monthly NQC - used August for LCR	Market
GILRPP_1_PL3X4	35853	GROYPKR3	13.8	46.00	1	Llagas	Monthly NQC - used August for LCR	Market
GRZZLY_1_BERKLY	32740	HILLSIDE	115	26.27	1	None		QF/Selfgen
GWFPW1_6_UNIT	33131	GWF #1	9.11	18.63	1	Pittsburg		QF/Selfgen
GWFPW2_1_UNIT 1	33132	GWF #2	13.8	18.78	1	Pittsburg		QF/Selfgen
GWFPW3_1_UNIT 1	33133	GWF #3	13.8	19.30	1	Pittsburg		QF/Selfgen
GWFPW4_6_UNIT 1	33134	GWF #4	13.8	19.09	1	Pittsburg		QF/Selfgen
GWFPW5_6_UNIT 1	33135	GWF #5	13.8	18.98	1	Pittsburg		QF/Selfgen
HICKS_7_GUADLP				2.07		None	Not modeled	QF/Selfgen
KIRKER_7_KELCYN	32951	KIRKER	115	3.21		Pittsburg	Not modeled	Market
LAWRNC_7_SUNYVL				0.30		None	Not modeled	Market

LECEF_1_UNITS	35854	LECEFGT1	13.8	46.50	1	San Jose	Monthly NQC - used August for LCR	Market
LECEF_1_UNITS	35855	LECEFGT2	13.8	46.50	1	San Jose	Monthly NQC - used August for LCR	Market
LECEF_1_UNITS	35856	LECEFGT3	13.8	46.50	1	San Jose	Monthly NQC - used August for LCR	Market
LECEF_1_UNITS	35857	LECEFGT4	13.8	46.50	1	San Jose	Monthly NQC - used August for LCR	Market
LFC 51_2_UNIT 1	35310	LFC FIN+	9.11	4.05	1	None	Monthly NQC - used August for LCR	Wind
LMBEPK_2_UNITA1	32173	LAMBGT1	13.8	47.00	1	None	Monthly NQC - used August for LCR	Market
LMBEPK_2_UNITA2	32174	GOOSEHGT	13.8	46.00	2	None	Monthly NQC - used August for LCR	Market
LMBEPK_2_UNITA3	32175	CREEDGT1	13.8	47.00	3	None	Monthly NQC - used August for LCR	Market
LMEC_1_PL1X3	33111	LMECCT2	18	163.20	1	Pittsburg	Monthly NQC - used August for LCR	Market
LMEC_1_PL1X3	33112	LMECCT1	18	163.20	1	Pittsburg	Monthly NQC - used August for LCR	Market
LMEC_1_PL1X3	33113	LMECST1	18	229.60	1	Pittsburg	Monthly NQC - used August for LCR	Market
MARKHM_1_CATLST	35863	CATALYST	9.11	0.00	1	San Jose		QF/Selfgen
MEDOLN_7_CHEVCP				0.68		Pittsburg	Not modeled	QF/Selfgen
METCLF_1_QF				0.00		None	Not modeled	QF/Selfgen
METEC_2_PL1X3	35881	MEC CTG1	18	178.43	1		Monthly NQC - used August for LCR	Market
METEC_2_PL1X3	35882	MEC CTG2	18	178.43	1		Monthly NQC - used August for LCR	Market
METEC_2_PL1X3	35883	MEC STG1	18	213.14	1		Monthly NQC - used August for LCR	Market
MILBRA_1_QF				0.00			Not modeled	QF/Selfgen
MISSIX_1_QF				0.03			Not modeled	QF/Selfgen
MLPTAS_7_QFUNTS				0.02		San Jose	Not modeled	QF/Selfgen
MNTAGU_7_NEWBYI				3.62		None	Not modeled	QF/Selfgen
NEWARK_1_QF				0.01		None	Not modeled	QF/Selfgen
OAK C_7_UNIT 1	32901	OAKLND 1	13.8	55.00	1	Oakland		Market
OAK C_7_UNIT 2	32902	OAKLND 2	13.8	55.00	1	Oakland		Market
OAK C_7_UNIT 3	32903	OAKLND 3	13.8	55.00	1	Oakland		Market
OAK L_7_EBMUD				0.44		Oakland	Not modeled	MUNI
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	1	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	2	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	3	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	4	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	5	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	6	None		Market

OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	7	None		Market
PALALT_7_COBUG				4.50		None	Not modeled	MUNI
PITTSP_7_UNIT 5	33105	PTSB 5	18	312.00	1	Pittsburg		Market
PITTSP_7_UNIT 6	33106	PTSB 6	18	317.00	1	Pittsburg		Market
PITTSP_7_UNIT 7	30000	PTSB 7	20	682.00	1	Pittsburg		Market
POTRPP_7_UNIT 3	33252	POTRERO3	20	206.00	1		Retired	Market
POTRPP_7_UNIT 4	33253	POTRERO4	13.8	52.0	1		Retired	Market
POTRPP_7_UNIT 5	33254	POTRERO5	13.8	52.0	1		Retired	Market
POTRPP_7_UNIT 6	33255	POTRERO6	13.8	52.00	1		Retired	Market
RICHMN_7_BAYENV				2.00		None	Not modeled	QF/Selfgen
RVRVEW_1_UNITA1	33178	RVEC_GEN	13.8	46.00	1	None	Monthly NQC - used August for LCR	Market
SEAWST_6_LAPOS	35312	SEAWESTF	9.11	0.34	1	None	Monthly NQC - used August for LCR	Wind
SRINTL_6_UNIT	33468	SRI INTL	9.11	0.89	1	None		QF/Selfgen
STAUFF_1_UNIT	33139	STAUFER	9.11	0.05	1	None		QF/Selfgen
STOILS_1_UNITS	32921	CHEVGEN1	13.8	0.09	1	Pittsburg		QF/Selfgen
STOILS_1_UNITS	32922	CHEVGEN2	13.8	0.09	1	Pittsburg		QF/Selfgen
TIDWTR_2_UNITS	33151	FOSTER W	12.5	6.44	1	Pittsburg		QF/Selfgen
TIDWTR_2_UNITS	33151	FOSTER W	12.5	6.44	2	Pittsburg		QF/Selfgen
TIDWTR_2_UNITS	33151	FOSTER W	12.5	6.44	3	Pittsburg		QF/Selfgen
UNCHEM_1_UNIT	32920	UNION CH	9.11	19.00	1	Pittsburg		QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.15	1	Pittsburg		QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.15	2	Pittsburg		QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.14	3	Pittsburg		QF/Selfgen
UNTDQF_7_UNITS	33466	UNTED CO	9.11	27.45	1	None		QF/Selfgen
USWNDR_2_SMUD	32169	SOLANOWP	21	11.06	1	None	Monthly NQC - used August for LCR	Wind
USWNDR_2_UNITS	32168	EXNCO	9.11	20.31	1	None	Monthly NQC - used August for LCR	Wind
USWPFK_6_FRICK	35320	USW FRIC	12	0.65	1	None	Monthly NQC - used August for LCR	Wind
USWPFK_6_FRICK	35320	USW FRIC	12	0.65	2	None	Monthly NQC - used August for LCR	Wind
USWPJR_2_UNITS	33838	USWP_#3	9.11	2.41	1	None	Monthly NQC - used August for LCR	Wind
WNDMAS_2_UNIT 1	33170	WINDMSTR	9.11	1.91	1	None	Monthly NQC - used August for LCR	Wind
ZOND_6_UNIT	35316	ZOND SYS	9.11	1.30	1	None	Monthly NQC - used August for LCR	Wind
IBMCTL_1_UNIT 1	35637	IBM-CTLE	115	0.00	1	San Jose	No NQC - historical data	Market
IMHOFF_1_UNIT 1	33136	CCCSD	12.5	4.40	1	Pittsburg	No NQC - historical data	QF/Selfgen
SHELRF_1_UNITS	33141	SHELL 1	12.5	19.60	1	Pittsburg		QF/Selfgen
SHELRF_1_UNITS	33142	SHELL 2	12.5	39.20	1	Pittsburg		QF/Selfgen
SHELRF_1_UNITS	33143	SHELL 3	12.5	39.20	1	Pittsburg		QF/Selfgen
ZANKER_1_UNIT 1	35861	SJ-SCL W	9.11	2.10	1	San Jose	No NQC - historical data	QF/Selfgen

New unit	32171	HIGHWND3	34.5	15.00	1	None	No NQC - estimated data	Wind

Major new projects modeled:

1. AHW #1 & #2 115kV Re-Cabling
2. New TransBay DC cable
3. Pittsburg-Tesla 230 kV Lines Reconductoring
4. New Oakland C-X #3 115kV Cable
5. San Mateo – Bay Meadows 115kV #1 & #2 Line Reconductoring

<u>Critical Contingency Analysis Summary</u>

San Francisco Sub-area

By 2011, Potrero units #3, #4, #5 and #6 (360 MW) will no longer be required once the Trans Bay DC cable is operational and re-cabling of the AHW #1 and # 2 115kV cables is complete.

Oakland Sub-area

The most critical contingency is an outage of the C-X #2 and #3 115 kV cables. The area limitation is thermal overloading of the Moraga-Claremont 115 kV lines. This limiting contingency establishes a LCR of 46 MW in 2011 (includes 49 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

This Oakland requirement does not include the need for Pittsburg/Oakland sub-area.

Effectiveness factors:

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

Llagas Sub-area

The most critical contingency is an outage between Metcalf D and Morgan Hill 115 kV (with one of the Gilroy Peaker off-line). The area limitation is thermal overloading of the Metcalf-Llagas 115 kV line as well as voltage drop (5%) at the Morgan Hill substation.

As documented within a CAISO Operating Procedure, this limitation is dependent on power flowing in the direction from Metcalf to Llagas/Morgan Hill. This limiting contingency establishes a LCR of 112 MW in 2011 (includes 0 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

San Jose Sub-area

The most critical contingency is an outage of Metcalf-El Patio #1 or #2 115 kV line followed by Metcalf-Evergreen #1 115 kV line. The area limitation is thermal overloading of the Metcalf-Evergreen #2 115 kV line. This limiting contingency establishes a LCR of 516 MW in 2011 (includes 54 MW of QF and 202 MW of Muni generation as well as 74 MW of deficiency) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

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

Pittsburg and Oakland Sub-area Combined

The most critical contingency is an outage of the Moraga #3 230/115 kV transformer combined with the loss of Delta Energy Center. The sub-area area limitation is thermal overloading of Moraga #1 230/115 kV transformer. This limiting contingency establishes a LCR of 2866 MW in 2011 (including 531 MW of QF/Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is an outage of the Moraga #3 230/115 kV transformer. The sub-area area limitation is thermal overloading of the Moraga #1 230/115 kV transformer. This limiting contingency establishes a LCR of 2453 MW in 2011 (including 531 MW of QF/Muni generation).

Effectiveness factors:

Please see Bay Area overall.

Bay Area overall

The most critical contingency is the loss of the Tesla-Metcalf 500 kV followed by Tesla-Newark #1 230 kV line or vice versa. The area limitation is thermal overload of the ADCC-Newark 230 kV section of the Tesla-Newark #2 230 kV line. This limiting contingency establishes a LCR of 4804 MW in 2011 (includes 624 MW of QF, 174 MW of Wind and 412 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this area.

The most critical single contingency is the loss of the Tesla-Metcalf 500 kV followed by Delta Energy Center or vice versa. The area limitation is reactive margin within the Bay Area. This limiting contingency establishes a LCR of 4036 MW in 2011 (includes 624 MW of QF, 174 MW of Wind and 412 MW of Muni generation).

Effectiveness factors:

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

Changes compared to last year's results:

Overall the load forecast went up by 46 MW and that drives a small LCR increase. The retirement of Potrero units 3, 4, 5 and 6 drive the rest of the LCR increase because they were the most effective units in mitigating the Tesla-Newark #2 230 kV line and they have to be replaced with less effective units. In the San Jose area there is a new deficiency due mostly to load shifting between substations and the fact that generation is the area is far less effective than the load. All the factors mentioned above have an overall effect of increasing the overall area LCR by 227 MW.

Bay Area Overall Requirements:

2011	Wind (MW)	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	174	624	412	5296	6506

2011	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[17]	4036	0	4036
Category C (Multiple)[18]	4804	74	4878

6. Greater Fresno Area

<u>Area Definition</u>

The transmission facilities coming into the Greater Fresno area are:

1) Gates-Gregg 230 kV Line
2) Gates-McCall 230 kV Line
3) Gates #1 230/115 kV Transformer Bank
4) Los Banos #3 230/70 kV Transformer Bank
5) Los Banos #4 230/70 kV Transformer Bank
6) Panoche-Helm 230 kV Line
7) Panoche-Kearney 230 kV Line
8) Panoche #1 230/115 kV Transformer
9) Panoche #2 230/115 kV Transformer
10) Warnerville-Wilson 230 kV Line

[17] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.
[18] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

11) Wilson-Melones 230 kV Line
12) Smyrna-Corcoran 115kV Line
13) Coalinga #1-San Miguel 70 kV Line

The substations that delineate the Greater Fresno area are:

1) Gates is out Henrietta is in
2) Gates is out Henrietta is in
3) Gates 230 kV is out Gates 115 kV is in
4) Los Banos 230 kV is out Los Banos 70 kV is in
5) Los Banos 230 kV is out Los Banos 70 kV is in
6) Panoche is out Helm is in
7) Panoche is out Mc Mullin is in
8) Panoche 115 kV is in Panoche 230 kV is out
9) Panoche 115 kV is in Panoche 230 kV is out
10) Warnerville is out Wilson is in
11) Wilson is in Melones is out
12) Quebec SP is out Corcoran is in
13) Coalinga is in San Miguel is out

2011 total busload within the defined area is 3212 MW with 94 MW of losses resulting in a total (load plus losses) of 3306 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
AGRICO_6_PL3N5	34608	AGRICO	13.8	16.00	3	Wilson, Herndon		Market
AGRICO_7_UNIT	34608	AGRICO	13.8	43.05	2	Wilson, Herndon		Market
AGRICO_7_UNIT	34608	AGRICO	13.8	7.45	4	Wilson, Herndon		Market
BALCHS_7_UNIT 1	34624	BALCH	13.2	34.00	1	Wilson, Herndon		Market
BALCHS_7_UNIT 2	34612	BLCH	13.8	52.50	1	Wilson, Herndon		Market
BALCHS_7_UNIT 3	34614	BLCH	13.8	52.50	1	Wilson, Herndon		Market
BORDEN_2_QF	30805	BORDEN	230	0.93		Wilson	Not modeled	QF/Selfgen
BULLRD_7_SAGNES				0.00		Wilson	Not modeled	QF/Selfgen
CAPMAD_1_UNIT 1	34179	MADERA_G	13.8	17.00	1	Wilson		Market
CHEVCO_6_UNIT 1	34652	CHV.COAL	9.11	8.84	1	Wilson		QF/Selfgen
CHEVCO_6_UNIT 2	34652	CHV.COAL	9.11	1.46	2	Wilson		QF/Selfgen
CHWCHL_1_BIOMAS	34305	CHWCHLA2	13.8	11.25	1	Wilson, Herndon		Market
CHWCHL_1_UNIT	34301	CHOWCOGN	13.8	48.00	1	Wilson, Herndon		Market
COLGA1_6_SHELLW	34654	COLNGAGN	9.11	35.41	1	Wilson		QF/Selfgen
CRESSY_1_PARKER	34140	CRESSEY	115	0.98		Wilson	Not modeled	MUNI
CRNEVL_6_CRNVA				0.71		Wilson	Not modeled - Monthly NQC - used August for	Market

							LCR	
CRNEVL_6_SJQN 2	34631	SJ2GEN	9.11	3.20	1	Wilson		Market
CRNEVL_6_SJQN 3	34633	SJ3GEN	9.11	4.20	1	Wilson		Market
DINUBA_6_UNIT	34648	DINUBA E	13.8	9.87	1	Wilson, Herndon		Market
ELNIDP_6_BIOMAS	34330	ELNIDO	13.8	11.25	1	Wilson		Market
EXCHEC_7_UNIT 1	34306	EXCHQUER	13.8	61.77	1	Wilson	Monthly NQC - used August for LCR	MUNI
FRIANT_6_UNITS	34636	FRIANTDM	6.6	3.18	2	Wilson		QF/Selfgen
FRIANT_6_UNITS	34636	FRIANTDM	6.6	1.70	3	Wilson		QF/Selfgen
FRIANT_6_UNITS	34636	FRIANTDM	6.6	0.45	4	Wilson		QF/Selfgen
GATES_6_PL1X2	34553	WHD_GAT2	13.8	41.50	1	Wilson		Market
GWFPWR_1_UNITS	34431	GWF_HEP1	13.8	42.20	1	Wilson, Herndon		Market
GWFPWR_1_UNITS	34433	GWF_HEP2	13.8	42.20	1	Wilson, Herndon		Market
GWFPWR_6_UNIT	34650	GWF-PWR.	9.11	24.57	1	Wilson, Henrietta		QF/Selfgen
HAASPH_7_PL1X2	34610	HAAS	13.8	68.15	1	Wilson, Herndon	Monthly NQC - used August for LCR	Market
HAASPH_7_PL1X2	34610	HAAS	13.8	68.15	2	Wilson, Herndon	Monthly NQC - used August for LCR	Market
HELMPG_7_UNIT 1	34600	HELMS	18	404.00	1	Wilson		Market
HELMPG_7_UNIT 2	34602	HELMS	18	404.00	2	Wilson		Market
HELMPG_7_UNIT 3	34604	HELMS	18	404.00	3	Wilson		Market
HENRTA_6_UNITA1	34539	GWF_GT1	13.8	45.33	1	Wilson, Henrietta		Market
HENRTA_6_UNITA2	34541	GWF_GT2	13.8	45.23	1	Wilson, Henrietta		Market
INTTRB_6_UNIT	34342	INT.TURB	9.11	2.01	1	Wilson	Monthly NQC - used August for LCR	QF/Selfgen
JRWOOD_1_UNIT 1	34332	JRWCOGEN	9.11	7.85	1	Wilson		QF/Selfgen
KERKH1_7_UNIT 1	34344	KERCKHOF	6.6	13.00	1	Wilson, Herndon		Market
KERKH1_7_UNIT 2	34344	KERCKHOF	6.6	8.50	2	Wilson, Herndon		Market
KERKH1_7_UNIT 3	34344	KERCKHOF	6.6	12.80	3	Wilson, Herndon		Market
KERKH2_7_UNIT 1	34308	KERCKHOF	13.8	153.90	1	Wilson, Herndon		Market
KINGCO_1_KINGBR	34642	KINGSBUR	9.11	29.75	1	Wilson, Herndon		QF/Selfgen
KINGRV_7_UNIT 1	34616	KINGSRIV	13.8	51.20	1	Wilson, Herndon		Market
MALAGA_1_PL1X2	34671	KRCDPCT1	13.8	48.00	1	Wilson, Herndon		Market
MALAGA_1_PL1X2	34672	KRCDPCT2	13.8	48.00	1	Wilson, Herndon		Market
MCCALL_1_QF				0.75		Wilson, Herndon	Not modeled	QF/Selfgen
MCSWAN_6_UNITS	34320	MCSWAIN	9.11	5.04	1	Wilson	Monthly NQC - used August for LCR	MUNI
MENBIO_6_UNIT	34334	BIO PWR	9.11	21.74	1	Wilson		QF/Selfgen

MERCFL_6_UNIT	34322	MERCEDFL	9.11	2.20	1	Wilson	Monthly NQC - used August for LCR	Market
PINFLT_7_UNITS	38720	PINEFLAT	13.8	70.00	1	Wilson, Herndon		MUNI
PINFLT_7_UNITS	38720	PINEFLAT	13.8	70.00	2	Wilson, Herndon		MUNI
PINFLT_7_UNITS	38720	PINEFLAT	13.8	70.00	3	Wilson, Herndon		MUNI
PNCHPP_1_PL1X2	34328	STARGT1	13.8	55.58	1	Wilson		Market
PNCHPP_1_PL1X2	34329	STARGT2	13.8	55.58	1	Wilson		Market
PNOCHE_1_PL1X2	34142	WHD_PAN2	13.8	40.00	1	Wilson, Herndon		Market
PNOCHE_1_UNITA1	34186	DG_PAN1	13.8	42.78	1	Wilson		Market
SGREGY_6_SANGER	34646	SANGERCO	9.11	37.47	1	Wilson		QF/Selfgen
STOREY_7_MDRCHW				0.82		Wilson	Not modeled	QF/Selfgen
ULTPFR_1_UNIT 1	34640	ULTR.PWR	9.11	20.01	1	Wilson, Herndon		QF/Selfgen
WISHON_6_UNITS	34658	WISHON	2.3	4.51	1	Wilson		Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	2	Wilson		Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	3	Wilson		Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	4	Wilson		Market
WISHON_6_UNITS	34658	WISHON	2.3	0.36	5	Wilson		Market
WRGHTP_7_AMENGY				0.60		Wilson	Not modeled	QF/Selfgen
NA	34485	FRESNOWW	12.5	9.00	1	Wilson	No NQC - historical data	QF/Selfgen
ONLLPP_6_UNIT 1	34316	ONEILPMP	9.11	0.50	1	Wilson	No NQC - historical data	MUNI
MENBIO_6_RENEW1	34339	CALRENEW	12.5	5.00	1	Wilson	No NQC - Pmax	Market
New Unit	34603	JQBSWLT	12.5	3.00	1	Wilson	No NQC - Pmax	Market

Major new projects modeled:

1. Two new small peakers

Critical Contingency Analysis Summary

Wilson Sub-area

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

The most critical contingency is the loss of the Melones - Wilson 230 kV line overlapped with one of the Helms units out of service. This contingency would thermally overload the Warnerville - Wilson 230 kV line (most stringent) and possibly also the Gates-McCall 230 kV line. This limiting contingency establishes a LCR of 1997 MW in 2011 (includes

207 MW of QF and 278 MW of Muni generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
34332	JRWCOGEN	1	40%
34330	ELNIDO	1	37%
34322	MERCEDFL	1	35%
34320	MCSWAIN	1	34%
34306	EXCHQUER	1	34%
34305	CHWCHLA2	1	32%
34301	CHOWCOGN	1	32%
34658	WISHON	1	28%
34658	WISHON	1	28%
34658	WISHON	1	28%
34658	WISHON	1	28%
34658	WISHON	1	28%
34631	SJ2GEN	1	28%
34633	SJ3GEN	1	27%
34636	FRIANTDM	2	27%
34636	FRIANTDM	3	27%
34636	FRIANTDM	4	27%
34600	HELMS 1	1	27%
34602	HELMS 2	1	27%
34604	HELMS 3	1	27%
34308	KERCKHOF	1	26%
34344	KERCKHOF	1	26%
34344	KERCKHOF	2	26%
34344	KERCKHOF	3	26%
34485	FRESNOWW	1	24%
34648	DINUBA E	1	22%
34179	MADERA_G	1	22%
34616	KINGSRIV	1	22%
34624	BALCH 1	1	21%
34671	KRCDPCT1	1	21%
34672	KRCDPCT2	1	21%
34640	ULTR.PWR	1	21%
34646	SANGERCO	1	21%
34642	KINGSBUR	1	19%
34610	HAAS	1	18%
34610	HAAS	1	18%
34614	BLCH 2-3	1	18%
34612	BLCH 2-2	1	17%
38720	PINE FLT	1	17%
38720	PINE FLT	2	17%
38720	PINE FLT	3	17%

34431	GWF_HEP1	1	17%
34433	GWF_HEP2	1	17%
34334	BIO PWR	1	14%
34608	AGRICO	2	14%
34608	AGRICO	3	14%
34608	AGRICO	4	14%
34539	GWF_GT1	1	14%
34541	GWF_GT2	1	14%
34650	GWF-PWR.	1	13%
34186	DG_PAN1	1	11%
34142	WHD_PAN2	1	11%
34652	CHV.COAL	1	10%
34652	CHV.COAL	2	10%
34553	WHD_GAT2	1	9%
34654	COLNGAGN	1	9%
34342	INT.TURB	1	6%
34316	ONEILPMP	1	6%

Herndon Sub-area

The most critical contingency is the loss of the Herndon #1 230/115 kV transformer overlapped with Kerckhoff II generator out of service. This contingency could thermally overload the parallel Herndon #2 230/115 kV transformer. This limiting contingency establishes a LCR of 1132 MW (includes 51 MW of QF and 210 MW of Muni generation) in 2011 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency for the Herndon sub-area is the loss of the Herndon #1 230/115 kV transformer, which could thermally overload the parallel Herndon #2 230/115 kV transformer. This limiting contingency establishes a LCR of 840 MW (includes 51 MW of QF and 210 MW of Muni generation) in 2011.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
34308	KERCKHOF	1	34%
34344	KERCKHOF	1	34%
34344	KERCKHOF	2	34%
34344	KERCKHOF	3	34%
34624	BALCH 1	1	33%
34646	SANGERCO	1	31%
34616	KINGSRIV	1	31%

34671	KRCDPCT1	1	31%
34672	KRCDPCT2	1	31%
34640	ULTR.PWR	1	30%
34648	DINUBA E	1	28%
34642	KINGSBUR	1	25%
38720	PINE FLT	1	23%
38720	PINE FLT	2	23%
38720	PINE FLT	3	23%
34610	HAAS	1	23%
34610	HAAS	2	23%
34614	BLCH 2-3	1	23%
34612	BLCH 2-2	1	23%
34431	GWF_HEP1	1	14%
34433	GWF_HEP2	1	14%
34301	CHOWCOGN	1	9%
34305	CHWCHLA2	1	9%
34608	AGRICO	2	7%
34608	AGRICO	3	7%
34608	AGRICO	4	7%
34332	JRWCOGEN	1	-6%
34600	HELMS 1	1	-12%
34602	HELMS 2	1	-12%
34604	HELMS 3	1	-12%
34485	FRESNOWW	1	-14%

Henrietta Sub-area

The two most critical contingencies listed below together establish a local capacity need of 57 MW (includes 25 MW of QF as well as 4 MW of deficiency) in 2011 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical contingency is the loss of Henrietta 230/70 kV transformer bank #4 and GWF Power unit. This contingency could thermally overload the Henrietta 230/70 kV transformer bank #2. This limiting contingency establishes a LCR of 28 MW in 2011 (includes 0 MW of QF generation).

The second most critical contingency is the loss of Henrietta 230/70 kV transformer bank #4 and one of the Henrietta-GWF Henrietta 70 kV line. This contingency could thermally overload the Henrietta 230/70 kV transformer bank #2. This limiting contingency establishes a LCR of 29 MW in 2011 (includes 25 MW of QF generation as well as 4 MW of deficiency).

The most critical single contingency is the loss of Henrietta 230/70 kV transformer bank #4. This contingency could thermally overload the Henrietta 230/70 kV transformer bank #2. This limiting contingency establishes a LCR of 28 MW in 2011 (includes 25 MW of QF generation).

Effectiveness factors:

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

Changes compared to last year's results:

Overall the load forecast is steady (down by 71 MW). Path 15 flow is 1275 MW N-S the same as last year. Due to small re-dispatch between sub-areas the total overall effect is that LCR has decreased by 200 MW.

Fresno Area Overall Requirements:

2011	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	207	278	2434	2919

2011	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single) [19]	2200	0	2200
Category C (Multiple) [20]	2444	4	2448

7. Kern Area

<u>Area Definition</u>

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

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

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

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

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

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

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

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

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

The substations that delineate the Weedpatch sub-area are:

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

2011 total busload within the defined area: 1370 MW with 16 MW of losses resulting in a total (load plus losses) of 1387 MW.

Total units and qualifying capacity available in this Kern area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BDGRCK_1_UNITS	35029	BADGERCK	9.11	41.98	1	Kern PP		QF/Selfgen
BEARMT_1_UNIT	35066	PSE-BEAR	9.11	44.41	1	Kern PP		QF/Selfgen
CHALK_1_UNIT	35038	CHLKCLF+	9.11	43.74	1	Kern PP		QF/Selfgen
CHEVCD_6_UNIT	35052	CHEV.USA	9.11	0.43	1	Kern PP		QF/Selfgen
CHEVCY_1_UNIT	35032	CHV-CYMR	9.11	5.53	1	Kern PP		QF/Selfgen
DEXZEL_1_UNIT	35024	DEXEL +	9.11	29.28	1	Kern PP		QF/Selfgen
DISCOV_1_CHEVRN	35062	DISCOVRY	9.11	3.02	1	Kern PP		QF/Selfgen
DOUBLC_1_UNITS	35023	DOUBLE C	9.11	46.58	1	Kern PP		QF/Selfgen
FELLOW_7_QFUNTS				2.17		Kern PP	Not modeled	QF/Selfgen
FRITO_1_LAY	35048	FRITOLAY	9.11	0.09	1	Kern PP		QF/Selfgen
KERNFT_1_UNITS	35026	KERNFRNT	9.11	45.53	1	Kern PP		QF/Selfgen
KERNRG_1_UNITS	35040	KERNRDGE	9.11	27.29	1	Kern PP		QF/Selfgen
KERNRG_1_UNITS	35040	KERNRDGE	9.11	27.91	2	Kern PP		QF/Selfgen
KRNCNY_6_UNIT	35018	KERNCNYN	9.11	9.22	1	Weedpatch	Monthly NQC - used August for LCR	Market
KRNOIL_7_TEXEXP				8.82		Kern PP	Not modeled	QF/Selfgen
LIVOAK_1_UNIT 1	35058	PSE-LVOK	9.11	44.18	1	Kern PP		QF/Selfgen
MIDSET_1_UNIT 1	35044	TX_MIDST	9.11	34.33	1	Kern PP		QF/Selfgen

MIDWAY_1_QF				0.02		Kern PP	Not modeled	QF/Selfgen
MKTRCK_1_UNIT 1	35060	PSEMCKIT	9.11	43.92	1	Kern PP		QF/Selfgen
MTNPOS_1_UNIT	35036	MT POSO	9.11	50.33	1	Kern PP		QF/Selfgen
NAVY35_1_UNITS	35064	NAVY 35R	9.11	0.00	1	Kern PP		QF/Selfgen
NAVY35_1_UNITS	35064	NAVY 35R	9.11	0.00	2	Kern PP		QF/Selfgen
OILDAL_1_UNIT 1	35028	OILDALE	9.11	39.68	1	Kern PP		QF/Selfgen
RIOBRV_6_UNIT 1	35020	RIOBRAVO	9.11	8.46	1	Weedpatch		QF/Selfgen
SIERRA_1_UNITS	35027	HISIERRA	9.11	45.80	1	Kern PP		QF/Selfgen
TANHIL_6_SOLART	35050	SLR-TANN	9.11	8.86	1	Kern PP		QF/Selfgen
TEMBLR_7_WELLPT				0.36		Kern PP	Not modeled	QF/Selfgen
TXMCKT_6_UNIT				3.44		Kern PP	Not modeled	QF/Selfgen
TXNMID_1_UNIT 2	34783	TEXCO_NM	9.11	0.01	1	Kern PP		QF/Selfgen
TXNMID_1_UNIT 2	34783	TEXCO_NM	9.11	0.01	2	Kern PP		QF/Selfgen
ULTOGL_1_POSO	35035	ULTR PWR	9.11	34.70	1	Kern PP		QF/Selfgen
UNVRSY_1_UNIT 1	35037	UNIVRSTY	9.11	33.36	1	Kern PP		QF/Selfgen
VEDDER_1_SEKERN	35046	SEKR	9.11	15.95	1	Kern PP		QF/Selfgen
MIDSUN_1_PL1X2	35034	MIDSUN +	9.11	0.00	1	Kern PP	Retired	Market
NA	35056	TX-LOSTH	4.16	9.00	1	Kern PP	No NQC - historical data	QF/Selfgen

Major new projects modeled: None

Critical Contingency Analysis Summary

Kern PP Sub-area

The most critical contingency is the outage of the Kern PP #5 230/115 kV transformer bank followed by the Kern PP – Kern Front 115 kV line, which could thermally overload the parallel Kern PP #3 and #3a 230/115 kV transformers. This limiting contingency establishes a LCR of 416 MW in 2011 (includes 691 MW of QF generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the loss of Kern PP #5 230/115 kV transformer bank, which could thermally overload the parallel Kern PP #3 and #3a 230/115 kV transformers. This limiting contingency establishes a LCR of 243 MW in 2011 (includes 691 MW of QF generation).

Effectiveness factors:

The following table shows units that are at least 5% effective:

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
35066	PSE-BEAR	1	22%
35029	BADGERCK	1	22%
35023	DOUBLE C	1	22%
35027	HISIERRA	1	22%

35026	KERNFRNT	1	21%
35058	PSE-LVOK	1	21%
35028	OILDALE	1	21%
35062	DISCOVRY	1	21%
35046	SEKR	1	21%
35024	DEXEL +	1	21%
35036	MT POSO	1	15%
35035	ULTR PWR	1	15%
35052	CHEV.USA	1	6%

Weedpatch Sub-area

The most critical contingency is the loss of the Wheeler Ridge – San Bernard 70 kV line followed by the Wheeler Ridge – Tejon 70 kV line, which could thermally overload the Wheeler Ridge – Weedpatch 70 kV line and cause low voltage problem at the local 70 kV transmission system. This limiting contingency establishes a LCR of 31 MW in 2011 (includes 8 MW of QF generation and 13 MW of deficiency) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Changes compared to last year's results:

Overall the load forecast went up by 147 MW and that drives the LCR up by 43 MW. The resources in this area are more effective in mitigating the constraint then the overall effect of the load increase.

Kern Area Overall Requirements:

2011	QF/Selfgen (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	699	9	708

2011	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single) [21]	243	0	243
Category C (Multiple) [22]	434	13	447

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

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

8. LA Basin Area

Area Definition

The transmission tie lines into the LA Basin Area are:

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

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

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

Total 2011 busload within the defined area is 19,715 MW with 486 MW of losses and 22 MW pumps resulting in total load + losses + pumps of 20,223 MW.

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

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ALAMIT_7_UNIT 1	24001	ALAMT1 G	18	174.56	1	Western		Market
ALAMIT_7_UNIT 2	24002	ALAMT2 G	18	175.00	2	Western		Market
ALAMIT_7_UNIT 3	24003	ALAMT3 G	18	332.18	3	Western		Market
ALAMIT_7_UNIT 4	24004	ALAMT4 G	18	335.67	4	Western		Market

ALAMIT_7_UNIT 5	24005	ALAMT5 G	20	497.97	5	Western		Market
ALAMIT_7_UNIT 6	24161	ALAMT6 G	20	495.00	6	Western		Market
ANAHM_7_CT	25203	ANAHEIMG	13.8	46.00	1	Western		MUNI
ARCOGN_2_UNITS	24011	ARCO 1G	13.8	62.72	1	Western		QF/Selfgen
ARCOGN_2_UNITS	24012	ARCO 2G	13.8	62.72	2	Western		QF/Selfgen
ARCOGN_2_UNITS	24013	ARCO 3G	13.8	62.72	3	Western		QF/Selfgen
ARCOGN_2_UNITS	24014	ARCO 4G	13.8	62.72	4	Western		QF/Selfgen
ARCOGN_2_UNITS	24163	ARCO 5G	13.8	31.37	5	Western		QF/Selfgen
ARCOGN_2_UNITS	24164	ARCO 6G	13.8	31.37	6	Western		QF/Selfgen
BARRE_2_QF	24016	BARRE	230	0.00		Western	Not modeled	QF/Selfgen
BARRE_6_PEAKER	28309	BARPKGEN	13.8	45.38	1	Western		Market
BRDWAY_7_UNIT 3	28007	BRODWYSC	13.8	65.00	1	Western		MUNI
BUCKWD_7_WINTCV	25634	BUCKWIND	115	0.14	W5	Eastern		Wind
CABZON_1_WINDA1	28280	CABAZON	33	9.66	1	Eastern	Monthly NQC - used August for LCR	Wind
CENTER_2_QF	24203	CENTER S	66	25.28		Western	Not Modeled	QF/Selfgen
CENTER_2_RHONDO	24203	CENTER S	66	1.91		Western	Not Modeled	QF/Selfgen
CENTER_6_PEAKER	28308	CTRPKGEN	13.8	44.57	1	Western		Market
CENTRY_6_PL1X4				36.00		Eastern	Not Modeled	Market
CHEVMN_2_UNITS	24022	CHEVGEN1	13.8	1.58	1	Western, El Nido		QF/Selfgen
CHEVMN_2_UNITS	24023	CHEVGEN2	13.8	1.61	2	Western, El Nido		QF/Selfgen
CHINO_2_QF	24024	CHINO	66	10.26		Western	Not modeled	QF/Selfgen
CHINO_6_CIMGEN	24026	CIMGEN	13.8	25.89	1	Western		QF/Selfgen
CHINO_6_SMPPAP	24140	SIMPSON	13.8	39.08	1	Western		QF/Selfgen
CHINO_7_MILIKN	24024	CHINO	66	1.90		Western	Not modeled	Market
COLTON_6_AGUAM1				43.00		Eastern	Not Modeled	MUNI
CORONS_6_CLRWTR	24210	MIRALOMA	66	14.00		Eastern	Not modeled	MUNI
CORONS_6_CLRWTR	24210	MIRALOMA	66	14.00		Eastern	Not modeled	MUNI
DEVERS_1_QF	25645	VENWIND	115	1.19	EU	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25635	ALTWIND	115	2.31	Q1	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	0.44	Q1	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25645	VENWIND	115	1.36	Q1	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25646	SANWIND	115	1.96	Q1	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25635	ALTWIND	115	1.06	Q2	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	0.46	Q2	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25645	VENWIND	115	1.79	Q2	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25646	SANWIND	115	0.21	Q2	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	24815	GARNET	115	5.23	QF	Eastern	Monthly NQC - used August for	QF/Selfgen

							LCR	
DEVERS_1_QF	25632	TERAWND	115	1.58	QF	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25633	CAPWIND	115	1.40	QF	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25634	BUCKWIND	115	1.20	QF	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25637	TRANWIND	115	2.81	QF	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25639	SEAWIND	115	1.89	QF	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25640	PANAERO	115	2.10	QF	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	0.63	W1	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
DMDVLY_1_UNITS	25425	ESRP P2	6.9	21.00		Eastern	Not modeled	QF/Selfgen
DREWS_6_PL1X4				36.00		Eastern	Not modeled	Market
DVLCYN_1_UNITS	25648	DVLCYN1G	13.8	48.64	1	Eastern		MUNI
DVLCYN_1_UNITS	25649	DVLCYN2G	13.8	48.64	2	Eastern		MUNI
DVLCYN_1_UNITS	25603	DVLCYN3G	13.8	64.86	3	Eastern		MUNI
DVLCYN_1_UNITS	25604	DVLCYN4G	13.8	64.86	4	Eastern		MUNI
ELLIS_2_QF	24197	ELLIS	66	0.29		Western	Not modeled	QF/Selfgen
ELSEGN_7_UNIT 3	24047	ELSEG3 G	18	335.00	3	Western, El Nido		Market
ELSEGN_7_UNIT 4	24048	ELSEG4 G	18	335.00	4	Western, El Nido		Market
ETIWND_2_FONTNA	24055	ETIWANDA	66	0.61		Eastern	Not modeled	QF/Selfgen
ETIWND_2_QF	24055	ETIWANDA	66	17.66		Eastern	Not modeled	QF/Selfgen
ETIWND_6_GRPLND	28305	ETWPKGEN	13.8	42.53	1	Eastern		Market
ETIWND_6_MWDETI	25422	ETI MWDG	13.8	21.19	1	Eastern		Market
ETIWND_7_MIDVLY	24055	ETIWANDA	66	2.10		Eastern	Not modeled	QF/Selfgen
ETIWND_7_UNIT 3	24052	MTNVIST3	18	320.00	3	Eastern		Market
ETIWND_7_UNIT 4	24053	MTNVIST4	18	320.00	4	Eastern		Market
GARNET_1_UNITS	24815	GARNET	115	0.53	G1	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
GARNET_1_UNITS	24815	GARNET	115	0.19	G2	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
GARNET_1_UNITS	24815	GARNET	115	0.38	G3	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
GARNET_1_UNITS	24815	GARNET	115	0.19	PC	Eastern	Monthly NQC - used August for LCR	QF/Selfgen
GARNET_1_WIND	24815	GARNET	115	0.61	W2	Eastern	Monthly NQC - used August for LCR	Wind
GARNET_1_WIND	24815	GARNET	115	0.61	W3	Eastern	Monthly NQC - used August for LCR	Wind
GLNARM_7_UNIT 1	28005	PASADNA1	13.8	22.30	1	Western		MUNI
GLNARM_7_UNIT 2	28006	PASADNA2	13.8	22.30	1	Western		MUNI

GLNARM_7_UNIT 3	28005	PASADNA1	13.8	44.83		Western	Not modeled	MUNI
GLNARM_7_UNIT 4	28006	PASADNA2	13.8	42.42		Western	Not modeled	MUNI
HARBGN_7_UNITS	24062	HARBOR G	13.8	76.28	1	Western		Market
HARBGN_7_UNITS	24062	HARBOR G	13.8	11.86	HP	Western		Market
HARBGN_7_UNITS	25510	HARBORG4	4.16	11.86	LP	Western		Market
HINSON_6_CARBGN	24020	CARBOGEN	13.8	29.00	1	Western		Market
HINSON_6_LBECH1	24078	LBEACH1G	13.8	65.00	1	Western		Market
HINSON_6_LBECH2	24170	LBEACH2G	13.8	65.00	2	Western		Market
HINSON_6_LBECH3	24171	LBEACH3G	13.8	65.00	3	Western		Market
HINSON_6_LBECH4	24172	LBEACH4G	13.8	65.00	4	Western		Market
HINSON_6_SERRGN	24139	SERRFGEN	13.8	28.10	1	Western		QF/Selfgen
HNTGBH_7_UNIT 1	24066	HUNT1 G	13.8	225.75	1	Western, Ellis		Market
HNTGBH_7_UNIT 2	24067	HUNT2 G	13.8	225.80	2	Western, Ellis		Market
HNTGBH_7_UNIT 3	24167	HUNT3 G	13.8	225.00	3	Western, Ellis		Market
HNTGBH_7_UNIT 4	24168	HUNT4 G	13.8	227.00	4	Western, Ellis		Market
INDIGO_1_UNIT 1	28190	WINTECX2	13.8	42.00	1	Eastern		Market
INDIGO_1_UNIT 2	28191	WINTECX1	13.8	42.00	1	Eastern		Market
INDIGO_1_UNIT 3	28180	WINTEC8	13.8	42.00	1	Eastern		Market
INLDEM_5_UNIT 1	28041	IEEC-G1	19.5	335.00	1	Eastern		Market
JOHANN_6_QFA1	24072	JOHANNA	230	0.00		Western	Not Modeled	QF/Selfgen
LACIEN_2_VENICE	24208	LCIENEGA	66	3.68		Western	Not modeled	QF/Selfgen
LAFRES_6_QF	24073	LA FRESA	66	3.28		Western	Not modeled	QF/Selfgen
LAGBEL_6_QF	24075	LAGUBELL	66	10.92		Western	Not modeled	QF/Selfgen
LGHTHP_6_ICEGEN	24070	ICEGEN	13.8	48.09	1	Western		QF/Selfgen
LGHTHP_6_QF	24083	LITEHIPE	66	0.92		Western	Not modeled	QF/Selfgen
MESAS_2_QF	24209	MESA CAL	66	1.17		Western	Not modeled	QF/Selfgen
MIRLOM_2_CORONA				1.94		Eastern	Not modeled	QF/Selfgen
MIRLOM_2_TEMESC				2.18		Eastern	Not modeled	QF/Selfgen
MIRLOM_6_DELGEN	24030	DELGEN	13.8	39.68	1	Eastern		QF/Selfgen
MIRLOM_6_PEAKER	28307	MRLPKGEN	13.8	43.18	1	Eastern		Market
MIRLOM_7_MWDLKM	24210	MIRALOMA	66	4.30		Eastern	Not modeled	MUNI
MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	4.67	1	Eastern		Market
MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	4.67	2	Eastern		Market
MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	4.67	3	Eastern		Market
MTWIND_1_UNIT 1				5.35		Eastern	Not modeled - Monthly NQC - used August for LCR	Wind
MTWIND_1_UNIT 2				2.36		Eastern	Not modeled - Monthly NQC - used August for LCR	Wind
MTWIND_1_UNIT 3				2.64		Eastern	Not modeled - Monthly NQC - used August for LCR	Wind
OLINDA_2_COYCRK	24211	OLINDA	66	3.13		Western	Not modeled	QF/Selfgen
OLINDA_2_QF	24211	OLINDA	66	3.39	1	Western		QF/Selfgen
OLINDA_7_LNDFIL	24201	BARRE	66	4.90		Western	Not modeled	QF/Selfgen
PADUA_2_ONTARO	24111	PADUA	66	1.04		Eastern	Not modeled	QF/Selfgen
PADUA_6_MWDSDM	24111	PADUA	66	5.70		Eastern	Not modeled	MUNI
PADUA_6_QF	24111	PADUA	66	4.46		Eastern	Not modeled	QF/Selfgen
PADUA_7_SDIMAS	24111	PADUA	66	1.05		Eastern	Not modeled Monthly NQC - used August for LCR	QF/Selfgen

PWEST_1_UNIT				0.27		Western	Not modeled	Market
REDOND_7_UNIT 5	24121	REDON5 G	18	178.87	5	Western		Market
REDOND_7_UNIT 6	24122	REDON6 G	18	175.00	6	Western		Market
REDOND_7_UNIT 7	24123	REDON7 G	20	493.24	7	Western		Market
REDOND_7_UNIT 8	24124	REDON8 G	20	495.90	8	Western		Market
RHONDO_2_QF	24213	RIOHONDO	66	1.27		Western	Not modeled	QF/Selfgen
RHONDO_6_PUENTE	24213	RIOHONDO	66	4.00		Western	Not modeled	Market
RVSIDE_6_RERCU1	24242	RERC1G	13.8	48.35	1	Eastern		MUNI
RVSIDE_6_RERCU2	24243	RERC2G	13.8	48.50	1	Eastern		MUNI
RVSIDE_6_SPRING	24244	SPRINGEN	13.8	36.00	1	Eastern		Market
SANTGO_6_COYOTE	24133	SANTIAGO	66	9.99	1	Western, Ellis		Market
SBERDO_2_PSP3	24921	MNTV-CT1	18	129.71	1	Eastern		Market
SBERDO_2_PSP3	24922	MNTV-CT2	18	129.71	1	Eastern		Market
SBERDO_2_PSP3	24923	MNTV-ST1	18	225.08	1	Eastern		Market
SBERDO_2_PSP4	24924	MNTV-CT3	18	129.71	1	Eastern		Market
SBERDO_2_PSP4	24925	MNTV-CT4	18	129.71	1	Eastern		Market
SBERDO_2_PSP4	24926	MNTV-ST2	18	225.08	1	Eastern		Market
SBERDO_2_QF	24214	SANBRDNO	66	0.16		Eastern	Not modeled	QF/Selfgen
SBERDO_2_SNTANA	24214	SANBRDNO	66	0.73		Eastern	Not modeled	QF/Selfgen
SBERDO_6_MILLCK	24214	SANBRDNO	66	2.23		Eastern	Not modeled	QF/Selfgen
SONGS_7_UNIT 2	24129	S.ONOFR2	22	1122.00	2	Western		Nuclear
SONGS_7_UNIT 3	24130	S.ONOFR3	22	1124.00	3	Western		Nuclear
TIFFNY_1_DILLON				7.72		Western	Not modeled	Wind
VALLEY_2_QF	24160	VALLEYSC	115	4.71		Eastern	Not modeled	QF/Selfgen
VALLEY_5_PERRIS	24160	VALLEYSC	115	7.94		Eastern	Not modeled	QF/Selfgen
VALLEY_5_REDMTN	24160	VALLEYSC	115	3.00		Eastern	Not modeled	QF/Selfgen
VALLEY_7_BADLND	24160	VALLEYSC	115	1.30		Eastern	Not modeled	Market
VALLEY_7_UNITA1	24160	VALLEYSC	115	3.74		Eastern	Not modeled	Market
VERNON_6_GONZL1				5.75		Western	Not modeled	MUNI
VERNON_6_GONZL2				5.75		Western	Not modeled	MUNI
VERNON_6_MALBRG	24239	MALBRG1G	13.8	42.37	C1	Western		MUNI
VERNON_6_MALBRG	24240	MALBRG2G	13.8	42.37	C2	Western		MUNI
VERNON_6_MALBRG	24241	MALBRG3G	13.8	49.26	S3	Western		MUNI
VILLPK_2_VALLYV	24216	VILLA PK	66	4.10		Western	Not modeled	QF/Selfgen
VILLPK_6_MWDYOR	24216	VILLA PK	66	3.90		Western	Not modeled	MUNI
VISTA_6_QF	24902	VSTA	66	0.13	1	Eastern		QF/Selfgen
WALNUT_6_HILLGEN	24063	HILLGEN	13.8	47.00	1	Western		QF/Selfgen
WALNUT_7_WCOVCT	24157	WALNUT	66	1.96		Western	Not modeled	Market
WALNUT_7_WCOVST	24157	WALNUT	66	3.19		Western	Not modeled	Market
WHTWTR_1_WINDA1	28061	WHITEWTR	33	7.06	1	Eastern	Monthly NQC - used August for LCR	Wind
ARCOGN_2_UNITS	24018	BRIGEN	13.8	35.00	1	Western	No NQC - historical data	Market
HINSON_6_QF	24064	HINSON	66	0.00	1	Western	No NQC - historical data	QF/Selfgen
INLAND_6_UNIT	24071	INLAND	13.8	30.00	1	Eastern	No NQC - historical data	QF/Selfgen
MOBGEN_6_UNIT 1	24094	MOBGEN	13.8	45.00	1	Western, El Nido	No NQC - historical data	QF/Selfgen
NA	24325	ORCOGEN	13.8	12.00	1	Western, Ellis	No NQC - Pmax	QF/Selfgen
NA	24327	THUMSGEN	13.8	49.00	1	Western	No NQC - Pmax	QF/Selfgen
NA	24330	OUTFALL1	13.8	17.00	1	Western, El Nido	No NQC - Pmax	QF/Selfgen
NA	24331	OUTFALL2	13.8	17.00	1	Western, El Nido	No NQC - Pmax	QF/Selfgen
NA	24337	VENICE	13.8	10.10	1	Western, El Nido	No NQC - Pmax	QF/Selfgen

NA	24341	COYGEN	13.8	20.00	1	Western, Ellis	No NQC - Pmax	QF/Selfgen
NA	24342	FEDGEN	13.8	24.70	1	Western	No NQC - Pmax	QF/Selfgen
NA	25303	CLTNAGUA	13.8	47.20	1	Eastern	No NQC - Pmax	QF/Selfgen
NA	28020	WINTEC6	115	0.00	1	Eastern	No NQC - historical data	Wind
NA	28023	WINTEC4	12	0.00	1	Eastern	No NQC - historical data	Wind
NA	28260	ALTAMSA4	115	0.00	1	Eastern	No NQC - historical data	Wind
NA	28951	REFUSE	13.8	12.00	1	Western	No NQC - Pmax	QF/Selfgen
NA	28953	SIGGEN	13.8	29.00	1	Western	No NQC - Pmax	QF/Selfgen
NA	29338	CLEARGEN	13.8	32.00	1	Eastern	No NQC - Pmax	QF/Selfgen
NA	29339	DELGEN	13.8	42.00	1	Eastern	No NQC - Pmax	QF/Selfgen
NA	24324	SANIGEN	13.8	8.00	D1	Eastern	No NQC - Pmax	QF/Selfgen
NA	24332	PALOGEN	13.8	13.00	D1	Western. El Nido	No NQC - Pmax	QF/Selfgen
NA	28060	SEAWEST	115	0.00	S1	Eastern	No NQC - historical data	Wind
NA	28060	SEAWEST	115	0.00	S2	Eastern	No NQC - historical data	Wind
NA	28060	SEAWEST	115	0.00	S3	Eastern	No NQC - historical data	Wind
INLDEM_5_UNIT 2	28042	IEEC-G2	19.5	336.70	1	Eastern	No NQC - Pmax	Market

Major new projects modeled:

1. 15 small existing resources have been modeled
2. As a part of TRTP project the existing Antelope-Mesa Cal 230 kV line will be permanently removed from service in 2011, to make room for a new 500 kV line

<u>Critical Contingency Analysis Summary</u>

LA Basin Overall:

The most critical contingency for LA Basin is the loss of one Songs unit followed by Palo Verde-Devers 500 kV line, which could exceed the approved 6400 MW rating for the South of Lugo path. This limiting contingency establishes a LCR of 10,589 MW in 2011 (includes 1127 MW of QF, 36 MW of Wind, 797 MW of Muni and 2246 MW of Nuclear generation) as the minimum generation capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	MW Eff. Fact (%)
24052	MTNVIST3	3	34
24053	MTNVIST4	4	34
24071	INLAND	1	33
25422	ETI MWDG	1	33
29305	ETWPKGEN	1	33
24905	RVCANAL1	R1	26
24906	RVCANAL2	R2	26
24907	RVCANAL3	R3	26
24908	RVCANAL4	R4	26
24921	MNTV-CT1	1	26
24922	MNTV-CT2	1	26
24923	MNTV-ST1	1	26
24924	MNTV-CT3	1	26
24925	MNTV-CT4	1	26
24926	MNTV-ST2	1	26
24242	RERC1G	1	26
24243	RERC2G	1	26
24244	SPRINGEN	1	26
25301	CLTNDREW	1	26
25302	CLTNCTRY	1	26
25303	CLTNAGUA	1	26
25603	DVLCYN3G	3	25
25604	DVLCYN4G	4	25
25648	DVLCYN1G	1	24
25649	DVLCYN2G	2	24
29041	IEEC-G1	1	24
29042	IEEC-G2	2	24
25203	ANAHEIMG	1	22
25632	TERAWND	QF	22
25634	BUCKWND	QF	22
25635	ALTWIND	Q1	22
25635	ALTWIND	Q2	22
25637	TRANWND	QF	22
25639	SEAWIND	QF	22
25640	PANAERO	QF	22
25645	VENWIND	EU	22
25645	VENWIND	Q2	22
25645	VENWIND	Q1	22
25646	SANWIND	Q2	22
29190	WINTECX2	1	22
29191	WINTECX1	1	22
29180	WINTEC8	1	22

24815	GARNET	QF	22
24815	GARNET	W3	22
24815	GARNET	W2	22
29023	WINTEC4	1	22
29060	SEAWEST	S1	22
29060	SEAWEST	S3	22
29060	SEAWEST	S2	22
29260	ALTAMSA4	1	22
29290	CABAZON	1	22
29021	WINTEC6	1	22
25657	MJVSPHN1	1	22
25658	MJVSPHN2	2	22
25659	MJVSPHN3	3	22
24030	DELGEN	1	21
25633	CAPWIND	QF	21
29061	WHITEWTR	1	21
24026	CIMGEN	D1	21
24140	SIMPSON	D1	21
29309	BARPKGEN	1	20
29307	MRLPKGEN	1	19
29338	CLEARGEN	1	19
29339	DELGEN	1	19
24066	HUNT1 G	1	18
24067	HUNT2 G	2	18
24167	HUNT3 G	3	18
24168	HUNT4 G	4	18
24129	S.ONOFR2	2	18
24130	S.ONOFR3	3	18
24133	SANTIAGO	1	18
24325	ORCOGEN	1	18
24341	COYGEN	1	18
24001	ALAMT1 G	1	17
24002	ALAMT2 G	2	17
24003	ALAMT3 G	3	17
24004	ALAMT4 G	4	17
24005	ALAMT5 G	5	17
24161	ALAMT6 G	6	17
24162	ALAMT7 G	R7	17
24063	HILLGEN	D1	16
29209	BLY1ST1	1	15
29207	BLY1CT1	1	15
29208	BLY1CT2	1	15
29953	SIGGEN	D1	15

24018	BRIGEN	1	14
24020	CARBGEN1	1	14
24064	HINSON	1	14
24070	ICEGEN	D1	14
24170	LBEACH12	2	14
24171	LBEACH34	3	14
24079	LBEACH7G	7	14
24080	LBEACH8G	8	14
24081	LBEACH9G	9	14
24062	HARBOR G	1	14
25510	HARBORG4	LP	14
24062	HARBOR G	HP	14
29308	CTRPKGEN	1	14
24139	SERRFGEN	D1	14
24170	LBEACH12	1	14
24171	LBEACH34	4	14
24173	LBEACH5G	R5	14
24174	LBEACH6G	R6	14
24327	THUMSGEN	1	14
24328	CARBGEN2	1	14
24337	VENICE	1	14
24011	ARCO 1G	1	13
24012	ARCO 2G	2	13
24013	ARCO 3G	3	13
24014	ARCO 4G	4	13
24163	ARCO 5G	5	13
24164	ARCO 6G	6	13
24022	CHEVGEN1	1	13
24023	CHEVGEN2	2	13
24047	ELSEG3 G	3	13
24048	ELSEG4 G	4	13
24094	MOBGEN1	1	13
24121	REDON5 G	5	13
24122	REDON6 G	6	13
24123	REDON7 G	7	13
24124	REDON8 G	8	13
24329	MOBGEN2	1	13
24330	OUTFALL1	1	13
24331	OUTFALL2	1	13
24332	PALOGEN	D1	13
24333	REDON1 G	R1	13
24334	REDON2 G	R2	13
24335	REDON3 G	R3	13

24336	REDON4 G	R4	13
24241	MALBRG3G	S3	11
24240	MALBRG2G	C2	11
24239	MALBRG1G	C1	11
29951	REFUSE	D1	11
24342	FEDGEN	1	11
29007	BRODWYSC	1	9
29005	PASADNA1	1	8
29006	PASADNA2	1	8

Western Sub-Area:

The most critical contingency for the Western sub-area is the loss of Serrano-Villa Park #1 or #2 230 kV line followed by the loss of the Serrano-Lewis 230 kV line or vice versa, which would result in thermal overload of the remaining Serrano-Villa Park #1 or #2 230 kV line. This limiting contingency establishes a LCR of 5828 MW (which includes 828 MW of QF, 8 MW of Wind, 392 MW of Muni and 2246 MW of nuclear generation) in 2011 as the generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Ellis sub-area

The most critical contingency for the Ellis sub-area is the loss of the Barre to Ellis 230 kV line followed by the loss of the Santiago to S.Onofre #1 and #2 230 kV lines, which would cause voltage collapse. This limiting contingency establishes a LCR of 492 MW in 2011 (which includes 32 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The generators inside the sub-area have the same effectiveness factors to mitigate the reliability problem.

El Nido sub-area

There are two most critical contingencies for the El Nido sub-area that cause the same LCR need.

1. The loss of the La Fresa-Redondo #1 and #2 230 kV lines which could overload La Fresa-Hinson 230 kV line.
2. The loss of the La Fresa – Hinson 230 kV line followed by the loss of the La Fresa – Redondo #1 and #2 230 kV lines, which would cause voltage collapse.

These two limiting contingencies establish a LCR of 360 MW in 2011 (which includes 105 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The generators inside the sub-area have the same effectiveness factors to mitigate the reliability problem.

Changes compared to last year's results:

Overall the load forecast went up by 165 MW resulting in an increase in LCR. 15 existing small resources (previously not modeled) have been added to the base case. The Ellis and El Nido sub-areas have been added. As a part of TRTP project the existing Antelope-Mesa Cal 230 kV line will be permanently removed from service in 2011, in order to make room for a new 500 kV line, which cause the LCR needs in Western sub-area and LA Basin overall to increase. The combination of these facts has resulted in a total LCR increase of 854 MW.

LA Basin Overall Requirements:

2011	QF/Wind (MW)	Muni (MW)	Nuclear (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	1163	797	2246	8103	12309

2011	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[23]	10,589	0	10,589
Category C (Multiple)[24]	10,589	0	10,589

9. Big Creek/Ventura Area

Area Definition

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

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

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

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

Total 2011 busload within the defined area is 4,295 MW with 90 MW of losses and 263 MW of pumps resulting in total load + losses + pumps of 4648 MW.

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

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ALAMO_6_UNIT	25653	ALAMO SC	13.8	16.00	1	Big Creek		Market
ANTLPE_2_QF	24457	ARBWIND	66	3.13	1	Big Creek	Monthly NQC - used August for LCR	Wind

23 A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.
24 Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

ANTLPE_2_QF	24458	ENCANWND	66	16.20	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	24459	FLOWIND	66	5.86	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	24460	DUTCHWND	66	2.01	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	24465	MORWIND	66	8.04	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	24491	OAKWIND	66	2.58	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	28501	MIDWIND	12	2.58	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	28502	SOUTHWND	12	0.95	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	28503	NORTHWND	12	2.78	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	28504	ZONDWND1	12	1.89	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	28505	ZONDWND2	12	1.84	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	28506	BREEZE1	12	0.65	1	Big Creek	Monthly NQC - used August for LCR	Wind
ANTLPE_2_QF	28507	BREEZE2	12	1.15	1	Big Creek	Monthly NQC - used August for LCR	Wind
BIGCRK_2_EXESWD	24306	B CRK1-1	7.2	19.38	1	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24308	B CRK2-1	13.8	49.48	1	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24311	B CRK3-1	13.8	34.09	1	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24317	MAMOTH1G	13.8	91.07	1	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24323	PORTAL	4.8	9.35	1	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24306	B CRK1-1	7.2	21.03	2	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24308	B CRK2-1	13.8	50.64	2	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24311	B CRK3-1	13.8	34.09	2	Big Creek, Rector, Vestal		Market

BIGCRK_2_EXESWD	24318	MAMOTH2G	13.8	91.07	2	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24307	B CRK1-2	13.8	21.03	3	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24309	B CRK2-2	7.2	18.22	3	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24312	B CRK3-2	13.8	34.09	3	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24307	B CRK1-2	13.8	30.39	4	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24309	B CRK2-2	7.2	19.19	4	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24312	B CRK3-2	13.8	39.93	4	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24310	B CRK2-3	7.2	16.55	5	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24313	B CRK3-3	13.8	37.99	5	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24310	B CRK2-3	7.2	18.02	6	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24314	B CRK 4	11.5	49.09	41	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24314	B CRK 4	11.5	49.28	42	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24315	B CRK 8	13.8	23.76	81	Big Creek, Rector, Vestal		Market
BIGCRK_2_EXESWD	24315	B CRK 8	13.8	42.85	82	Big Creek, Rector, Vestal		Market
EASTWD_7_UNIT	24319	EASTWOOD	13.8	199.00	1	Big Creek, Rector, Vestal		Market
EDMONS_2_NSPIN	25605	EDMON1AP	14.4	10.57	1	Big Creek		MUNI
EDMONS_2_NSPIN	25606	EDMON2AP	14.4	10.57	2	Big Creek		MUNI
EDMONS_2_NSPIN	25607	EDMON3AP	14.4	10.57	3	Big Creek		MUNI
EDMONS_2_NSPIN	25607	EDMON3AP	14.4	10.57	4	Big Creek		MUNI
EDMONS_2_NSPIN	25608	EDMON4AP	14.4	10.57	5	Big Creek		MUNI
EDMONS_2_NSPIN	25608	EDMON4AP	14.4	10.57	6	Big Creek		MUNI
EDMONS_2_NSPIN	25609	EDMON5AP	14.4	10.57	7	Big Creek		MUNI
EDMONS_2_NSPIN	25609	EDMON5AP	14.4	10.57	8	Big Creek		MUNI
EDMONS_2_NSPIN	25610	EDMON6AP	14.4	10.57	9	Big Creek		MUNI
EDMONS_2_NSPIN	25610	EDMON6AP	14.4	10.57	10	Big Creek		MUNI
EDMONS_2_NSPIN	25611	EDMON7AP	14.4	10.57	11	Big Creek		MUNI
EDMONS_2_NSPIN	25611	EDMON7AP	14.4	10.57	12	Big Creek		MUNI
EDMONS_2_NSPIN	25612	EDMON8AP	14.4	10.57	13	Big Creek		MUNI
EDMONS_2_NSPIN	25612	EDMON8AP	14.4	10.57	14	Big Creek		MUNI

GOLETA_2_QF	24057	GOLETA	66	0.40		Ventura, S.Clara, Moorpark	Not modeled	QF/Selfgen
GOLETA_6_ELLWOD	28004	ELLWOOD	13.8	54.00	1	Ventura, S.Clara, Moorpark		Market
GOLETA_6_EXGEN	24057	GOLETA	66	0.65		Ventura, S.Clara, Moorpark	Not modeled	QF/Selfgen
GOLETA_6_GAVOTA	24057	GOLETA	66	9.90		Ventura, S.Clara, Moorpark	Not modeled	QF/Selfgen
GOLETA_6_TAJIGS	24057	GOLETA	66	2.80		Ventura, S.Clara, Moorpark	Not modeled	Market
KERRGN_1_UNIT 1	24437	KERNRVR	66	22.69	1	Big Creek		Market
LEBECS_2_UNITS	28051	PSTRIAG1	18	157.90	G1	Big Creek	Monthly NQC - used August for LCR	Market
LEBECS_2_UNITS	28052	PSTRIAG2	18	157.90	G2	Big Creek	Monthly NQC - used August for LCR	Market
LEBECS_2_UNITS	28054	PSTRIAG3	18	157.90	G3	Big Creek	Monthly NQC - used August for LCR	Market
LEBECS_2_UNITS	28053	PSTRIAS1	18	162.40	S1	Big Creek	Monthly NQC - used August for LCR	Market
LEBECS_2_UNITS	28055	PSTRIAS2	18	78.90	S2	Big Creek	Monthly NQC - used August for LCR	Market
MNDALY_7_UNIT 1	24089	MANDLY1G	13.8	215.00	1	Ventura, Moorpark		Market
MNDALY_7_UNIT 2	24090	MANDLY2G	13.8	215.29	2	Ventura, Moorpark		Market
MNDALY_7_UNIT 3	24222	MANDLY3G	16	130.00	3	Ventura, S.Clara, Moorpark		Market
MONLTH_6_BOREL	24456	BOREL	66	9.05	1	Big Creek		QF/Selfgen
MOORPK_6_QF	24098	MOORPARK	66	27.52		Ventura, Moorpark	Not modeled	QF/Selfgen
MOORPK_7_UNITA1	24098	MOORPARK	66	2.49		Ventura, Moorpark	Not modeled	QF/Selfgen
OMAR_2_UNITS	24102	OMAR 1G	13.8	77.25	1	Big Creek		QF/Selfgen
OMAR_2_UNITS	24103	OMAR 2G	13.8	77.25	2	Big Creek		QF/Selfgen
OMAR_2_UNITS	24104	OMAR 3G	13.8	77.25	3	Big Creek		QF/Selfgen
OMAR_2_UNITS	24105	OMAR 4G	13.8	77.25	4	Big Creek		QF/Selfgen
ORMOND_7_UNIT 1	24107	ORMOND1G	26	741.27	1	Ventura, Moorpark		Market
ORMOND_7_UNIT 2	24108	ORMOND2G	26	775.00	2	Ventura, Moorpark		Market
OSO_6_NSPIN	25614	OSO A P	13.2	1.01	1	Big Creek		MUNI
OSO_6_NSPIN	25614	OSO A P	13.2	1.01	2	Big Creek		MUNI
OSO_6_NSPIN	25614	OSO A P	13.2	1.01	3	Big Creek		MUNI
OSO_6_NSPIN	25614	OSO A P	13.2	1.01	4	Big Creek		MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	1.01	5	Big Creek		MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	1.01	6	Big Creek		MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	1.01	7	Big Creek		MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	1.01	8	Big Creek		MUNI
PANDOL_6_UNIT	24113	PANDOL	13.8	18.18	1	Big Creek,		QF/Selfgen

						Vestal		
PANDOL_6_UNIT	24113	PANDOL	13.8	14.82	2	Big Creek, Vestal		QF/Selfgen
RECTOR_2_KAWEAH	24212	RECTOR	66	0.78		Big Creek, Rector, Vestal	Not modeled	Market
RECTOR_2_KAWH 1	24212	RECTOR	66	1.41		Big Creek, Rector, Vestal	Not modeled	Market
RECTOR_2_QF	24212	RECTOR	66	10.23		Big Creek, Rector, Vestal	Not modeled	QF/Selfgen
RECTOR_7_TULARE	24212	RECTOR	66	1.60		Big Creek, Rector, Vestal	Not modeled	QF/Selfgen
SAUGUS_6_MWDFTH	24135	SAUGUS	66	6.50		Big Creek	Not modeled	MUNI
SAUGUS_6_PTCHGN	24118	PITCHGEN	13.8	21.54	1	Big Creek		MUNI
SAUGUS_6_QF	24135	SAUGUS	66	2.72		Big Creek	Not modeled	QF/Selfgen
SAUGUS_7_LOPEZ	24135	SAUGUS	66	5.70		Big Creek	Not modeled	QF/Selfgen
SNCLRA_6_OXGEN	24110	OXGEN	13.8	46.38	1	Ventura, S.Clara, Moorpark		QF/Selfgen
SNCLRA_6_PROCGN	24119	PROCGEN	13.8	45.37	1	Ventura, S.Clara, Moorpark		Market
SNCLRA_6_QF	24127	S.CLARA	66	2.04	1	Ventura, S.Clara, Moorpark		QF/Selfgen
SNCLRA_6_WILLMT	24159	WILLAMET	13.8	14.20	1	Ventura, S.Clara, Moorpark		QF/Selfgen
SPRGVL_2_QF	24215	SPRINGVL	66	0.52		Big Creek, Rector, Vestal	Not modeled	QF/Selfgen
SPRGVL_2_TULE	24215	SPRINGVL	66	1.11		Big Creek, Rector, Vestal	Not modeled Monthly NQC - used August for LCR	Market
SPRGVL_2_TULESC	24215	SPRINGVL	66	0.52		Big Creek, Rector, Vestal	Not modeled	Market
SYCAMR_2_UNITS	24143	SYCCYN1G	13.8	69.73	1	Big Creek		QF/Selfgen
SYCAMR_2_UNITS	24144	SYCCYN2G	13.8	69.73	2	Big Creek		QF/Selfgen
SYCAMR_2_UNITS	24145	SYCCYN3G	13.8	69.73	3	Big Creek		QF/Selfgen
SYCAMR_2_UNITS	24146	SYCCYN4G	13.8	69.74	4	Big Creek		QF/Selfgen
TENGEN_6_UNIT 1	24148	TENNGEN1	13.8	19.93	1	Big Creek		Market
TENGEN_6_UNIT 2	24149	TENNGEN2	13.8	17.50	2	Big Creek		Market
VESTAL_2_KERN	24152	VESTAL	66	4.17	1	Big Creek, Vestal		QF/Selfgen
VESTAL_6_QF	24152	VESTAL	66	1.97		Big Creek, Vestal	Not modeled	QF/Selfgen
VESTAL_6_ULTRGN	24150	ULTRAGEN	13.8	34.98	1	Big Creek, Vestal		QF/Selfgen
VESTAL_6_WDFIRE	28008	LAKEGEN	13.8	7.00	1	Big Creek, Vestal		QF/Selfgen
WARNE_2_UNIT	25651	WARNE1	13.8	38.00	1	Big Creek		Market
WARNE_2_UNIT	25652	WARNE2	13.8	38.00	1	Big Creek		Market
MNDALY_6_MCGRTH	28306	MCGPKGEN	13.8	47.20	1	Ventura, S.Clara, Moorpark	No NQC - Pmax	Market

NA	23370	KAWGEN	13.8	18.00	1	Big Creek, Rector, Vestal	No NQC - Pmax	QF/Selfgen
NA	24340	CHARMIN	13.8	20.40	1	Ventura, S.Clara, Moorpark	No NQC - Pmax	QF/Selfgen
NA	24372	KR 3-1	13.8	22.80	1	Big Creek, Vestal	No NQC - Pmax	QF/Selfgen
NA	24373	KR 3-2	13.8	21.50	1	Big Creek, Vestal	No NQC - Pmax	QF/Selfgen
NA	24422	PALMDALE	66	1.00	1	Big Creek	No NQC - historical data	Market
NA	24436	GOLDTOWN	66	13.00	1	Big Creek	No NQC - historical data	Market
NA	28952	CAMGEN	13.8	28.00	1	Ventura, S.Clara, Moorpark	No NQC - Pmax	QF/Selfgen
NA	24362	Exgen2	13.8	29.00	G1	Ventura, S.Clara, Moorpark	No NQC - Pmax	QF/Selfgen
NA	24326	Exgen1	13.8	20.00	S1	Ventura, S.Clara, Moorpark	No NQC - Pmax	QF/Selfgen

Major new projects modeled:

1. Antelope Transmission Project (Segments 1, 2 and 3)
2. 6 small existing resources have been modeled

<u>Critical Contingency Analysis Summary</u>

Big Creek/Ventura overall:

The most critical contingency is the loss of Sylmar-Pardee #1 (or # 2) line followed by Ormond Beach Unit #2, which could thermally overload the remaining Sylmar-Pardee #1 or #2 230 kV line. This limiting contingency establishes a LCR of 2786 MW in 2011 (includes 962 MW of QF, 184 MW of Muni and 50 MW of Wind generation) as the minimum generation capacity necessary for reliable load serving capability within this area.

The second most critical contingency is the loss of the Lugo-Victorville 500 kV followed by Sylmar-Pardee #1 or #2 230 kV line, which could thermally overload the remaining Sylmar-Pardee #1 or #2 230 kV line. This limiting contingency establishes a LCR of 2727 MW in 2011 (includes 962 MW of QF, 184 MW of Muni and 50 MW of Wind generation).

Effectiveness factors:

The following table has units that have at least 5% effectiveness to any one of the Sylmar-Pardee 230 kV lines after the loss of the Lugo-Victorville 500 kV followed by one of the other Sylmar-Pardee 230 kV line in this area:

Gen Bus	Gen Name	Gen ID	MW Eff. Fctr. (%)
24009	APPGEN1G	1	29
24010	APPGEN2G	2	29
24107	ORMOND1G	1	29
24108	ORMOND2G	2	29
24118	PITCHGEN	1	28
24148	TENNGEN1	1	28
24149	TENNGEN2	2	28
24089	MANDLY1G	1	27
24090	MANDLY2G	2	27
24110	OXGEN	1	27
24119	PROCGEN	1	27
24159	WILLAMET	1	27
25651	WARNE1	1	27
25652	WARNE2	1	27
28004	ELLWOOD	1	27
24361	EXGEN1	1	27
24362	EXGEN2	2	27
28051	PSTRIAG1	G1	26
25606	EDMON2AP	2	26
25607	EDMON3AP	3	26
25607	EDMON3AP	4	26
25608	EDMON4AP	5	26
25608	EDMON4AP	6	26
25609	EDMON5AP	7	26
25609	EDMON5AP	8	26
25610	EDMON6AP	9	26
25610	EDMON6AP	10	26
25611	EDMON7AP	11	26
25611	EDMON7AP	12	26
25612	EDMON8AP	13	26
25612	EDMON8AP	14	26
28054	PSTRIAG3	G3	25
25615	OSO B P	7	25
25615	OSO B P	8	25
28952	CAMGEN	13.8	25
24127	S.CLARA	1	25
24340	CHARMIN	1	25
28055	PSTRIAS2	S2	24
28053	PSTRIAS1	S1	24
28052	PSTRIAG2	G2	24
25605	EDMON1AP	1	24
24143	SYCCYN1G	1	24

24144	SYCCYN2G	2	24
24145	SYCCYN3G	3	24
24146	SYCCYN4G	4	24
24102	OMAR 1G	1	23
24103	OMAR 2G	2	23
24104	OMAR 3G	3	23
24105	OMAR 4G	4	23
25614	OSO A P	1	23
25614	OSO A P	2	23
25653	ALAMO SC	1	23
24222	MANDLY3G	3	20
28008	LAKEGEN	1	20
24150	ULTRAGEN	1	20
24152	VESTAL	1	20
24372	KR 3-1	1	45
24373	KR 3-2	2	45
24370	KAWGEN	1	45
24319	EASTWOOD	1	20
24306	B CRK1-1	1	20
24306	B CRK1-1	2	20
24307	B CRK1-2	3	20
24307	B CRK1-2	4	20
24308	B CRK2-1	1	20
24308	B CRK2-1	2	20
24309	B CRK2-2	3	20
24309	B CRK2-2	4	20
24310	B CRK2-3	5	20
24310	B CRK2-3	6	20
24311	B CRK3-1	1	20
24311	B CRK3-1	2	20
24312	B CRK3-2	3	20
24312	B CRK3-2	4	20
24313	B CRK3-3	5	20
24314	B CRK 4	41	20
24314	B CRK 4	42	20
24315	B CRK 8	81	20
24315	B CRK 8	82	20
24317	MAMOTH1G	1	20
24318	MAMOTH2G	2	20
24113	PANDOL	1	19
24113	PANDOL	2	19
24437	KERNRVR	1	18
24459	FLOWIND	1	14
24436	GOLDTOWN	1	14
28501	MIDWIND	1	14
24457	ARBWIND	1	13
24456	BOREL	1	12
24458	ENCANWND	1	12
24460	DUTCHWND	1	12
24465	MORWIND	1	12

28503	NORTHWND	1	12
28504	ZONDWND1	1	12
28505	ZONDWND2	1	12
25618	PEARBMBP	5	6
25618	PEARBMBP	6	6
25619	PEARBMCP	7	6
25619	PEARBMCP	8	6
25617	PEARBMAP	1	5
25617	PEARBMAP	2	5
25620	PEARBMDP	9	5
24136	SEAWEST	1	5

Rector Sub-area

The most critical contingency for the Rector sub-area is the loss of one of the Rector-Vestal 230 kV lines with the Eastwood unit out of service, which would thermally overload the remaining Rector-Vestal 230 kV line. This limiting contingency establishes a LCR of 641 MW (includes 30 MW of QF generation) in 2011 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

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

24314	B CRK 4	41	38
24314	B CRK 4	42	38

Vestal Sub-area

The most critical contingency for the Vestal sub-area is the loss of one of the Magunden-Vestal 230 kV lines with the Eastwood unit out of service, which would thermally overload the remaining Magunden-Vestal 230 kV line. This limiting contingency establishes a LCR of 854 MW in 2011 (which includes 156 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

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

24314	B CRK 4	41	22
24314	B CRK 4	42	22

S. Clara sub-areas

The most critical contingency for the S.Clara sub-area is the loss of the Pardee to S.Clara 230 kV line followed by the loss of the Moorpark to S.Clara #1 and #2 230 kV lines, which would cause voltage collapse. This limiting contingency establishes a LCR of 346 MW in 2011 (which includes 171 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The generators inside the sub-area have the same effectiveness factors to mitigate the reliability problem.

Moorpark sub-areas

The most critical contingency for the Moorpark sub-area is the loss of one of the Pardee to Moorpark 230 kV lines followed by the loss of the remaining two Moorpark to Pardee 230 kV lines, which would cause voltage collapse. This limiting contingency establishes a LCR of 606 MW in 2011 (which includes 201 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The generators inside the sub-area have the same effectiveness factors to mitigate the reliability problem.

Changes compared to last year's results:

Overall the load forecast went down by 385 MW. 6 existing small resources (previously not modeled) have been added to the base case. The Santa Clara and Moorpark sub-areas have been added. The transmission boundary has changed slightly due removal and addition of transmission projects required under TRTP; without impact to the amount of load or resources in this local area. The overall effect is that the LCR has decreased by 607 MW.

Big Creek Overall Requirements:

2011	QF/Wind (MW)	MUNI (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	1012	184	4110	5306

2011	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[25]	2786	0	2786
Category C (Multiple)[26]	2786	0	2786

10. San Diego Area

<u>Area Definition</u>

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

1) Imperial Valley – Miguel 500 kV Line
2) Otay Mesa – Tijuana 230 kV Line
3) San Onofre - San Luis Rey #1 230 kV Line
4) San Onofre - San Luis Rey #2 230 kV Line
5) San Onofre - San Luis Rey #3 230 kV Line
6) San Onofre – Talega #1 230 kV Line
7) San Onofre – Talega #2 230 kV Line

The substations that delineate the San Diego Area are:

1) Imperial Valley is out Miguel is in
2) Otay Mesa is in Tijuana is out
3) San Onofre is out San Luis Rey is in
4) San Onofre is out San Luis Rey is in
5) San Onofre is out San Luis Rey is in
6) San Onofre is out Talega is in
7) San Onofre is out Talega is in

Total 2011 busload within the defined area: 4920 MW with 116 MW of losses resulting in total load + losses of 5036 MW.

[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.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BORDER_6_UNITA1	22149	CALPK_BD	13.8	43.80	1	None		Market
CBRLLO_6_PLSTP1	22092	CABRILLO	69	2.12	1	None		QF/Selfgen
CCRITA_7_RPPCHF	22124	CHCARITA	138	3.92	1	None		QF/Selfgen
CHILLS_1_SYCLFL	22120	CARLTNHS	138	0.52	1	None		QF/Selfgen
CHILLS_7_UNITA1	22120	CARLTNHS	138	2.00	2	None		QF/Selfgen
CPSTNO_7_PRMADS	22112	CAPSTRNO	138	6.10	1	None		QF/Selfgen
CRSTWD_6_KUMYAY	22915	KUMEYAAY	34.5	6.33	1	None	Monthly NQC - used August for LCR	Wind
DIVSON_6_NSQF	22172	DIVISION	69	47.00	1	None		QF/Selfgen
EGATE_7_NOCITY	22204	EASTGATE	69	1.00	1	None		QF/Selfgen
ELCAJN_6_UNITA1	22150	CALPK_EC	13.8	42.20	1	El Cajon		Market
ELCAJN_7_GT1	22212	ELCAJNGT	12.5	16.00	1	El Cajon		Market
ENCINA_7_EA1	22233	ENCINA 1	14.4	106.00	1	None		Market
ENCINA_7_EA2	22234	ENCINA 2	14.4	103.00	1	None		Market
ENCINA_7_EA3	22236	ENCINA 3	14.4	109.00	1	None		Market
ENCINA_7_EA4	22240	ENCINA 4	22	299.00	1	None		Market
ENCINA_7_EA5	22244	ENCINA 5	24	329.00	1	None		Market
ENCINA_7_GT1	22248	ENCINAGT	12.5	14.00	1	None		Market
ESCNDO_6_PL1X2	22257	MMC_ES	13.8	35.50	1	None		Market
ESCNDO_6_UNITB1	22153	CALPK_ES	13.8	45.50	1	None		Market
ESCO_6_GLMQF	22332	GOALLINE	69	47.39	1	Escondido		QF/Selfgen
KEARNY_7_KY1	22377	KEARNGT1	12.5	16.00	1	None		Market
KEARNY_7_KY2	22373	KEARN2AB	12.5	15.02	1	None		Market
KEARNY_7_KY2	22374	KEARN2CD	12.5	15.02	1	None		Market
KEARNY_7_KY2	22373	KEARN2AB	12.5	15.02	2	None		Market
KEARNY_7_KY2	22374	KEARN2CD	12.5	13.95	2	None		Market
KEARNY_7_KY3	22375	KEARN3AB	12.5	14.98	1	None		Market
KEARNY_7_KY3	22376	KEARN3CD	12.5	14.98	1	None		Market
KEARNY_7_KY3	22375	KEARN3AB	12.5	16.05	2	None		Market
KEARNY_7_KY3	22376	KEARN3CD	12.5	14.98	2	None		Market
LARKSP_6_UNIT 1	22074	LRKSPBD1	13.8	46.00	1	None		Market
LARKSP_6_UNIT 2	22075	LRKSPBD2	13.8	46.00	1	None		Market
MRGT_6_MEF2	22487	MFE_MR2	13.8	47.90	1	None	No NQC - Pmax	Market
MRGT_6_MMAREF	22486	MFE_MR1	13.8	46.60	1	None		Market
MRGT_7_UNITS	22488	MIRAMRGT	12.5	18.55	1	None		Market
MRGT_7_UNITS	22488	MIRAMRGT	12.5	17.45	2	None		Market
MSHGTS_6_MMARLF	22448	MESAHGTS	69	3.00	1	None		QF/Selfgen
MSSION_2_QF	22496	MISSION	69	0.90	1	None		QF/Selfgen
NIMTG_6_NIQF	22576	NOISLMTR	69	35.84	1	None		QF/Selfgen
OTAY_6_PL1X2	22617	MMC_OY	13.8	35.50	1	None		Market
OTAY_6_UNITB1	22604	OTAY	69	1.50	1	None		QF/Selfgen
OTAY_6_UNITB1	22604	OTAY	69	1.49	2	None		QF/Selfgen
OTAY_7_UNITC1	22604	OTAY	69	3.75	3	None		QF/Selfgen
OTMESA_2_PL1X3	22605	OTAYMGT1	18	185.06	1	None		Market
OTMESA_2_PL1X3	22606	OTAYMGT2	18	185.06	1	None		Market
OTMESA_2_PL1X3	22607	OTAYMST1	16	233.48	1	None		Market
PALOMR_2_PL1X3	22262	PEN_CT1	18	162.17	1	None		Market
PALOMR_2_PL1X3	22263	PEN_CT2	18	162.17	1	None		Market
PALOMR_2_PL1X3	22265	PEN_ST	18	240.66	1	None		Market
PTLOMA_6_NTCCGN	22660	POINTLMA	69	2.16	2	None		QF/Selfgen
PTLOMA_6_NTCQF	22660	POINTLMA	69	22.28	1	None		QF/Selfgen
SAMPSN_6_KELCO1	22704	SAMPSON	12.5	4.02	1	None		QF/Selfgen
SMRCOS_6_UNIT 1	22724	SANMRCOS	69	0.75	1	None		QF/Selfgen

SOBAY_7_GT1	22776	SOUTHBGT	12.5	15.00	1	None		Market
SOBAY_7_SY1	22780	SOUTHBY1	15	146.00	1	None		Market
SOBAY_7_SY2	22784	SOUTHBY2	15	149.60	1	None		Market
KYCORA_7_UNIT 1	22384	KYOCERA	69	0.00	1	None	No NQC - historical data	QF/Selfgen
NA	22008	ASH	69	0.90	1	None	No NQC - historical data	QF/Selfgen
NA	22532	MURRAY	69	0.20	1	None	No NQC - historical data	QF/Selfgen
NA	22680	R.SNTAFE	69	0.40	1	None	No NQC - historical data	QF/Selfgen
NA	22760	SHADOWR	138	0.10	1	None	No NQC - historical data	QF/Selfgen
NA	22916	PFC-AVC	0.6	0.00	1	None	No NQC - historical data	QF/Selfgen
NA	22680	R.SNTAFE	69	0.30	2	None	No NQC - historical data	QF/Selfgen
ELCAJN_6_LM6K	23320	C509	13.8	49.90	1	El Cajon	No NQC - Pmax	Market
LAKHDG_6_UNIT 1	22625	LKHODG1	13.8	20.00	1	Bernardo	No NQC - Pmax	Market
LAKHDG_6_UNIT 2	22626	LKHODG2	13.8	20.00	2	Bernardo	No NQC - Pmax	Market
New unit	23120	BULLMOOS	13.8	27.00	1	None	No NQC - Pmax	Market
OGROVE_6_PL1X2	22628	PA99MWQ1	13.8	47.00	1	Pala	No NQC - Pmax	Market
OGROVE_6_PL1X2	22629	PA99MWQ2	13.8	47.00	2	Pala	No NQC - Pmax	Market

Major new projects modeled:

1. Otay Mesa Power Plant (603 MW)
2. New peaker at Miramar 69 kV substation (47.9 MW)
3. New biomass unit at Border 69 kV substation (27 MW) and its associated transmission upgrade, reconductor TL649A, Otay-Otay Lakes Tap 69kV
4. New peaker units at Pala 69 kV substation (94 MW)
5. New peaker unit at El Cajon 69kV substation (49 MW)
6. New generating units at Escondido 69kV (40 MW)
7. Transmission project to reconductor TL6927, Eastgate-Rose Canyon 69kV
8. New and/or upgrade of 69kV capacitors at Lilac, Rincon, Santa Ysabel and Warners 69kV substation
9. Advancement of Sunrise capacitors at South Bay 69kV and San Luis Rey 230kV substations
10. TL13802D, Encina-Calavera Tap 138 kV project: Upgrade and re-arrange Cannon-Calavera Tap (TL13802D) to create two new 138kV transmission lines: Encina-Calavera Tap-Shadow ridge (274mva) and Cannon-Calavera Tap-San Luis Rey (204mva); re-energize existing Escondido Bank 50

Critical Contingency Analysis Summary

El Cajon Sub-area:

The most critical contingency for the El Cajon sub-area is the loss of the El Cajon-Jamacha 69 kV line (TL624) followed by the loss of Miguel-Granite-Los Coches 69 kV line (TL632), which would thermally overload the Garfield-Murray 69 kV line. This limiting contingency establishes a LCR of 66 MW (including 0 MW of QF generation) in 2011 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area (El Cajon Peaker, El Cajon GT, and new peaker at El Cajon substation) have the same effectiveness factor.

Rose Canyon Sub-area

This sub-area has been eliminated due to recently approved transmission project, TL6927, Eastgate-Rose Canyon 69 kV reconductor.

Bernardo Sub-area:

The most critical contingency for the Bernardo sub-area is the loss of Artesian - Sycamore 69 kV line followed by the loss of Poway-Rancho Carmel 69 kV line, which would thermally overload the Felicita Tap-Bernardo 69 kV line. This limiting contingency establishes a LCR of 66 MW (including 0 MW of QF generation and 26 MW of deficiency) in 2011 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Border 69 kV Sub-area

Sub-area eliminated due to new generation project upgrade, reconductor TL649A, Otay-Otay Lakes Tap 69 kV.

If the project reconductoring is delayed beyond June 1, 2011, the most critical contingency for the Border sub area will be the loss of Border – Miguel 69 kV line (TL6910) followed by the loss of Imperial Beach-Otay-San Ysidro 69 kV line (TL623), which would thermally overload Otay-Otay Lake Tap (TL649). This limiting contingency would establish a local capacity need of 31 MW (includes 0 MW of QF generation) in 2011 as the minimum generation capacity necessary for reliable load serving capability within this sub area.

Effectiveness factors:

If the reconductoring project is completed by June 1, 2011, no units will be needed. If the project is not completed, Border Cal Peak, Larkspur and Bullmoose all have the same effectiveness factor.

Escondido Sub-area

The most critical contingency for the Escondido sub-area is the loss of Poway-Pomerado 69 kV line followed by the loss of Bernardo-Rancho Carmel 69kV line which would thermally overload the Esco-Escondido 69 kV line. This limiting contingency establishes a LCR of 82 MW (including 47 MW of QF generation and 35 MW of deficiency) in 2011 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency for the Escondido sub-area is the loss of Poway-Pomerado 69 kV line which would thermally overload the Esco-Escondido 69 kV line. This limiting contingency establishes a LCR of 10 MW (including 47 MW of QF generation) in 2011 within this sub-area.

Effectiveness factors:

All units within this sub-area (Goal line) are needed so no effectiveness factor is required.

South Bay 69 kV Sub-area

This sub-area has been eliminated because South Bay Units 3 and 4 are retired.

San Diego overall:

The most limiting contingency in the San Diego area is described by the outage of the 500 kV Southwest Power Link (SWPL) between Imperial Valley and Miguel Substations over-lapping with an outage of the Otay Mesa Combined-Cycle Power plant (603 MW) while staying within the South of San Onofre (WECC Path 44) non-simultaneous import capability rating of 2,500 MW. This contingency establishes a LCR of 3146 MW in 2011 (includes 188 MW of QF generation and 6 MW of Wind) as the minimum generation capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

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

Changes compared to last year's results:

Overall the load forecast went down by 91 MW and that lead to a decrease in the LCR by same amount. Also the new Otay Mesa Power Plant's NQC was increased from 573 MW to 603 MW, increasing the LCR by 30 MW. In addition, losses increased by 7 MW post SWPL out contingency, causing LCR to increase by the same amount.

San Diego Overall Requirements:

2011	QF (MW)	Wind (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	188	6	3227	3421

2011	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[27]	3146	0	3146
Category C (Multiple)[28]	3146	61	3207

[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.

Rulemaking: 12-03-014

Exhibit No.: ISO-16

Witness: ______________

2012 Local Capacity Technical Analysis

Final Report and Study Results

2012
LOCAL CAPACITY TECHNICAL ANALYSIS

FINAL REPORT
AND STUDY RESULTS

April 29, 2011

Local Capacity Technical Study
Overview and Results

I. Executive Summary

This Report documents the results and recommendations of the 2012 Local Capacity Technical (LCT) Study. The LCT Study assumptions, processes, and criteria were discussed and recommended through the 2012 Local Capacity Technical Study Criteria, Methodology and Assumptions Stakeholder Meeting held on November 10, 2010. On balance, the assumptions, processes, and criteria used for the 2012 LCT Study mirror those used in the 2007-2011 LCT Studies, which were previously discussed and recommended through the LCT Study Advisory Group ("LSAG")[1], an advisory group formed by the CAISO to assist the CAISO in its preparation for performing prior LCT Studies.

The 2012 LCT study results are provided to the CPUC for consideration in its 2012 resource adequacy requirements program. These results will also be used by the CAISO for identifying the minimum quantity of local capacity necessary to meet the North American Electric Reliability Corporation (NERC) Reliability Criteria used in the LCT Study (this may be referred to as "Local Capacity Requirements" or "LCR") and for assisting in the allocation of costs of any CAISO procurement of capacity needed to achieve the Reliability Criteria notwithstanding the resource adequacy procurement of Load Serving Entities (LSEs).[2] In this regard, the 2012 LCT Study also provides additional information on sub-area needs and effectiveness factors (where applicable) in order to allow LSEs to engage in more informed procurement.

---

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

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

Below is a comparison of the 2012 vs. 2011 total LCR:

2012 Local Capacity Requirements

	Qualifying Capacity			2012 LCR Need Based on Category B			2012 LCR Need Based on Category C with operating procedure		
Local Area Name	**QF/ Muni (MW)**	**Market (MW)**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**Existing Capacity Needed****	**Deficiency**	**Total (MW)**
Humboldt	54	168	222	159	0	**159**	190	22*	**212**
North Coast / North Bay	131	728	859	613	0	**613**	613	0	**613**
Sierra	1277	760	2037	1489	36*	**1525**	1685	289*	**1974**
Stockton	246	259	505	145	0	**145**	389	178*	**567**
Greater Bay	1312	5276	6588	3647	0	**3647**	4278	0	**4278**
Greater Fresno	356	2414	2770	1873	0	**1873**	1899	8*	**1907**
Kern	602	9	611	180	0	**180**	297	28*	**325**
LA Basin	4029	8054	12083	10865	0	**10865**	10865	0	**10865**
Big Creek/ Ventura	1191	4041	5232	3093	0	**3093**	3093	0	**3093**
San Diego	162	2925	3087	2849	0	**2849**	2849	95*	**2944**
Total	**9360**	**24634**	**33994**	**24913**	**36**	**24949**	**26158**	**620**	**26778**

2011 Local Capacity Requirements

	Qualifying Capacity			2011 LCR Need Based on Category B			2011 LCR Need Based on Category C with operating procedure		
Local Area Name	**QF/ Muni (MW)**	**Market (MW)**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**Existing Capacity Needed****	**Deficiency**	**Total (MW)**
Humboldt	57	166	223	147	0	**147**	188	17*	**205**
North Coast / North Bay	133	728	861	734	0	**734**	734	0	**734**
Sierra	1057	759	1816	1330	313*	**1643**	1510	572*	**2082**
Stockton	267	259	526	374	0	**374**	459	223*	**682**
Greater Bay	1210	5296	6506	4036	0	**4036**	4804	74*	**4878**
Greater Fresno	485	2434	2919	2200	0	**2200**	2444	4*	**2448**
Kern	699	9	708	243	0	**243**	434	13*	**447**
LA Basin	4206	8103	12309	10589	0	**10589**	10589	0	**10589**
Big Creek/ Ventura	1196	4110	5306	2786	0	**2786**	2786	0	**2786**
San Diego	194	3227	3421	3146	0	**3146**	3146	61*	**3207**
Total	**9504**	**25091**	**34595**	**25585**	**313**	**25898**	**27094**	**964**	**28058**

* No local area is “overall deficient”. Resource deficiency values result from a few deficient sub-areas; and since there are no resources that can mitigate this deficiency the numbers are carried forward into the total area needs. Resource deficient sub-area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.
** Since “deficiency” cannot be mitigated by any available resource, the “Existing Capacity Needed” will be split among LSEs on a load share ratio during the assignment of local area resource responsibility.

Overall, the LCR needs have decreased by more than 1200 MW or almost 5% from 2011 to 2012. The LCR needs have decreased in the following areas: North Coast/North Bay and Greater Bay Area due to downward trend for load; Sierra, Stockton, Fresno, Kern and San Diego due to downward trend for load and new transmission projects. The LCR needs have slightly increased in Humboldt due to load growth; LA Basin and Big Creek /Ventura due to small load growth as well as load allocation change (conform with new CEC forecast). The write-up for each Local Capacity Area lists important new projects included in the base cases as well as a description of reason for changes between 2012 and 2011 LCRs.

Table of Contents

II. Study Overview: Inputs, Outputs and Options

A. Objectives

As was the objective of the five previous annual LCT Studies, the intent of the 2012 LCT Study is to identify specific areas within the CAISO Balancing Authority Area that have limited import capability and determine the minimum generation capacity (MW) necessary to mitigate the local reliability problems in those areas.

B. Key Study Assumptions

1. Inputs and Methodology

The CAISO incorporated into its 2012 LCT study the same criteria, input assumptions and methodology that were incorporated into its previous years LCR studies. These inputs, assumptions and methodology were discussed and agreed to by stakeholders at the 2012 LCT Study Criteria, Methodology and Assumptions Stakeholder Meeting held on November 10, 2010.

The following table sets forth a summary of the approved inputs and methodology that have been used in the previous LCT studies as well as this 2012 LCT Study:

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

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

Further details regarding the 2012 LCT Study methodology and assumptions are provided in Section III, below.

C. Grid Reliability

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

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

---

[3] Pub. Utilities Code § 345

there are other levels of performance where security can be maintained without ensuring adequacy.

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

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

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

E. Performance Criteria

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

a. Performance Criteria- Category B

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

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

b. Performance Criteria- Category C

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

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

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

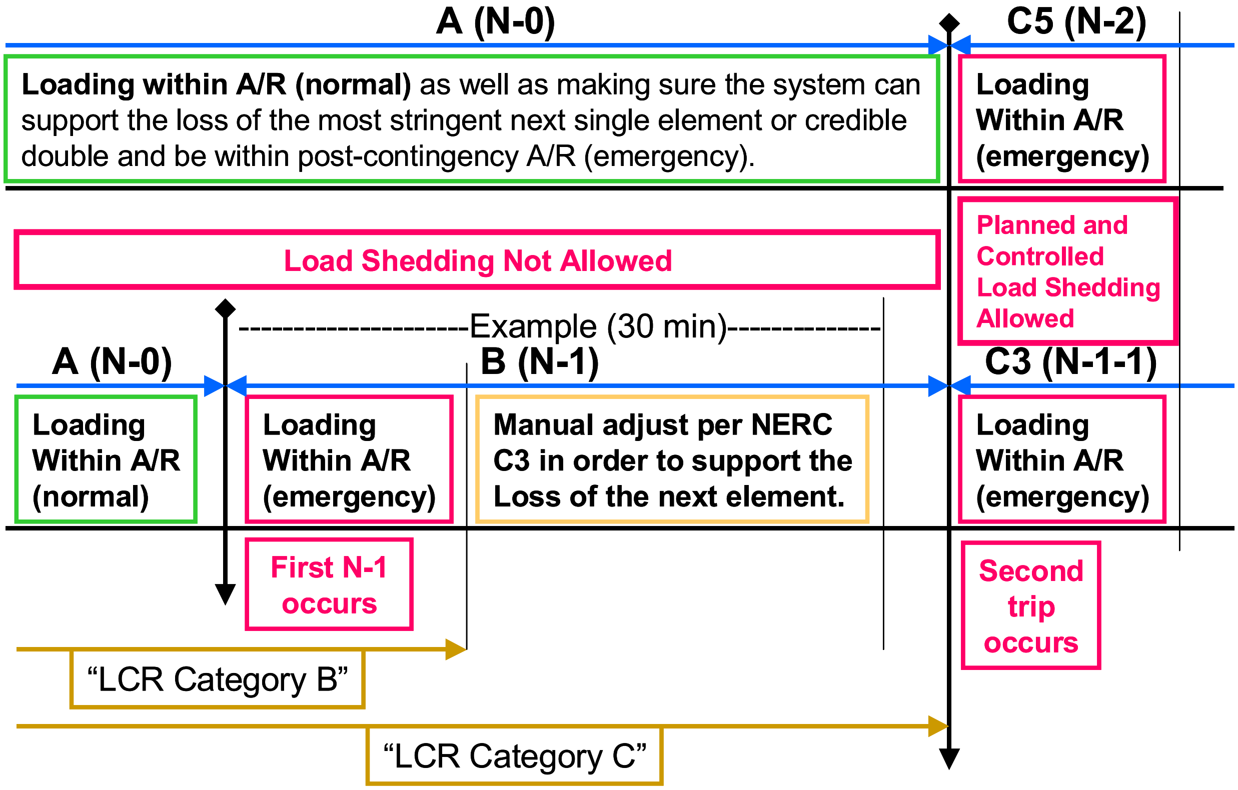
Generally, Category C describes system performance that is expected following the loss of two or more system elements. This loss of two elements is generally expected to happen simultaneously, referred to as N-2. It should be noted that once the "next" element is lost after the first contingency, as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

c. <u>CAISO Statutory Obligation Regarding Safe Operation</u>

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

---

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.



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

__Applicable Rating:__

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

Normal rating is to be used under normal conditions.

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

Short-term emergency ratings, if available, can be used as long as "system readjustment" is provided in the "short-time" available in order to reduce the flow to within the long-term emergency ratings where the element can be kept for another length of time (specific to each element) before the flow needs to be reduced the below the normal ratings. If not available long-term emergency rating should be used.

Temperature-adjusted ratings shall not be used because this is a year-ahead study not a real-time tool, as such the worst-case scenario must be covered. In case temperature-adjusted ratings are the only ratings available then the minimum rating (highest temperature) given the study conditions shall be used.

CAISO Transmission Register is the only official keeper of all existing ratings mentioned above.

Ratings for future projects provided by PTO and agree upon by the CAISO shall be used.

Other short-term ratings not included in the CAISO Transmission Register may be used as long as they are engineered, studied and enforced through clear operating procedures that can be followed by real-time operators.

Path Ratings need to be maintained in order for these studies to comply with the Minimum Operating Reliability Criteria and assure that proper capacity is available in order to operate the system in real-time.

Controlled load drop:

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

Planned load drop:

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

Special Protection Scheme:

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

System Readjustment:

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

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

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

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

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

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

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

Time allowed for manual readjustment:

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

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

F. The Two Options Presented In This LCT Report

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

1. Option 1- Meet Performance Criteria Category B

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

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

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

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

III. Assumption Details: How the Study was Conducted

A. System Planning Criteria

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

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

Table 4: Criteria Comparison

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

1 System must be able to readjust to a safe operating zone in order to be able to support the loss of the next contingency.

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

3 Evaluate for risks and consequence, per NERC standards. No voltage collapse or dynamic instability allowed.

4 Evaluate for risks and consequence, per NERC standards.

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

1. Power Flow Assessment:

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

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

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

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

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

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

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

[7] During normal operation or following the first contingency (N-1), the generation must be sufficient to allow the operators to prepare for the next worst N-1 or common mode N-2 without pre-contingency interruptible or firm load shedding. SPS/RAS/Safety Nets may be utilized to satisfy the criteria after the second N-1

or common mode N-2 except if the problem is of a thermal nature such that short-term ratings could be utilized to provide the operators time to shed either interruptible or firm load. T-2s (two transformer bank outages) would be excluded from the criteria.

2. Post Transient Load Flow Assessment:

<u>Contingencies</u> **Selected** [1]	<u>Reactive Margin Criteria</u> [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:

<u>Contingencies</u> **Selected** [1]	<u>Stability Criteria</u> [2] **Applicable Rating**

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

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

B. Load Forecast

1. System Forecast

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

2. Base Case Load Development Method

The method used to develop the base case loads is a melding process that extracts, adjusts and modifies the information from the system, distribution and municipal utility forecasts. The melding process consists of two parts: Part 1 deals with the PTO load and Part 2 deals with the municipal utility load. There may be small differences between the methodologies used by each PTO to disaggregate the CEC load forecast to their level of local area as well as bar-bus model.

a. PTO Loads in Base Case

The methods used to determine the PTO loads are, for the most part, similar. One part of the method deals with the determination of the division[6] loads that would meet the requirements of 1-in-5 or 1-in-10 system or area base cases and the other part deals with the allocation of the division load to the transmission buses.

i. Determination of division loads

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

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

ii. Allocation of division load to transmission bus level

Since the base case loads are modeled at the various transmission buses, the division loads developed must be allocated to those buses. The allocation process is different depending on the load types. For the most part, each PTO classifies its loads into four types: conforming, non-conforming, self-generation and generation-plant loads. Since the non-conforming and self-generation loads are assumed to not vary with temperature, their magnitude would be the same in the system or area base cases of the same year. The remaining load (the total division load developed above, less the quantity of non-conforming and self-generation load) is the conforming load. The remaining load is allocated to the transmission buses based on the relative magnitude of the distribution forecast. The summation of all base case loads is generally higher than the load forecast because some load, i.e., self-generation and generation-plant, are behind the meter and must be modeled in the base cases. However, for the most part, metered or aggregated data with telemetry is used to come up with the load forecast.

b. Municipal Loads in Base Case

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

C. Power Flow Program Used in the LCT analysis

The technical studies were conducted using General Electric's Power System Load Flow (GE PSLF) program version 17.0. This GE PSLF program is available directly from GE or through the Western System Electricity Council (WECC) to any member.

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

Electronic contingency files provided by the PTOs were utilized to perform the numerous contingencies required to identify the LCR. These contingency files include remedial action and special protection schemes that are expected to be in operation

during the year of study. An CAISO created EPCL (a GE programming language contained within the GE PSLF package) routine was used to run the combination of contingencies; however, other routines are available from WECC with the GE PSFL package or can be developed by third parties to identify the most limiting combination of contingencies requiring the highest amount of generation within the local area to maintain power flows within applicable ratings.

IV. Local Capacity Requirement Study Results

A. Summary of Study Results

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

Table 5: 2012 Local Capacity Needs vs. Peak Load and Local Area Generation

	2012 Total LCR (MW)	Peak Load (1 in10) (MW)	2012 LCR as % of Peak Load	Total Dependable Local Area Generation (MW)	2012 LCR as % of Total Area Generation
Humboldt	212	210	101%	222	95%**
North Coast/North Bay	613	1420	43%	859	71%
Sierra	1974	1816	109%	2037	97%**
Stockton	567	1086	52%	505	112%**
Greater Bay	4278	9954	43%	6588	65%
Greater Fresno	1907	3120	61%	2770	69%**
Kern	325	1110	29%	611	53%**
LA Basin	10865	19931	55%	12083	90%
Big Creek/Ventura	3093	4693	66%	5232	59%
San Diego	2944	4844	61%	3087	95%**
Total	**26,778**	**48184***	**56%***	**33,994**	**79%**

Table 6: 2011 Local Capacity Needs vs. Peak Load and Local Area Generation

	2011 Total LCR (MW)	Peak Load (1 in10) (MW)	2011 LCR as % of Peak Load	Total Dependable Local Area Generation (MW)	2011 LCR as % of Total Area Generation
Humboldt	205	206	100%	223	92%**
North Coast/North Bay	734	1574	47%	861	85%
Sierra	2082	1977	105%	1816	115%**
Stockton	682	1163	59%	526	130%**
Greater Bay	4878	10322	47%	6506	75%**
Greater Fresno	2448	3306	74%	2919	84%**
Kern	447	1387	32%	708	63%**
LA Basin	10589	20223	52%	12309	86%
Big Creek/Ventura	2786	4648	60%	5306	53%
San Diego	3207	5036	64%	3421	94%**
Total	**28,058**	**49842***	**56%***	**34,595**	**81%**

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

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

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

The term "Qualifying Capacity" used in this report is the latest "Net Qualifying Capacity" ("NQC") posted on the CAISO web site at:

http://www.caiso.com/1796/179688b22c970.html

The NQC list includes the area (if applicable) where each resource is located for units already operational. Neither the NQC list nor this report incorporates Demand Side Management programs and their related NQC. Units scheduled to become operational before 6/1/2012 have been included in this 2012 LCR Report and added to the total NQC values for those respective areas (see detail write-up for each area).

The first column, “Qualifying Capacity,” reflects two sets of generation. The first set is comprised of generation that would normally be expected to be on-line such as Municipal generation and Regulatory Must-take generation (state, federal, QFs, wind and nuclear units). The second set is “market” generation. The second column, “2012 LCR Requirement Based on Category B” identifies the local capacity requirements, and deficiencies that must be addressed, in order to achieve a service reliability level based on Performance Criteria- Category B. The third column, “2012 LCR Requirement Based on Category C with Operating Procedure”, sets forth the local capacity requirements, and deficiencies that must be addressed, necessary to attain a service reliability level based on Performance Criteria-Category C with operational solutions.

B. Summary of Zonal Needs

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

Zone	Load Forecast (MW)	15% reserves (MW)	(-) Allocated imports (MW)	(-) Allocated Path 26 Flow (MW)	Total Zonal Resource Need (MW)
SP26	27442	4116	-8849	-3750	**18959**
NP26=NP15+ZP26	21174	3176	-4724	-2902	**16724**

Where:

Load Forecast is the most recent 1 in 2 CEC forecast for year 2012.

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

Allocated Imports are the actual 2011 Available Import Capability for loads in the CAISO control area numbers that are not expected to change much by 2012 because there are no additional import transmission additions to the grid between now and summer of 2012.

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

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

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

Changes compared to last year's results:

- The load forecast went down in Southern California by about 800 MW and down in Northern California by about 900 MW.
- The Import Allocations went up in Southern California by about 300 MW and down in Northern California by about 150 MW.
- The Path 26 transfer capability has not changed and is not envisioned to change in the near future. As such, the LSEs should assume that their load/share ratio allocation for path 26 will stay at the same levels as 2011. If there are any changes, they will be heavily influenced by the pre-existing "grandfathered contracts" and when they expire most of the LSEs will likely see their load share ratio going up, while the owners of these grandfathered contracts may see their share decreased to the load-share ratio.

---

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

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

C. Summary of Results by Local Area

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

1. Humboldt Area

Area Definition

The transmission tie lines into the area include:

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

The substations that delineate the Humboldt Area are:

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

Total 2012 busload within the defined area: 200 MW with 10 MW of losses resulting in total load + losses of 210 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BRDGVL_7_BAKER				0.00		None	Not modeled Aug NQC	QF/Selfgen
FAIRHV_6_UNIT	31150	FAIRHAVN	13.8	14.49	1	Humboldt 60 kV	Aug NQC	QF/Selfgen

FTSWRD_7_QFUNTS				0.40		Humboldt 60 kV	Not modeled Aug NQC	QF/Selfgen
HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.76	1	None		Market
HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.76	2	None		Market
HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.76	3	None		Market
HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.77	4	None		Market
HUMBPP_6_UNITS1	31181	HUMB_G2	13.8	17.00	5	Humboldt 60 kV		Market
HUMBPP_6_UNITS1	31181	HUMB_G2	13.8	16.99	6	Humboldt 60 kV		Market
HUMBPP_6_UNITS2	31182	HUMB_G2	13.8	16.83	8	Humboldt 60 kV		Market
HUMBPP_6_UNITS2	31182	HUMB_G2	13.8	16.83	9	Humboldt 60 kV		Market
HUMBPP_6_UNITS2	31182	HUMB_G2	13.8	16.83	10	Humboldt 60 kV		Market
HUMBSB_1_QF				0.00		None	Not modeled Aug NQC	QF/Selfgen
KEKAWK_6_UNIT	31166	KEKAWAK	9.1	0.00	1	Humboldt 60 kV	Aug NQC	QF/Selfgen
LAPAC_6_UNIT	31158	LP SAMOA	12.5	20.00	1	Humboldt 60 kV		QF/Selfgen
PACLUM_6_UNIT	31152	PAC.LUMB	13.8	7.42	1	Humboldt 60 kV	Aug NQC	QF/Selfgen
PACLUM_6_UNIT	31152	PAC.LUMB	13.8	7.41	2	Humboldt 60 kV	Aug NQC	QF/Selfgen
PACLUM_6_UNIT	31153	PAC.LUMB	2.4	4.45	3	Humboldt 60 kV	Aug NQC	QF/Selfgen
WLLWCR_6_CEDRFL				0.00		Humboldt 60 kV	Not modeled Aug NQC	QF/Selfgen
HUMBPP_6_UNITS1	31181	HUMB_G2	13.8	16.60	7	Humboldt 60 kV	No NQC - Pmax	Market
ULTPBL_6_UNIT 1	31156	ULTRAPWR	12.5	0.00	1	Humboldt 60 kV	Energy Only	Market

Major new projects modeled:

1. Humboldt Bay Repower
2. Humboldt Reactive Support
3. Blue Lake generation project (energy only 0 MW NQC)

Critical Contingency Analysis Summary

Humboldt 60 kV Sub-area:

The most critical contingency for the Humboldt 60 kV Sub-area area is the outage of the Humboldt 115/60 Transformer and one of the gen tie-line connecting the new Humboldt Bay units (on 60 kV side). The area limitation is the overload on the parallel Humboldt

115/60 kV Transformer. This contingency establishes a LCR of 177 MW in 2012 (includes 54 MW of QF/Selfgen generation as well as 22 MW of deficiency) as the minimum capacity necessary for reliable load serving capability within this area.

The most critical single contingency is the outage of the Humboldt 115/60 kV Transformer. The limitation is thermal overload on the parallel Humboldt 115/60 kV Transformer. This limiting contingency establishes a LCR of 129 MW in 2012 (includes 54 MW of QF/Selfgen generation).

Effectiveness factors:

The following table has units within the Humboldt 60 kV Sub-area area with at least 5% effective to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31150	FAIRHAVN	1	73
31158	LP SAMOA	1	73
31182	HUMB_G3	10	68
31182	HUMB_G3	9	68
31182	HUMB_G3	8	68
31181	HUMB_G2	7	68
31181	HUMB_G2	6	68
31181	HUMB_G2	5	68
31180	HUMB_G1	4	-14
31180	HUMB_G1	3	-14
31180	HUMB_G1	2	-14
31180	HUMB_G1	1	-14
31152	PAC.LUMB	1	40
31152	PAC.LUMB	2	40
31153	PAC.LUMB	3	40

Humboldt overall:

The most critical contingency for the Humboldt area is the outage of the Bridgeville-Cottonwood 115 kV Line overlapping with an outage of one of the tie-line connecting the new Humboldt Bay units on the 115 kV side. The area limitation is the overload on the Humboldt – Trinity 115 kV Line. This contingency establishes a LCR of 190 MW in 2012 (includes 54 MW of QF/Selfgen generation) as the minimum capacity necessary for reliable load serving capability within this area.

For the single contingency, the most critical one is an outage of the Bridgeville-Cottonwood 115 kV Line when one of the Humboldt Bay Power Plant units connected to the 115 kV bus is out of service. The limitation is the overload on the Humboldt – Trinity 115 kV Line. This limiting contingency establishes a LCR of 159 MW in 2012 (includes 54 MW of QF/Selfgen generation).

Effectiveness factors:

The following table has units within the Humboldt Overall system with at least 5% effective to the above-mentioned constraint

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31150	FAIRHAVN	1	58
31158	LP SAMOA	1	58
31182	HUMB_G3	10	57
31182	HUMB_G3	9	57
31182	HUMB_G3	8	57
31181	HUMB_G2	7	57
31181	HUMB_G2	6	57
31181	HUMB_G2	5	57
31180	HUMB_G1	4	59
31180	HUMB_G1	3	59
31180	HUMB_G1	2	59
31180	HUMB_G1	1	59
31152	PAC.LUMB	1	52
31152	PAC.LUMB	2	52
31153	PAC.LUMB	3	52

Changes compared to last year's results:

The Humboldt Repowering Project (HBPP) was modeled an on-line in both 2011 and 2012 LCR studies. Two new transmission projects, the Maple Creek and Garberville Reactive support projects were modeled in 2011 studies, but not in 2012 because these projects were delayed past the 2012 peak. The overall load is expected to increase by 4 MW from 2011 to 2012 the overall LCR need has increased by 6 MW and the LCR resource need increased by 2 MW. The limiting outage and limiting facilities were the same as in the 2011 LCR.

Humboldt Overall Requirements:

2012	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	54	0	168	222

2012	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[9]	159	0	159
Category C (Multiple)[10]	190	22	212

2. North Coast / North Bay Area

<u>Area Definition</u>

The North Coast/North Bay Area is composed of three sub-areas and the generation requirements within them. The transmission tie facilities coming into the North Coast/North Bay area are:

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

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

1) Cortina is out Mendocino and Indian Valley are in
2) Cortina is out, Eagle Rock, Highlands and Homestake are in
3) Willits and Lytonville are in, Garberville and Kekawaka are out
4) Vaca Dixon is out Lakeville is in

[9] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.
[10] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

5) Tulucay is in Vaca Dixon is out
6) Lakeville is in, Sobrante is out
7) Ignacio is in, Sobrante and Crocket are out

Total 2012 busload within the defined area: 1386 MW with 34 MW of losses resulting in total load + losses of 1420 MW.

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

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ADLIN_1_UNITS	31435	GEO.ENGY	9.1	8.00	1	Eagle Rock, Fulton, Lakeville		Market
ADLIN_1_UNITS	31435	GEO.ENGY	9.1	8.00	2	Eagle Rock, Fulton, Lakeville		Market
BEARCN_2_UNITS	31402	BEAR CAN	13.8	6.50	1	Fulton, Lakeville		Market
BEARCN_2_UNITS	31402	BEAR CAN	13.8	6.50	2	Fulton, Lakeville		Market
FULTON_1_QF				0.05		Fulton, Lakeville	Not modeled Aug NQC	QF/Selfgen
GEYS11_7_UNIT11	31412	GEYSER11	13.8	60.00	1	Eagle Rock, Fulton, Lakeville		Market
GEYS12_7_UNIT12	31414	GEYSER12	13.8	50.00	1	Fulton, Lakeville		Market
GEYS13_7_UNIT13	31416	GEYSER13	13.8	56.00	1	Lakeville		Market
GEYS14_7_UNIT14	31418	GEYSER14	13.8	50.00	1	Fulton, Lakeville		Market
GEYS16_7_UNIT16	31420	GEYSER16	13.8	49.00	1	Fulton, Lakeville		Market
GEYS17_2_BOTRCK	31421	BOTTLERK	13.8	14.70	1	Fulton, Lakeville		Market
GEYS17_7_UNIT17	31422	GEYSER17	13.8	47.00	1	Fulton, Lakeville		Market
GEYS18_7_UNIT18	31424	GEYSER18	13.8	45.00	1	Lakeville		Market
GEYS20_7_UNIT20	31426	GEYSER20	13.8	40.00	1	Lakeville		Market
GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	40.00	1	Eagle Rock, Fulton, Lakeville		Market
GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	40.00	2	Eagle Rock, Fulton, Lakeville		Market
GYS7X8_7_UNITS	31408	GEYSER78	13.8	38.00	1	Eagle Rock, Fulton, Lakeville		Market

GYS7X8_7_UNITS	31408	GEYSER78	13.8	38.00	2	Eagle Rock, Fulton, Lakeville		Market
GYSRVL_7_WSPRNG				1.68		Fulton, Lakeville	Not modeled Aug NQC	QF/Selfgen
HIWAY_7_ACANYN				1.04		Lakeville	Not modeled Aug NQC	QF/Selfgen
IGNACO_1_QF				0.00		Lakeville	Not modeled Aug NQC	QF/Selfgen
INDVLY_1_UNITS	31436	INDIAN V	9.1	0.81	1	Eagle Rock, Fulton, Lakeville	Aug NQC	QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	3.90	1	Fulton, Lakeville	Aug NQC	QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	3.90	2	Fulton, Lakeville	Aug NQC	QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	0.93	3	Fulton, Lakeville	Aug NQC	QF/Selfgen
NAPA_2_UNIT				0.02		Lakeville	Not modeled Aug NQC	QF/Selfgen
NCPA_7_GP1UN1	38106	NCPA1GY1	13.8	31.00	1	Lakeville	Aug NQC	MUNI
NCPA_7_GP1UN2	38108	NCPA1GY2	13.8	28.00	1	Lakeville	Aug NQC	MUNI
NCPA_7_GP2UN3	38110	NCPA2GY1	13.8	0.00	1	Fulton, Lakeville	Aug NQC	MUNI
NCPA_7_GP2UN4	38112	NCPA2GY2	13.8	52.73	1	Fulton, Lakeville	Aug NQC	MUNI
POTTER_6_UNITS	31433	POTTRVLY	2.4	4.70	1	Eagle Rock, Fulton, Lakeville	Aug NQC	Market
POTTER_6_UNITS	31433	POTTRVLY	2.4	2.25	3	Eagle Rock, Fulton, Lakeville	Aug NQC	Market
POTTER_6_UNITS	31433	POTTRVLY	2.4	2.25	4	Eagle Rock, Fulton, Lakeville	Aug NQC	Market
POTTER_7_VECINO				0.02		Eagle Rock, Fulton, Lakeville	Not modeled Aug NQC	QF/Selfgen
SANTFG_7_UNITS	31400	SANTA FE	13.8	30.00	1	Lakeville		Market
SANTFG_7_UNITS	31400	SANTA FE	13.8	30.00	2	Lakeville		Market
SMUDGO_7_UNIT 1	31430	SMUDGEO1	13.8	37.00	1	Lakeville		Market
SNMALF_6_UNITS	31446	SONMA LF	9.1	5.15	1	Fulton, Lakeville	Aug NQC	QF/Selfgen
UKIAH_7_LAKEMN				1.70		Eagle Rock, Fulton, Lakeville	Not modeled	MUNI
WDFRDF_2_UNITS	31404	WEST FOR	13.8	12.51	1	Fulton, Lakeville		Market
WDFRDF_2_UNITS	31404	WEST FOR	13.8	12.49	2	Fulton, Lakeville		Market

Major new projects modeled: None

Critical Contingency Analysis Summary

Eagle Rock Sub-area

The most critical overlapping contingency is the outage of the Cortina-Mendocino 115 kV line overlapping with an outage of the Fulton-Lakeville 230 kV line. The sub-area area limitation is thermal overloading of the Eagle Rock-Cortina 115 kV line. This limiting contingency establishes a LCR of 207 MW in 2012 (includes 1 MW of QF/MUNI generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the outage of the Cortina-Mendocino 115 kV line. The sub-area area limitation is thermal overloading of the Eagle Rock-Cortina 115 kV line. This limiting contingency establishes a LCR of 166 MW in 2012 (includes 1 MW of QF/MUNI generation).

Effectiveness factors:

All the units within the Eagle-Rock sub-area have the same effectiveness to the described constraints. Units outside this area are not effective.

Fulton Sub-area

The most critical overlapping contingency is the outage of the Lakeville-Fulton 230 kV line #1 and the Fulton-Ignacio 230 kV line #1. The sub-area area limitation is thermal overloading of Santa Rosa-Corona 115 kV line #1. This limiting contingency establishes a LCR of 293 MW (includes 16 MW of QF and 54 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area. All of the resources needed to meet the Eagle Rock sub-area count towards the Fulton sub-area LCR need.

Effectiveness factors:

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

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

Lakeville Sub-area

The most limiting contingency is the outage of Vaca Dixon-Tulucay 230 kV line with DEC power plant out of service. The sub-area limitation is thermal overloading of the Vaca Dixon-Lakeville 230 kV. This limiting contingency establishes a LCR of 613 MW (includes 18 MW of QF and 113 MW of MUNI generation) as the minimum capacity necessary for reliable load serving capability within this sub-area. The LCR resources needed for Eagle Rock and Fulton sub-areas can be counted toward fulfilling the requirement of Lakeville sub-area.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31400	SANTA FE	2	37
31430	SMUDGEO1	1	37
31400	SANTA FE	1	37
31416	GEYSER13	1	37
31424	GEYSER18	1	37

31426	GEYSER20	1	37
38106	NCPA1GY1	1	37
38108	NCPA1GY2	1	37
31421	BOTTLERK	1	35
31404	WEST FOR	2	35
31402	BEAR CAN	1	35
31402	BEAR CAN	2	35
31404	WEST FOR	1	35
31414	GEYSER12	1	35
31418	GEYSER14	1	35
31420	GEYSER16	1	35
31422	GEYSER17	1	35
38110	NCPA2GY1	1	35
38112	NCPA2GY2	1	35
31406	GEYSR5-6	1	19
31406	GEYSR5-6	2	19
31408	GEYSER78	1	19
31408	GEYSER78	2	19
31412	GEYSER11	1	19
31435	GEO.ENGY	1	19
31435	GEO.ENGY	2	19

Changes compared to last year's results:

Overall the load forecast went down by 154 MW for 2012 compared with last year load forecast for 2011 and the LCR need went down by 121 MW.

North Coast/North Bay Overall Requirements:

2012	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	18	113	728	859

2012	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[11]	613	0	613
Category C (Multiple)[12]	613	0	613

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

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

3. Sierra Area

Area Definition

The transmission tie lines into the Sierra Area are:

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

The substations that delineate the Sierra Area are:

1) Table Mountain is out Rio Oso is in
2) Table Mountain is out Palermo is in
3) Table Mt is out Pease is in
4) Caribou is out Palermo is in
5) Drum is in Summit is out
6) Drum is in Summit is out
7) Spaulding is in Summit is out
8) Brighton is in Bellota is out
9) Rio Oso is in Lockeford is out
10) Gold Hill is in Eight Mile is out
11) Lodi STIG is in Eight Mile Road is out
12) Gold Hill is in Lake is out

Total 2012 busload within the defined area: 1713 MW with 103 MW of losses resulting in total load + losses of 1816 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BELDEN_7_UNIT 1	31784	BELDEN	13.8	115.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
BIOMAS_1_UNIT 1	32156	WOODLAND	9.1	21.64	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
BNNIEN_7_ALTAPH	32376	BONNIE N	60	0.63		Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
BOGUE_1_UNITA1	32451	FREC	13.8	45.00	1	Bogue, Drum-Rio Oso, South of Table Mountain	Aug NQC	Market
BOWMN_6_UNIT	32480	BOWMAN	9.1	2.41	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
BUCKCK_7_OAKFLT				1.06		South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
BUCKCK_7_PL1X2	31820	BCKS CRK	11	29.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
BUCKCK_7_PL1X2	31820	BCKS CRK	11	29.00	2	South of Palermo, South of Table Mountain	Aug NQC	Market
CHICPK_7_UNIT 1	32462	CHI.PARK	11.5	38.00	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI

COLGAT_7_UNIT 1	32450	COLGATE1	13.8	161.65	1	South of Table Mountain	Aug NQC	MUNI
COLGAT_7_UNIT 2	32452	COLGATE2	13.8	161.68	1	South of Table Mountain	Aug NQC	MUNI
CRESTA_7_PL1X2	31812	CRESTA	11.5	35.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
CRESTA_7_PL1X2	31812	CRESTA	11.5	35.00	2	South of Palermo, South of Table Mountain	Aug NQC	Market
DAVIS_7_MNMETH				2.11		Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
DEADCK_1_UNIT	31862	DEADWOOD	9.1	0.00	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
DEERCR_6_UNIT 1	32474	DEER CRK	9.1	3.78	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DRUM_7_PL1X2	32504	DRUM 1-2	6.6	13.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DRUM_7_PL1X2	32504	DRUM 1-2	6.6	13.00	2	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DRUM_7_PL3X4	32506	DRUM 3-4	6.6	13.70	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DRUM_7_PL3X4	32506	DRUM 3-4	6.6	13.70	2	Drum-Rio Oso, South of Palermo,	Aug NQC	Market

						South of Table Mountain		
DRUM_7_UNIT 5	32454	DRUM 5	13.8	49.50	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DUTCH1_7_UNIT 1	32464	DTCHFLT1	11	22.00	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DUTCH2_7_UNIT 1	32502	DTCHFLT2	6.9	26.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
ELDORO_7_UNIT 1	32513	ELDRADO1	21.6	11.00	1	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain		Market
ELDORO_7_UNIT 2	32514	ELDRADO2	21.6	11.00	1	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain		Market
FMEADO_6_HELLHL	32486	HELLHOLE	9.1	0.36	1	South of Rio Oso, Soth of Palermo, South of Table Mountain	Aug NQC	MUNI
FMEADO_7_UNIT	32508	FRNCH MD	4.2	16.01	1	South of Rio Oso, Soth of Palermo, South of Table Mountain	Aug NQC	MUNI
FORBST_7_UNIT 1	31814	FORBSTWN	11.5	39.00	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
GOLDHL_1_QF				0.00		Placerville, South of	Not modeled	QF/Selfgen

						Rio Oso, South of Palermo, South of Table Mountain		
GRNLF1_1_UNITS	32490	GRNLEAF1	13.8	6.19	1	Bogue, Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
GRNLF1_1_UNITS	32490	GRNLEAF1	13.8	31.65	2	Bogue, Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
GRNLF2_1_UNIT	32492	GRNLEAF2	13.8	35.29	1	Pease, Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
HALSEY_6_UNIT	32478	HALSEY F	9.1	6.71	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
HAYPRS_6_QFUNTS	32488	HAYPRES+	9.1	0.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
HAYPRS_6_QFUNTS	32488	HAYPRES+	9.1	0.00	2	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
HIGGNS_7_QFUNTS				0.04		Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	QF/Selfgen
KANAKA_1_UNIT				0.00		Drum-Rio Oso, South of Table Mountain	Not modeled Aug NQC	MUNI
KELYRG_6_UNIT	31834	KELLYRDG	9.1	10.00	1	Drum-Rio Oso, South of Table	Aug NQC	MUNI

						Mountain		
MDFKRL_2_PROJCT	32456	MIDLFORK	13.8	62.18	1	South of Rio Oso, Soth of Palermo, South of Table Mountain	Aug NQC	MUNI
MDFKRL_2_PROJCT	32458	RALSTON	13.8	84.32	1	South of Rio Oso, Soth of Palermo, South of Table Mountain	Aug NQC	MUNI
MDFKRL_2_PROJCT	32456	MIDLFORK	13.8	62.18	2	South of Rio Oso, Soth of Palermo, South of Table Mountain	Aug NQC	MUNI
NAROW1_2_UNIT	32466	NARROWS1	9.1	2.98	1	Colgate, South of Table Mountain	Aug NQC	Market
NAROW2_2_UNIT	32468	NARROWS2	9.1	20.52	1	Colgate, South of Table Mountain	Aug NQC	MUNI
NWCSTL_7_UNIT 1	32460	NEWCSTLE	13.2	0.00	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
OROVIL_6_UNIT	31888	OROVLLE	9.1	4.71	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
OXBOW_6_DRUM	32484	OXBOW F	9.1	6.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
PACORO_6_UNIT	31890	PO POWER	9.1	7.97	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
PACORO_6_UNIT	31890	PO POWER	9.1	7.97	2	Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen

PLACVL_1_CHILIB	32510	CHILIBAR	4.2	2.30	1	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PLACVL_1_RCKCRE				0.00		Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
PLSNTG_7_LNCLND	32408	PLSNT GR	60	0.72		Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
POEPH_7_UNIT 1	31790	POE 1	13.8	60.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
POEPH_7_UNIT 2	31792	POE 2	13.8	60.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
RCKCRK_7_UNIT 1	31786	ROCK CK1	13.8	56.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
RCKCRK_7_UNIT 2	31788	ROCK CK2	13.8	56.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
RIOOSO_1_QF				0.94		Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	QF/Selfgen
ROLLIN_6_UNIT	32476	ROLLINSF	9.1	11.09	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
SLYCRK_1_UNIT 1	31832	SLY.CR.	9.1	10.36	1	Drum-Rio Oso, South of Table	Aug NQC	MUNI

						Mountain		
SPAULD_6_UNIT 3	32472	SPAULDG	9.1	5.47	3	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
SPAULD_6_UNIT12	32472	SPAULDG	9.1	4.96	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
SPAULD_6_UNIT12	32472	SPAULDG	9.1	4.96	2	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
SPI LI_2_UNIT 1	32498	SPILINCF	12.5	10.55	1	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
STIGCT_2_LODI	38114	Stig CC	13.8	49.50	1	South of Rio Oso, Soth of Palermo, South of Table Mountain		MUNI
ULTRCK_2_UNIT	32500	ULTR RCK	9.1	19.12	1	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
WDLEAF_7_UNIT 1	31794	WOODLEAF	13.8	55.00	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
WHEATL_6_LNDFIL	32350	WHEATLND	60	1.20		Colgate, South of Table Mountain	Not modeled Aug NQC	Market
WISE_1_UNIT 1	32512	WISE	12	9.84	1	Placer, Drum-Rio Oso, South of Rio Oso, South of	Aug NQC	Market

						Palermo, South of Table Mountain		
WISE_1_UNIT 2	32512	WISE	12	0.22	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
YUBACT_1_SUNSWT	32494	YUBA CTY	9.1	26.26	1	Pease, Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
YUBACT_6_UNITA1	32496	YCEC	13.8	46.00	1	Pease, Drum-Rio Oso, South of Table Mountain		Market
CAMPFW_7_FARWST	32470	CMP.FARW	9.1	4.60	1	Colgate, South of Table Mountain	No NQC - hist. data	MUNI
NA	32162	RIV.DLTA	9.11	0.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	No NQC - hist. data	QF/Selfgen
UCDAVS_1_UNIT	32166	UC DAVIS	9.1	3.50	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	No NQC - hist. data	QF/Selfgen
New unit	38123	Q267CT1	18	166.00	1	South of Rio Oso, Soth of Palermo, South of Table Mountain	No NQC - Pmax	MUNI
New unit	38124	Q267ST1	18	114.00	1	South of Rio Oso, Soth of Palermo, South of Table Mountain	No NQC - Pmax	MUNI

Major new projects modeled:

1. Table Mountain-Rio Oso Reconductor and Tower Upgrade
2. Atlantic-Lincoln 115 kV Transmission Upgrade

3. Gold Hill – Horseshoe 115 kV line Reconductoring
4. Palermo-Rio Oso 115 kV Reconductoring
5. Lodi Energy Center

<u>Critical Contingency Analysis Summary</u>

South of Table Mountain Sub-area

The most critical contingency is the loss of the Table Mountain-Rio Oso 230 kV and Table Mountain-Palermo double circuit tower line outage. The area limitation is thermal overloading of the Caribou-Palermo 115 kV line. This limiting contingency establishes in 2012 a LCR of 1399 MW (includes 176 MW of QF and 1101 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this area.

The units required for the South of Palermo sub-area satisfy the category B requirement for this sub-area.

Effectiveness factors:

The following table has all units in Sierra area and their effectiveness factor to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	Eff Fctr. (%)
31814	FORBSTWN	1	8
31794	WOODLEAF	1	8
31832	SLY.CR.	1	7
31862	DEADWOOD	1	7
31888	OROVLLE	1	6
31890	PO POWER	2	6
31890	PO POWER	1	6
31834	KELLYRDG	1	6
32452	COLGATE2	1	5
32450	COLGATE1	1	5
32466	NARROWS1	1	5
32468	NARROWS2	1	5
32470	CMP.FARW	1	5
32451	FREC	1	5
32490	GRNLEAF1	2	4
32490	GRNLEAF1	1	4
32496	YCEC	1	3
32494	YUBA CTY	1	3

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

Colgate Sub-area

No requirements due to the addition of the Atlantic-Lincoln 115 kV transmission upgrade project. If this project is delayed all units within this area (Narrows #1 & #2 and Camp Far West) are needed.

Pease Sub-area

The most critical contingency is the loss of the Palermo-East Nicolaus 115 kV line with Green Leaf II Cogen unit out of service. The area limitation is thermal overloading of the Palermo-Pease 115 kV line. This limiting contingency establishes a LCR of 103 MW (includes 62 MW of QF generation) in 2012 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area (Greenleaf #2, Yuba City and Yuba City EC) have the same effectiveness factor.

Bogue Sub-area

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

South of Palermo Sub-area

The most critical contingency is the loss of the Double Circuit Tower Line Table Mountain-Rio Oso and Colgate-Rio Oso 230 kV lines. The area limitation is thermal overloading of the Pease-Rio Oso 115 kV line. This limiting contingency establishes a LCR of 1626 MW (includes 694 MW of QF and Muni generation as well as 268 MW of deficiency) in 2012 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the loss of the Palermo- East Nicolaus 115 kV line with Belden unit out of service. The area limitation is thermal overloading of the Pease-Rio Oso 115 kV line. This contingency establishes in 2012 a LCR of 1394 MW (includes 694 MW of QF and Muni generation as well as 36 MW of deficiency).

Effectiveness factors:

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

Placerville Sub-area

The most critical contingency is the loss of the Gold Hill-Clarksville 115 kV line followed by loss of the Gold Hill-Missouri Flat #2 115 kV line. The area limitation is thermal overloading of the Gold Hill-Missouri Flat #1 115 kV line. This limiting contingency establishes a LCR of 81 MW (includes 0 MW of QF and Muni generation as well as 57 MW of deficiency) in 2012 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area (El Dorado units 1&2 and Chili Bar) are needed therefore no effectiveness factor is required.

Placer Sub-area

The most critical contingency is the loss of the Gold Hill-Placer #1 115 kV line followed by loss of the Gold Hill-Placer #2 115 kV line. The area limitation is thermal overloading of the Drum-Higgins 115 kV line. This limiting contingency establishes a LCR of 75 MW (includes 0 MW of QF and Muni generation) in 2012 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency is the loss of the Gold Hill-Placer #2 115 kV line with Chicago Park unit out of service. The area limitation is thermal overloading of the Drum-Higgins 115 kV line. This limiting contingency establishes a local capacity need of 44 MW (includes 0 MW of QF and Muni generation) in 2012 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area (Chicago Park, Dutch Flat#1, Wise units 1&2, Newcastle and Halsey) have the same effectiveness factor.

Drum-Rio Oso Sub-area

The most critical contingency is the loss of the Rio Oso #2 230/115 transformer followed by loss of the Rio Oso-Brighton 230 kV line. The area limitation is thermal overloading of the Rio Oso #1 230/115 kV transformer. This limiting contingency establishes in 2012 a LCR of 625 MW (includes 374 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency is the loss of the Rio Oso #2 230/115 transformer. The area limitation is thermal overloading of the Rio Oso #1 230/115 kV transformer. This limiting contingency establishes in 2012 a LCR of 254 MW (includes 374 MW of QF and Muni generation).

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr. (%)
32156	WOODLAND	1	22
32490	GRNLEAF1	1	22
32490	GRNLEAF1	2	22
32451	FREC	1	21
32166	UC DAVIS	1	18
32498	SPILINCF	1	15
32502	DTCHFLT2	1	15
32494	YUBA CTY	1	14
32496	YCEC	1	14
32492	GRNLEAF2	1	13
32454	DRUM 5	1	13
32476	ROLLINSF	1	13
32474	DEER CRK	1	13
32504	DRUM 1-2	1	13
32504	DRUM 1-2	2	13
32506	DRUM 3-4	1	13
32506	DRUM 3-4	2	13
32484	OXBOW F	1	13
32472	SPAULDG	3	12

32472	SPAULDG	1	12
32472	SPAULDG	2	12
32488	HAYPRES+	1	12
32480	BOWMAN	1	12
32488	HAYPRES+	2	12
32464	DTCHFLT1	1	11
32162	RIV.DLTA	1	11
32462	CHI.PARK	1	9
32500	ULTR RCK	1	6
31862	DEADWOOD	1	5
31814	FORBSTWN	1	5
31832	SLY.CR.	1	5
31794	WOODLEAF	1	5
32478	HALSEY F	1	2
31888	OROVLLE	1	2
32512	WISE	1	2
31834	KELLYRDG	1	2
31890	PO POWER	1	2
31890	PO POWER	2	2
32460	NEWCSTLE	1	1

South of Rio Oso Sub-area

The most critical contingency is the loss of the Rio Oso-Gold Hill 230 line followed by loss of the Rio Oso-Lincoln 115 kV line or vice versa. The area limitation is thermal overloading of the Rio Oso-Atlantic 230 kV line. This limiting contingency establishes a LCR of 630 MW (includes 622 MW of QF and Muni) in 2012 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency is the loss of the Rio Oso-Gold Hill 230 line with the Ralston unit out of service. The area limitation is thermal overloading of the Rio Oso-Atlantic 230 kV line. This limiting contingency establishes a LCR of 453 MW (includes 622 MW of QF and Muni generation) in 2012.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr. (%)
32498	SPILINCF	1	49
32500	ULTR RCK	1	49
32456	MIDLFORK	1	33

32456	MIDLFORK	2	33
32458	RALSTON	1	33
32513	ELDRADO1	1	32
32514	ELDRADO2	1	32
32510	CHILIBAR	1	32
32486	HELLHOLE	1	31
32508	FRNCH MD	1	30
32460	NEWCSTLE	1	26
32478	HALSEY F	1	24
32512	WISE	1	24
38114	Stig CC	1	14
38123	Q267CT	1	14
38124	Q267ST	1	14
32462	CHI.PARK	1	8
32464	DTCHFLT1	1	4

Changes compared to last year's results:

Overall the Sierra Area load forecast went down by 161 MW. Along with a few new transmission projects there is also one new power plant (Lodi Energy Center) modeled within the Sierra LCR area. As a result, the existing generation capacity needed is increased by 175 MW. As such, the magnitude of the deficiency has significantly reduced because of this resource addition.

Sierra Overall Requirements:

2012	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	176	1101	760	2037

2012	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[13]	1489	36	1525
Category C (Multiple)[14]	1685	289	1974

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

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

4. Stockton Area

Area Definition

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

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

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

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

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

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

The substations that delineate the Lockeford Sub-area are:

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

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

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

3) Weber 230/60 kV Transformer #2a

The substations that delineate the Weber Sub-area are:

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

Total 2011 busload within the defined area: 1067 MW with 19 MW of losses resulting in total load + losses of 1086 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BEARDS_7_UNIT 1	34074	BEARDSLY	6.9	8.36	1	Tesla-Bellota	Aug NQC	MUNI
COGNAT_1_UNIT	33818	COG.NTNL	12	25.46	1	Weber	Aug NQC	QF/Selfgen
CURIS_1_QF				0.49		Tesla-Bellota	Not modeled Aug NQC	QF/Selfgen
DONNLS_7_UNIT	34058	DONNELLS	13.8	72.00	1	Tesla-Bellota	Aug NQC	MUNI
LODI25_2_UNIT 1	38120	LODI25CT	9.11	22.70	1	Lockeford		MUNI
PHOENX_1_UNIT				1.46		Tesla-Bellota	Not modeled Aug NQC	Market
SCHLTE_1_UNITA1	33805	GWFTRCY1	13.8	83.56	1	Tesla-Bellota		Market
SCHLTE_1_UNITA2	33807	GWFTRCY2	13.8	82.88	1	Tesla-Bellota		Market
SNDBAR_7_UNIT 1	34060	SANDBAR	13.8	10.67	1	Tesla-Bellota	Aug NQC	MUNI
SPIFBD_1_PL1X2	33917	FBERBORD	115	2.28	1	Tesla-Bellota	Aug NQC	QF/Selfgen
SPRGAP_1_UNIT 1	34078	SPRNG GP	6	0.02	1	Tesla-Bellota	Aug NQC	Market
STANIS_7_UNIT 1	34062	STANISLS	13.8	91.00	1	Tesla-Bellota	Aug NQC	Market
STNRES_1_UNIT	34056	STNSLSRP	13.8	15.72	1	Tesla-Bellota	Aug NQC	QF/Selfgen
STOKCG_1_UNIT 1	33814	CPC STCN	12.5	42.74	1	Tesla-Bellota	Aug NQC	QF/Selfgen
TULLCK_7_UNITS	34076	TULLOCH	6.9	8.23	1	Tesla-Bellota	Aug NQC	MUNI
TULLCK_7_UNITS	34076	TULLOCH	6.9	8.24	2	Tesla-Bellota	Aug NQC	MUNI
ULTPCH_1_UNIT 1	34050	CH.STN.	13.8	13.34	1	Tesla-Bellota	Aug NQC	QF/Selfgen
VLYHOM_7_SSJID				1.39		Tesla-Bellota	Not modeled Aug NQC	QF/Selfgen
CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	3.50	1	Tesla-Bellota	No NQC - hist. data	MUNI

CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	3.50	2	Tesla-Bellota	No NQC - hist. data	MUNI
CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	3.50	3	Tesla-Bellota	No NQC - hist. data	MUNI
NA	33687	STKTN WW	60	1.50	1	Weber	No NQC - hist. data	QF/Selfgen
NA	33830	GEN.MILL	9.11	2.50	1	Lockeford	No NQC - hist. data	QF/Selfgen

Major new projects modeled:

1. Tesla 115 kV Capacity Increase
2. Tesla-Schulte, Lammer-Kasson & Schulte-Lammers Tower Raise Project
3. Weber-Stockton “A” #1 & #2 60 kV Reconductoring

Critical Contingency Analysis Summary

Stockton overall

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

Tesla-Bellota Sub-area

The two most critical contingencies listed below together establish a local capacity need of 451 MW (includes 76 MW of QF and 118 MW of Muni generation as well as 114 MW of deficiency) in 2012 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical contingency for the Tesla-Bellota pocket is the loss of Tesla-Tracy 115 kV and Schulte-Lammers 115 kV. The area limitation is thermal overload of the Tesla-Kasson-Manteca 115 kV line above its emergency rating. This limiting contingency establishes a local capacity need of 401 MW (includes 76 MW of QF and 118 MW of Muni generation as well as 114 MW of deficiency) in 2012.

The second most critical contingency for the Tesla-Bellota pocket is the loss of Tesla-Tracy 115 kV and Tesla-Kasson-Manteca 115 kV. The area limitation is thermal overload of the Tesla-Schulte 115 kV line. This limiting contingency establishes a 2012 local capacity need of 337 MW (includes 76 MW of QF and 118 MW of Muni generation).

The single most critical contingency for the Tesla-Bellota pocket is the loss of Tesla-Tracy 115 kV line and the loss of the Stanislaus unit #1. The area limitation is thermal overload of the Tesla-Schulte 115 kV line. This single contingency establishes a local capacity need of 123 MW (includes 194 MW of QF and Muni generation) in 2012.

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

Lockeford Sub-area
The critical contingency for the Lockeford area is the loss of Lockeford-Industrial 60 kV circuit and Lockeford-Lodi #2 60 kV circuit. The area limitation is thermal overloading of the Lockeford-Lodi Jct. section of the Lockeford-Lodi #3 60 kV circuit. This limiting contingency establishes a 2012 local capacity need of 55 MW (including 2 MW of QF and 23 MW of Muni generation as well as 30 MW of deficiency) as the minimum capacity necessary for reliable load serving capability within this area.

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

Weber Sub-area
The critical contingency for the Weber area is the loss of the Weber 230/60 kV Transformer #1 with the Cogeneration National out of service. The area limitation is thermal overloading of the remaining Weber 230/60 kV Transformers #2 & #2a. This limiting contingency establishes a local capacity need of 61 MW (including 27 MW of QF and Muni generation as well as a deficiency of 34 MW) in 2012 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency for this sub-area is the loss of Weber 230/60 kV Transformer #1. The area limitation is thermal overloading of the remaining Weber 230/60 kV Transformers #2 & #2a. This limiting contingency establishes a local capacity need of 22 MW (including 27 MW of QF and Muni generation) in 2012.

Effectiveness factors:

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

Changes compared to last year's results:

Overall the Stockton area load forecast went down by 77 MW. There are also two new transmission upgrades (Tesla-Schulte, Lammer-Kasson & Schulte-Lammers Tower Raise Project & Weber-Stockton "A" #1 & #2 60 kV Reconductoring) modeled in the Stockton LCR area this year. As a result, the overall requirement for the Stockton area went down by 126 MW.

Stockton Overall Requirements:

2012	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	105	141	259	505

2012	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[15]	145	0	145
Category C (Multiple)[16]	389	178	567

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

---

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

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

5) Lambie SW Sta-Vaca Dixon 230 kV
6) Peabody-Birds Landing SW Sta 230 kV
7) Tesla-Kelso 230 kV
8) Tesla-Delta Switching Yard 230 kV
9) Tesla-Pittsburg #1 230 kV
10) Tesla-Pittsburg #2 230 kV
11) Tesla-Newark #1 230 kV
12) Tesla-Newark #2 230 kV
13) Tesla-Ravenswood 230 kV
14) Tesla-Metcalf 500 kV
15) Moss Landing-Metcalf 500 kV
16) Moss Landing-Metcalf #1 230 kV
17) Moss Landing-Metcalf #2 230 kV
18) Oakdale TID-Newark #1 115 kV
19) Oakdale TID-Newark #2 115 kV

The substations that delineate the Greater Bay Area are:

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

Total 2012 bus load within the defined area is 9493 MW with 197 MW of losses and 264 MW of pumps resulting in total load + losses + pumps of 9954 MW. This corresponds to about 9355 MW of load per CEC forecast since there are about 600 MW of loads behind the meter modeled in the base cases.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ALMEGT_1_UNIT 1	38118	ALMDACT1	13.8	23.80	1	Oakland		MUNI
ALMEGT_1_UNIT 2	38119	ALMDACT2	13.8	24.40	1	Oakland		MUNI
BANKPP_2_NSPIN	38820	DELTA A	13.2	9.00	1	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38820	DELTA A	13.2	9.00	2	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38820	DELTA A	13.2	22.00	3	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38815	DELTA B	13.2	28.00	4	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38815	DELTA B	13.2	28.00	5	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38770	DELTA C	13.2	28.00	6	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38770	DELTA C	13.2	28.00	7	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38765	DELTA D	13.2	28.00	8	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38765	DELTA D	13.2	28.00	9	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38760	DELTA E	13.2	28.00	10	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38760	DELTA E	13.2	28.00	11	Contra Costa	Pumps	MUNI
BLHVN_7_MENLOP				1.16		None	Not modeled Aug NQC	QF/Selfgen
BRDSLD_2_HIWIND	32172	HIGHWINDS	34.5	34.53	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_SHILO1	32176	SHILOH	34.5	37.11	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_SHILO2	32177	SHILO	34.5	36.03	2	Contra Costa	Aug NQC	Wind
CALPIN_1_AGNEW	35860	OLS-AGNE	9.11	22.35	1	San Jose	Aug NQC	QF/Selfgen
CARDCG_1_UNITS	33463	CARDINAL	12.5	11.04	1	None	Aug NQC	QF/Selfgen
CARDCG_1_UNITS	33463	CARDINAL	12.5	11.04	2	None	Aug NQC	QF/Selfgen
CLRMTK_1_QF				0.00		Oakland	Not modeled	QF/Selfgen
COCOPP_7_UNIT 6	33116	C.COS 6	18	337.00	1	Contra Costa		Market
COCOPP_7_UNIT 7	33117	C.COS 7	18	337.00	1	Contra Costa		Market
CONTAN_1_UNIT	36856	CCA100	13.8	25.80	1	San Jose	Aug NQC	QF/Selfgen

CROKET_7_UNIT	32900	CRCKTCOG	18	173.57	1	Pittsburg	Aug NQC	QF/Selfgen
CSCCOG_1_UNIT 1	36854	Cogen	12	3.00	1	San Jose		MUNI
CSCCOG_1_UNIT 1	36854	Cogen	12	3.00	2	San Jose		MUNI
CSCGNR_1_UNIT 1	36858	Gia100	13.8	24.00	1	San Jose		MUNI
CSCGNR_1_UNIT 2	36895	Gia200	13.8	24.00	2	San Jose		MUNI
DELTA_2_PL1X4	33107	DEC STG1	24	269.61	1	Pittsburg	Aug NQC	Market
DELTA_2_PL1X4	33108	DEC CTG1	18	181.13	1	Pittsburg	Aug NQC	Market
DELTA_2_PL1X4	33109	DEC CTG2	18	181.13	1	Pittsburg	Aug NQC	Market
DELTA_2_PL1X4	33110	DEC CTG3	18	181.13	1	Pittsburg	Aug NQC	Market
DUANE_1_PL1X3	36863	DVRaGT1	13.8	49.27	1	San Jose		MUNI
DUANE_1_PL1X3	36864	DVRbGT2	13.8	49.27	1	San Jose		MUNI
DUANE_1_PL1X3	36865	DVRaST3	13.8	49.26	1	San Jose		MUNI
FLOWD1_6_ALTPP1	35318	FLOWDPTR	9.11	0.00	1	Contra Costa	Aug NQC	Wind
FLOWD2_2_UNIT 1	35318	FLOWDPTR	9.11	3.32	1	Contra Costa	Aug NQC	Wind
GATWAY_2_PL1X3	33118	GATEWAY1	18	189.27	1	Contra Costa	Aug NQC	Market
GATWAY_2_PL1X3	33119	GATEWAY2	18	185.36	1	Contra Costa	Aug NQC	Market
GATWAY_2_PL1X3	33120	GATEWAY3	18	185.36	1	Contra Costa	Aug NQC	Market
GILROY_1_UNIT	35850	GLRY COG	13.8	69.30	1	Llagas	Aug NQC	Market
GILROY_1_UNIT	35850	GLRY COG	13.8	35.70	2	Llagas	Aug NQC	Market
GILRPP_1_PL1X2	35851	GROYPKR1	13.8	45.50	1	Llagas	Aug NQC	Market
GILRPP_1_PL1X2	35852	GROYPKR2	13.8	45.50	1	Llagas	Aug NQC	Market
GILRPP_1_PL3X4	35853	GROYPKR3	13.8	46.00	1	Llagas	Aug NQC	Market
GRZZLY_1_BERKLY	32740	HILLSIDE	115	24.96	1	None	Aug NQC	QF/Selfgen
GWFPW1_6_UNIT	33131	GWF #1	9.11	18.01	1	Pittsburg, Contra Costa	Aug NQC	QF/Selfgen
GWFPW2_1_UNIT 1	33132	GWF #2	13.8	18.00	1	Pittsburg	Aug NQC	QF/Selfgen
GWFPW3_1_UNIT 1	33133	GWF #3	13.8	16.94	1	Pittsburg, Contra Costa	Aug NQC	QF/Selfgen
GWFPW4_6_UNIT 1	33134	GWF #4	13.8	16.77	1	Pittsburg, Contra Costa	Aug NQC	QF/Selfgen
GWFPW5_6_UNIT 1	33135	GWF #5	13.8	17.72	1	Pittsburg	Aug NQC	QF/Selfgen
HICKS_7_GUADLP				2.07		None	Not modeled Aug NQC	QF/Selfgen
KIRKER_7_KELCYN	32951	KIRKER	115	3.21		Pittsburg	Not modeled	Market
LAWRNC_7_SUNYVL				0.12		None	Not modeled Aug	Market

							NQC	
LECEF_1_UNITS	35854	LECEFGT1	13.8	46.50	1	San Jose	Aug NQC	Market
LECEF_1_UNITS	35855	LECEFGT2	13.8	46.50	1	San Jose	Aug NQC	Market
LECEF_1_UNITS	35856	LECEFGT3	13.8	46.50	1	San Jose	Aug NQC	Market
LECEF_1_UNITS	35857	LECEFGT4	13.8	46.50	1	San Jose	Aug NQC	Market
LFC 51_2_UNIT 1	35310	LFC FIN+	9.11	2.05	1	None	Aug NQC	Wind
LMBEPK_2_UNITA1	32173	LAMBGT1	13.8	47.00	1	Contra Costa	Aug NQC	Market
LMBEPK_2_UNITA2	32174	GOOSEHGT	13.8	46.00	2	Contra Costa	Aug NQC	Market
LMBEPK_2_UNITA3	32175	CREEDGT1	13.8	47.00	3	Contra Costa	Aug NQC	Market
LMEC_1_PL1X3	33111	LMECCT2	18	163.20	1	Pittsburg	Aug NQC	Market
LMEC_1_PL1X3	33112	LMECCT1	18	163.20	1	Pittsburg	Aug NQC	Market
LMEC_1_PL1X3	33113	LMECST1	18	229.60	1	Pittsburg	Aug NQC	Market
MARKHM_1_CATLST	35863	CATALYST	9.11	0.00	1	San Jose		QF/Selfgen
METCLF_1_QF				0.08		None	Not modeled Aug NQC	QF/Selfgen
METEC_2_PL1X3	35881	MEC CTG1	18	178.43	1	None	Aug NQC	Market
METEC_2_PL1X3	35882	MEC CTG2	18	178.43	1	None	Aug NQC	Market
METEC_2_PL1X3	35883	MEC STG1	18	213.14	1	None	Aug NQC	Market
MILBRA_1_QF				0.00		None	Not modeled	QF/Selfgen
MISSIX_1_QF				0.09		None	Not modeled Aug NQC	QF/Selfgen
MLPTAS_7_QFUNTS				0.01		San Jose	Not modeled Aug NQC	QF/Selfgen
MNTAGU_7_NEWBYI				3.56		None	Not modeled Aug NQC	QF/Selfgen
NEWARK_1_QF				0.02		None	Not modeled Aug NQC	QF/Selfgen
OAK C_7_UNIT 1	32901	OAKLND 1	13.8	55.00	1	Oakland		Market
OAK C_7_UNIT 2	32902	OAKLND 2	13.8	55.00	1	Oakland		Market
OAK C_7_UNIT 3	32903	OAKLND 3	13.8	55.00	1	Oakland		Market
OAK L_7_EBMUD				0.48		Oakland	Not modeled Aug NQC	MUNI
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	1	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	2	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	3	None		Market

OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	4	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	5	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	6	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	7	None		Market
PALALT_7_COBUG				4.50		None	Not modeled	MUNI
PITTSP_7_UNIT 5	33105	PTSB 5	18	312.00	1	Pittsburg		Market
PITTSP_7_UNIT 6	33106	PTSB 6	18	317.00	1	Pittsburg		Market
PITTSP_7_UNIT 7	30000	PTSB 7	20	682.00	1	Pittsburg		Market
RICHMN_7_BAYENV				2.00		None	Not modeled Aug NQC	QF/Selfgen
RVRVEW_1_UNITA1	33178	RVEC_GEN	13.8	46.00	1	Contra Costa	Aug NQC	Market
SEAWST_6_LAPOS	35312	SEAWESTF	9.11	0.31	1	Contra Costa	Aug NQC	Wind
SRINTL_6_UNIT	33468	SRI INTL	9.11	0.63	1	None	Aug NQC	QF/Selfgen
STAUFF_1_UNIT	33139	STAUFER	9.11	0.03	1	None	Aug NQC	QF/Selfgen
STOILS_1_UNITS	32921	CHEVGEN1	13.8	1.41	1	Pittsburg	Aug NQC	QF/Selfgen
STOILS_1_UNITS	32922	CHEVGEN2	13.8	1.41	1	Pittsburg	Aug NQC	QF/Selfgen
TIDWTR_2_UNITS	33151	FOSTER W	12.5	5.59	1	Pittsburg	Aug NQC	QF/Selfgen
TIDWTR_2_UNITS	33151	FOSTER W	12.5	5.59	2	Pittsburg	Aug NQC	QF/Selfgen
TIDWTR_2_UNITS	33151	FOSTER W	12.5	5.59	3	Pittsburg	Aug NQC	QF/Selfgen
UNCHEM_1_UNIT	32920	UNION CH	9.11	14.68	1	Pittsburg	Aug NQC	QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.00	1	Pittsburg	Aug NQC	QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.00	2	Pittsburg	Aug NQC	QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.00	3	Pittsburg	Aug NQC	QF/Selfgen
UNTDQF_7_UNITS	33466	UNTED CO	9.11	22.96	1	None	Aug NQC	QF/Selfgen
USWNDR_2_SMUD	32169	SOLANOWP	21	12.79	1	Contra Costa	Aug NQC	Wind
USWNDR_2_UNITS	32168	EXNCO	9.11	21.68	1	Contra Costa	Aug NQC	Wind
USWPFK_6_FRICK	35320	USW FRIC	12	0.64	1	Contra Costa	Aug NQC	Wind
USWPFK_6_FRICK	35320	USW FRIC	12	0.64	2	Contra Costa	Aug NQC	Wind
USWPJR_2_UNITS	33838	USWP_#3	9.11	2.27	1	Contra Costa	Aug NQC	Wind
WNDMAS_2_UNIT 1	33170	WINDMSTR	9.11	2.62	1	Contra Costa	Aug NQC	Wind
ZOND_6_UNIT	35316	ZOND SYS	9.11	4.70	1	Contra Costa	Aug NQC	Wind
IBMCTL_1_UNIT 1	35637	IBM-CTLE	115	0.00	1	San Jose	No NQC - hist. data	Market
IMHOFF_1_UNIT 1	33136	CCCSD	12.5	4.40	1	Pittsburg	No NQC - hist. data	QF/Selfgen

SHELRF_1_UNITS	33141	SHELL 1	12.5	20.00	1	Pittsburg	No NQC - hist. data	QF/Selfgen
SHELRF_1_UNITS	33142	SHELL 2	12.5	40.00	1	Pittsburg	No NQC - hist. data	QF/Selfgen
SHELRF_1_UNITS	33143	SHELL 3	12.5	40.00	1	Pittsburg	No NQC - hist. data	QF/Selfgen
ZANKER_1_UNIT 1	35861	SJ-SCL W	9.11	5.00	1	San Jose	No NQC - hist. data	QF/Selfgen
BRDSLD_2_MTZUMA	32171	HIGHWND3	34.5	10.00	1	Contra Costa	No NQC - est. data	Wind
New Unit	32179	T222	0.69	19.5	1	Contra Costa	No NQC - est. data	Wind
New Unit	32186	P0609	34.5	40	1	Contra Costa	No NQC - est. data	Wind
New Unit	32188	P0611G	34.5	7.5	1	Contra Costa	No NQC - est. data	Wind
New Unit	32190	Q039	0.58	24.9	1	Contra Costa	No NQC - est. data	Wind
New Unit	35304	Q045CTG1	15	0.00	1	None	Delayed	Market
New Unit	35305	Q045CTG2	15	0.00	1	None	Delayed	Market
New Unit	35306	Q067STG1	15	0.00	1	None	Delayed	Market
POTRPP_7_UNIT 3	33252	POTRERO3	20	0.00	1	None	Retired	Market
POTRPP_7_UNIT 4	33253	POTRERO4	13.8	0.00	1	None	Retired	Market
POTRPP_7_UNIT 5	33254	POTRERO5	13.8	0.00	1	None	Retired	Market
POTRPP_7_UNIT 6	33255	POTRERO6	13.8	0.00	1	None	Retired	Market

Major new projects modeled:

1. AHW #1 & #2 115kV Re-Cabling
2. New TransBay DC cable
3. New Oakland C-X #3 115kV Cable
4. San Mateo – Bay Meadows 115kV #1 & #2 Line Reconductoring
5. Four Wind farms connected to Birds Landing (~ 340 MW P max)
6. Retirement of Potrero #3, #4, #5 and #6

<u>Critical Contingency Analysis Summary</u>

San Francisco Sub-area

LCR need has been eliminated due to the Trans Bay DC cable and re-cabling of the AHW #1 and # 2 115 kV.

Oakland Sub-area

The most critical contingency is an outage of the C-X #2 and #3 115 kV cables. The area limitation is thermal overloading of the D-L 115 kV lines. This limiting contingency establishes a LCR of 55 MW in 2012 (includes 49 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

This Oakland requirement does not include the need for Pittsburg/Oakland sub-area.

Effectiveness factors:

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

Llagas Sub-area

The most critical contingency is an outage between Metcalf D and Morgan Hill 115 kV (with one of the Gilroy Peaker off-line). The area limitation is thermal overloading of the Metcalf-Llagas 115 kV line as well as voltage drop (5%) at the Morgan Hill substation. As documented within a CAISO Operating Procedure, this limitation is dependent on power flowing in the direction from Metcalf to Llagas/Morgan Hill. This limiting contingency establishes a LCR of 100 MW in 2012 (includes 0 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

San Jose Sub-area

The most critical contingency is an outage of Metcalf-El Patio #1 or #2 115 kV line followed by Metcalf-Evergreen #1 115 kV line. The area limitation is thermal overloading of the Evergreen – San Jose B 115 kV line. This limiting contingency establishes a LCR of 352 MW in 2012 (includes 53 MW of QF and 202 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

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

Pittsburg and Oakland Sub-area Combined

The most critical contingency is an outage of the Moraga #3 230/115 kV transformer combined with the loss of Delta Energy Center. The sub-area area limitation is thermal overloading of Moraga #1 230/115 kV transformer. This limiting contingency establishes a LCR of 3008 MW in 2012 (including 448 MW of QF/Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is an outage of the Moraga #3 230/115 kV transformer. The sub-area area limitation is thermal overloading of the Moraga #1 230/115 kV transformer. This limiting contingency establishes a LCR of 2729 MW in

2012 (including 448 MW of QF/Muni generation).

Effectiveness factors:

Please see Bay Area overall.

Contra Costa Sub-area

The most critical contingency is an outage of Kelso-Tesla 230 kV with the Gateway off line. The area limitation is thermal overloading of the Delta Switching Yard-Tesla 230 kV line. This limiting contingency establishes a LCR of 875 MW in 2012 (includes 52 MW of QF and 259 MW of Wind generation and 264 MW of MUNI pumps) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
33175	ALTAMONT	1	83
38760	DELTA E	10	71
38760	DELTA E	11	71
38765	DELTA D	8	71
38765	DELTA D	9	71
38770	DELTA C	6	71
38770	DELTA C	7	71
38815	DELTA B	4	71
38815	DELTA B	5	71
38820	DELTA A	3	71
33170	WINDMSTR	1	68
33118	GATEWAY1	1	23
33119	GATEWAY2	1	23
33120	GATEWAY3	1	23
33116	C.COS 6	1	23
33117	C.COS 7	1	23
33133	GWF #3	1	23
33134	GWF #4	1	23
33178	RVEC_GEN	1	23
33131	GWF #1	1	22
32179	T222	1	18
32188	P0611G	1	18
32190	Q039	1	18

32186	P0609	1	18
32171	HIGHWND3	1	18
32177	Q0024	1	18
32168	ENXCO	2	18
32169	SOLANOWP	1	18
32172	HIGHWNDS	1	18
32176	SHILOH	1	18
33838	USWP_#3	1	18
32173	LAMBGT1	1	14
32174	GOOSEHGT	2	14
32175	CREEDGT1	3	14
35312	SEAWESTF	1	11
35316	ZOND SYS	1	11
35320	USW FRIC	1	11

Bay Area overall

As the aggregate sub pocket LCR is adequate to cover the overall Bay area contingency,

- Sum of the sub pockets for Category B is binding at 3647 MW
- Sum of the sub pockets for Category C is binding at 4278 MW

Effectiveness factors:

For most helpful procurement information please read procedure T-133Z effectiveness factors (posted under M-403Z) at: http://www.caiso.com/237e/237eda4b5070.pdf

Changes compared to last year's results:

Overall the load forecast went down by 368 MW. As a result, LCR decreases by 426 MW. Due to the significantly increased Delta pump load (from 157 MW to 264 MW), a new pocket is modeled this year to calculate the LCR for the effective generation to mitigate a contingency in this sub-pocket. Furthermore the sum of the sub pocket LCR needs is adequate to cover the overall Bay area contingency. Therefore, no additional LCR is needed for the overall Bay area.

Bay Area Overall Requirements:

2012	Wind (MW)	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	261	532	519	5276	6588

2012	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[17]	3647	0	3647
Category C (Multiple)[18]	4278	0	4278

6. Greater Fresno Area

Area Definition

The transmission facilities coming into the Greater Fresno area are:

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

The substations that delineate the Greater Fresno area are:

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

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

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

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

2012 total busload within the defined area is 3014 MW with 105 MW of losses resulting in a total (load plus losses) of 3120 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
AGRICO_6_PL3N5	34608	AGRICO	13.8	16.00	3	Wilson, Herndon		Market
AGRICO_7_UNIT	34608	AGRICO	13.8	43.05	2	Wilson, Herndon		Market
AGRICO_7_UNIT	34608	AGRICO	13.8	7.45	4	Wilson, Herndon		Market
BALCHS_7_UNIT 1	34624	BALCH	13.2	34.00	1	Wilson, Herndon	Aug NQC	Market
BALCHS_7_UNIT 2	34612	BLCH	13.8	52.50	1	Wilson, Herndon	Aug NQC	Market
BALCHS_7_UNIT 3	34614	BLCH	13.8	52.50	1	Wilson, Herndon	Aug NQC	Market
BORDEN_2_QF	30805	BORDEN	230	0.68		Wilson	Not modeled Aug NQC	QF/Selfgen
BULLRD_7_SAGNES				0.00		Wilson	Not modeled Aug NQC	QF/Selfgen
CAPMAD_1_UNIT 1	34179	MADERA_G	13.8	17.00	1	Wilson		Market
CHEVCO_6_UNIT 1	34652	CHV.COAL	9.11	7.69	1	Wilson	Aug NQC	QF/Selfgen
CHEVCO_6_UNIT 2	34652	CHV.COAL	9.11	1.62	2	Wilson	Aug NQC	QF/Selfgen
CHWCHL_1_BIOMAS	34305	CHWCHLA2	13.8	5.76	1	Wilson, Herndon	Aug NQC	Market
CHWCHL_1_UNIT	34301	CHOWCOGN	13.8	48.00	1	Wilson, Herndon		Market
COLGA1_6_SHELLW	34654	COLNGAGN	9.11	35.57	1	Wilson	Aug NQC	QF/Selfgen
CRESSY_1_PARKER	34140	CRESSEY	115	1.20		Wilson	Not modeled Aug NQC	MUNI
CRNEVL_6_CRNVA				0.71		Wilson	Not modeled Aug NQC	Market

CRNEVL_6_SJQN 2	34631	SJ2GEN	9.11	3.20	1	Wilson	Aug NQC	Market
CRNEVL_6_SJQN 3	34633	SJ3GEN	9.11	4.20	1	Wilson	Aug NQC	Market
DINUBA_6_UNIT	34648	DINUBA E	13.8	9.87	1	Wilson, Herndon		Market
ELNIDP_6_BIOMAS	34330	ELNIDO	13.8	5.66	1	Wilson	Aug NQC	Market
EXCHEC_7_UNIT 1	34306	EXCHQUER	13.8	61.77	1	Wilson	Aug NQC	MUNI
FRIANT_6_UNITS	34636	FRIANTDM	6.6	5.29	2	Wilson	Aug NQC	QF/Selfgen
FRIANT_6_UNITS	34636	FRIANTDM	6.6	2.83	3	Wilson	Aug NQC	QF/Selfgen
FRIANT_6_UNITS	34636	FRIANTDM	6.6	0.75	4	Wilson	Aug NQC	QF/Selfgen
GATES_6_PL1X2	34553	WHD_GAT2	13.8	41.50	1	Wilson		Market
GWFPWR_1_UNITS	34431	GWF_HEP1	13.8	42.20	1	Wilson, Herndon		Market
GWFPWR_1_UNITS	34433	GWF_HEP2	13.8	42.20	1	Wilson, Herndon		Market
GWFPWR_6_UNIT	34650	GWF-PWR.	9.11	24.03	1	Wilson, Henrietta	Aug NQC	QF/Selfgen
HAASPH_7_PL1X2	34610	HAAS	13.8	68.15	1	Wilson, Herndon	Aug NQC	Market
HAASPH_7_PL1X2	34610	HAAS	13.8	68.15	2	Wilson, Herndon	Aug NQC	Market
HELMPG_7_UNIT 1	34600	HELMS	18	404.00	1	Wilson	Aug NQC	Market
HELMPG_7_UNIT 2	34602	HELMS	18	404.00	2	Wilson	Aug NQC	Market
HELMPG_7_UNIT 3	34604	HELMS	18	404.00	3	Wilson	Aug NQC	Market
HENRTA_6_UNITA1	34539	GWF_GT1	13.8	45.33	1	Wilson, Henrietta		Market
HENRTA_6_UNITA2	34541	GWF_GT2	13.8	45.23	1	Wilson, Henrietta		Market
INTTRB_6_UNIT	34342	INT.TURB	9.11	1.63	1	Wilson	Aug NQC	QF/Selfgen
JRWOOD_1_UNIT 1	34332	JRWCOGEN	9.11	3.68	1	Wilson	Aug NQC	QF/Selfgen
KERKH1_7_UNIT 1	34344	KERCKHOF	6.6	13.00	1	Wilson, Herndon	Aug NQC	Market
KERKH1_7_UNIT 2	34344	KERCKHOF	6.6	8.50	2	Wilson, Herndon	Aug NQC	Market
KERKH1_7_UNIT 3	34344	KERCKHOF	6.6	12.80	3	Wilson, Herndon	Aug NQC	Market
KERKH2_7_UNIT 1	34308	KERCKHOF	13.8	153.90	1	Wilson, Herndon	Aug NQC	Market
KINGCO_1_KINGBR	34642	KINGSBUR	9.11	23.31	1	Wilson, Herndon	Aug NQC	QF/Selfgen
KINGRV_7_UNIT 1	34616	KINGSRIV	13.8	51.20	1	Wilson, Herndon	Aug NQC	Market
MALAGA_1_PL1X2	34671	KRCDPCT1	13.8	48.00	1	Wilson, Herndon		Market
MALAGA_1_PL1X2	34672	KRCDPCT2	13.8	48.00	1	Wilson, Herndon		Market
MCCALL_1_QF				0.72		Wilson, Herndon	Not modeled Aug NQC	QF/Selfgen
MCSWAN_6_UNITS	34320	MCSWAIN	9.11	4.57	1	Wilson	Aug NQC	MUNI
MENBIO_6_UNIT	34334	BIO PWR	9.11	21.61	1	Wilson	Aug NQC	QF/Selfgen
MERCFL_6_UNIT	34322	MERCEDFL	9.11	2.03	1	Wilson	Aug NQC	Market
PINFLT_7_UNITS	38720	PINEFLAT	13.8	33.12	1	Wilson, Herndon	Aug NQC	MUNI

PINFLT_7_UNITS	38720	PINEFLAT	13.8	33.12	2	Wilson, Herndon	Aug NQC	MUNI
PINFLT_7_UNITS	38720	PINEFLAT	13.8	33.13	3	Wilson, Herndon	Aug NQC	MUNI
PNCHPP_1_PL1X2	34328	STARGT1	13.8	55.58	1	Wilson		Market
PNCHPP_1_PL1X2	34329	STARGT2	13.8	55.58	1	Wilson		Market
PNOCHE_1_PL1X2	34142	WHD_PAN2	13.8	40.00	1	Wilson, Herndon		Market
PNOCHE_1_UNITA1	34186	DG_PAN1	13.8	42.78	1	Wilson		Market
SGREGY_6_SANGER	34646	SANGERCO	9.11	26.96	1	Wilson	Aug NQC	QF/Selfgen
STOREY_7_MDRCHW				0.88		Wilson	Not modeled Aug NQC	QF/Selfgen
ULTPFR_1_UNIT 1	34640	ULTR.PWR	9.11	17.30	1	Wilson, Herndon	Aug NQC	QF/Selfgen
WISHON_6_UNITS	34658	WISHON	2.3	4.51	1	Wilson	Aug NQC	Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	2	Wilson	Aug NQC	Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	3	Wilson	Aug NQC	Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	4	Wilson	Aug NQC	Market
WISHON_6_UNITS	34658	WISHON	2.3	0.36	5	Wilson	Aug NQC	Market
WRGHTP_7_AMENGY				0.53		Wilson	Not modeled Aug NQC	QF/Selfgen
NA	34485	FRESNOWW	12.5	9.00	1	Wilson	No NQC - hist. data	QF/Selfgen
NA	34485	FRESNOWW	12.5	4.00	2	Wilson	No NQC - hist. data	QF/Selfgen
NA	34485	FRESNOWW	12.5	1.00	3	Wilson	No NQC - hist. data	QF/Selfgen
ONLLPP_6_UNIT 1	34316	ONEILPMP	9.11	0.50	1	Wilson	No NQC - hist. data	MUNI
MENBIO_6_RENEW1	34339	CALRENEW	12.5	0.00	1	Wilson	Energy Only	Market
New Unit	34696	Q478	21	0.00	1	Wilson, Herndon	Energy Only	Market
New Unit	34603	JQBSWLT	12.5	0.00	ST	Wilson	Energy Only	Market

Major new projects modeled:

1. Herndon 230 to 115 kV Transformer bank # 3

Critical Contingency Analysis Summary

Wilson Sub-area

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

The most critical contingency is the loss of the Melones - Wilson 230 kV line overlapped with one of the Helms units out of service. This contingency would thermally overload the Warnerville - Wilson 230 kV line (most stringent) and possibly also the Gates-McCall 230 kV line. This limiting contingency establishes a LCR of 1873 MW in 2012 (includes 189 MW of QF and 167 MW of Muni generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
34332	JRWCOGEN	1	40%
34330	ELNIDO	1	37%
34322	MERCEDFL	1	35%
34320	MCSWAIN	1	34%
34306	EXCHQUER	1	34%
34305	CHWCHLA2	1	32%
34301	CHOWCOGN	1	32%
34658	WISHON	1	28%
34658	WISHON	1	28%
34658	WISHON	1	28%
34658	WISHON	1	28%
34658	WISHON	1	28%
34631	SJ2GEN	1	28%
34633	SJ3GEN	1	27%
34636	FRIANTDM	2	27%
34636	FRIANTDM	3	27%
34636	FRIANTDM	4	27%
34600	HELMS 1	1	27%
34602	HELMS 2	1	27%
34604	HELMS 3	1	27%
34308	KERCKHOF	1	26%
34344	KERCKHOF	1	26%
34344	KERCKHOF	2	26%
34344	KERCKHOF	3	26%
34485	FRESNOWW	1	24%
34648	DINUBA E	1	22%

34179	MADERA_G	1	22%
34616	KINGSRIV	1	22%
34624	BALCH 1	1	21%
34671	KRCDPCT1	1	21%
34672	KRCDPCT2	1	21%
34640	ULTR.PWR	1	21%
34646	SANGERCO	1	21%
34642	KINGSBUR	1	19%
34696	Q478	1	18%
34610	HAAS	1	18%
34610	HAAS	1	18%
34614	BLCH 2-3	1	18%
34612	BLCH 2-2	1	17%
38720	PINE FLT	1	17%
38720	PINE FLT	2	17%
38720	PINE FLT	3	17%
34431	GWF_HEP1	1	17%
34433	GWF_HEP2	1	17%
34334	BIO PWR	1	14%
34608	AGRICO	2	14%
34608	AGRICO	3	14%
34608	AGRICO	4	14%
34539	GWF_GT1	1	14%
34541	GWF_GT2	1	14%
34650	GWF-PWR.	1	13%
34186	DG_PAN1	1	11%
34142	WHD_PAN2	1	11%
34652	CHV.COAL	1	10%
34652	CHV.COAL	2	10%
34553	WHD_GAT2	1	9%
34654	COLNGAGN	1	9%
34342	INT.TURB	1	6%
34316	ONEILPMP	1	6%

Herndon Sub-area

The most critical contingency is the loss of the Herndon -Barton 115 kV line along with Herndon-Woodward 115 kV line. This contingency could thermally overload the Herndon–Manchester 115 kV line. This limiting contingency establishes a LCR of 275 MW (includes 41 MW of QF and 99 MW of Muni generation) in 2011 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The Category B LCR requirement for the Herndon sub area was eliminated due to the construction of the new Herndon# 3 230/115 kV transformer bank.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
34308	KERCKHOF	1	34%
34344	KERCKHOF	1	34%
34344	KERCKHOF	2	34%
34344	KERCKHOF	3	34%
34624	BALCH 1	1	33%
34646	SANGERCO	1	31%
34616	KINGSRIV	1	31%
34671	KRCDPCT1	1	31%
34672	KRCDPCT2	1	31%
34640	ULTR.PWR	1	30%
34648	DINUBA E	1	28%
34642	KINGSBUR	1	25%
34696	Q478	1	25%
38720	PINE FLT	1	23%
38720	PINE FLT	2	23%
38720	PINE FLT	3	23%
34610	HAAS	1	23%
34610	HAAS	2	23%
34614	BLCH 2-3	1	23%
34612	BLCH 2-2	1	23%
34431	GWF_HEP1	1	14%
34433	GWF_HEP2	1	14%
34301	CHOWCOGN	1	9%
34305	CHWCHLA2	1	9%
34608	AGRICO	2	7%
34608	AGRICO	3	7%
34608	AGRICO	4	7%
34332	JRWCOGEN	1	-6%
34600	HELMS 1	1	-12%
34602	HELMS 2	1	-12%
34604	HELMS 3	1	-12%
34485	FRESNOWW	1	-14%

Henrietta Sub-area

The two most critical contingencies listed below together establish a local capacity need of 68 MW (includes 24 MW of QF as well as 8 MW of deficiency) in 2012 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical contingency is the loss of Henrietta 230/70 kV transformer bank #4 and GWF Power unit. This contingency could thermally overload the Henrietta 230/70 kV transformer bank #2. This limiting contingency establishes a LCR of 36 MW in 2011 (includes 0 MW of QF generation).

The second most critical contingency is the loss of Henrietta 230/70 kV transformer bank #4 and one of the Henrietta-GWF Henrietta 70 kV line. This contingency could thermally overload the Henrietta 230/70 kV transformer bank #2. This limiting contingency establishes a LCR of 32 MW in 2011 (includes 24 MW of QF generation as well as 8 MW of deficiency).

The most critical single contingency is the loss of Henrietta 230/70 kV transformer bank #4. This contingency could thermally overload the Henrietta 230/70 kV transformer bank #2. This limiting contingency establishes a LCR of 35 MW in 2012 (includes 24 MW of QF generation).

Effectiveness factors:

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

Changes compared to last year's results:

Overall the load forecast is down by 186 MW. Path 15 flow is 1275 MW N-S the same as last year. Due to the new Herndon # 3 230/115 kV bank & lower load forecast, the total Fresno LCR requirement has decreased by 542 MW.

Fresno Area Overall Requirements:

2012	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	189	167	2414	2770

2012	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single) [19]	1873	0	1873
Category C (Multiple) [20]	1899	8	1907

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

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

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

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

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

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

The substations that delineate the Weedpatch sub-area are:

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

2012 total busload within the defined area: 1099 MW with 11 MW of losses resulting in

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

a total (load plus losses) of 1110 MW.

Total units and qualifying capacity available in this Kern area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BDGRCK_1_UNITS	35029	BADGERCK	9.11	42.21	1	Kern PP	Aug NQC	QF/Selfgen
BEARMT_1_UNIT	35066	PSE-BEAR	9.11	45.79	1	Kern PP, West Park	Aug NQC	QF/Selfgen
CHALK_1_UNIT	35038	CHLKCLF+	9.11	45.27	1	Kern PP	Aug NQC	QF/Selfgen
CHEVCD_6_UNIT	35052	CHEV.USA	9.11	1.27	1	Kern PP	Aug NQC	QF/Selfgen
CHEVCY_1_UNIT	35032	CHV-CYMR	9.11	5.24	1	Kern PP	Aug NQC	QF/Selfgen
DEXZEL_1_UNIT	35024	DEXEL +	9.11	28.24	1	Kern PP	Aug NQC	QF/Selfgen
DISCOV_1_CHEVRN	35062	DISCOVRY	9.11	1.70	1	Kern PP	Aug NQC	QF/Selfgen
DOUBLC_1_UNITS	35023	DOUBLE C	9.11	37.59	1	Kern PP	Aug NQC	QF/Selfgen
FELLOW_7_QFUNTS				1.28		Kern PP	Not modeled Aug NQC	QF/Selfgen
FRITO_1_LAY	35048	FRITOLAY	9.11	0.09	1	Kern PP	Aug NQC	QF/Selfgen
KERNFT_1_UNITS	35026	KERNFRNT	9.11	37.60	1	Kern PP	Aug NQC	QF/Selfgen
KERNRG_1_UNITS	35040	KERNRDGE	9.11	0.51	1	Kern PP	Aug NQC	QF/Selfgen
KERNRG_1_UNITS	35040	KERNRDGE	9.11	0.51	2	Kern PP	Aug NQC	QF/Selfgen
KRNCNY_6_UNIT	35018	KERNCNYN	9.11	9.38	1	Weedpatch	Aug NQC	Market
KRNOIL_7_TEXEXP				6.11		Kern PP	Not modeled Aug NQC	QF/Selfgen
LIVOAK_1_UNIT 1	35058	PSE-LVOK	9.11	44.40	1	Kern PP	Aug NQC	QF/Selfgen
MIDSET_1_UNIT 1	35044	TX MIDST	9.11	33.56	1	Kern PP	Aug NQC	QF/Selfgen
MIDWAY_1_QF				0.03		Kern PP	Not modeled Aug NQC	QF/Selfgen
MKTRCK_1_UNIT 1	35060	PSEMCKIT	9.11	43.07	1	Kern PP	Aug NQC	QF/Selfgen
MTNPOS_1_UNIT	35036	MT POSO	9.11	43.39	1	Kern PP	Aug NQC	QF/Selfgen
NAVY35_1_UNITS	35064	NAVY 35R	9.11	0.00	1	Kern PP	Aug NQC	QF/Selfgen
NAVY35_1_UNITS	35064	NAVY 35R	9.11	0.00	2	Kern PP	Aug NQC	QF/Selfgen
OILDAL_1_UNIT 1	35028	OILDALE	9.11	37.50	1	Kern PP	Aug NQC	QF/Selfgen
RIOBRV_6_UNIT 1	35020	RIOBRAVO	9.11	6.50	1	Weedpatch	Aug NQC	QF/Selfgen
SIERRA_1_UNITS	35027	HISIERRA	9.11	42.98	1	Kern PP	Aug NQC	QF/Selfgen
TANHIL_6_SOLART	35050	SLR-TANN	9.11	9.79	1	Kern PP	Aug NQC	QF/Selfgen
TEMBLR_7_WELLPT				0.30		Kern PP	Not modeled Aug NQC	QF/Selfgen
TXMCKT_6_UNIT				4.12		Kern PP	Not modeled Aug NQC	QF/Selfgen
TXNMID_1_UNIT 2	34783	TEXCO_NM	9.11	0.01	1	Kern PP	Aug NQC	QF/Selfgen
TXNMID_1_UNIT 2	34783	TEXCO_NM	9.11	0.01	2	Kern PP	Aug NQC	QF/Selfgen
ULTOGL_1_POSO	35035	ULTR PWR	9.11	34.70	1	Kern PP	Aug NQC	QF/Selfgen
UNVRSY_1_UNIT 1	35037	UNIVRSTY	9.11	31.66	1	Kern PP	Aug NQC	QF/Selfgen
VEDDER_1_SEKERN	35046	SEKR	9.11	8.01	1	Kern PP	Aug NQC	QF/Selfgen
MIDSUN_1_PL1X2	35034	MIDSUN +	9.11	0.00	1	Kern PP	Retired	Market
NA	35056	TX-LOSTH	4.16	8.80	1	Kern PP	No NQC - hist. data	QF/Selfgen
New Unit	35000	Q340	21	0.00	1	Kern PP	Energy Only	Market
New Unit	35012	Q473	21	0.00	1	Kern PP	Energy Only	Market
New Unit	35013	Q479	21	0.00	1	Kern PP	Energy Only	Market

Major new projects modeled:

1. Kern Bank 3 & 3a 230/115 kV bank replacement
2. Midway Bank 2 & 2a 230/115 kV bank replacement

Critical Contingency Analysis Summary

Kern PP Sub-area

The most critical contingency is the outage of the Kern PP #5/#3 230/115 kV transformer bank followed by the Kern PP – Kern Front 115 kV line, which could thermally overload the parallel Kern PP #4 230/115 kV transformer. This limiting contingency establishes a LCR of 296 MW in 2012 (includes 596 MW of QF generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the loss of Kern PP #5 or #3 230/115 kV transformer bank, which could thermally overload the parallel Kern PP #4230/115 kV transformer. This limiting contingency establishes a LCR of 180 MW in 2012 (includes 596 MW of QF generation).

Effectiveness factors:

The following table shows units that are at least 5% effective:

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
35066	PSE-BEAR	1	22%
35029	BADGERCK	1	22%
35023	DOUBLE C	1	22%
35027	HISIERRA	1	22%
35026	KERNFRNT	1	21%
35058	PSE-LVOK	1	21%
35028	OILDALE	1	21%
35062	DISCOVRY	1	21%
35046	SEKR	1	21%
35024	DEXEL +	1	21%
35036	MT POSO	1	15%
35035	ULTR PWR	1	15%
35052	CHEV.USA	1	6%

Weedpatch Sub-area

The most critical contingency is the loss of the Wheeler Ridge – San Bernard 70 kV line followed by the Wheeler Ridge – Tejon 70 kV line, which could thermally overload the Wheeler Ridge – Weedpatch 70 kV line and cause low voltage problem at the local 70 kV transmission system. This limiting contingency establishes a LCR of 30 MW in 2012 (includes 7 MW of QF generation and 14 MW of deficiency) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

West Park Sub-area

The most critical contingency is the loss of common mode Kern - West Park # 1 & #2 115 kV lines, resulting in the overload of the 6/42 To Magunden section of Kern – Magunden - Witco 115 kV line. This limitation establishes a LCR of 60 MW (includes 46 MW of QF generation and 14 MW of deficiency).

Effectiveness factors:

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

Changes compared to last year's results:

Overall the load forecast went down by 277 MW and that drives the LCR down by 138 MW. The load reduction is less effective in mitigating the main Kern PP constraint compared to resources in the area.

Kern Area Overall Requirements:

2012	QF/Selfgen (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	602	9	611

2012	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single) [21]	180	0	180
Category C (Multiple) [22]	297	28	325

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

8. LA Basin Area

Area Definition

The transmission tie lines into the LA Basin Area are:

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

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

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

---

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

Total 2012 busload within the defined area is 19,774 MW with 129 MW of losses and 27 MW pumps resulting in total load + losses + pumps of 19,930 MW.

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

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ALAMIT_7_UNIT 1	24001	ALAMT1 G	18	174.56	1	Western		Market
ALAMIT_7_UNIT 2	24002	ALAMT2 G	18	175.00	2	Western		Market
ALAMIT_7_UNIT 3	24003	ALAMT3 G	18	332.18	3	Western		Market
ALAMIT_7_UNIT 4	24004	ALAMT4 G	18	335.67	4	Western		Market
ALAMIT_7_UNIT 5	24005	ALAMT5 G	20	497.97	5	Western		Market
ALAMIT_7_UNIT 6	24161	ALAMT6 G	20	495.00	6	Western		Market
ANAHM_7_CT	25203	ANAHEIMG	13.8	40.64	1	Western	Aug NQC	MUNI
ARCOGN_2_UNITS	24011	ARCO 1G	13.8	56.62	1	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24012	ARCO 2G	13.8	56.62	2	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24013	ARCO 3G	13.8	56.62	3	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24014	ARCO 4G	13.8	56.62	4	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24163	ARCO 5G	13.8	28.31	5	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24164	ARCO 6G	13.8	28.32	6	Western	Aug NQC	QF/Selfgen
BARRE_2_QF	24016	BARRE	230	0.00		Western	Not modeled	QF/Selfgen
BARRE_6_PEAKER	28309	BARPKGEN	13.8	45.38	1	Western		Market
BRDWAY_7_UNIT 3	28007	BRODWYSC	13.8	65.00	1	Western		MUNI
BUCKWD_7_WINTCV	25634	BUCKWIND	115	0.11	W5	Eastern	Aug NQC	Wind
CABZON_1_WINDA1	28280	CABAZON	33	8.81	1	Eastern	Aug NQC	Wind
CENTER_2_QF	24203	CENTER S	66	17.99		Western	Not modeled Aug NQC	QF/Selfgen
CENTER_2_RHONDO	24203	CENTER S	66	1.91		Western	Not modeled	QF/Selfgen
CENTER_6_PEAKER	28308	CTRPKGEN	13.8	44.57	1	Western		Market
CENTRY_6_PL1X4				36.00		Eastern	Not modeled Aug NQC	Market
CHEVMN_2_UNITS	24022	CHEVGEN1	13.8	0.15	1	Western, El Nido	Aug NQC	QF/Selfgen
CHEVMN_2_UNITS	24023	CHEVGEN2	13.8	0.16	2	Western, El Nido	Aug NQC	QF/Selfgen
CHINO_2_QF	24024	CHINO	66	9.30		Western	Not modeled Aug NQC	QF/Selfgen
CHINO_6_CIMGEN	24026	CIMGEN	13.8	25.07	1	Western	Aug NQC	QF/Selfgen
CHINO_6_SMPPAP	24140	SIMPSON	13.8	25.07	1	Western	Aug NQC	QF/Selfgen
CHINO_6_SOLAR	24024	CHINO	66	0.00		Western	Not modeled	Market
CHINO_7_MILIKN	24024	CHINO	66	1.26		Western	Not modeled Aug NQC	Market
COLTON_6_AGUAM1				43.00		Eastern	Not modeled	MUNI
CORONS_6_CLRWTR	24210	MIRALOMA	66	14.00		Eastern	Not modeled	MUNI
CORONS_6_CLRWTR	24210	MIRALOMA	66	14.00		Eastern	Not modeled	MUNI
DEVERS_1_QF	25645	VENWIND	115	1.08	EU	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25635	ALTWIND	115	0.96	Q1	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	0.42	Q1	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25645	VENWIND	115	2.53	Q1	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25646	SANWIND	115	0.57	Q1	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25635	ALTWIND	115	1.77	Q2	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	1.61	Q2	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25645	VENWIND	115	1.71	Q2	Eastern	Aug NQC	QF/Selfgen

DEVERS_1_QF	25646	SANWIND	115	1.90	Q2	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	24815	GARNET	115	1.07	QF	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25632	TERAWND	115	2.08	QF	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25633	CAPWIND	115	0.40	QF	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25634	BUCKWIND	115	1.22	QF	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25637	TRANWIND	115	4.72	QF	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25639	SEAWIND	115	1.42	QF	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25640	PANAERO	115	1.27	QF	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	0.19	W1	Eastern	Aug NQC	QF/Selfgen
DMDVLY_1_UNITS	25425	ESRP P2	6.9	21.00		Eastern	Not modeled	QF/Selfgen
DREWS_6_PL1X4				36.00		Eastern	Not modeled Aug NQC	Market
DVLCYN_1_UNITS	25648	DVLCYN1G	13.8	50.35	1	Eastern	Aug NQC	MUNI
DVLCYN_1_UNITS	25649	DVLCYN2G	13.8	50.35	2	Eastern	Aug NQC	MUNI
DVLCYN_1_UNITS	25603	DVLCYN3G	13.8	67.15	3	Eastern	Aug NQC	MUNI
DVLCYN_1_UNITS	25604	DVLCYN4G	13.8	67.15	4	Eastern	Aug NQC	MUNI
ELLIS_2_QF	24197	ELLIS	66	0.11		Western, Ellis	Not modeled Aug NQC	QF/Selfgen
ELSEGN_7_UNIT 3	24047	ELSEG3 G	18	335.00	3	Western, El Nido		Market
ELSEGN_7_UNIT 4	24048	ELSEG4 G	18	335.00	4	Western, El Nido		Market
ETIWND_2_FONTNA	24055	ETIWANDA	66	0.67		Eastern	Not modeled Aug NQC	QF/Selfgen
ETIWND_2_QF	24055	ETIWANDA	66	15.11		Eastern	Not modeled Aug NQC	QF/Selfgen
ETIWND_6_GRPLND	28305	ETWPKGEN	13.8	42.53	1	Eastern		Market
ETIWND_6_MWDETI	25422	ETI MWDG	13.8	15.56	1	Eastern	Aug NQC	Market
ETIWND_7_MIDVLY	24055	ETIWANDA	66	1.58		Eastern	Not modeled Aug NQC	QF/Selfgen
ETIWND_7_UNIT 3	24052	MTNVIST3	18	320.00	3	Eastern		Market
ETIWND_7_UNIT 4	24053	MTNVIST4	18	320.00	4	Eastern		Market
GARNET_1_UNITS	24815	GARNET	115	0.57	G1	Eastern	Aug NQC	QF/Selfgen
GARNET_1_UNITS	24815	GARNET	115	0.20	G2	Eastern	Aug NQC	QF/Selfgen
GARNET_1_UNITS	24815	GARNET	115	0.41	G3	Eastern	Aug NQC	QF/Selfgen
GARNET_1_UNITS	24815	GARNET	115	0.20	PC	Eastern	Aug NQC	QF/Selfgen
GARNET_1_WIND	24815	GARNET	115	0.66	W2	Eastern	Aug NQC	Wind
GARNET_1_WIND	24815	GARNET	115	0.66	W3	Eastern	Aug NQC	Wind
GLNARM_7_UNIT 1	28005	PASADNA1	13.8	22.30	1	Western		MUNI
GLNARM_7_UNIT 2	28006	PASADNA2	13.8	22.30	1	Western		MUNI
GLNARM_7_UNIT 3	28005	PASADNA1	13.8	44.83		Western	Not modeled	MUNI
GLNARM_7_UNIT 4	28006	PASADNA2	13.8	42.42		Western	Not modeled	MUNI
HARBGN_7_UNITS	24062	HARBOR G	13.8	76.28	1	Western		Market
HARBGN_7_UNITS	24062	HARBOR G	13.8	11.86	HP	Western		Market
HARBGN_7_UNITS	25510	HARBORG4	4.16	11.86	LP	Western		Market
HINSON_6_CARBGN	24020	CARBOGEN	13.8	22.67	1	Western	Aug NQC	Market
HINSON_6_LBECH1	24078	LBEACH1G	13.8	65.00	1	Western		Market
HINSON_6_LBECH2	24170	LBEACH2G	13.8	65.00	2	Western		Market
HINSON_6_LBECH3	24171	LBEACH3G	13.8	65.00	3	Western		Market
HINSON_6_LBECH4	24172	LBEACH4G	13.8	65.00	4	Western		Market
HINSON_6_SERRGN	24139	SERRFGEN	13.8	27.67	1	Western	Aug NQC	QF/Selfgen
HNTGBH_7_UNIT 1	24066	HUNT1 G	13.8	225.75	1	Western, Ellis		Market
HNTGBH_7_UNIT 2	24067	HUNT2 G	13.8	225.80	2	Western, Ellis		Market
HNTGBH_7_UNIT 3	24167	HUNT3 G	13.8	225.00	3	Western, Ellis		Market
HNTGBH_7_UNIT 4	24168	HUNT4 G	13.8	227.00	4	Western, Ellis		Market

INDIGO_1_UNIT 1	28190	WINTECX2	13.8	42.00	1	Eastern		Market
INDIGO_1_UNIT 2	28191	WINTECX1	13.8	42.00	1	Eastern		Market
INDIGO_1_UNIT 3	28180	WINTEC8	13.8	42.00	1	Eastern		Market
INLDEM_5_UNIT 1	28041	IEEC-G1	19.5	335.00	1	Eastern	Aug NQC	Market
INLDEM_5_UNIT 2	28042	IEEC-G2	19.5	335.00	1	Eastern	Aug NQC	Market
JOHANN_6_QFA1	24072	JOHANNA	230	0.00		Western, Ellis	Not modeled Aug NQC	QF/Selfgen
LACIEN_2_VENICE	24208	LCIENEGA	66	4.39		Western	Not modeled Aug NQC	QF/Selfgen
LAFRES_6_QF	24073	LA FRESA	66	2.89		Western, El Nido	Not modeled Aug NQC	QF/Selfgen
LAGBEL_6_QF	24075	LAGUBELL	66	10.90		Western	Not modeled Aug NQC	QF/Selfgen
LGHTHP_6_ICEGEN	24070	ICEGEN	13.8	45.72	1	Western	Aug NQC	QF/Selfgen
LGHTHP_6_QF	24083	LITEHIPE	66	0.95		Western	Not modeled Aug NQC	QF/Selfgen
MESAS_2_QF	24209	MESA CAL	66	1.15		Western	Not modeled Aug NQC	QF/Selfgen
MIRLOM_2_CORONA				2.12		Eastern	Not modeled Aug NQC	QF/Selfgen
MIRLOM_2_TEMESC				2.41		Eastern	Not modeled Aug NQC	QF/Selfgen
MIRLOM_6_DELGEN	24030	DELGEN	13.8	32.04	1	Eastern	Aug NQC	QF/Selfgen
MIRLOM_6_PEAKER	28307	MRLPKGEN	13.8	43.18	1	Eastern		Market
MIRLOM_7_MWDLKM	24210	MIRALOMA	66	3.90		Eastern	Not modeled Aug NQC	MUNI
MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	4.67	1	Eastern	Aug NQC	Market
MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	4.67	2	Eastern	Aug NQC	Market
MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	4.67	3	Eastern	Aug NQC	Market
MTWIND_1_UNIT 1				5.13		Eastern	Not modeled Aug NQC	Wind
MTWIND_1_UNIT 2				2.10		Eastern	Not modeled Aug NQC	Wind
MTWIND_1_UNIT 3				2.07		Eastern	Not modeled Aug NQC	Wind
OLINDA_2_COYCRK	24211	OLINDA	66	3.13		Western	Not modeled	QF/Selfgen
OLINDA_2_QF	24211	OLINDA	66	1.02	1	Western	Aug NQC	QF/Selfgen
OLINDA_7_LNDFIL	24201	BARRE	66	4.50		Western	Not modeled Aug NQC	QF/Selfgen
PADUA_2_ONTARO	24111	PADUA	66	0.63		Eastern	Not modeled Aug NQC	QF/Selfgen
PADUA_6_MWDSDM	24111	PADUA	66	5.60		Eastern	Not modeled Aug NQC	MUNI
PADUA_6_QF	24111	PADUA	66	2.18		Eastern	Not modeled Aug NQC	QF/Selfgen
PADUA_7_SDIMAS	24111	PADUA	66	1.05		Eastern	Not modeled Aug NQC	QF/Selfgen
PWEST_1_UNIT				0.22		Western	Not modeled Aug NQC	Market
REDOND_7_UNIT 5	24121	REDON5 G	18	178.87	5	Western		Market
REDOND_7_UNIT 6	24122	REDON6 G	18	175.00	6	Western		Market
REDOND_7_UNIT 7	24123	REDON7 G	20	505.96	7	Western		Market
REDOND_7_UNIT 8	24124	REDON8 G	20	495.90	8	Western		Market
RHONDO_2_QF	24213	RIOHONDO	66	1.62		Western	Not modeled Aug NQC	QF/Selfgen
RHONDO_6_PUENTE	24213	RIOHONDO	66	0.00		Western	Not modeled Aug NQC	Market
RVSIDE_6_RERCU1	24242	RERC1G	13.8	48.35	1	Eastern		MUNI

RVSIDE_6_RERCU2	24243	RERC2G	13.8	48.50	1	Eastern		MUNI
RVSIDE_6_SPRING	24244	SPRINGEN	13.8	36.00	1	Eastern		Market
SANTGO_6_COYOTE	24133	SANTIAGO	66	4.22	1	Western, Ellis	Aug NQC	Market
SBERDO_2_PSP3	24921	MNTV-CT1	18	129.71	1	Eastern		Market
SBERDO_2_PSP3	24922	MNTV-CT2	18	129.71	1	Eastern		Market
SBERDO_2_PSP3	24923	MNTV-ST1	18	225.08	1	Eastern		Market
SBERDO_2_PSP4	24924	MNTV-CT3	18	129.71	1	Eastern		Market
SBERDO_2_PSP4	24925	MNTV-CT4	18	129.71	1	Eastern		Market
SBERDO_2_PSP4	24926	MNTV-ST2	18	225.08	1	Eastern		Market
SBERDO_2_QF	24214	SANBRDNO	66	0.17		Eastern	Not modeled Aug NQC	QF/Selfgen
SBERDO_2_SNTANA	24214	SANBRDNO	66	0.05		Eastern	Not modeled Aug NQC	QF/Selfgen
SBERDO_6_MILLCK	24214	SANBRDNO	66	1.08		Eastern	Not modeled Aug NQC	QF/Selfgen
SONGS_7_UNIT 2	24129	S.ONOFR2	22	1122.00	2	Western		Nuclear
SONGS_7_UNIT 3	24130	S.ONOFR3	22	1124.00	3	Western		Nuclear
TIFFNY_1_DILLON				6.37		Western	Not modeled Aug NQC	Wind
VALLEY_5_PERRIS	24160	VALLEYSC	115	7.94		Eastern	Not modeled Aug NQC	QF/Selfgen
VALLEY_5_REDMTN	24160	VALLEYSC	115	0.16		Eastern	Not modeled Aug NQC	QF/Selfgen
VALLEY_7_BADLND	24160	VALLEYSC	115	0.38		Eastern	Not modeled Aug NQC	Market
VALLEY_7_UNITA1	24160	VALLEYSC	115	1.13		Eastern	Not modeled Aug NQC	Market
VERNON_6_GONZL1				5.75		Western	Not modeled	MUNI
VERNON_6_GONZL2				5.75		Western	Not modeled	MUNI
VERNON_6_MALBRG	24239	MALBRG1G	13.8	42.37	C1	Western		MUNI
VERNON_6_MALBRG	24240	MALBRG2G	13.8	42.37	C2	Western		MUNI
VERNON_6_MALBRG	24241	MALBRG3G	13.8	49.26	S3	Western		MUNI
VILLPK_2_VALLYV	24216	VILLA PK	66	4.10		Western	Not modeled Aug NQC	QF/Selfgen
VILLPK_6_MWDYOR	24216	VILLA PK	66	4.30		Western	Not modeled Aug NQC	MUNI
VISTA_6_QF	24902	VSTA	66	0.26	1	Eastern	Aug NQC	QF/Selfgen
WALNUT_6_HILLGEN	24063	HILLGEN	13.8	46.68	1	Western	Aug NQC	QF/Selfgen
WALNUT_7_WCOVCT	24157	WALNUT	66	3.43		Western	Not modeled Aug NQC	Market
WALNUT_7_WCOVST	24157	WALNUT	66	2.98		Western	Not modeled Aug NQC	Market
WHTWTR_1_WINDA1	28061	WHITEWTR	33	6.61	1	Eastern	Aug NQC	Wind
ARCOGN_2_UNITS	24018	BRIGEN	13.8	0.00	1	Western	No NQC - hist. data	Market
HINSON_6_QF	24064	HINSON	66	0.00	1	Western	No NQC - hist. data	QF/Selfgen
INLAND_6_UNIT	24071	INLAND	13.8	30.30	1	Eastern	No NQC - hist. data	QF/Selfgen
MOBGEN_6_UNIT 1	24094	MOBGEN	13.8	20.20	1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24325	ORCOGEN	13.8	0.00	1	Western, Ellis	No NQC - hist. data	QF/Selfgen
NA	24327	THUMSGEN	13.8	0.00	1	Western	No NQC - hist. data	QF/Selfgen
NA	24330	OUTFALL1	13.8	0.00	1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24331	OUTFALL2	13.8	0.00	1	Western, El Nido	No NQC -	QF/Selfgen

							hist. data	
NA	24337	VENICE	13.8	0.00	1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24341	COYGEN	13.8	18.00	1	Western, Ellis	No NQC - hist. data	QF/Selfgen
NA	24342	FEDGEN	13.8	0.00	1	Western	No NQC - hist. data	QF/Selfgen
NA	25301	CLTNDREW	13.8	47.20	1	Eastern	No NQC - Pmax	QF/Selfgen
NA	25302	CLTNCTRY	13.8	47.20	1	Eastern	No NQC - Pmax	QF/Selfgen
NA	25303	CLTNAGUA	13.8	45.00	1	Eastern	No NQC - Pmax	QF/Selfgen
NA	29338	CLEARGEN	13.8	0.00	1	Eastern	No NQC - hist. data	QF/Selfgen
NA	29339	DELGEN	13.8	0.00	1	Eastern	No NQC - hist. data	QF/Selfgen
NA	24324	SANIGEN	13.8	6.80	D1	Eastern	No NQC - hist. data	QF/Selfgen
NA	24332	PALOGEN	13.8	3.20	D1	Western, El Nido	No NQC - hist. data	QF/Selfgen
RVSIDE_2_RERCU3	24299	RERC2G3	13.8	50.00	1	Eastern	No NQC - Pmax	MUNI
RVSIDE_2_RERCU4	24300	RERC2G4	13.8	50.00	1	Eastern	No NQC - Pmax	MUNI

Major new projects modeled:

1. 2 small new resources have been modeled

Critical Contingency Analysis Summary

LA Basin Overall:

The most critical contingency for LA Basin is the loss of one Songs unit followed by Palo Verde-Devers 500 kV line, which could exceed the approved 6400 MW rating for the South of Lugo path. This limiting contingency establishes a LCR of 10,865 MW in 2012 (includes 850 MW of QF, 33 MW of Wind, 900 MW of Muni and 2246 MW of Nuclear generation) as the minimum generation capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

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

Gen Bus	Gen Name	Gen ID	MW Eff. Fact (%)
24052	MTNVIST3	3	34

24053	MTNVIST4	4	34
24071	INLAND	1	33
25422	ETI MWDG	1	33
29305	ETWPKGEN	1	33
24905	RVCANAL1	R1	26
24906	RVCANAL2	R2	26
24907	RVCANAL3	R3	26
24908	RVCANAL4	R4	26
24921	MNTV-CT1	1	26
24922	MNTV-CT2	1	26
24923	MNTV-ST1	1	26
24924	MNTV-CT3	1	26
24925	MNTV-CT4	1	26
24926	MNTV-ST2	1	26
24242	RERC1G	1	26
24243	RERC2G	1	26
24242	RERC1G	1	26
24243	RERC2G	1	26
24244	SPRINGEN	1	26
25301	CLTNDREW	1	26
25302	CLTNCTRY	1	26
25303	CLTNAGUA	1	26
25603	DVLCYN3G	3	25
25604	DVLCYN4G	4	25
25648	DVLCYN1G	1	24
25649	DVLCYN2G	2	24
29041	IEEC-G1	1	24
29042	IEEC-G2	2	24
25203	ANAHEIMG	1	22
25632	TERAWND	QF	22
25634	BUCKWND	QF	22
25635	ALTWIND	Q1	22
25635	ALTWIND	Q2	22
25637	TRANWND	QF	22
25639	SEAWIND	QF	22
25640	PANAERO	QF	22
25645	VENWIND	EU	22
25645	VENWIND	Q2	22
25645	VENWIND	Q1	22
25646	SANWIND	Q2	22
29190	WINTECX2	1	22
29191	WINTECX1	1	22
29180	WINTEC8	1	22

24815	GARNET	QF	22
24815	GARNET	W3	22
24815	GARNET	W2	22
29023	WINTEC4	1	22
29060	SEAWEST	S1	22
29060	SEAWEST	S3	22
29060	SEAWEST	S2	22
29260	ALTAMSA4	1	22
29290	CABAZON	1	22
29021	WINTEC6	1	22
25657	MJVSPHN1	1	22
25658	MJVSPHN2	2	22
25659	MJVSPHN3	3	22
24030	DELGEN	1	21
25633	CAPWIND	QF	21
29061	WHITEWTR	1	21
24026	CIMGEN	D1	21
24140	SIMPSON	D1	21
29309	BARPKGEN	1	20
29307	MRLPKGEN	1	19
29338	CLEARGEN	1	19
29339	DELGEN	1	19
24066	HUNT1 G	1	18
24067	HUNT2 G	2	18
24167	HUNT3 G	3	18
24168	HUNT4 G	4	18
24129	S.ONOFR2	2	18
24130	S.ONOFR3	3	18
24133	SANTIAGO	1	18
24325	ORCOGEN	1	18
24341	COYGEN	1	18
24001	ALAMT1 G	1	17
24002	ALAMT2 G	2	17
24003	ALAMT3 G	3	17
24004	ALAMT4 G	4	17
24005	ALAMT5 G	5	17
24161	ALAMT6 G	6	17
24162	ALAMT7 G	R7	17
24063	HILLGEN	D1	16
29209	BLY1ST1	1	15
29207	BLY1CT1	1	15
29208	BLY1CT2	1	15
29953	SIGGEN	D1	15

24018	BRIGEN	1	14
24020	CARBGEN1	1	14
24064	HINSON	1	14
24070	ICEGEN	D1	14
24170	LBEACH12	2	14
24171	LBEACH34	3	14
24079	LBEACH7G	7	14
24080	LBEACH8G	8	14
24081	LBEACH9G	9	14
24062	HARBOR G	1	14
25510	HARBORG4	LP	14
24062	HARBOR G	HP	14
29308	CTRPKGEN	1	14
24139	SERRFGEN	D1	14
24170	LBEACH12	1	14
24171	LBEACH34	4	14
24173	LBEACH5G	R5	14
24174	LBEACH6G	R6	14
24327	THUMSGEN	1	14
24328	CARBGEN2	1	14
24337	VENICE	1	14
24011	ARCO 1G	1	13
24012	ARCO 2G	2	13
24013	ARCO 3G	3	13
24014	ARCO 4G	4	13
24163	ARCO 5G	5	13
24164	ARCO 6G	6	13
24022	CHEVGEN1	1	13
24023	CHEVGEN2	2	13
24047	ELSEG3 G	3	13
24048	ELSEG4 G	4	13
24094	MOBGEN1	1	13
24121	REDON5 G	5	13
24122	REDON6 G	6	13
24123	REDON7 G	7	13
24124	REDON8 G	8	13
24329	MOBGEN2	1	13
24330	OUTFALL1	1	13
24331	OUTFALL2	1	13
24332	PALOGEN	D1	13
24333	REDON1 G	R1	13
24334	REDON2 G	R2	13
24335	REDON3 G	R3	13

24336	REDON4 G	R4	13
24241	MALBRG3G	S3	11
24240	MALBRG2G	C2	11
24239	MALBRG1G	C1	11
29951	REFUSE	D1	11
24342	FEDGEN	1	11
29007	BRODWYSC	1	9
29005	PASADNA1	1	8
29006	PASADNA2	1	8

Western Sub-Area:

The most critical contingency for the Western sub-area is the loss of Serrano-Villa Park #1 or #2 230 kV line followed by the loss of the Serrano-Lewis 230 kV line or vice versa, which would result in thermal overload of the remaining Serrano-Villa Park 230 kV line. This limiting contingency establishes a LCR of 5785 MW (includes 559 MW of QF, 6 MW of Wind, 387 MW of Muni and 2246 MW of nuclear generation) in 2012 as the generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Ellis sub-area

The most critical contingency for the Ellis sub-area is the loss of the Barre to Ellis 230 kV line followed by the loss of the Santiago to S.Onofre #1 and #2 230 kV lines, which would cause voltage collapse. This limiting contingency establishes a LCR of 474 MW in 2012 (which includes 18 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

El Nido sub-area

There are two most critical contingencies for the El Nido sub-area that cause the same LCR need:

1. The loss of the La Fresa-Redondo #1 and #2 230 kV lines which could overload La Fresa-Hinson 230 kV line.
2. The loss of the La Fresa – Hinson 230 kV line followed by the loss of the La Fresa – Redondo #1 and #2 230 kV lines, which would cause voltage collapse.

These two limiting contingencies establish a LCR of 362 MW in 2012 (which includes 27 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Changes compared to last year's results:

Overall the load forecast went up by 45 MW resulting in an increase in LCR by 276 MW. The higher LCR increase is due in part to load allocation change, between LA Basin, Big Creek Ventura and the rest of SCE system based on new CEC load forecast and the decrease in LCR needs for the San Diego area due to the new Sunrise Power Link.

LA Basin Overall Requirements:

2012	QF/Wind (MW)	Muni (MW)	Nuclear (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	883	900	2246	8054	12083

2012	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[23]	10,865	0	10,865
Category C (Multiple)[24]	10,865	0	10,865

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

9. Big Creek/Ventura Area

Area Definition

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

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

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

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

Total 2012 busload within the defined area is 4260 MW with 78 MW of losses and 355 MW of pumps resulting in total load + losses + pumps of 4693 MW.

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

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ALAMO_6_UNIT	25653	ALAMO SC	13.8	16.00	1	Big Creek	Aug NQC	Market
ANTLPE_2_QF	24457	ARBWIND	66	2.90	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	24458	ENCANWND	66	15.03	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	24459	FLOWIND	66	5.43	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	24460	DUTCHWND	66	1.86	1	Big Creek	Aug NQC	Wind

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

ANTLPE_2_QF	24465	MORWIND	66	7.45	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	24491	OAKWIND	66	2.40	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28501	MIDWIND	12	2.40	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28502	SOUTHWND	12	0.88	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28503	NORTHWND	12	2.58	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28504	ZONDWND1	12	1.76	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28505	ZONDWND2	12	1.70	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28506	BREEZE1	12	0.60	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28507	BREEZE2	12	1.06	1	Big Creek	Aug NQC	Wind
BIGCRK_2_EXESWD	24306	B CRK1-1	7.2	19.38	1	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24308	B CRK2-1	13.8	49.48	1	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24311	B CRK3-1	13.8	34.09	1	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24317	MAMOTH1G	13.8	91.07	1	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24323	PORTAL	4.8	9.35	1	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24306	B CRK1-1	7.2	21.03	2	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24308	B CRK2-1	13.8	50.64	2	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24311	B CRK3-1	13.8	34.09	2	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24318	MAMOTH2G	13.8	91.07	2	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24307	B CRK1-2	13.8	21.03	3	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24309	B CRK2-2	7.2	18.22	3	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24312	B CRK3-2	13.8	34.09	3	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24307	B CRK1-2	13.8	30.39	4	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24309	B CRK2-2	7.2	19.19	4	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24312	B CRK3-2	13.8	39.93	4	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24310	B CRK2-3	7.2	16.55	5	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24313	B CRK3-3	13.8	37.99	5	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24310	B CRK2-3	7.2	18.02	6	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24314	B CRK 4	11.5	49.09	41	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24314	B CRK 4	11.5	49.28	42	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24315	B CRK 8	13.8	23.76	81	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24315	B CRK 8	13.8	42.85	82	Big Creek, Rector, Vestal	Aug NQC	Market
EASTWD_7_UNIT	24319	EASTWOOD	13.8	199.00	1	Big Creek, Rector, Vestal		Market
EDMONS_2_NSPIN	25605	EDMON1AP	14.4	24.11	1	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25606	EDMON2AP	14.4	24.11	2	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25607	EDMON3AP	14.4	24.11	3	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25607	EDMON3AP	14.4	24.11	4	Big Creek	Pumps	MUNI

EDMONS_2_NSPIN	25608	EDMON4AP	14.4	24.11	5	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25608	EDMON4AP	14.4	24.11	6	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25609	EDMON5AP	14.4	24.11	7	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25609	EDMON5AP	14.4	24.11	8	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25610	EDMON6AP	14.4	24.11	9	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25610	EDMON6AP	14.4	24.11	10	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25611	EDMON7AP	14.4	24.10	11	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25611	EDMON7AP	14.4	24.10	12	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25612	EDMON8AP	14.4	24.10	13	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25612	EDMON8AP	14.4	24.10	14	Big Creek	Pumps	MUNI
GOLETA_2_QF	24057	GOLETA	66	0.17		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	QF/Selfgen
GOLETA_6_ELLWOD	28004	ELLWOOD	13.8	54.00	1	Ventura, S.Clara, Moorpark		Market
GOLETA_6_EXGEN	24057	GOLETA	66	0.35		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	QF/Selfgen
GOLETA_6_GAVOTA	24057	GOLETA	66	1.50		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	QF/Selfgen
GOLETA_6_TAJIGS	24057	GOLETA	66	2.77		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	Market
KERRGN_1_UNIT 1	24437	KERNRVR	66	11.75	1	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	28051	PSTRIAG1	18	157.90	G1	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	28052	PSTRIAG2	18	157.90	G2	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	28054	PSTRIAG3	18	157.90	G3	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	28053	PSTRIAS1	18	162.40	S1	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	28055	PSTRIAS2	18	78.90	S2	Big Creek	Aug NQC	Market
MNDALY_7_UNIT 1	24089	MANDLY1G	13.8	215.00	1	Ventura, Moorpark		Market
MNDALY_7_UNIT 2	24090	MANDLY2G	13.8	215.29	2	Ventura, Moorpark		Market
MNDALY_7_UNIT 3	24222	MANDLY3G	16	130.00	3	Ventura, S.Clara, Moorpark		Market
MONLTH_6_BOREL	24456	BOREL	66	8.75	1	Big Creek	Aug NQC	QF/Selfgen
MOORPK_2_CALABS	24099	MOORPARK	230	6.96		Ventura, Moorpark	Not modeled	Market
MOORPK_6_QF	24098	MOORPARK	66	26.61		Ventura, Moorpark	Not modeled Aug NQC	QF/Selfgen
MOORPK_7_UNITA1	24098	MOORPARK	66	1.10		Ventura, Moorpark	Not modeled Aug NQC	QF/Selfgen
OMAR_2_UNITS	24102	OMAR 1G	13.8	77.25	1	Big Creek		QF/Selfgen
OMAR_2_UNITS	24103	OMAR 2G	13.8	77.25	2	Big Creek		QF/Selfgen
OMAR_2_UNITS	24104	OMAR 3G	13.8	77.25	3	Big Creek		QF/Selfgen
OMAR_2_UNITS	24105	OMAR 4G	13.8	77.25	4	Big Creek		QF/Selfgen
ORMOND_7_UNIT 1	24107	ORMOND1G	26	741.27	1	Ventura, Moorpark		Market
ORMOND_7_UNIT 2	24108	ORMOND2G	26	775.00	2	Ventura, Moorpark		Market
OSO_6_NSPIN	25614	OSO A P	13.2	2.30	1	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25614	OSO A P	13.2	2.30	2	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25614	OSO A P	13.2	2.30	3	Big Creek	Pumps	MUNI

OSO_6_NSPIN	25614	OSO A P	13.2	2.30	4	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	2.30	5	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	2.30	6	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	2.30	7	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	2.30	8	Big Creek	Pumps	MUNI
PANDOL_6_UNIT	24113	PANDOL	13.8	21.61	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
PANDOL_6_UNIT	24113	PANDOL	13.8	17.61	2	Big Creek, Vestal	Aug NQC	QF/Selfgen
RECTOR_2_KAWEAH	24212	RECTOR	66	0.30		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
RECTOR_2_KAWH 1	24212	RECTOR	66	0.41		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
RECTOR_2_QF	24212	RECTOR	66	2.34		Big Creek, Rector, Vestal	Not modeled Aug NQC	QF/Selfgen
RECTOR_7_TULARE	24212	RECTOR	66	1.60		Big Creek, Rector, Vestal	Not modeled	QF/Selfgen
SAUGUS_6_MWDFTH	24135	SAUGUS	66	6.40		Big Creek	Not modeled Aug NQC	MUNI
SAUGUS_6_PTCHGN	24118	PITCHGEN	13.8	20.31	1	Big Creek	Aug NQC	MUNI
SAUGUS_6_QF	24135	SAUGUS	66	1.17		Big Creek	Not modeled Aug NQC	QF/Selfgen
SAUGUS_7_LOPEZ	24135	SAUGUS	66	5.37		Big Creek	Not modeled Aug NQC	QF/Selfgen
SNCLRA_6_OXGEN	24110	OXGEN	13.8	32.53	1	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SNCLRA_6_PROCGN	24119	PROCGEN	13.8	44.65	1	Ventura, S.Clara, Moorpark	Aug NQC	Market
SNCLRA_6_QF	24127	S.CLARA	66	1.73	1	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SNCLRA_6_WILLMT	24159	WILLAMET	13.8	12.64	1	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SPRGVL_2_QF	24215	SPRINGVL	66	0.19		Big Creek, Rector, Vestal	Not modeled Aug NQC	QF/Selfgen
SPRGVL_2_TULE	24215	SPRINGVL	66	0.23		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
SPRGVL_2_TULESC	24215	SPRINGVL	66	0.42		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
SYCAMR_2_UNITS	24143	SYCCYN1G	13.8	64.47	1	Big Creek	Aug NQC	QF/Selfgen
SYCAMR_2_UNITS	24144	SYCCYN2G	13.8	64.47	2	Big Creek	Aug NQC	QF/Selfgen
SYCAMR_2_UNITS	24145	SYCCYN3G	13.8	64.47	3	Big Creek	Aug NQC	QF/Selfgen
SYCAMR_2_UNITS	24146	SYCCYN4G	13.8	64.46	4	Big Creek	Aug NQC	QF/Selfgen
TENGEN_2_PL1X2	24148	TENNGEN1	13.8	18.39	1	Big Creek	Aug NQC	Market
TENGEN_2_PL1X2	24149	TENNGEN2	13.8	18.38	2	Big Creek	Aug NQC	Market
VESTAL_2_KERN	24152	VESTAL	66	2.02	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
VESTAL_6_QF	24152	VESTAL	66	2.17		Big Creek, Vestal	Not modeled Aug NQC	QF/Selfgen
VESTAL_6_ULTRGN	24150	ULTRAGEN	13.8	34.76	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
VESTAL_6_WDFIRE	28008	LAKEGEN	13.8	5.68	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
WARNE_2_UNIT	25651	WARNE1	13.8	38.00	1	Big Creek	Aug NQC	Market
WARNE_2_UNIT	25652	WARNE2	13.8	38.00	1	Big Creek	Aug NQC	Market

NA	24340	CHARMIN	13.8	15.20	1	Ventura, S.Clara, Moorpark	No NQC - hist. data	QF/Selfgen
NA	24372	KR 3-1	13.8	0.00	1	Big Creek, Vestal	No NQC - hist. data	QF/Selfgen
NA	24373	KR 3-2	13.8	0.00	1	Big Creek, Vestal	No NQC - hist. data	QF/Selfgen
NA	24422	PALMDALE	66	0.00	1	Big Creek	No NQC - hist. data	Market
NA	24436	GOLDTOWN	66	0.00	1	Big Creek	No NQC - hist. data	Market
NA	24362	Exgen2	13.8	0.00	G1	Ventura, S.Clara, Moorpark	No NQC - hist. data	QF/Selfgen
NA	24326	Exgen1	13.8	0.00	S1	Ventura, S.Clara, Moorpark	No NQC - hist. data	QF/Selfgen

Major new projects modeled: None

Critical Contingency Analysis Summary

Big Creek/Ventura overall:

The most critical contingency is the loss of Sylmar-Pardee #1 (or # 2) line followed by Ormond Beach Unit #2, which could thermally overload the remaining Sylmar-Pardee 230 kV line. This limiting contingency establishes a LCR of 3093 MW in 2012 (includes 762 MW of QF, 383 MW of Muni and 46 MW of Wind generation) as the minimum generation capacity necessary for reliable load serving capability within this area.

The second most critical contingency is the loss of the Lugo-Victorville 500 kV followed by Sylmar-Pardee #1 or #2 230 kV line, which could thermally overload the remaining Sylmar-Pardee 230 kV line. This limiting contingency establishes a LCR of 3009 MW in 2012 (includes 762 MW of QF, 383 MW of Muni and 46 MW of Wind generation).

Effectiveness factors:

The following table has units that have at least 5% effectiveness to any one of the Sylmar-Pardee 230 kV lines after the loss of the Lugo-Victorville 500 kV followed by one of the other Sylmar-Pardee 230 kV line in this area:

Gen Bus	Gen Name	Gen ID	MW Eff. Fctr. (%)
24009	APPGEN1G	1	29
24010	APPGEN2G	2	29

24107	ORMOND1G	1	29
24108	ORMOND2G	2	29
24118	PITCHGEN	1	28
24148	TENNGEN1	1	28
24149	TENNGEN2	2	28
24089	MANDLY1G	1	27
24090	MANDLY2G	2	27
24110	OXGEN	1	27
24119	PROCGEN	1	27
24159	WILLAMET	1	27
25651	WARNE1	1	27
25652	WARNE2	1	27
28004	ELLWOOD	1	27
24361	EXGEN1	1	27
24362	EXGEN2	2	27
28051	PSTRIAG1	G1	26
25606	EDMON2AP	2	26
25607	EDMON3AP	3	26
25607	EDMON3AP	4	26
25608	EDMON4AP	5	26
25608	EDMON4AP	6	26
25609	EDMON5AP	7	26
25609	EDMON5AP	8	26
25610	EDMON6AP	9	26
25610	EDMON6AP	10	26
25611	EDMON7AP	11	26
25611	EDMON7AP	12	26
25612	EDMON8AP	13	26
25612	EDMON8AP	14	26
28054	PSTRIAG3	G3	25
25615	OSO B P	7	25
25615	OSO B P	8	25
28952	CAMGEN	13.8	25
24127	S.CLARA	1	25
24340	CHARMIN	1	25
28055	PSTRIAS2	S2	24
28053	PSTRIAS1	S1	24
28052	PSTRIAG2	G2	24
25605	EDMON1AP	1	24
24143	SYCCYN1G	1	24
24144	SYCCYN2G	2	24
24145	SYCCYN3G	3	24
24146	SYCCYN4G	4	24
24102	OMAR 1G	1	23
24103	OMAR 2G	2	23
24104	OMAR 3G	3	23
24105	OMAR 4G	4	23
25614	OSO A P	1	23
25614	OSO A P	2	23
25653	ALAMO SC	1	23

24222	MANDLY3G	3	20
28008	LAKEGEN	1	20
24150	ULTRAGEN	1	20
24152	VESTAL	1	20
24372	KR 3-1	1	45
24373	KR 3-2	2	45
24370	KAWGEN	1	45
24319	EASTWOOD	1	20
24306	B CRK1-1	1	20
24306	B CRK1-1	2	20
24307	B CRK1-2	3	20
24307	B CRK1-2	4	20
24308	B CRK2-1	1	20
24308	B CRK2-1	2	20
24309	B CRK2-2	3	20
24309	B CRK2-2	4	20
24310	B CRK2-3	5	20
24310	B CRK2-3	6	20
24311	B CRK3-1	1	20
24311	B CRK3-1	2	20
24312	B CRK3-2	3	20
24312	B CRK3-2	4	20
24313	B CRK3-3	5	20
24314	B CRK 4	41	20
24314	B CRK 4	42	20
24315	B CRK 8	81	20
24315	B CRK 8	82	20
24317	MAMOTH1G	1	20
24318	MAMOTH2G	2	20
24113	PANDOL	1	19
24113	PANDOL	2	19
24437	KERNRVR	1	18
24459	FLOWIND	1	14
24436	GOLDTOWN	1	14
28501	MIDWIND	1	14
24457	ARBWIND	1	13
24456	BOREL	1	12
24458	ENCANWND	1	12
24460	DUTCHWND	1	12
24465	MORWIND	1	12
28503	NORTHWND	1	12
28504	ZONDWND1	1	12
28505	ZONDWND2	1	12
25618	PEARBMBP	5	6
25618	PEARBMBP	6	6
25619	PEARBMCP	7	6
25619	PEARBMCP	8	6
25617	PEARBMAP	1	5
25617	PEARBMAP	2	5
25620	PEARBMDP	9	5

24136	SEAWEST	1	5

Rector Sub-area

The most critical contingency for the Rector sub-area is the loss of one of the Rector-Vestal 230 kV lines with the Eastwood unit out of service, which would thermally overload the remaining Rector-Vestal 230 kV line. This limiting contingency establishes a LCR of 525 MW (includes 4 MW of QF generation) in 2012 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

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

Vestal Sub-area

The most critical contingency for the Vestal sub-area is the loss of one of the Magunden-Vestal 230 kV lines with the Eastwood unit out of service, which would thermally overload the remaining Magunden-Vestal 230 kV line. This limiting contingency establishes a LCR of 776 MW in 2012 (which includes 88 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

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

S. Clara sub-areas

The most critical contingency for the S.Clara sub-area is the loss of the Pardee to S.Clara 230 kV line followed by the loss of the Moorpark to S.Clara #1 and #2 230 kV lines, which would cause voltage collapse. This limiting contingency establishes a LCR of 296 MW in 2012 (which includes 64 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Moorpark sub-areas

The most critical contingency for the Moorpark sub-area is the loss of one of the Pardee to Moorpark 230 kV lines followed by the loss of the remaining two Moorpark to Pardee 230 kV lines, which would cause voltage collapse. This limiting contingency establishes a LCR of 377 MW in 2012 (which includes 92 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Changes compared to last year's results:

Overall the load forecast went up by 45 MW. The overall effect is that the LCR has increase by 307 MW. The higher LCR increase is due to load allocation change within the Big Creek Ventura.

Big Creek Overall Requirements:

2012	QF/Wind (MW)	MUNI (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	808	383	4041	5232

2012	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[25]	3093	0	3093
Category C (Multiple)[26]	3093	0	3093

[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.

10. San Diego Area

Area Definition

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

1) Imperial Valley – Miguel 500 kV Line
2) Imperial Valley – Central 500kV Line
3) Otay Mesa – Tijuana 230 kV Line
4) San Onofre - San Luis Rey #1 230 kV Line
5) San Onofre - San Luis Rey #2 230 kV Line
6) San Onofre - San Luis Rey #3 230 kV Line
7) San Onofre – Talega #1 230 kV Line
8) San Onofre – Talega #2 230 kV Line

The substations that delineate the San Diego Area are:

1) Imperial Valley is out Miguel is in
2) Imperial Valley is out Central is in
3) Otay Mesa is in Tijuana is out
4) San Onofre is out San Luis Rey is in
5) San Onofre is out San Luis Rey is in
6) San Onofre is out San Luis Rey is in
7) San Onofre is out Talega is in
8) San Onofre is out Talega is in

Total 2012 busload within the defined area: 4770 MW with 74 MW of losses resulting in total load + losses of 4844 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BORDER_6_UNITA1	22149	CALPK_BD	13.8	43.80	1	Border		Market
CBRLLO_6_PLSTP1	22092	CABRILLO	69	2.15	1		Aug NQC	QF/Selfgen
CCRITA_7_RPPCHF	22124	CHCARITA	138	2.63	1		Aug NQC	QF/Selfgen
CHILLS_1_SYCLFL	22120	CARLTNHS	138	0.43	1		Aug NQC	QF/Selfgen
CHILLS_7_UNITA1	22120	CARLTNHS	138	1.26	2		Aug NQC	QF/Selfgen
CPSTNO_7_PRMADS	22112	CAPSTRNO	138	3.49	1		Aug NQC	QF/Selfgen
CRSTWD_6_KUMYAY	22915	KUMEYAAY	34.5	6.46	1		Aug NQC	Wind
DIVSON_6_NSQF	22172	DIVISION	69	36.47	1		Aug NQC	QF/Selfgen

EGATE_7_NOCITY	22204	EASTGATE	69	0.21	1		Aug NQC	QF/Selfgen
ELCAJN_6_LM6K	23320	C509	13.8	48.00	1	El Cajon		Market
ELCAJN_6_UNITA1	22150	CALPK_EC	13.8	42.20	1	El Cajon		Market
ELCAJN_7_GT1	22212	ELCAJNGT	12.5	16.00	1	El Cajon		Market
ENCINA_7_EA1	22233	ENCINA 1	14.4	106.00	1			Market
ENCINA_7_EA2	22234	ENCINA 2	14.4	104.00	1			Market
ENCINA_7_EA3	22236	ENCINA 3	14.4	110.00	1			Market
ENCINA_7_EA4	22240	ENCINA 4	22	300.00	1			Market
ENCINA_7_EA5	22244	ENCINA 5	24	330.00	1			Market
ENCINA_7_GT1	22248	ENCINAGT	12.5	14.00	1			Market
ESCNDO_6_PL1X2	22257	ESGEN	13.8	35.50	1			Market
ESCNDO_6_UNITB1	22153	CALPK_ES	13.8	45.50	1			Market
ESCO_6_GLMQF	22332	GOALLINE	69	44.04	1	Esco	Aug NQC	QF/Selfgen
KEARNY_7_KY1	22377	KEARNGT1	12.5	16.00	1	Rose Canyon, Mission		Market
KEARNY_7_KY2	22373	KEARN2AB	12.5	15.02	1	Rose Canyon, Mission		Market
KEARNY_7_KY2	22374	KEARN2CD	12.5	15.02	1	Rose Canyon, Mission		Market
KEARNY_7_KY2	22373	KEARN2AB	12.5	15.02	2	Rose Canyon, Mission		Market
KEARNY_7_KY2	22374	KEARN2CD	12.5	13.95	2	Rose Canyon, Mission		Market
KEARNY_7_KY3	22375	KEARN3AB	12.5	14.98	1	Rose Canyon, Mission		Market
KEARNY_7_KY3	22376	KEARN3CD	12.5	14.98	1	Rose Canyon, Mission		Market
KEARNY_7_KY3	22375	KEARN3AB	12.5	16.05	2	Rose Canyon, Mission		Market
KEARNY_7_KY3	22376	KEARN3CD	12.5	14.98	2	Rose Canyon, Mission		Market
LARKSP_6_UNIT 1	22074	LRKSPBD1	13.8	46.00	1	Border		Market
LARKSP_6_UNIT 2	22075	LRKSPBD2	13.8	46.00	1	Border		Market
MRGT_6_MEF2	22487	MFE_MR2	13.8	47.90	1	Mission		Market
MRGT_6_MMAREF	22486	MFE_MR1	13.8	46.60	1	Mission		Market
MRGT_7_UNITS	22488	MIRAMRGT	12.5	18.55	1	Mission		Market
MRGT_7_UNITS	22488	MIRAMRGT	12.5	17.45	2	Mission		Market
MSHGTS_6_MMARLF	22448	MESAHGTS	69	2.94	1	Mission	Aug NQC	QF/Selfgen
MSSION_2_QF	22496	MISSION	69	0.80	1		Aug NQC	QF/Selfgen
NIMTG_6_NIQF	22576	NOISLMTR	69	34.16	1		Aug NQC	QF/Selfgen
OGROVE_6_PL1X2	22628	PA99MWQ1	13.8	49.95	1			Market
OGROVE_6_PL1X2	22629	PA99MWQ2	13.8	49.95	2			Market
OTAY_6_PL1X2	22617	OYGEN	13.8	35.50	1			Market
OTAY_6_UNITB1	22604	OTAY	69	2.90	1		Aug NQC	QF/Selfgen
OTAY_7_UNITC1	22604	OTAY	69	2.70	3		Aug NQC	QF/Selfgen
OTMESA_2_PL1X3	22605	OTAYMGT1	18	185.06	1			Market
OTMESA_2_PL1X3	22606	OTAYMGT2	18	185.06	1			Market
OTMESA_2_PL1X3	22607	OTAYMST1	16	233.48	1			Market
PALOMR_2_PL1X3	22262	PEN_CT1	18	162.17	1			Market
PALOMR_2_PL1X3	22263	PEN_CT2	18	162.17	1			Market
PALOMR_2_PL1X3	22265	PEN_ST	18	240.66	1			Market
PTLOMA_6_NTCCGN	22660	POINTLMA	69	1.64	2		Aug NQC	QF/Selfgen
PTLOMA_6_NTCQF	22660	POINTLMA	69	17.18	1		Aug NQC	QF/Selfgen
SAMPSN_6_KELCO1				2.72			Aug NQC	QF/Selfgen
SMRCOS_6_UNIT 1	22724	SANMRCOS	69	0.65	1		Aug NQC	QF/Selfgen
NA	22916	PFC-AVC	0.6	0.00	1		No NQC -	QF/Selfgen

							hist. data	
LAKHDG_6_UNIT 1	22625	LKHODG1	13.8	20.00	1	Bernardo	No NQC - Pmax	Market
LAKHDG_6_UNIT 2	22626	LKHODG2	13.8	20.00	2	Bernardo	No NQC - Pmax	Market
New unit	23120	BULLMOOS	13.8	27.00	1	Border	No NQC - Pmax	Market

Major new projects modeled:

1. Sunrise Power Link Project (Southern Route)
2. 3 small new resources and the LGIP upgrades associated with Bullmoose Project (Otay – Otay Lake Tap 69kV, TL649 reconductor)
3. Retirement of South Bay Power Plant
4. Eastgate – Rose Canyon 69kV (TL6927) reconductor

Critical Contingency Analysis Summary

El Cajon Sub-area:

The most critical contingency for the El Cajon sub-area is the loss of the El Cajon-Jamacha 69 kV line (TL624) followed by the loss of Miguel-Granite-Los Coches 69 kV line (TL632), which would thermally overload the Garfield-Murray 69 kV line. This limiting contingency establishes a LCR of 35 MW (including 0 MW of QF generation) in 2012 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area (El Cajon Peaker, El Cajon GT, and new peaker at El Cajon substation) have the same effectiveness factor.

Rose Canyon Sub-area

This sub-area has been eliminated due to recently approved transmission project, TL6927, Eastgate-Rose Canyon 69 kV reconductor. If the project reconductoring is delayed beyond June 1, 2012, the most critical contingency for the Rose Canyon sub area will be the loss of Imperial Valley – Miguel 500kV line (TL50001) followed by the loss of Rose Canyon – Miramar - Penasquitos 69kV line (TL664A) would thermally overload Eastgate – Rose Canyon 69kV line (TL6927). This limiting contingency would establish a local capacity need of 53 MW (includes 0 MW of QF generation) in 2012.

Effectiveness factors:

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

Mission Sub-area

The most critical contingency for the Mission sub-area is the loss of Mission - Kearny 69 kV line (TL663) followed by the loss of Mission – Mesa Heights 69kV line (TL676), which would thermally overload the Mission - Clairmont 69kV line (TL670). This limiting contingency establishes a local capacity need of 233 MW (including 3 MW of QF generation) in 2012.

Effectiveness factors:

Miramar Energy Facility units and Miramar GTs (Cabrillo Power II) are 6% effective, Miramar Landfill unit and all Kearny peakers are 32% effective.

Bernardo Sub-area:

The most critical contingency for the Bernardo sub-area is the loss of Artesian - Sycamore 69 kV line followed by the loss of Poway-Rancho Carmel 69 kV line, which would thermally overload the Felicita Tap-Bernardo 69 kV line (TL689). This limiting contingency establishes a LCR of 105 MW (including 0 MW of QF generation and 65 MW of deficiency) in 2012 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

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

Border Sub-area

Sub-area eliminated due to new generation project upgrade, reconductor TL649A, Otay-Otay Lakes Tap 69 kV. If the project reconductoring is delayed beyond June 1, 2012, the most critical contingency for the Border sub area will be the loss of Border – Miguel 69 kV line (TL6910) followed by the loss of Imperial Beach-Otay-San Ysidro 69 kV line (TL623), which would thermally overload Otay-Otay Lake Tap (TL649). This limiting contingency would establish a local capacity need of 27 MW (includes 0 MW of QF generation) in 2012 as the minimum generation capacity necessary for reliable load serving capability within this sub area.

Effectiveness factors:
If the reconductoring project is completed by June 1, 2012, no units will be needed. If the project is not completed, Border Cal Peak, Larkspur and Bullmoose all have the same effectiveness factor.

Esco Sub-area
The most critical contingency for the Esco sub-area is the loss of Poway-Pomerado 69 kV line followed by the loss of Bernardo-Rancho Carmel 69kV line which would thermally overload the Esco-Escondido 69 kV line. This limiting contingency establishes a LCR of 74 MW (including 44 MW of QF generation and 30 MW of deficiency) in 2012 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

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

San Diego overall:
The most limiting contingency in the San Diego area is described by the outage of the 500 kV Southwest Power Link (SWPL) between Imperial Valley and Miguel Substations over-lapping with an outage of the Otay Mesa Combined-Cycle Power plant (603 MW) while staying within the 1000 MW rating of Imperial Valley - Central 500 kV line (Sunrise Power Link). Post-contingency import limit of 3,500 MW is not the most limiting condition here. Sunrise Power Link hits 1,000 MW before SDGE import hits 3,500 MW. This contingency establishes a LCR of 2849 MW in 2012 (includes 156 MW of QF

generation and 6 MW of Wind) as the minimum generation capacity necessary for reliable load serving capability within this area.

If the Sunrise Power Link is delayed beyond June 1, 2012, the most critical contingency for the San Diego overall area will be the loss of Imperial Valley – Miguel 500 kV line with Otay Mesa Power Plant out of service, which would require the system to be within the South of SONGS path rating of 2500 MW. This limiting contingency would establish a local capacity need of 2989 MW (includes 156 MW of QF generation and 6 MW of Wind) in 2012 as the minimum generation capacity necessary for reliable load serving capability within this sub area.

Effectiveness factors:

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

Greater IV-San Diego area:

The most limiting contingency in the Greater Imperial Valley-San Diego area is described by the outage of 500 kV Southwest Power Link (SWPL) between Imperial Valley and N. Gila Substations over-lapping with an outage of the Otay Mesa Combined-Cycle Power plant (603 MW) while staying within the South of San Onofre (WECC Path 44) non-simultaneous import capability rating of 2,500 MW. This limiting contingency establishes a local capacity need of 2804 MW in 2012 as the minimum capacity necessary for reliable load serving capability within this area. It is worth mentioning that there were no additional upgrades modeled between the IID and CAISO or CFE and CAISO control areas at Imperial Valley 230 kV bus in 2012 base case. The CAISO acknowledges that the LCR needs for the Greater Imperial Valley-San Diego area will decrease as additional transmission is constructed between the IID/CFE systems and Imperial Valley and more power is flowing in real-time from these control areas into the CAISO control area.

The Greater Imperial Valley/San Diego area and San Diego Overall LCR needs are very similar in magnitude. In future years, either of these areas may become more stringent depending on the study assumptions and future projects.

The CAISO will continue to use the existing San Diego boundary as a local area for year 2012 because the requirements of the Greater Imperial Valley/San Diego area are not binding during 2012 and because a delay in Sunrise Power Link construction would require even higher local requirement within the existing San Diego area.

Changes compared to last year's results:

Overall the load forecast went down by 182 MW and total resource capacity needed for LCR decreased by 297 MW. The addition of Sunrise Power Link is the reason for the further decrease in LCR beyond load forecast.

San Diego Overall Requirements:

2012	QF (MW)	Wind (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	156	6	2925	3087

2012	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[27]	2849	0	2849
Category C (Multiple)[28]	2849	95	2944

[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.

Rulemaking 12-03-014
Exhibit No.: ISO-18
Witness:

FINAL MANUAL

2013 LOCAL CAPACITY AREA TECHNICAL STUDY

Final Manual

2013 Local Capacity Area Technical Study

January 2012

Version

Prepared by:

California Independent System Operator

2013 Local Capacity Area Technical Study Manual
Table of Contents

Introduction

The Local Capacity Area Technical Study ("Technical Study" or "LCR Study") is intended to determine the minimum capacity needed in each identified transmission constrained "load pocket" or Local Capacity Area to ensure reliable grid operations. The existence of local capacity requirements precedes restructuring of the California electric system in 1998. Prior to restructuring, the investor-owned utilities operated integrated systems where conscious trade-offs were made between investing in transmission and generation. As a result, some areas where planned in a manner that consciously relied on local generation to supplement transmission capacity into the local area to satisfy demand and reliability requirements. Electric restructuring itself did not change the topology of the electric system and the physical need for local generation. Rather, it changed the means of access to such resources. The investor-owned utilities no longer owned much of the local generation, having been directed to divest a significant portion of their generation assets (so as to prevent the exercise of generation market power by the incumbent utilities). Consequently, prior to ISO start-up, it was determined that the ISO needed to have certain resources available to meet local reliability needs, and thus directly contracted with Reliability Must-Run or "RMR" generation for such purposes.

Over time, it has become more and more apparent that ISO should only be engaged in a rather small number of contracts in order to maintain the reliability of the grid and that the vast majority of the units needed to reliably serve local area load should be procured by Load Serving Entities (LSE). The adoption by the State of resource adequacy requirements facilitates this transition. The Technical Study works is intended to work in conjunction with resource adequacy requirements to ensure that the ISO has access to sufficient local generation to ensure reliability standards are satisfied.

There are several components of the reliability standards underlying the Technical Study. Consistent with the mandatory nature of the NERC Planning Standards, the ISO is under a statutory obligation to ensure efficient use and reliable operation of the transmission grid consistent with achievement of the NERC Planning Standards.[1] The ISO 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 Local Reliability Criteria, which reflect Reliability Criteria unique to the transmission systems of each Participating Transmission Owners ("PTOs"). Pursuant to its tariff authority, the ISO, in consultation with the PTOs and other stakeholders, has adopted ISO Grid Planning Standards intended to, among other things, interpret NERC Planning Standards and identify circumstances in which the ISO should apply standards more stringent than those adopted by NERC. Together, these pre-established criteria form Reliability Criteria to be followed in order to maintain desired performance of the ISO Controlled Grid under Contingency and steady state conditions. 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.,

[1] Pub. Utilities Code § 345

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.

The study process includes a number of opportunities for stakeholder input. This input is incorporated into the next phase of studies.

Study Objectives

Similar to studies performed for 2006-2012, the purpose of the 2013 Local Capacity Area Technical Study ("Technical Study" or "LCR Study") is to identify specific areas within the ISO Controlled Grid that have local reliability needs and to determine the minimum generation capacity (MW) that would be required to satisfy these local reliability requirements, while enforcing generation deliverability status and Maximum Import Capability for all common mode contingencies (Category A, B, C5).

Technical Study Assessment and Required Capacity Summary

Preface

The technical analysis the ISO performed for the 2012 calendar year to determine the local reliability requirements evaluated ten local areas within the ISO Controlled Grid where operational history has shown that local reliability issues exist. Seven of these areas (Humboldt, North Coast/North Bay, Greater Bay, Sierra, Stockton, Fresno and Kern) are in PG&E's service area; two (LA Basin and Big Creek/Ventura) are in SCE service area and one (San Diego) in SDG&E service area. A number of these areas are further subdivided as needed into sub-areas. A map of the areas is shown in Figure 1 below.

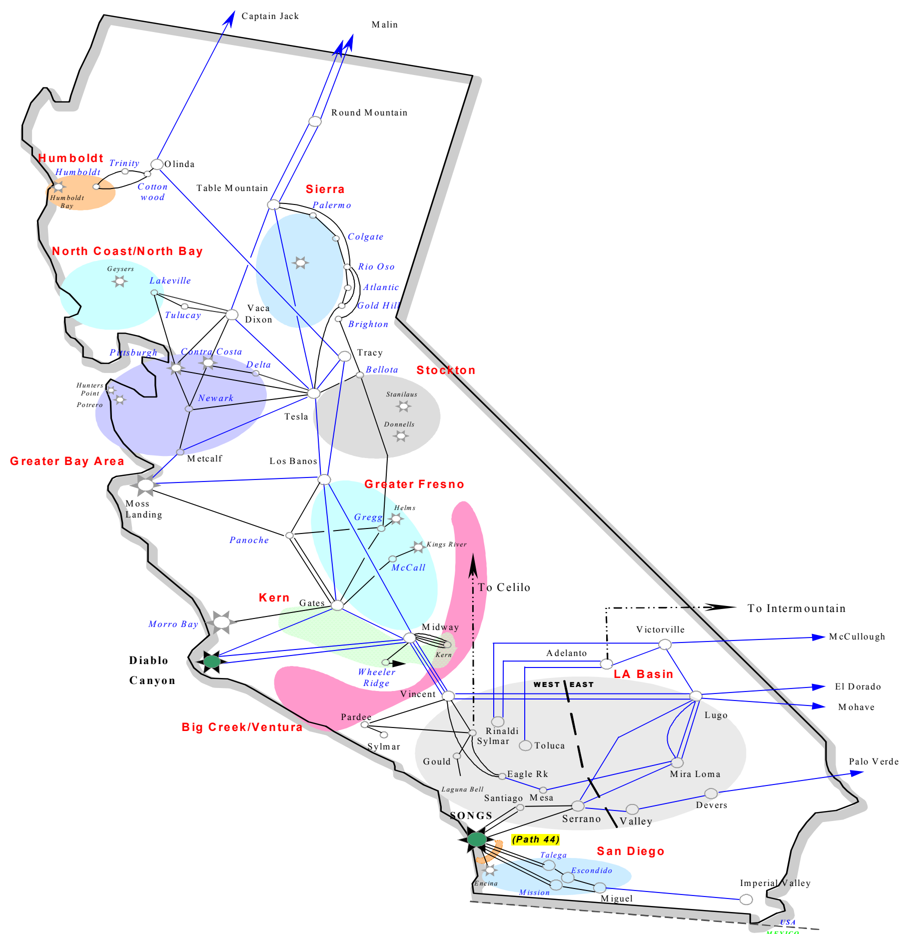


Figure 1 – Local Capacity Area Map

Base Case Input Assumptions

Transmission System Configuration:

The existing transmission system shall be modeled, including all projects operational on or before June 1, 2013 and all other feasible operational solutions brought forth by the PTOs and as agreed to by the ISO.

Review:

The majority of local areas peak in the summer time. In order to be consistent with past practices for base case development the ISO will model all transmission projects operational on or before June 1. Exemption: Humboldt area peaks in the winter and therefore only projects up to January 1, 2013 are included.

Risks:

Certain system modifications may have the impact of reducing Local Capacity Area Resource requirements ("LCR"). If so, the possibility exists that prior to the time the system modification is implemented, the ISO will be required to augment the quantity of capacity needed in a certain Local Capacity Area to account for the greater LCR that would otherwise exist in the absence of the assumed modification.

Generation Modeled:

All existing generation resources shall be modeled (less announced retirements) and shall also include all new generation projects that will be on-line and commercial on or before June 1, 2013. For new generation data should be available from the CEC web site: http://www.energy.ca.gov/sitingcases/all_projects.html or through the ISO interconnection process if no CEC license is required. Generation resources shall be dispatch up to the latest available net qualifying capacity or historical output values (if NQC not available) for purposes of the 2013 Technical Study.

Review:

The majority of local areas peak in the summer time. In order to be consistent with past practices for base case development, the ISO will model all generation projects operational on or before June 1, 2013. Exemption: Humboldt area peaks in the winter and therefore only new generation up to January 1, 2013 should be included.

Risks:

If the new generation resources account for a significant portion of the LCR requirements, then the possibility exists that the ISO cannot manage the transmission system in the first few moths of the year without additional (existing) generation (beyond the minimum contracted amount – required after June 1) being made available to the ISO. As such, the ISO may be required to augment the quantity of capacity available in the first few months.

Load Forecast:

A 1-in-10 year summer peak load forecast shall be used.

Review:

An overwhelming majority of stakeholders and the ISO have indicated that the Technical Study should be integrated into the annual transmission planning process in order select or identify the optimal alternative among potential solutions (transmission, generation or demand side) to resolve the most stringent constraints into the local area. The transmission planning process uses the 1-in-10 year summer peak forecast for local areas (See ISO Planning Standards at: http://www.caiso.com/Documents/TransmissionPlanningStandards.pdf). This requirement for local areas is necessary because fewer options exist during actual operation to mitigate performance concerns. In addition, due to diversity in load, there is greater certainty in a regional load forecast than in the local area load forecast. The 1-in-10 load forecast standard for local areas minimizes the potential for interruption of end-use customers. In order to avoid bias among transmission, generation and demand side alternatives, all options should be validated against the same load forecast (1-in-10). Using a lower load forecast (1-in-2, 1-in-5) for LCR studies would benefit transmission alternatives (approved on 1-in-10 local load forecast during planning process) over generation or demand side.

Risks:

None. The annual transmission planning process should address cost effectiveness because all alternatives are presented and studied using the same level of local load forecast (1-in-10).

Methodology

Maximize Import Capability into the Local Area:

Import capability into the local area shall be maximized, thus minimizing the generation required in the local area to meet reliability requirements. In other words, after the most stringent contingencies have been taken, the limiting element should be loaded at 100% of its applicable rating for constraints driven by equipment loading limits. Also, the voltage and/or reactive margin should be at their respective minimum allowable levels, after the most restrictive contingencies have been taken, for voltage and/or reactive margin driven constraints.

Review:

An overwhelming majority of stakeholders have indicated that the Technical Study must present the minimum number of MW required in local area in order to meet the reliability criteria.

Risks:

It is possible that the LSEs will comply in purchasing the minimum capacity requirement from units that are less effective (or that do not solve all the area constraints). If this should happen, the ISO would be forced to augment the local capacity available to it to satisfy the reliability criteria. The ISO will seek to minimize this exposure by publishing data to facilitate more effective LSE procurement, such as single or multiple effectiveness factors for resources in local areas or sub-areas where excess capacity exists.

Maintaining Path Flows:

Path flows shall be maintained below all established path ratings into the local areas, including 500 kV elements. For clarification, given the existing transmission system configuration, the only 500 kV paths that flows directly into a local area and, therefore, considered in the LCR Study is the South of Lugo transfer path flowing into the LA Basin.

Paths that do not directly flow into a local area, but influence the local area LCR need, should be set at or below the established path rating such that it assures the path operator that it can sustain any flow on this path at peak time for this local area. Currently the only known path that influences but does not flow directly into a local area is Path 15. Based on previous LCR studies the maximum flow of 1275 MW N-S yields the highest amount of LCR for the Greater Fresno and this assumption assures that at Fresno peak time the ISO can support any Path 15 flow.

Review:

All established path ratings should be maintained below their maximum limits regardless of voltage level. Paths that do not flow directly into a local area need to set such that they will assure flexible operation of the electric system for any condition encountered in real-time at the peak of the local area.

Risks:

If insufficient resources are provided, the ISO would be required to augment available local capacity to prevent dropping load under normal conditions (or immediately after a single contingency in some cases) in order to maintain path flows bellow their limits.

If paths that do not flow directly into a load pocket are not fully covered at peak time than there is a chance this local area problem could evolve into a zonal or system problem and that is to be avoided.

QF/Nuclear/State/Federal Units:

Regulatory Must-take and similarly situated units like QF/Nuclear/State/Federal resources shall be modeled on-line at Net Qualifying Capacity ("NQC") or historical output values (if NQC not available) for purposes of the 2013 Technical Study.

Review:

These units have an assured revenue stream and can be assumed to offer available capacity during 2013 summer operations.

Risks:

None.

Units Owned or Under Long-term Contracts with LSEs:

Units owned or under long-term contracts with LSEs shall be modeled on-line at NQC or historical output values (if NQC not available) for purposes of the 2013 LCR Study. This information may be provided by LSEs.

Review:

These units have an assumed revenue stream and therefore are assumed to make their capacity available during 2013 summer operations.

Risks:

None.

Maintaining Deliverability of Generation as well as Import Allocations Relied upon by RA:

Generation and import capability, relied upon in the RA program, deliverability status shall be maintained for all common mode contingencies (including all single contingencies as well as double circuit tower line and same right-of-way contingencies). The import capability utilized shall be the Maximum Import Capability calculated by the ISO for import assignment purposes. This value reflects the maximum deliverable quantity across each branch group.

Review:

The Maximum Import Capability has been demonstrated to be deliverable during high peak load conditions, while complying with reliability criteria. Also, all generators been demonstrated to be fully deliverable to the aggregate of load and therefore have established NQCs. For the Technical Study, the Maximum Import Capability and generation deliverability must be maintained to avoid the need to reduce the import flows across branch groups and deliverability of certain generators. The last approach is to be avoided because, in addition to market participant equitability issues, for the most part there will be rather large decreases in import allocations and generation deliverability for rather small decreases in local area LCR requirements. After a single contingency during the “System Readjustment” all generating units as well as imports can be reduced (up to a limit – see system readjustment) in order to protect for the next most limiting contingency.

Risks:

It is imperative that good coordination is achieved between generation and import deliverability relative to LCR studies because otherwise it is possible that not all contracts already deemed deliverable can be delivered during the summer peak study conditions.

Load Pocket Boundary:

The 2013 Technical Study shall be produced based on load pockets defined by a fixed boundary.

Review:

An overwhelming majority of stakeholders and the ISO have indicated that the requirement for the Technical Study should be reasonably stable over time to encourage longer-term contracting by LSEs. Transmission configurations as well as unit and load effectiveness factors change every year due to new transmission projects added to the grid. As such, the only way to have a stable area is to define it as a fix boundary based on past experience of known constraints into any one area. The area definition is subject to change only if new major transmission and/or generation projects significantly change the local area constraints.

Risks:

There may be some units or loads located outside the local area boundary that may help reduce one or more of the constraints within the local area, but nevertheless not qualify as a Local Capacity Area Resource. However, in the great majority of cases, units and load outside the defined local area are less valuable in that they either do not mitigate the binding constraint or do not help to reduce flows on the majority of other potential constraints resulting from other less severe contingencies when compared to resources located within the local area. During the validation of local procurement, the ISO will use all units procured by all LSEs, regardless of location, in order to see if any further procurement is needed to satisfy Reliability Criteria.

ISO Statutory Obligation Regarding Safe Operation:

The ISO must maintain the system in a safe operating mode at all times. This obligation translates into respecting the Reliability Criteria at all times. For example, during normal operating conditions, the ISO must protect for all single contingencies and common mode double line outages. As a further example, after a single contingency, the ISO must readjust the system in order to be able to support the loss of the next most stringent contingency.

Review:

Many stakeholders do not understand this concept and claim that a single contingency only happens with a small probability and therefore additional NERC performance categories may be ignored. However, the ISO must be prepared under normal conditions (100% of the time) to support all Category B and C5 contingencies. Furthermore, after a single contingency has occurred, the ISO must be able to readjust the system in order to prepare for the next worst contingency (Category C3).

Risks:

None.

Local Capacity Criteria to be studied

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)	*Grid Planning*	*Local Capacity*
A – No Contingencies	X	X
B – Loss of a single element		
1. Generator (G-1)	X1	X1
2. Transmission Circuit (L-1)	X1	X1
3. Transformer (T-1)	X1	X1,2
4. Single Pole (dc) Line	X1	X1
5. G-1 system readjusted L-1	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	X3	X
D – Extreme event – loss of two or more elements		
Any B1-4 system readjusted (Common Mode) L-2	X4	X3
All other extreme combinations D1-14.	X4	

1 System must be able to readjust and support the loss of the next element within A/R.

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 area. Using power flow, post-transient load flow, and stability assessment tools, the system performance results of all tested contingencies 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 until performance requirements were met for the local area. The adjusted generation constitutes the minimum generation needed in the local 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] Most severe 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 including all established path ratings.

[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 operating range (voltage and loading) and/or appropriate OTC following the studied outage conditions and be able to safely prepare for the loss of the next most stringent element and be within Applicable Rating after the loss of the second element.

[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 Flow Assessment:*

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

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

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

3. *Stability Assessment:*

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

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

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

Definition of Terms

Applicable Rating:

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

Normal rating is to be used under normal conditions.

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

Short-term emergency ratings, if available, can be used as long as "system readjustment" is provided in the "short-time" available in order to reduce the flow to within the long-term emergency ratings where the element can be kept for another length of time (specific to each element) before the flow needs to be reduced the below the normal ratings. If not available long-term emergency rating should be used.

Temperature-adjusted ratings shall not be used because this is a year-ahead study not a real-time tool, as such the worst-case scenario must be covered. In case temperature-adjusted ratings are the only ratings available then the minimum rating (highest temperature) given the study conditions shall be used.

ISO Transmission Register is the only official keeper of all existing ratings mentioned above.

Ratings for future projects provided by PTO and agree upon by the ISO shall be used.

Other short-term ratings not included in the ISO Transmission Register may be used as long as they are engineered, studied and enforced through clear operating procedures that can be followed by real-time operators.

Path Ratings need to be maintained in order for these studies to comply with the Minimum Operating Reliability Criteria and assure that proper capacity is available in order to operate the system in real-time.

System Readjustment:

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

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

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

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

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

Review:

This is one of the most controversial aspects of the interpretation of the existing NERC Planning Standards, because the relevant footnote mentions that load drop can be done after a category B event in certain local areas. However, discussion in the main body of the criteria provides that NO load shedding should be done following a single contingency. All stakeholders and the ISO agree that no load shedding should be done immediately after a single contingency. It is the conclusion of the LSAG that after a single contingency, the system is in a Category B condition and the system should be planned based on the body of the criteria with no load shedding even if capable of occurring immediately or within 15-30 minutes after the first contingency. It follows that load shedding may not be utilized as part of the system readjustment period – in order to protect for the next most limiting contingency.

Category C conditions exist after the second contingency has occurred. At this point in time, firm load shedding is allowed in a planned and controlled manner. A robust California system should be planned based on the main body of the criteria, not the footnote regarding Category B contingencies. Therefore, if there are available resources in the local area, such resources should be used during the manual adjustment period (and included in the LCR requirement) before resorting to shedding firm load.

Risks:

This interpretation tends to guarantee that firm load shedding is used to address Category B conditions only under the limited circumstances where no other resource or validated operational measure is available. A contrary interpretation would constitute a departure from existing practice and degrade current service expectations by increasing load's exposure to service interruptions.

Time allowed for manual readjustment:

This is the amount of time required for the operator to take all actions necessary to prepare the system for the next contingency. This time should be less than 30 minutes in accordance with existing ISO Grid Planning Standards.

Review:

This item is very specific in the ISO Grid Planning Standards that were adopted in consultation with PTOs and stakeholders in 2002. Nevertheless, some stakeholders argue that 30 minutes only allows generation re-dispatch and automated switching where remote control is possible. If remote capability does not exist, a person must be dispatched in the field to perform the switching functions and 30 minutes may not provide sufficient time. The ISO will consider limited exemptions from the existing time requirements for small local areas with very limited load exposure. The exemption must be documented in an ISO approved operating procedures that will remain effective only until remote controlled switching equipment can be installed.

Risks:

None, it is consistent with the existing interpretation of the ISO Grid Planning standards.

Special Protection Schemes:

All known SPS shall all be used. New SPS must be verified and approved by the ISO and comply with the new SPS guideline described in the ISO Grid Planning Standards.

Review:

Not a controversial issue.

Risks:

None.

Effectiveness Factor:

Effectiveness factors are determined relative to the limiting equipment after applying the contingency(s). The ISO methodology for establishing the effectiveness factor of an individual unit increases the output of the tested unit and decreases (same amount) from all the other on-line units in the ISO Control Area (except the designated system swing). The amount of the “other” units’ decreases is based on their Pgen multiplied by the ratio of the total P increase versus total Pgen for all on-line units in the control area.

Review:

Not a controversial issue.

Risks:

None.

Pump model:

During the Technical Study, pumps should be modeled as firm loads up to the maximum of CEC coincident peak load forecast for these pumps or the firm transmission service (if available).

Review:

Due to weather and environmental changes, it is somewhat unpredictable, in the year ahead timeframe, how much pump is needed and at what level a year ahead of time, as such the pump owner should have reserved its firm transmission service even if this would exceed CEC load forecast. Coordinate with pump owner for further details. This is needed since the ISO can consider pump values above CEC forecast as being non-firm except for cases where firm transmission right exist and therefore need to be protected for by the ISO. The only pump in a local area that the ISO is aware at this time that this rule will apply is Delta PMP in the Bay Area.

Risks:

Could slightly increase the LCR requirements in that local area in order to protect for firm transmission rights.

Studies by Performance Level

Performance Level A – Normal conditions:

1. Set the base case based on the existing input assumptions.
2. Based on the particular local area studied, schedule all imports (with influence on the local area) at the level of Maximum Import Capability for the particular branch groups plus any increase due to new capability that may be related to new transmission projects. This step is done in order to protect the deliverability of imports to the aggregate of load.
3. Screen the local area for highest flows due to normal flow pattern. Find one or more elements (or approved path ratings) that could be normally overloaded if not enough generation is maintained in the local area.
4. For the most stringent element (s), find all units that aggravate the constraint (suggestion – stop at the 5% effectiveness factor or 5% flow on the line whichever comes last). Make sure all these units are on-line at their deliverable output – check deliverability studies for consistency. This is done in order to maintain the deliverability of units (otherwise if they sign contracts with LSE they could become undeliverable).
5. Go back to the units within the local area that help reduce the flow on the most limiting element. Turn on these units (most effective unit first within each category – after you finish one category move to the most effective unit in the next category and so on) in the following order until the equipment is at the 100% of normal rating:
   a. QF/Nuclear/State/Federal units
   b. Units under known existing long-term contracts with LSEs
   c. Other market units without long-term contracts
6. Add the output of all units that reduce the flow. This is the Category A requirement. Keep this so that it can be compared with category B and C requirements. It will only be used if higher then Category B or C requirements.
7. Repeat this for any sub area if required.

Performance Level B – Single Contingency Conditions:

1. Set the base case based on the existing input assumptions. (You can start with the base case used for category A study).
2. Based on the particular local area studied, schedule all imports (with influence on the local area) at the Maximum Import Capability for the particular branch groups with influence plus any increase

due to new allocations that may be related to new transmission projects. – This step is done in order to protect the deliverability of imports to the aggregate of load.

3. Screen the area for highest emergency flows due to single contingency conditions. Find one or more elements (or approved path ratings) that could be overloaded based on their emergency ratings (under single contingency conditions) if not enough generation is maintained in the area.
4. For the most stringent element(s), find all units that aggravate the constraint (suggestion – stop at the 5% effectiveness factor or 5% flow on the line whichever comes last). Make sure all these units are on-line at their deliverable output – check deliverability studies for consistency. This is done in order to maintain the deliverability of all units deemed so (otherwise if they sign contracts with LSE they could become undeliverable).
5. Go back to the units within the area that help reduce the flow on the most limiting element. Turn on these units (most effective unit first within each category – after you finish one category move to the most effective unit in the next category and so on) in the following order until the equipment is at the 100% of normal rating:
    a. QF/Nuclear/State/Federal units
    b. Units under known existing long-term contracts with LSEs
    c. Other market units without long-term contracts
6. Add the output of all units that reduce the flow. This is the Category B requirement. Keep this so that it can be compared with category A and C requirements. It will only be used if higher then Category A or C requirements.
7. Repeat this for any sub area if required.

<u>Performance Level C5 – Double Circuit Tower Line and Two Lines in the Same Right-of-Way Conditions:</u>

1. Set the base case based on the existing input assumptions. (You can start with the base case used for category A study).
2. Based on the particular local area studied, schedule all imports (with influence on the local area) at the Maximum Import Capability for the particular branch groups plus any increase due to new allocations that may be related to new transmission projects. – This step is done in order to protect the deliverability of imports to the aggregate of load.
3. Screen the area for highest emergency flows due to C4, C5 and WECC-S3 double contingency conditions. Find one or more elements (or approved path ratings) that could be overloaded based on their emergency ratings (under double contingency conditions) if not enough generation is maintained in the area. (Use all known automatic [including firm load shedding special protection schemes] or manual operating procedures that help reduce the flow on the most limiting element.)
4. For the most stringent element(s), find all units that aggravate the constraint (suggestion – stop at the 5% effectiveness factor or 5% flow on the line whichever comes last). Make sure all these units are on-line at their deliverable output – check deliverability studies for consistency. This is done in order to maintain the deliverability of all units deemed so (otherwise if they sign contracts with LSE they could become undeliverable).
5. Go back to the units within the area that help reduce the flow on the most limiting element. Turn on these units (most effective unit first within each category – after you finish one category move to the most effective unit in the next category and so on) in the following order until the equipment is at the 100% of normal rating:

   a. QF/Nuclear/State/Federal units
   b. Units under known existing long-term contracts with LSEs
   c. Other market units without long-term contracts
6. Add the output of all units that reduce the flow. This may be the Category C4, C5 and WECC-S3 requirement. Keep this so that it can be compared with other category C requirements. It will only be used if higher then other category C requirements.
7. Repeat this for any sub area if required.

Performance Level C3 – Any Two Single contingencies with System Readjustment Conditions:

1. Start with the base cases set for category B study.
2. Screen the area for highest emergency flows due to any double contingency conditions (except for two transformer outages). Find one or more elements (or approved path ratings) that could be overloaded based on their emergency ratings (under double contingency conditions) if not enough generation is maintained in the area. (Use all known automatic [including firm load shedding special protection schemes] or manual operating procedures that help reduce the flow on the most limiting element.)
3. For the most stringent element (s) find all units that aggravate the constraint (suggestion – stop at the 5% effectiveness factor or 5% flow on the line whichever comes last).
4. After the first contingency, do the following system readjustment before taking the next worst contingency:
   a. System configuration change – based on validated and approved operating procedures
   b. Decrease generation from units that aggravate the constraint (deliverability is not protected for this C3 category). Stop decreasing a certain generator when:
      i. Another known flow limit in the system has been reached.
      ii. Total generation decrease reaches 1150 MW – limit given by single contingency SPS as part of the ISO Grid Planning standards (ISO G4).
   c. Increase generation from units that help reduce the flow on the most stringent element – this generation will become part of the LCR need (read next bullet).
5. Go back to the units within the area that help reduce the flow on the most limiting element. Turn on these units (most effective unit first within each category – after you finish one category move to the most effective unit in the next category and so on) in the following order until the equipment is at the 100% of normal rating:
   a. QF/Nuclear/State/Federal units
   b. Units under known existing long-term contracts with LSEs
   c. Other market units without long-term contracts
6. Add the output of all units that reduce the flow. This may be the Category C3 requirement. Keep this so that it can be compared with other category C requirements. It will only be used if higher then other Category C requirements.
7. Repeat this for any sub area if required.

Protect against voltage collapse for Performance Level B followed by C5 Conditions:

1. Start with the base cases set for category B study.

2. Screen the area for voltage collapse only based on any single contingencies followed by C5 (double circuit tower line outages or two lines in the same right-of-way) contingency conditions if not enough generation is maintained in the area. (Use all known automatic [including firm load shedding] special protection schemes and/or operating procedures that help avoid voltage collapse.)
3. For the most stringent element (s) find all units that aggravate the constraint (suggestion – stop at the 5% effectiveness factor or 5% flow on the line whichever comes last).
4. After the first contingency, do the following system readjustment before taking the next worst C5 contingency:
    a. System configuration change – based on validated and approved operating procedures
    b. Decrease generation from units that aggravate the constraint only. Stop decreasing a certain generator when:
        i. Another known flow limit in the system has been reached.
        ii. Total generation decrease reaches 1150 MW – limit given by single contingency SPS as part of the ISO Grid Planning standards (ISO G4).
    c. Increase generation from units that help maintain voltage stability – this generation will become part of the LCR need (read next bullet).
5. Go back to the units within the area that help eliminate the voltage collapse situation. Turn on these units up to their NQC (most effective unit first within each category – after you finish one category move to the most effective unit in the next category and so on) in the following order until the voltage collapse situation has been eliminated:
    a. QF/Nuclear/State/Federal units
    b. Units under known existing long-term contracts with LSEs
    c. Other market units without long-term contracts
6. Add the output of all units that help maintain the voltage stability in the local area. This may be the Category B1 + C5 requirement. Keep this so that it can be compared with other category C requirements. It will only be used if higher then other Category C requirements.
7. Repeat this for any sub area if required.

Total Area LCR Requirement:

For any given area or sub area compare the requirement for Category A, B and C. The most stringent one will dictate that area LCR requirement.

General helpful tips:

If the area of study has one or more sub areas, then start with the smallest and/or most easy (radial) sub areas. All the units required in order to meet the sub area requirements should be turned on and accounted as part of the bigger sub area or entire area requirements (if they help reduce the flow on the most stringent element.)

If these units (those needed in a sub area) aggravate other sub area requirements, then be very careful during system re-dispatch so that the decrease of this generation does not cause problems in the previous sub area.

Service Reliability

This 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 ISO, in consultation with the PTOs. Under this option, there is no expected load interruption to end-use customers as the ISO operators prepare for the second contingency. However, the customer load may be interrupted after the second contingency occurs.

Rulemaking: 12-03-014
Exhibit No.: ISO-19
Witness:

California ISO Planning Standards

California ISO
Planning Standards

June 23, 2011

Table of Contents

I. Introduction

The California ISO (ISO) tariff provides for the establishment of planning guidelines and standards above those established by NERC and WECC to ensure the secure and reliable operation of the ISO controlled grid. The primary guiding principle of these Planning Standards is to develop consistent reliability standards for the ISO grid that will maintain or improve transmission system reliability to a level appropriate for the California system.

These ISO Planning Standards are not intended to duplicate the NERC and WECC reliability standards, but to complement them where it is in the best interests of the security and reliability of the ISO controlled grid. The ISO planning standards will be revised from time to time to ensure they are consistent with the current state of the electrical industry and in conformance with NERC Reliability Standards and WECC Regional Criteria. In particular, the ISO planning standards:

- Address specifics not covered in the NERC Reliability Standards and WECC Regional Criteria;
- Provide interpretations of the NERC Reliability Standards and WECC Regional Criteria specific to the ISO Grid;
- Identify whether specific criteria should be adopted that are more stringent than the NERC Reliability Standards and WECC Regional Criteria where it is in the best interest of ensuring the ISO controlled grid remains secure and reliable.

NERC Reliability Standards and WECC Regional Criteria:

The following links provide the minimum standards that ISO needs to follow in its planning process unless NERC or WECC formally grants an exemption or deference to the ISO. They are the NERC Transmission Planning (TPL) standards, other applicable NERC standards (i.e., NUC-001 Nuclear Plant Interface Requirements (NPIRs) for Diablo Canyon Power Plant and San Onofre Nuclear Generating Station), and the WECC Regional Criteria:

http://www.nerc.com/page.php?cid=2|20

http://www.wecc.biz/Standards/WECC%20Criteria/Forms/AllItems.aspx

Section II of this document provides additional details about the ISO Planning Standards. Guidelines are provided in subsequent sections to address certain ISO planning standards, such as the use of new Special Protection Systems, which are not specifically addressed at the regional level of NERC and WECC. Where appropriate, background information behind the development of these standards and references (web links) to subjects associated with reliable transmission planning and operation are provided.

II. ISO Planning Standards

The ISO Planning Standards are:

1. Applicability of NERC Reliability Standards to Low Voltage Facilities under ISO Operational Control

The ISO will apply NERC Transmission Planning (TPL) standards, the NUC-001 Nuclear Plant Interface Requirements (NPIRs) for Diablo Canyon Power Plant and San Onofre Nuclear Generating Station, and the approved WECC Regional Criteria to facilities with voltages levels less than 100 kV or otherwise not covered under the NERC Bulk Electric System definition that have been turned over to the ISO operational control.

2. Combined Line and Generator Outage Standard

A single transmission circuit outage with one generator already out of service and the system adjusted shall meet the performance requirements of the NERC TPL standards for single contingencies (TPL002). Supporting information is located within Section IV of this document.

3. Voltage Standard

Standardization of low and high voltage levels as well as voltage deviations across the TPL-001, TPL-002, and TPL-003 standards is required across all transmission elements in the ISO controlled grid. The low voltage and voltage deviation guideline applies only to load and generating buses within the ISO controlled grid (including generator auxiliary load) since they are impacted by the magnitude of low voltage and voltage deviations. The high voltage standard applies to all buses since unacceptable high voltages can damage station and transmission equipment. These voltage standards are shown in Table 1.

All buses within the ISO controlled grid that cannot meet the requirements specified in Table 1 will require further investigation. Exceptions to this voltage standard may be granted by the ISO based on documented evidence vetted through an open stakeholder process. The ISO will make public all exceptions through its website.

Table 1
(Voltages are relative to the nominal voltage of the system studied)

Voltage level	Normal Conditions (TPL-001)		Contingency Conditions (TPL-002 & TPL-003)		Voltage Deviation	
	Vmin (pu)	Vmax (pu)	Vmin (pu)	Vmax (pu)	TPL-002	TPL-003
≤ 200 kV	0.95	1.05	0.90	1.1	≤5%	≤10%
≥ 200 kV	0.95	1.05	0.90	1.1	≤5%	≤10%
≥ 500 kV	1.0	1.05	0.90	1.1	≤5%	≤10%

4. Specific Nuclear Unit Standards

The criteria pertaining to the Diablo Canyon Power Plant (DCPP) and San Onofre Nuclear Generating Station (SONGS), as specified in the NUC-001 Nuclear Plant Interface Requirements (NPIRs) for DCPP and SONGS, and Appendix E of the Transmission Control Agreement located on the ISO web site at: http://www.caiso.com/docs/09003a6080/25/a3/09003a608025a3bd.pdf

5. Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard

A single module of a combined cycle power plant is considered a single contingency (G-1) and shall meet the performance requirements of the NERC TPL standards for single contingencies (TPL002). Supporting information is located in Section V of this document. Furthermore a single transmission circuit outage with one combined cycle module already out of service and the system adjusted shall meet the performance requirements of the NERC TPL standards for single contingencies (TPL002) as established in item 1 above.

A re-categorization of any combined cycle facility that falls under this standard to a less stringent requirement is allowed if the operating performance of the combined cycle facility demonstrates a re-categorization is warranted. The ISO will assess re-categorization on a case by case based on the following:

a) Due to high historical outage rates in the first few years of operation no exceptions will be given for the first two years of operation of a new combined cycle module.
b) After two years, an exception can be given upon request if historical data proves that no outage of the combined cycle module was encountered since start-up.
c) After three years, an exception can be given upon request if historical data proves that outage frequency is less than once in three years.

The ISO may withdraw the re-categorization if the operating performance of the combined cycle facility demonstrates that the combined cycle module exceeds a failure rate of once in three year. The ISO will make public all exceptions through its website.

6. Planning for New Transmission versus Involuntary Load Interruption Standard

This standard sets out when it is necessary to upgrade the transmission system from a radial to a looped configuration or to eliminate load dropping otherwise permitted by WECC and NERC planning standards through transmission infrastructure improvements. It does not address all circumstances under which load dropping is permitted under NERC and WECC planning standards.

1. No single contingency (TPL002 and ISO standard [G-1] [L-1]) should result in loss of more than 250 MW of load. This includes consequential loss of load as well as load that may need to be dropped after the first contingency (during the system adjustment period) in order to position the electric system for reliable operation in anticipation of the next worst contingency.
2. All single substations of 100 MW or more should be served through a looped system with at least two transmission lines “closed in” during normal operation.
3. Existing radial loads with available back-tie(s) (drop and automatic or manual pick-up schemes) should have their back-up tie(s) sized at a minimum of 50% of the yearly peak load or to accommodate the load 80% of the hours in a year (based on actual load shape for the area), whichever is more constraining.
4. Upgrades to the system that are not required by the standards in 1, 2 and 3 above may be justified by eliminating or reducing load outage exposure, through a benefit to cost ratio (BCR) above 1.0 and/or where there are other extenuating circumstances.

   To better understand the potential impact of the updated “planning for new transmission versus involuntary load interruption” standard, this standard will be considered a guideline for the first year that it is in effect in order to get an inventory of stations and transmission elements not in compliance and a cost impact of bringing them into compliance.

III. ISO Planning Guidelines

The ISO Planning Guidelines include the following:

1. New Special Protection Systems

As stated in the NERC glossary, a Special Protection System (SPS) is “an automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition of faulted components to maintain system reliability.” In the context of new projects, the possible action of an SPS would be to detect a transmission outage (either a single contingency or credible multiple contingencies) or an overloaded transmission facility and then curtail generation output and/or load in order to avoid potentially overloading facilities or prevent the situation of not meeting other system performance criteria. A SPS can also have different functions such as executing plant generation reduction requested by other SPS; detecting unit outages and transmitting commands to other locations for specific action to be taken; forced excitation pulsing; capacitor and reactor switching; out-of-step tripping; and load dropping among other things.

The primary reasons why SPS might be selected over building new transmission facilities are that SPS can normally be implemented much more quickly and at a much lower cost than constructing new infrastructure. In addition, SPS can increase the utilization of the existing transmission facilities, make better use of scarce transmission resources and maintain system reliability. Due to these advantages, SPS is a commonly considered alternative to building new infrastructure in an effort to keep costs down when integrating new generation into the grid and/or addressing reliability concerns under multiple contingency conditions. While SPSs have substantial advantages, they have disadvantages as well. With the increased transmission system utilization that comes with application of SPS, there can be increased exposure to not meeting system performance criteria if the SPS fails or inadvertently operates. Transmission outages can become more difficult to schedule due to increased flows across a larger portion of the year; and/or the system can become more difficult to operate because of the independent nature of the SPS. If there are a large number of SPSs, it may become difficult to assess the interdependency of these various schemes on system reliability. These reliability concerns necessarily dictate that guidelines be established to ensure that performance of all SPSs are consistent across the ISO controlled grid. It is the intent of these guidelines to allow the use of SPSs to maximize the capability of existing transmission facilities while maintaining system reliability and optimizing operability of the ISO controlled grid. Needless to say, with the large number of generator interconnections that are occurring on the ISO controlled grid, the need for these guidelines has become more critical.

It needs to be emphasized that these are guidelines rather than standards. In general, these guidelines are intended to be applied with more flexibility for low exposure outages (e.g., double line outages, bus outages, etc.) than for high exposure outages (e.g., single contingencies). This is to emphasize that best engineering practice and judgement will need to be exercised by system planners and operators in determining when the application of SPS will be acceptable. It is recognized that it is not possible or desirable to have strict standards for the acceptability of the use of SPS in all potential applications.

ISO SPS1

The overall reliability of the system should not be degraded after the combined addition of the SPS.

ISO SPS2

The SPS needs to be highly reliable. Normally, SPS failure will need to be determined to be non-credible. In situations where the design of the SPS requires WECC approval, the WECC Remedial Action Scheme Design Guide will be followed.

ISO SPS3

The total net amount of generation tripped by a SPS for a single contingency cannot exceed the ISO's largest single generation contingency (currently one Diablo Canyon unit at 1150 MW). The total net amount of generation tripped by a SPS for a double contingency cannot exceed 1400 MW. This amount is related to the minimum amount of spinning reserves that the ISO has historically been required to carry. The quantities of generation specified in this standard represent the current upper limits for generation tripping. These quantities will be reviewed periodically and revised as needed. In addition, the actual amount of generation that can be tripped is project specific and may depend on specific system performance issues to be addressed. Therefore, the amount of generation that can be tripped for a specific project may be lower than the amounts provided in this guide. The net amount of generation is the gross plant output less the plant's and other auxiliary load tripped by the same SPS.

ISO SPS4

For SPSs, the following consequences are unacceptable should the SPS fail to operate correctly:

A) Cascading outages beyond the outage of the facility that the SPS is intended to protect: For example, if a SPS were to fail to operate as designed for a single contingency and the transmission line that the SPS was intended to protect were to trip on overload protection, then the subsequent loss of additional facilities due to overloads or system stability would not be an acceptable consequence.

B) Voltage instability, transient instability, or small signal instability: While these are rare concerns associated with the addition of new generation, the consequences can be so severe that they are deemed to be unacceptable results following SPS failure.

ISO SPS5

Close coordination of SPS is required to eliminate cascading events. All SPS in a local area (such as SDG&E, Fresno, etc.) and grid-wide need to be evaluated as a whole and studied as such.

ISO SPS6

The SPS must be simple and manageable. As a general guideline:

A) There should be no more than 6 local contingencies (single or credible double contingencies) that would trigger the operation of a SPS.

B) The SPS should not be monitoring more than 4 system elements or variables. A variable can be a combination of related elements, such as a path flow, if it is used as a single variable in the logic equation. Exceptions include:

   i. The number of elements or variables being monitored may be increased if it results in the elimination of unnecessary actions, for example: generation tripping, line sectionalizing or load shedding.

   ii. If the new SPS is part of an existing SPS that is triggered by more than 4 local contingencies or that monitors more than 4 system elements or variables, then the new generation cannot materially increase the complexity of the existing SPS scheme. However, additions to an existing SPS using a modular design should be considered as preferable to the addition of a new SPS that deals with the same contingencies covered by an existing SPS.

C) Generally, the SPS should only monitor facilities that are connected to the plant or to the first point of interconnection with the grid. Monitoring remote facilities may add substantial complexity to system operation and should be avoided.

D) An SPS should not require real-time operator actions to arm or disarm the SPS or change its set points.

ISO SPS7

If the SPS is designed for new generation interconnection, the SPS may not include the involuntary interruption of load. Voluntary interruption of load paid for by the generator is acceptable. The exception is that the new generator can be added to an existing SPS that includes involuntary load tripping. However, the amount of involuntary load tripped by the combined SPS may not be increased as a result of the addition of the generator.

ISO SPS8

Action of the SPS shall limit the post-disturbance loadings and voltages on the system to be within all applicable ratings and shall ultimately bring the system to within the long-term (4 hour or longer) emergency ratings of the transmission equipment. For example, the operation of SPS may result in a transmission line initially being loaded at its one-hour rating. The SPS could then automatically trip or run-back additional generation (or trip load if not already addressed under ISO SPS7 above) to bring the line loading within the line's four-hour or longer rating. This is intended to minimize real-time operator intervention.

ISO SPS9

The SPS needs to be agreed upon by the ISO and may need to be approved by the WECC Remedial Action Scheme Reliability Task Force.

ISO SPS10

The ISO, in coordination with affected parties, may relax SPS requirements as a temporary "bridge" to system reinforcements. Normally this "bridging" period would be limited to the time it takes to implement a specified alternative solution. An example of a relaxation of SPS requirement would be to allow 8 initiating events rather than limiting the SPS to 6 initiating events until the identified system reinforcements are placed into service.

ISO SPS11

The ISO will consider the expected frequency of operation in its review of SPS proposals.

ISO SPS12

The actual performance of existing and new SPS schemes will be documented by the transmission owners and periodically reviewed by the ISO and other interested parties so that poorly performing schemes may be identified and revised.

ISO SPS13
All SPS schemes will be documented by the owner of the transmission system where the SPS exists. The generation owner, the transmission owner, and the ISO shall retain copies of this documentation.

ISO SPS14
To ensure that the ISO's transmission planning process consistently reflects the utilization of SPS in its annual plan, the ISO will maintain documentation of all SPS utilized to meet its reliability obligations under the NERC reliability standards, WECC regional criteria, and ISO planning standards.

ISO SPS15
The transmission owner in whose territory the SPS is installed will, in coordination with affected parties, be responsible for designing, installing, testing, documenting, and maintaining the SPS.

ISO SPS16 Generally, the SPS should trip load and/or resources that have the highest effectiveness factors to the constraints that need mitigation such that the magnitude of load and/or resources to be tripped is minimized. As a matter of principle, voluntary load tripping and other pre-determined mitigations should be implemented before involuntary load tripping is utilized.

ISO SPS17
Telemetry from the SPS (e.g., SPS status, overload status, etc.) to both the Transmission Owner and the ISO is required unless otherwise deemed unnecessary by the ISO. Specific telemetry requirements will be determined by the Transmission Owner and the ISO on a project specific basis.

IV. Combined Line and Generator Unit Outage Standards Supporting Information

Combined Line and Generator Outage Standard - A single transmission circuit outage with one generator already out of service and the system adjusted shall meet the performance requirements of the NERC TPL standards for single contingencies (TPL002).

The ISO Planning Standards require that system performance for an over-lapping outage of a generator unit (G-1) and transmission line (L-1) must meet the same system performance level defined for the NERC standard TPL-002. The ISO recognizes that this planning standard is more stringent than allowed by NERC, but it is considered appropriate for assessing the reliability of the ISO's controlled grid as it remains consistent with the standard utilized by the PTOs prior to creation of the ISO.

V. Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard Supporting Information

Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard - A single module of a combined cycle power plant is considered a single (G-1) contingency and shall meet the performance requirements of the NERC TPL standards for single contingencies (TPL002).

The purpose of this standard is to require that an outage of any turbine element of a combustion turbine be considered as a single outage of the entire plant and therefore must meet the same performance level as the NERC TPL standard TPL-002.

The ISO has determined that, a combined cycle module should be treated as a single contingency. In making this determination, the ISO reviewed the actual operating experience to date with similar (but not identical) combined cycle units currently in operation in California. The ISO's determination is based in large part on the performance history of new combined cycle units and experience to date with these units. The number of combined cycle facility forced outages that have taken place does not support a double contingency categorization for combined cycle module units in general. It should be noted that all of the combined cycle units that are online today are treated as single contingencies.

Immediately after the first few combined cycle modules became operational, the ISO undertook a review of their performance. In defining the appropriate categorization for combined cycle modules, the ISO reviewed the forced outage history for the following three combined cycle facilities in California: Los Medanos Energy Center (Los Medanos), Delta Energy Center (Delta), and Sutter Energy Center (Sutter)[1]. Los Medanos and Sutter have been in service since the summer of 2001, Delta has only been operational since early summer 2002.

Table 2 below sets forth the facility forced outages for each of these facilities after they went into operation (i.e. forced outages [2]that resulted in an output of zero MWs.) The table demonstrates that facility forced outages have significantly exceeded once every 3 to 30 years. Moreover**,** the ISO considers that the level of facility forced outages is significantly above the once every 3 to 30 years even accounting for the fact that new combined cycle facilities tend to be less reliable during start-up periods and during the initial weeks of operation. For example, four of the forced outages that caused all the

---

[1] Los Medanos and Sutter have two combustion turbines (CT's) and one steam turbine (ST) each in a 2x1 configuration. Delta has three combustion turbines (CT's) and one steam turbine (ST) in a 3x1 configuration. All three are owned by the Calpine Corporation.

[2] Only forced outages due to failure at the power plant itself are reported, forced outages due to failure on the transmission system/switchyard are excluded. The fact that a facility experienced a forced outage on a particular day is public information. In fact, information on unavailable generating units has been posted daily on the ISO website since January 1, 2001. However, the ISO treats information regarding the cause of an outage as confidential information.

three units at Los Medanos to go off-line took place more than nine months after the facility went into operation.

Facility	Date	# units lost
Sutter[3]	08/17/01	No visibility
Sutter	10/08/01	1 CT
Sutter	12/29/01	All 3
Sutter	04/15/02	1 CT + ST
Sutter	05/28/02	1 CT
Sutter	09/06/02	All 3
Los Medanos[4]	10/04/01	All 3
Los Medanos	06/05/02	All 3
Los Medanos	06/17/02	All 3
Los Medanos	06/23/02	1CT+ST
Los Medanos	07/19/02	All 3
Los Medanos	07/23/02	1CT+ST
Los Medanos	09/12/02	All 3
Delta[5]	06/23/02	All 4
Delta	06/29/02	2 CT's + ST
Delta	08/07/02	2 CT's + ST

Table 2: Forced outages that have resulted in 0 MW output from Sutter, Los Medanos and Delta after they became operational

The ISO realizes that this data is very limited. Nevertheless, the data adequately justifies the current classification of each module of these three power plants as a single contingency.

VI. Background behind Planning for New Transmission versus Involuntary Load Interruption Standard

For practical and economic reasons, all electric transmission systems are planned to allow for some involuntary loss of firm load under certain contingency conditions. For some systems, such a loss of load may require several contingencies to occur while for other systems, loss of load may occur in the event of a specific single contingency. Historically, a wide variation among the PTOs has existed predominantly due to slightly differing planning and design philosophies. This standard is intended to provide a consistent framework upon which involuntary load interruption decisions can be made by the ISO when planning infrastructure needs for the ISO controlled grid.

[3] Data for Sutter is recorded from 07/03/01 to 08/10/02
[4] Data for Los Medanos is recorded from 08/23/01 to 08/10/02
[5] Data for Delta is recorded from 06/17/02 to 08/10/02

The overarching requirement is that implementation of these standards should not result in lower levels of reliability to end-use customers than existed prior to restructuring. As such, the following is required:

1. No single contingency (TPL002 and ISO standard [G-1] [L-1]) may result in loss of more than 250 MW of load. This includes consequential loss of load as well as load that may need to be dropped after the first contingency (during the system adjustment period) in order to protect for the next worst single contingency.

   This standard is intended to coordinate ISO planning standards with the WECC requirement that all transmission outages with at least 300 MW or more be directly reported to WECC. It is the ISO's intent that no single contingency (TPL002 and ISO standard [G-1] [L-1]) should trigger loss of 300 MW or more of load. The 250 MW level is chosen in order to allow for differences between the load forecast and actual real time load that can be higher in some instances than the forecast and to also allow time for transmission projects to become operational since some require 5-6 years of planning and permitting with inherent delays. It is also ISO's intent to put a cap on the footnote to the NERC TPL-002 that may allow radial and/or non-consequential loss of load for single contingencies.

2. All single substations of 100 MW or more should be served through a looped system with at least two transmission lines "closed in" during normal operation.

   This standard is intended to bring consistency between the PTOs' substation designs. It is not the ISO's intention to disallow substations with load below 100 MW from having looped connections; however it is ISO's intention that all substations with peak load above 100 MW must be connected through a looped configuration to the grid.

3. Existing radial loads with available back-tie(s) (drop and automatic or manual pick-up schemes) should have their back-up tie(s) sized at a minimum of 50% of the yearly peak load or to accommodate the load 80% of the hours in a year (based on actual load shape for the area), whichever is more stringent.

   This standard is intended to insure that the system is maintained at the level that existed prior to restructuring. It is obvious that as load grows, existing back-ties for radial loads (or remaining feed after a single contingency for looped substations) may not be able to pick up the entire load; therefore the reliability to customers connected to this system may deteriorate over time. It is the ISO's intention to establish a minimum level of back-up tie capability that needs to be maintained.

4. Upgrades to the system that are not required by the standards in 1, 2 and 3 above may be justified by eliminating or reducing load outage exposure through a benefit to cost ratio (BCR) above 1.0 and/or where there are other extenuating circumstances.

It is ISO's intention to allow the build-up of transmission projects that are proven to have a positive benefit to ratepayers by reducing load drop exposure.

Information Required for BCR calculation: For each of the outages that required involuntary interruption of load, the following should be estimated:

- The maximum amount of load that would need to be interrupted.
- The duration of the interruption.
- The annual energy that would not be served or delivered.
- The number of interruptions per year.
- The time of occurrence of the interruption (e.g., week day summer afternoon).
- The number of customers that would be interrupted.
- The composition of the load (i.e., the percent residential, commercial, industrial, and agricultural).
- Value of service or performance-based ratemaking assumptions concerning the dollar impact of a load interruption.

The above information will be documented in the ISO Transmission Plan for areas where additional transmission reinforcement is needed or justified through benefit to cost ratio determination.

VII. Interpretations of terms from NERC Reliability Standard and WECC Regional Criteria

Listed below are several ISO interpretations of the terms that are used in the NERC standards that are not already addressed by NERC.

Combined Cycle Power Plant Module: A **combined cycle** is an assembly of heat engines that work in tandem off the same source of heat, converting it into mechanical energy, which in turn usually drives electrical generators. In a combined cycle power plant (CCPP), or combined cycle gas turbine (CCGT) plant, one or more gas turbine generator(s) generates electricity and heat in the exhaust is used to make steam, which in turn drives a steam turbine to generate additional electricity.

Entity Responsible for the Reliability of the Interconnected System Performance: In the operation of the grid, the ISO has primary responsibility for reliability. In the planning of the grid, reliability is a joint responsibility between the PTO and the ISO subject to appropriate coordination and review with the relevant local, state, regional and federal regulatory authorities.

Entity Required to Develop Load Models: The PTOs, in coordination with the utility distribution companies (UDCs) and others, develop load models.

Entity Required to Develop Load Forecast: The California Energy Commission (CEC) has the main responsibility for providing load forecast. If load forecast is not provided by the CEC or is not detailed and/or specific enough for a certain study then the ISO, at its sole discretion, may use load forecasts developed by the PTOs in coordination with the UDCs and others.

Projected Customer Demands: The load level modeled in the studies can significantly impact the facility additions that the studies identify as necessary. For studies that address regional transmission facilities such as the design of major interties, a 1 in 5-year extreme weather load level should be assumed. For studies that are addressing local load serving concerns, the studies should assume a 1 in 10-year extreme weather load level. The more stringent requirement for local areas is necessary because fewer options exist during actual operation to mitigate performance concerns. In addition, due to diversity in load, there is more certainty in a regional load forecast than in the local area load forecast. Having a more stringent standard for local areas will help minimize the potential for interruption of end-use customers.

Planned or Controlled Interruption: Load interruptions can be either automatic or through operator action as long as the specific actions that need to be taken, including the magnitude of load interrupted, are identified and corresponding operating procedures are in place when required.

Time Allowed for Manual Readjustment: This is the amount of time required for the operator to take all actions necessary to prepare the system for the next contingency. This time should be less than 30 minutes.

Rulemaking: 12-03-014

Exhibit No.: ISO-20

Witness: ______________________

Comments of the California Independent System Operator Corporation on the Alternate Proposed Decision Adopting Demand Response Activities and Budgets for 2012 through 2014

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U39E) for Approval of Demand Response Programs, Pilots, and Budgets for 2012-2014	Application 11-03-001 (Filed: March 1, 2011)
and Related Matters	Application 11-03-002 Application 11-03-003

COMMENTS OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION ON THE ALTERNATE PROPOSED DECISION ADOPTING DEMAND RESPONSE ACTIVITIES AND BUDGETS FOR 2012 THROUGH 2014

The California Independent System Operator Corporation ("ISO") submits these comments regarding the Alternate Proposed Decision of Commissioner Ferron ("APD") adopting demand response activities and budgets for 2012 through 2014.[1] The ISO submits its comments pursuant to Rule 14.3 of the Commission's Rules of Practice and Procedure.

I. Introduction

The ISO agrees with many of the proposals contained in the APD and suggests certain minor revisions to the APD in these comments. In particular, the ISO believes that the APD appropriately describes the need for additional demand response as a flexible resource to meet the future energy needs of California and for integrating demand response into the wholesale energy markets. However, the ISO urges the Commission to promptly take action beyond that set forth in the APD, to explain its policy vision and outline the steps the Commission thinks necessary to significantly increase the development of demand response through the competitive market in order to align with the ADP's articulated policy that demand response should help integrate intermittent renewable resources.

Further, the Commission should extend the Aggregator Management Program ("AMP") contracts described in the APD for one year and should require that renegotiated AMP contracts be bid into the ISO market. The Commission should also expand policies stated in this APD that ensure the development of durable, generation-substitutable demand response resources that fulfill the spirit of the loading order and can be procured and planned on like other resource

---

[1] *[Alternate Proposed] Decision Adopting Demand Response Activities and Budgets for 2012 Through 2014*, issued on March 20, 2012, accessible on the Commission's website at http://docs.cpuc.ca.gov/efile/ALT/162146.pdf. The APD is an alternate proposed decision to the *[Proposed] Decision Adopting Demand Response Activities and Budgets for 2012 Through 2014*, issued on October 28, 2011 ("PD"), accessible on the Commission's website at http://docs.cpuc.ca.gov/word_pdf/AGENDA_DECISION/155437.pdf.

types. Lastly, the Commission should revise the APD to incorporate language from the original PD regarding allocation of demand response costs.

II. The APD Appropriately Describes the Need for Additional Demand Response to Meet California's Future Energy Needs

The ISO appreciates and agrees with the statements in the APD that demand response is more than just a tool for addressing emergency conditions and reducing peak load, but is also a flexible resource whose attributes can help pave the way to California's clean energy future by enabling the integration of large numbers of renewable resources into the markets operated by the ISO. For example, the APD states:

> The California Clean Energy Future plan expressly acknowledges that in addition to its historic role as an emergency and peak demand management tool, DR [demand response] will be able to provide a range of services that can support grid integration of large quantities of intermittent and variable renewable resources. The plan also articulates our collective commitment to integrating DR into the CAISO's wholesale energy markets.[2]
>
> . . . .
>
> Looking ahead to our pursuit of SB 1X's requirement that the Utilities obtain 33% of the energy they deliver from renewable resources in 2020, we also expect that DR will likely be called upon to meet new needs beyond its historic role as an emergency resource and peak shaving tool. DR is ideally suited to support grid integration of renewable generation, much of which will be intermittent or variable.[3]

These statements in the APD are important for understanding and interpreting California's foundational loading order and for evaluating and approving future demand response programs.[4] The APD is consistent with the position of the ISO that the loading order does not simply promote *any type* of demand response that is deemed cost-effective, but, rather, that the loading

---

[2] APD at p. 13.

[3] *Id.* at pp. 76-77.

[4] As explained in the APD, "[f]or more than a decade, California's energy and air quality agencies have recognized the vital role of DR in meeting our shared responsibilities to provide clean, safe and reliable energy at reasonable rates. The foundational principal is . . . California's loading order policy, adopted by California energy agencies in the 2003 Energy Action Plan and reiterated in the Energy Action Plan II." *Id.* at pp. 11-12.

order promotes resources that can meet California's "growing energy needs."[5] As the APD makes clear, satisfying California's future energy needs through extremely use-limited demand response and emergency load shedding is not a satisfactory interpretation of the loading order.

III. The Commission Must Take Action to Explain Its Policy Vision and the Steps Necessary to Increase the Development of Demand Response Through the Competitive Market

The ISO appreciates the recognition in the APD that third-party demand response providers can supply the innovation needed to fulfill the goals of the loading order – specifically by providing new demand response innovations, products, and services that will help meet California's growing energy needs. However, as discussed below, the Commission should take more action than is envisioned in the APD to promote third-party supply of demand response.

The APD acknowledges that having third parties operating in the competitive market can deliver demand response products and services in ways that are "superior to the Utilities' abilities":[6]

> We noted however that "Acting expeditiously to allow end use customers or aggregators to bid DR resources directly in [CAISO's] markets . . . is consistent with our identification of DR as one of the state's preferred means of meeting growing energy needs."[7]
>
> . . . .
>
> We think that third party aggregators can provide additional innovation and services to the market, yielding additional uncaptured potential benefits to DR in California.[8]
>
> . . . .
>
> As customers are being transitioned to other programs because of the termination of PeakChoice [the PeakChoice program operated by Pacific Gas and Electric

---

5 *Id.* at p. 15 (citation omitted).

6 *Id.* at p. 122.

7 *Id.* at p. 15 (citation omitted).

8 *Id.* at pp. 16-17.

> Company ("PG&E")] we encourage the MWs to be transitioned to third party contracts, when feasible, <u>because we envision that their ability to address customers' needs will be superior to the Utilities' abilities</u>.[9]
>
> . . . .
>
> The changing nature of the electrical grid, which we previously discussed, has generated additional requirements that call into question whether a utility-centric model for DR programs and services can meet current and future needs.[10]

As this discussion in the APD makes clear, the Commission questions the robustness of the utility-centric model and envisions greater customer benefits and demand response innovations can be provided through the competitive market rather than through the existing utility-centric delivery model. It would seem to follow from this discussion that issuing directives that promote the establishment of a competitive demand response market, such as requiring more competitive solicitations for demand response resources in the current application cycle, would be positive first steps. The APD, however, does not propose any such steps. Instead, the APD continues to promote significant investment in demand response almost exclusively through the utility-centric model, and encourages, but does not require, a transition to third-party supply of demand response, and then only in limited cases. Consequently, even though the Commission acknowledges the benefits of a competitive market for demand response, it does not take any definitive steps in the APD to evolve the existing utility-centric paradigm. The Commission defers any such steps to a future rulemaking.

In this regard, the Commission asserts in the APD that it must determine the future goals and policy objectives for demand response before it addresses competitive market issues:

> Dismantling of the utility-centric model, as suggested by some parties in this proceeding, requires thought and deliberation beyond the time provided in the current proceeding. Furthermore, the issues go beyond the three-year cycle of a DR Application and are more appropriately addressed in the DR rulemaking. <u>The</u>

---

9 *Id.* at p. 122 (emphasis added).

10 *Id.* at pp. 188-89.

> Commission must determine the future goals and policy objectives for DR before addressing these issues. At this time, however, the most prudent path forward is to continue to gather information to develop a better record before making lasting changes to the current structure. We will address these issues in the DR rulemaking proceeding, R.07-01-041 or its successor.[11]

The APD does signal that the Commission holds a policy vision that demand response needs to be integrated into the ISO market.

> For the reasons discussed above, and consistent with our policy vision on integration into and direct participation of DR resources in the CAISO market, we deny PG&E's request for an RFP for new AMP contracts. Instead, we adopt the DR procurement model as proposed by the CAISO. The specifics of the DR procurement model will be further developed in the current DR Rulemaking proceeding, R.07-01-041, or its successor. We expect the Utilities to hold competitive solicitations for new PDR contracts as a part of their Resource Adequacy portfolio, once we have finalized the direct participation rules and implemented new Resource Adequacy rules for wholesale DR resources. We require the Utilities to work closely with CAISO, Commission Staff, and the Procurement Review Groups when developing the RFP requirements to meet future system needs, e.g., integration of renewable resources.[12]

The ISO is encouraged by this policy statement. However, because the above statement claims that the "Commission must determine the future goals and policy objectives for DR before addressing these [competitive market] issues," the ISO urges the Commission to establish and articulate its future goals and policy objectives for demand response to resolve these somewhat conflicting statements within the APD that recognize the benefits of the competitive market and direct participation, yet hold back from taking affirmative action until future goals and policy steps are determined.

In this and other application cycles, the Commission has authorized hundreds of millions of dollars be invested in demand response, yet it does not appear to have a clear or updated objective as how this significant investment helps project demand response along a particular path to achieve the Commission's energy policy goals. To shape and guide the demand response

11 *Id.* at p. 190 (emphasis added).

12 *Id.* at pp. 187-88.

discussion, the ISO encourages the Commission to direct the Energy Division to draft a demand response paper that captures the Commission's preferred goals, policies, and principles for demand response as a priority resource. This paper could then be made available for discussion and comment by interested parties. The demand response paper should ultimately be reviewed and sanctioned by the Commission. For the engaged parties, such a paper would provide important guideposts for new proposals and programs that align with the Commission's demand response policy vision.

IV. The Commission Should Extend the AMP Contracts for One Year and Should Require that Renegotiated AMP Contracts Can Be Bid into the ISO Market

The ISO supports extension of the AMP contracts for one year while the Commission and interested parties complete and conclude the direct participation rules.[13] Thus, the ISO encourages the Commission to implement the direct participation phase in its demand response rulemaking proceeding (R.07-01-041) ("Demand Response Proceeding"), so that clear objectives for demand response can be set and third-party demand response providers can begin to competitively develop flexible, ISO-integrated demand response resources in earnest in 2013.

As to implementation of the direct participation phase, the ISO notes the following statement in the APD:

> Moreover, as we anticipate that we will expect the Utilities to rely more on competitive provision of DR services once we do open up Direct Participation, we find that it is prudent to maintain the presence of Third Party Aggregators during this transitional period.[14]

The Commission should clarify in the APD that, if PG&E elects to extend the current AMP contracts beyond 2012, any renegotiation between PG&E and the third-party demand response aggregator must ensure that the underlying demand response which is the subject of the AMP

[13] *See id.* at p. 71.

[14] *Id.* at p. 72.

contracts can be bid directly into the ISO market. This clarification would be consistent with the following statements in the APD:

> [I]f PG&E elects to extend the current AMP contracts beyond 2012, it must renegotiate the terms of the contracts to improve their cost-effectiveness, increasing the TRC [Total Resource Cost] ratio to be cost effective as set forth in this decision.[15]
>
> . . . .
>
> As discussed above, we agree with the Applicants and parties that the Commission should preserve the DR resources from current and future AMP contracts because they can be bid into the CAISO market.[16]

V. The Commission Should Take Steps to Promote Durable Demand Response Products

The APD should direct the restart of phase 4 of the Demand Response Proceeding. Restarting phase 4 is necessary to permit the establishment of rules that will enable durable demand response products to be developed and offered to customers. Such durability is extremely important. As explained in the APD:

> While we regard DR as a substitute for generation and are pursuing efforts to ensure that it can compete on equal terms, we recognize that DR and generation are produced in fundamentally different ways. Power plants are long-lived physical assets, which can generally be expected to remain available even if idled or mothballed during periods of excess capacity. While DR resources require some investment in software and equipment, <u>they depend to a great degree upon investments in human capital and management decisions that are easily reversed. The shorter procurement timeframe for DR resources raises the specter of a stop-start-stop-start cycle that may discourage investment by participants and aggregators alike</u>. We wish to avoid such an outcome and intend instead to continue to develop dependable and sustainable DR resources that will be viable substitutes for generation as the reserve margin begins to close later in this decade.[17]

---

15 *Id.* at p. 75.

16 *Id.* at p. 76.

17 *Id.* at pp. 72-73 (emphasis added).

The challenge presented by the type of stop-start-stop-start cycle described in the APD is that the ISO, as a system operator, must perform system planning, and resources do not readily fit into resource planning efforts and studies if they "cycle in and out" and if their performance is too uncertain over time they may not be sufficiently "reliable" for system planning purposes. The ISO performs resource planning with the expectation that the resource portfolios studied are reasonably durable, viable, and effective, and will be around for the following year or years. Thus, durability is a critical attribute that demand response must demonstrate, especially when California is considering thousands of megawatts of demand response to be in production by 2020 and it is to be one of the state's preferred means of meeting growing energy needs.

VI. The Commission Should Revise the APD to Incorporate Language from the PD Regarding Allocation of Demand Response Costs

The October 28, 2011 PD included an important point regarding allocation of demand response costs that has not been retained in the APD. Specifically, the PD explained in the following underlined language that issues regarding demand response cost allocation should be addressed in a consistent manner across the three investor-owned utilities ("IOUs") and are best handled in the Demand Response Proceeding:

> Moreover, until the Commission makes a final determination about the future structure of the DR market, changing the current cost recovery and rate design process for DR is not ripe for discussion. Normally, in order for the Commission to consider DACC and AReM's proposal to restructure rates, we would require additional data and fact finding studies that are best handled in rate design. <u>However, we agree that these issues should be considered in a consistent manner across all three utilities and thus are best handled in one proceeding, the DR Rulemaking, 07-01-041 or its successor</u>.[18]

[18] PD at p. 207 (emphasis added). The PD is accessible on the Commission's proceeding website at http://docs.cpuc.ca.gov/word_pdf/AGENDA_DECISION/155437.pdf.

The APD, by comparison, included all of this quoted language except for the underlined language.[19]

The ISO has stated in this proceeding that before a viable competitive demand response market can be established, the Commission must address the issue of how demand response costs will be allocated. If the IOUs are allowed to spread demand response program costs to all distribution service customers, but a demand response provider is only able to spread such costs to its participating customers, this creates an un-level and anti-competitive playing field.

Therefore, the ISO submits that the APD should be revised to incorporate the original underlined language from the PD that the APD had omitted. The principle of cost allocation is best handled consistently across all three utilities as cost allocation is not only a major policy issue but is also a challenge for the development of a competitive demand response market. The ISO believes it is inappropriate to address the principle of demand response cost allocation in separate and disparate general IOU rate case proceedings. This issue is too significant to not resolve head-on in a single proceeding.

VII. Statewide DR Marketing / Flex Alert Campaign Funding for 2012 is Appropriate

The ISO appreciates the Commission's attention to evaluating the funding amounts for the statewide demand response marketing and Flex Alert campaign. The ISO appreciates the APD's inclusion of additional funding levels for 2012, and believes that the additional funding will appropriately continue to provide critical public awareness about the need to conserve energy during periods when the system is highly stressed. The Flex Alert campaign and "Flex Your Power"™ brand is known and recognized by California energy users, and has served as an effective and valuable tool for the grid operator to seek load relief through statewide and regional energy conservation messaging when it is needed most.

---

19 APD at p. 203.

The ISO also appreciates that the APD provides for consideration of statewide Marketing, Education & Outreach in its own proceeding, rather than relegating the matter to either the Energy Efficiency or Demand Response application proceedings. This procedural path will give these funding issues the attention they merit and will prevent them from being subsumed in the many other important issues to be resolved in the demand response and energy efficiency proceedings.

VIII. Conclusion

The ISO respectfully requests that the Commission consider the comments provided above in its determinations regarding the APD.

Dated: April 9, 2012

Respectfully submitted,

By: */s/ Baldassaro "Bill" Di Capo*

Nancy Saracino
General Counsel
Sidney Davies
Assistant General Counsel
Baldassaro "Bill" Di Capo
Senior Counsel
California Independent System
Operator Corporation
250 Outcropping Way
Folsom, CA 95630
Tel (916) 608-7157
Fax (916) 608-7222
bdicapo@caiso.com

APPENDIX A

Appendix A to ISO Comments on
Alternative Proposed Decision of Commission Ferron
adopting demand response activities and budgets for 2012 through 2014

Requested Modifications to the APD

I. Issues Regarding Allocation of Demand Response Costs

Within **Section 10 [Cost Recovery]**, in the second paragraph at page 203, the ISO requests the following underlined additions:

> Moreover, until the Commission makes a final determination about the future structure of the DR market, changing the current cost recovery and rate design process for DR is not ripe for discussion. Normally, in order for the Commission to consider DACC and AReM's proposal to restructure rates, we would require additional data and fact finding studies that are best handled in rate design. <u>However, we agree that these issues should be considered in a consistent manner across all three utilities and thus are best handled in one proceeding, the DR Rulemaking, 07-01-041 or its successor</u>.

Rulemaking: 12-03-014

Exhibit No.: ISO-21

Witness: ____________

California ISO Renewable Integration Study in Support of the California Air Resources Board for Meeting Assembly Bill (AB) 1318

California ISO
Renewable Integration Study in Support of the California Air Resources Board for Meeting Assembly Bill (AB) 1318

July 20, 2012

California ISO
Shaping a Renewed Future

1. Introduction

In support of the directives of Assembly Bill 1318 (AB 1318, Perez, Chapter 285, Statutes of 2009), the California Independent System Operator Corporation (ISO) conducted production simulations to evaluate the performance of resources in the L.A. Basin and to identify incremental system-wide capacity needs to manage variations between load and supply on the ISO's system. The simulation relies on the Plexos model that the ISO is using in connection with its renewable integration study efforts as well as the long-term procurement plan proceedings before the California Public Utilities Commission. The modeling methodology and assumptions were reviewed by stakeholders participating in these processes. In addition, the ISO had submitted testimony in the Commission's proceedings based on the simulation results of the model.

2. Modeling Assumptions

1) Production simulation methodology

Plexos is production simulation optimization software. It finds the minimum cost solution to meet demand, including variable generation cost, as well as start-up and shut-down costs. Generation unit commitment decisions are also made in the optimization. The simulation runs chronologically through all hours of year 2020 in hourly intervals. The simulation enforces generating unit constraints, including ramp rate, start-up time, minimum run and minimum down time.

2) Structure of the model

This model has zonal configurations for the entire Western Electricity Coordinating Council region. There are total 25 zones, eight of them in California. The ISO is divided into four zones, PG&E~~-BayArea~~ Bay Area, PG&E-Valley, SCE, and SDG&E.

The model assumes that there is no transmission constraint inside of each zone but transmission limits between the zones are enforced. The transmission limits between any two zones reflect the maximum simultaneous direct transfer capabilities between the two zones.

Each zone has a load forecast that can be met by generation from units inside the zone and from generation outside the zone. Imports are subject to the transmission limits into the zone. Besides load, there are also requirements for ancillary services (regulation-up, regulation-down, spinning reserve, and non-spinning reserve) and load following (up and down) capacity for the ISO and for other California balancing authority areas.[1]

The requirement for spinning reserve equals 3% of total load. Non-spinning reserve requirement is also 3% of load. A tool developed by Pacific Northwest National Laboratory (PNNL) was used to calculate the requirements for regulation and load

[1] A sensitivity case was developed in which the zones outside California also have ancillary services and load following requirements.

following up and down based on 1-minunte forecasts and forecast errors of load as well as solar and wind generation.

Ancillary service requirements can be met by generation capacity that is on-line and can ramp to the required capacity level within 10 minutes. Some units can also provide non-spinning reserve while they are off-line based on their start-up and ramping capability within 10 minutes. Load following requirements can be met by generation capacity that is online and can ramp to the required capacity level within20 minutes. Inter-hour energy changes can be met by generation capacity that is online and can ramp to the required capacity level within 60 minutes. The ramping capability of each generating unit that is online contributes to the energy, ancillary services and load following requirements.

3) Base data of the model

The ISO developed the model based on the WECC Transmission Expansion Planning Policy Committee (TEPPC) model version PC0 dated March 21, 2011. Data for California reflects renewable portfolios identified in Table 1 and load scenarios developed in connection with the CPUC's long-term procurement plan proceeding.[2]

Table 1. Renewable Portfolios for 2020

Scenario	Region	Biomass/ biogas	Geothermal	Small Hydro	Solar PV	Distributed Solar	Solar Thermal	Wind	Total
Trajectory	CREZ-North CA	3	0	0	900	0	0	1,205	**2,108**
	CREZ-South CA	30	667	0	2,344	0	3,069	3,830	**9,940**
	Out-of-State	34	154	16	340	0	400	4,149	**5,093**
	Non-CREZ	271	0	0	283	1,052	520	0	**2,126**
	Scenario Total	338	821	16	3,867	1,052	3,989	9,184	**19,266**
Environmentally Constrained	CREZ-North CA	25	0	0	1,700	0	0	375	**2,100**
	CREZ-South CA	158	240	0	565	0	922	4,051	**5,935**
	Out-of-State	222	270	132	340	0	400	1,454	**2,818**
	Non-CREZ	399	0	0	50	9,077	150	0	**9,676**
	Scenario Total	804	510	132	2,655	9,077	1,472	5,880	**20,530**
Cost Constrained	CREZ-North CA	0	22	0	900	0	0	378	**1,300**
	CREZ-South CA	60	776	0	599	0	1,129	4,569	**7,133**
	Out-of-State	202	202	14	340	0	400	5,639	**6,798**
	Non-CREZ	399	0	0	50	1,052	150	611	**2,263**
	Scenario Total	661	1,000	14	1,889	1,052	1,679	11,198	**17,493**
Time Constrained	CREZ-North CA	22	0	0	900	0	0	78	**1,000**
	CREZ-South CA	94	0	0	1,593	0	934	4,206	**6,826**
	Out-of-State	177	158	223	340	0	400	7,276	**8,574**
	Non-CREZ	268	0	0	50	2,322	150	611	**3,402**
	Scenario Total	560	158	223	2,883	2,322	1,484	12,171	**19,802**
High Load	CREZ-North CA	3	0	0	900	0	0	1,205	**2,108**
	CREZ-South CA	30	1,591	0	2,502	0	3,069	4,245	**11,437**
	Out-of-State	34	154	16	340	0	400	4,149	**5,093**
	Non-CREZ	271	0	0	283	1,052	520	0	**2,126**
	Scenario Total	338	1,745	16	4,024	1,052	3,989	9,599	**20,763**

For this effort, the ISO used the 33% Trajectory High-Load scenario for 2020. This scenario reflects a combination of future uncertainties, including increased load growth

[2] *See generally* http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/LTPP2010/2010+LTPP+Tools+and+Spreadsheets.htm

and lack of performance from demand side management resources. The Trajectory High-Load scenario also has 1,497MW of additional renewable resources when compared to the Trajectory Base Load scenario to meet the 33% Renewable Portfolio Standard target.

4) New resource assumptions

This study uses the results of the once through cooling (OTC) studies conducted by the ISO in the 2011-2012 transmission planning process. The OTC studies identify 3,173 MW resource needs in local capacity areas. This amount reflects the total low end of the range of needed new or repowered local resources for the Trajectory case in the San Diego (373MW), Los Angeles Basin (2,370MW) and Big Creek Ventura areas (430MW). Based on the findings of the OTC studies, the ISO added two 500 MW combined cycle generating turbine (CCGT) units and eighteen 100 MW gas turbine (GT) units to SCE zone. The ISO added one 373 MW CCGT unit to SDG&E zone. Table 2 compares the characteristics of these new resources, also referred to as Local Capacity Requirement (LCR) resources, with similar existing units.

Table 2. Characteristics of New Resources and Other Existing Similar Units

Resource[3]	Max/Min Capacity (MW)	Full-Load Heat Rate (Btu/kWh)	Ramp Rate (MW/min)	Forced Outage Rate (%)[4]	Maintenance Rate (%)	Start-up Time (hour)	Start-up Cost ($)
SCE NEW GT	100/40	9,191	12.0	7.24	10.0		1,200
SCE NEW CCGT	500/200	7,000	7.5	4.96	10.0	2	44,520
SDGE NEW CCGT	373/200	7,000	7.5	4.96	10.0	2	44,520
Gateway (CCGT)	530/265	7,000	10.0	10.00	10.0	2	24,411
Sentinel (GT)	106/43	9,191	12.0	10.00	10.0		1,000

Chart 1. Comparison of Ramp Rates by Unit Type

[3] SCE NEW CCGT represents two identical CCGT units, SCE NEW GT represents eighteen identical units, and SDGE NEW CCGT represents one unit.

[4] Forced outage rates of the new resources are based on NERC Generating Availability Data System 2006-2010 average EFORd, CCGT for all MW sizes and GT for 50 plus MW. The ISO set the forced outage rate of existing units at 10% to match total MW outage in California in 2020 with the ISO monthly minimum actual MW outage in 2010.

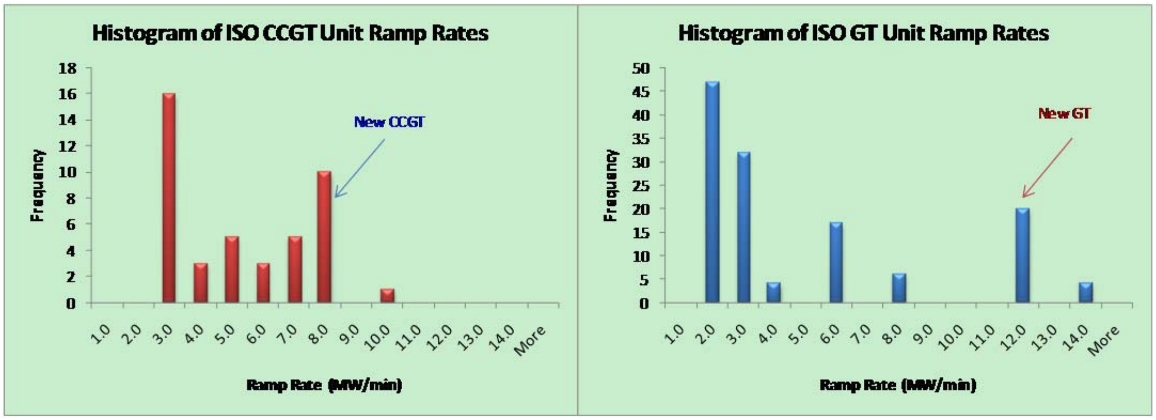


Chart 1 presents a comparison of ramp rates of the modeled new CCGT and GT resources in SCE and SDG&E's zones with the ramp rates of other units of the same type in the ISO area. As shown in the chart, the modeled new CCGT and GT resources generally have higher ramp rates (i.e., more flexible) than other existing units.

3. Summary of simulation results

The ISO conducted simulations for year 2020 with two separate model runs.

The first model run is called production cost run and the second is called need run. The difference between the two runs is in the values of regulation and load following requirements. In the production cost run regulation and load following (up and down) requirements have hourly values as calculated by the PNNL tool. In the need run, regulation and load following (up and down) requirements are set to monthly maximum value of each hour. For example, the regulation-up requirements of hour 1 of all 31 days in January are set to the maximum of the hourly requirement calculated by the PNNL tool for hour 1 of the 31 days in January.

The production cost run produces the results of generation output, costs, ancillary service and load following requirements, as well as imports and exports. The need run is used to identify ramping capacity shortages and capacity needs. The purpose is to ensure that the fleet has sufficient capability to meet a wide range of expected conditions for each month. In this section all results, except ramping capacity shortages, are from the production cost run. Ramping capacity shortage is the results of need run.

1) Utilization of the new resources

Table 3 reflects the monthly and annual capacity factors of the new resources as well as the average capacity factors of existing CCGT and GT units in the ISO area (excluding the new resources).

Table 3. Comparison of Monthly Capacity Factors

Resource	1	2	3	4	5	6	7	8	9	10	11	12	Annual
SCE NEW GT	9.5	11.2	10.0	9.8	12.0	16.5	20.3	17.9	7.9	10.0	8.0	10.2	11.9
SCE NEW CCGT	53.1	60.0	61.4	64.2	59.4	64.1	73.7	83.4	80.9	66.9	61.1	68.3	66.4
SDGE NEW CCGT	49.2	62.1	55.9	20.4	72.6	76.5	69.0	87.4	83.7	50.9	37.8	20.3	57.1
Gateway (CCGT)	52.0	45.6	55.3	48.7	45.5	56.1	62.8	55.2	60.1	56.2	60.3	60.7	54.9

Sentinel (GT)	22.1	20.3	17.2	18.3	21.1	19.6	20.4	19.1	11.6	16.2	16.0	12.1	17.8
GT Average	10.9	10.7	8.0	10.8	10.9	12.0	11.2	9.5	6.6	8.4	9.3	10.4	9.8
CCGT Average	48.5	45.9	40.6	39.8	36.1	40.2	62.0	65.4	55.1	51.0	49.6	51.9	49.4

The new resources have higher capacity factors than the average of the same type of units in the ISO area. This outcome is expected because the new resources are more flexible and have lower forced outage rates than most of the existing CCGT and GT units. The new resources' heat rates are also lower than the average of the existing CCGT and GT units.

Compared to Sentinel, the SCE NEW GT has higher start-up cost. As a result, it has a lower capacity factor. For GT units running at low capacity factor, the difference in forced outage rates does not have a significant impact on utilization. The new CCGT resources run more than Gateway unit. In this case, the higher forced outage rate does make a difference.

Of the two new CCGT resources, SDGE NEW CCGT has a lower capacity factor than the SCE NEW CCGT. This outcome is likely due to the ramp range (the range between minimum and maximum capacity). The SDGE NEW CCGT has 173 MW while the SCE NEW CCGT has 300 MW of range per unit. Since both have the same start-up cost and ramp rate, in certain circumstances the optimization may choose to commit the unit with the larger ramp range over the unit with the smaller range.

2) Contribution to ancillary services and load following (total and average per hour)

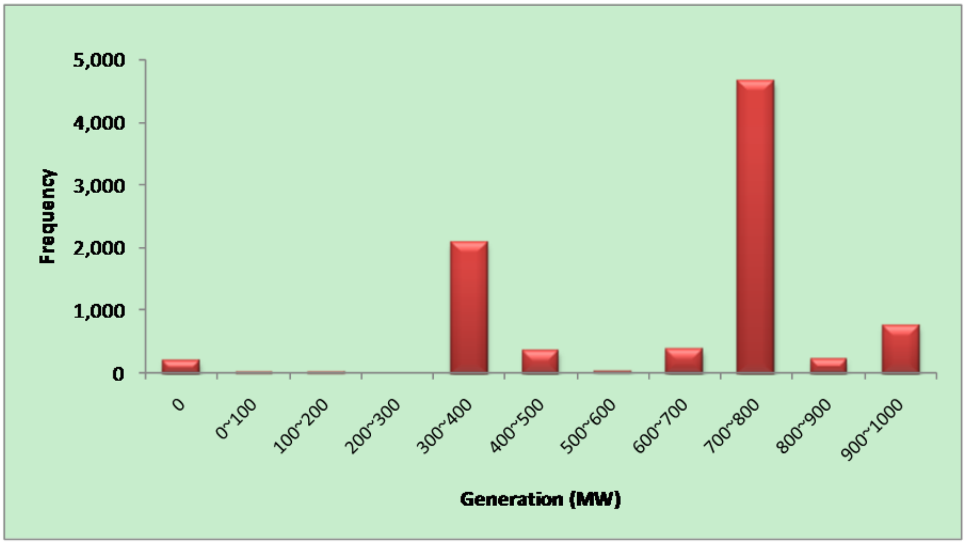
Besides producing energy, the new resources also contribute to meet ancillary service and load following requirements. Table 4 has the annual total contributions to ancillary services and load following by the new resources.

Table 4. Ancillary Service and Load Following Contribution (GWh)

Resource	LF Down	LF Up	Non-Spin	Reg-D	Reg-U	Spin
SCE NEW GT	23.9	537.3	1.9	32.1	320.0	914.8
SCE NEW CCGT	1,888.0	849.2	0.5	101.8	11.6	577.2
SDGE NEW CCGT	264.9	217.8	0.0	202.7	78.6	56.4

Chart 2. Histogram of SCE NEW CCGT Hourly Generation[5]

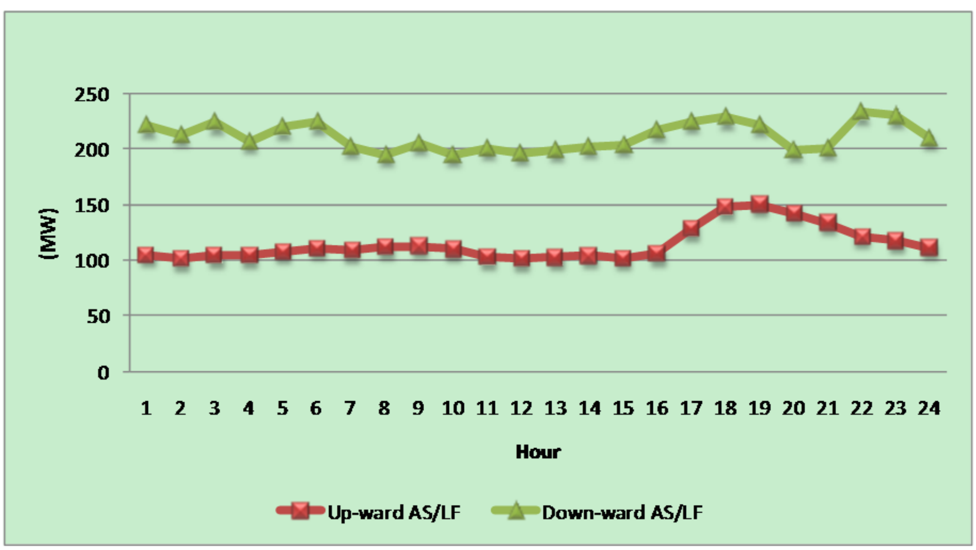
[5] This chart reflects the total generation of two identical CCGT units under the name SCE NEW CCGT. Each has a 200 MW minimum capacity and 2 hours start time. At the end of first hour in the start-up process a unit will generate 100 MW. Therefore there is generation between 0 and 200 MW in the chart. Zero generation means both units are in outage mode.



Contributing to upward ancillary services and load following requires the resource to maintain certain headroom in dispatch. On the other hand, to contribute to downward regulation and load following the resource must be dispatched above its minimum capacity. Contribution to ancillary services and load following is not reflected in the capacity factor of the resource, but should be counted in its utilization.

As shown in Chart 2, the SCE NEW CCGT runs mostly in the range of 700–800 MW out of its 1,000 MW maximum capacity. The headroom allows the resource to provide upward ancillary services and load following between 100 and 150 MW each hour on average (see Chart 3). This new resource also provides 200 to 230 MW of downward ancillary service and load following each hour. This results mainly due to the flexibility of the new resource. These capabilities are important to the reliability of the system, especially during the high load and fast ramping hours in the late afternoon.

Chart 3. Average Hourly AS/LF Contribution by SCE NEW CCGT



3) Number of starts of the new resources

With the increase in intermittent renewable resources interconnecting to the ISO, the system needs to deploy more flexible conventional resources to respond to the variations of renewable generation. That may cause some resources to cycle more. Cycling of generation resources depends on many factors such as start time, ramp rate, minimum run and down time, and start-up cost. More flexible ones may cycle more. Units with lower start-up costs may see a higher number of starts than units with higher start-up costs.

Tables 5 shows the number of starts of the new resources, similar units, and the average of existing CCGT and GT units in the ISO area (excluding new resources).

The results show much higher number of starts for GT units than the CCGT units. SCE NEW GT resources have higher start-up costs than Sentinel unit, which may have resulted in a lower number of starts for the SCE NEW GT resources.

The new CCGT resources have lower number of starts than Gateway unit. As shown in Table 2, the Gateway unit has a higher ramp rate. It is easier to cycle than the new CCGT resources. More importantly, the higher start-up cost makes new CCGT resources uneconomic to cycle compared to Gateway unit.

Table 5. Comparison of Number of Starts[6]

Resource	1	2	3	4	5	6	7	8	9	10	11	12	Annual
SCE NEW GT	26.2	20.3	21.8	20.9	18.7	16.8	25.4	27.4	20.8	24.8	24.1	25.3	272.6
SCE NEW CCGT	3.0	3.0	3.0	2.5	1.0	2.0	1.5	0.0	0.0	2.5	2.5	2.0	23.0
SDGE NEW CCGT	2.0	3.0	3.0	2.0	1.0	1.0	1.0	0.0	0.0	2.0	1.0	3.0	19.0
Gateway (CCGT)	6.0	8.0	6.0	8.0	5.0	4.0	5.0	5.0	4.0	6.0	3.0	3.0	63.0
Sentinel (GT)	54.0	44.0	40.0	42.0	46.0	39.0	32.0	28.0	22.0	35.0	29.0	34.0	445.0
GT Average	8.0	7.9	8.7	7.4	6.9	5.6	12.8	10.8	6.0	6.7	6.9	7.8	95.5
CCGT Average	3.7	3.7	4.3	3.8	3.4	3.6	5.0	4.8	3.0	4.7	3.7	3.8	47.4

4) Additional system-wide capacity shortage

With the 3,173 MW new resources added, the need run of the ISO's simulation still finds a 1,251 MW shortage in the 20-minute load following up requirement. Additional flexible capacity is necessary to meet the load following up requirement. As the Plexos model has a zonal configuration, it does not determine where the additional capacity should be added. From a flexibility perspective. The ISO does not believe the additional capacity needs to be in the LA Basin. Based on historical patterns, however, it may be a better fit if some of the residual need were located south of path 26. These results do not consider the possibility of operating without the generating units at the San Onofre Nuclear Generating Station.

The ISO has previously identified a need for 4,600 MW of capacity in the operational relevant Trajectory High-Load scenario.[7] In the simulation supporting that determination,

[6] This is the average number of start of each of the units under each new resource name.

the ISO assumed that the 4,600 MWs would comprise flexible GT units without forced and maintenance outages. Since then, the modeling of demand response resources has improved. Some of the high cost demand response resources have a 4-hour minimum time together with limited energy usage. These limitations prevented the demand response resources being fully utilized. At some peak load hours, the demand response resources cannot be deployed as the remaining energy is insufficient to run for 4 hours. In this study the ISO has relaxed the 4-hour minimum run time limit, thereby reducing the ramping capacity shortage during the peak load hours.

This study did not evaluate the frequency response and inertial benefits of the new resources or needs for frequency response and inertia in the ISO system generally. The ISO has conducted a study to analyze the system wide frequency response requirement under higher renewable scenarios. A study report can be found on the ISO website at http://www.caiso.com/Documents/Report-FrequencyResponseStudy.pdf.

4. Conclusion

Based on the production simulation, the flexibility of new resources is very important to reduce the shortage in ramping capacity. With the new resources that the ISO modeled, there remains a 1,251 MW shortage in meeting the 20-minute load following up requirement. Alternatives to the observed shortages including adding flexible resources at locations that are deliverable to the system load should be considered Due to historical patterns of Path 26's north to south flow constraint it may be desirable to locate at least a portion of the residual need for flexible resources south of Path 26.

[7] The ISO also previously ran the other 4 CPUC scenarios. The results did not show need for capacity.