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 (Filed March 22, 2012)

PREPARED TESTIMONY OF KEVIN WOODRUFF ON BEHALF OF THE UTILITY REFORM NETWORK REGARDING TRACK I – LOCAL RELIABILITY

Kevin Woodruff
Principal
Woodruff Expert Services
1100 K Street, Suite 204
Sacramento, CA 95814
916-442-4877
kdw@woodruff-expert-services.com
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INTRODUCTION

Q. Please introduce yourself.

A. I am Kevin Woodruff. I am the Principal of the consulting firm of Woodruff Expert Services. I have testified before this Commission on many occasions regarding electric utility resource planning and procurement and project valuation issues. My resume is appended hereto as Attachment 1.

Q. On whose behalf are you testifying?

A. I am providing this testimony on behalf of The Utility Reform Network (TURN), an organization that has long represented the interests of smaller consumers before this Commission.

Q. What issues are you addressing in your testimony?

A. I am addressing the testimony the California Independent System Operator (CAISO) served in this docket on May 23, 2012, and the Supplemental Testimony the CAISO served in this docket on June 19, 2012, regarding replacement of generation using Once Through Cooling (OTC) technologies needed to meet Local Capacity Requirements (LCRs) in the service territory of Southern California Edison (Edison) and CAISO system-wide renewable integration needs.[1] I also address some implementation issues related to the procurement of any new resources needed to meet LCRs.

SUMMARY AND RECOMMENDATIONS

Q. Please summarize your conclusions to date regarding the CAISO's testimony.

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[1] Specifically, I am addressing the Testimony of Robert Sparks and Testimony of Mark Rothleder served May 23 and the Supplemental Testimony of Robert Sparks served June 19. Mr. Sparks's testimonies generally addressed LCR needs and Mr. Rothleder's testimony generally addressed renewable integration needs. I refer to these documents as Sparks Testimony, Rothleder Testimony and Sparks Supplemental Testimony, respectively.

A. The CAISO testimony addresses key issues facing this Commission in its role as the major Local Regulatory Authority (LRA) setting procurement policy for CAISO markets. However, I am concerned that the CAISO testimony presents its studies of both LCR issues and renewable integration issues as definitive rather than just one particular view of the issues. In particular, the CAISO appears to be asserting certain policies and findings that deserve explicit consideration by the Commission as established policy or fact.

Q. Please summarize your conclusions to date regarding the implementation of any procurement of new capacity the Commission authorizes in this docket this year.

A. I have concluded that:

- If the Commission wants the procurement of local resources to meet LCR needs to begin this year, that the only entity capable of conducting such procurement effectively is Edison itself.
- Though market power in new generation may not be an issue in large Local Reliability Areas – such as the Western Los Angeles (LA) Basin – there is market power – in fact, virtually monopoly power – in some sub-areas, such as Ellis. Such differences in market power among regions may call for very different procurement approaches, as presented below.

Q. Do you feel that LCR and renewable integration needs are attributable to particular customer classes or are more of a generalized system need?

A. I do not think it is possible to attribute LCR needs differentially to any particular customer class or type at this time. I thus think the costs of any such investments the Commission directs should be shared among all customers equally.

Q. What specific policy recommendations do you have at this time?

A. Based on my conclusions above about the realities of procuring new generation in Southern California and the equal responsibility customers have for needs at issue in this docket, I suggest that the Commission task Edison with procurement of any new local resources in this docket and allocate the capacity costs of such resources among customer classes pursuant to Senate Bill 695, Senate Bill 790 and other Commission policies.

In addition, I recommend the Commission adopt one or more mechanisms to mitigate potential market power issues and other procurement challenges in LCR procurement, such as:

- Holding RFPs to seek the most competitive replacements for OTC resources, even in sub-areas in which there are currently no known alternatives to an OTC unit, to ensure that all potential options are considered. In addition to conventional generation, such RFPs should also solicit non-fossil alternatives for meeting specific area or sub-area needs, such as Demand Response.
- Providing minimum and maximum procurement targets (a) to ensure some truly needed minimum amount is procured, (b) to prevent procurement of capacity that will not necessarily be needed, and (c) to provide purchaser(s) flexibility when negotiating with bidders.
- Implementing some type of "circuit breaker" mechanism to allow procurement of lower amounts of capacity – such as the lower end of a range of capacity need – should prices of one or more bids greatly exceed a reasonable cost.
- Providing OTC unit owners in sub-areas with cost-of-service contracts for development and operation of needed resources.
- Prioritizing procurement in the most logistically challenging areas first, such as the Ellis and Moorpark sub-areas.

I am not suggesting the above options as permanent mechanisms for procuring new capacity in California. Rather, given the unique circumstances of LCR procurement in Edison's territory, I make the above recommendations solely for application in any procurement that is authorized in this specific track of this docket.

Q. Do you have any policy recommendations to make regarding specific LCR procurement targets?

A. No, not at this time. I raise some questions regarding the CAISO's studies and recommendations below that I think merit consideration before the Commission acts to authorize specific amounts of LCR procurement. I expect the CAISO and other parties to address these issues in today's testimony, rebuttal testimony and future data requests. I may have more specific recommendations in my rebuttal testimony.

LOCAL CAPACITY PROCUREMENT

Q. Please summarize briefly the CAISO's recommendations to the Commission regarding procurement of local capacity in Southern California.

A. Based on the CAISO's *2011-2012 Transmission Plan*, CAISO witness Sparks recommends the Commission authorize procurement of the amounts of local capacity in Edison's service territory shown in Table 1. These recommendations are based on the specific need to replace capacity at or near current plants that rely on OTC systems, which must generally retire or be refurbished to minimize their use of the OTC technology over the next decade. The CAISO made these recommendations based on the "Trajectory" Renewable Portfolio Standard (RPS) case Commission staff developed in the last Long-Term Procurement Plan (LTPP) rulemaking.[2] Mr. Sparks also recommends that "replacement OTC generation have flexibility characteristics similar to the OTC generation".[3]

2 Rulemaking 10-05-006.
3 Sparks Testimony, 17:15-16.

TABLE 1

CAISO Recommended "Replacement OTC" Procurement [4]

Local Reliability Area	MW	Comment
Western LA Basin Sub-area	2,400	embedded in LA Basin Area
Ellis Sub-Area	225	embedded in Western LA Basin Sub-area
Moorpark Sub-Area	430	embedded in Big Creek-Ventura Area

Q. Do you think the Commission should adopt this CAISO recommendation without further analysis and consideration?

A. No. I think there are several major concerns with the CAISO's approach that should be addressed first. Depending on the answers, the Commission may reasonably decide to adopt the CAISO's recommendation, change the amounts and timing of any authorization, and/or add other terms and conditions to its authorization.

COMMISSION HAS LITTLE PRECEDENT TO GUIDE AUTHORIZATION OF LONG-TERM PROCUREMENT FOR LOCAL CAPACITY NEEDS

Q. Do you have any preliminary cautions to the Commission about the CAISO's recommendations that procurement be authorized to address specific local reliability needs?

A. Yes. To my knowledge, the only long-term system planning decisions that this Commission has based more than minimally on local reliability concerns related to the San Diego Gas & Electric Company (SDG&E). Because SDG&E faces unique load pocket issues in its service territory that drive much of its resource planning, various options for meeting capacity needs in the San Diego Local Reliability Area (LRA) have been key issues in many Commission proceedings, such as the dockets addressing the Valley-Rainbow and Sunrise Powerlink transmission lines, SDG&E's contract for the Otay Mesa power plant and SDG&E's current application for approval of three new

[4] Sparks Testimony, 16:26-17:16.

contracts for local capacity.[5] But the focus on SDG&E's long-term needs has been the exception rather than the rule in Commission proceedings.

Q. Does the Commission's experience addressing SDG&E LCR issues provide relevant experience or precedents for addressing long-term LCR issues outside SDG&E's service territory?

A. No. The SDG&E example does not give the Commission general experience at analyzing these issues nor precedents to guide its decisions in this docket. SDG&E was the applicant in all the above cases and had a well-defined responsibility of meeting a burden of proof. The Commission and/or SDG&E thus established the assumptions for analyzing such local needs rather than the CAISO.[6] The Commission and SDG&E were able to specify these analyses without the CAISO because the San Diego LRA need could be analyzed in a spreadsheet template and did not require re-simulating the load flow models the CAISO generally uses to set LCRs in other areas.[7]

But in this case, the CAISO has proposed LCR procurement based on its own modeling methodology and explicitly rejected some of the Commission's planning assumptions. I discuss this issue further below.

Q. Does not the Commission review and approve CAISO LCR studies and recommendations every year with little or no change?

A. Yes. The Commission has reviewed and approved CAISO LCR recommendations for several years. However, these studies have always been conducted annually to set LCRs for the following year. For example, the LCR targets the Commission set just last Thursday (June 21, 2012) in issuing Decision (D.) 12-06-025 will apply only for the 2013

[5] Application (A.) 01-03-036, Rulemaking (R.) 01-10-024, A.06-08-010 and A.11-05-023, respectively. I am not herein expressing any opinion about the issues in these dockets.

[6] The CAISO did submit testimony in some of these applications on local reliability issues.

[7] With the recent completion of the Sunrise Powerlink, the computation of LCRs affecting SDG&E's customers has changed. See CPUC Decision D.12-06-025, Section 3.1.

calendar year. The CAISO's annual studies make no effort to project needs several years in advance.

As discussed below, the CAISO has made several LCR forecasts for future years, but to my knowledge the Commission has made little use of these studies – and, aside from San Diego LCR issues, has not issued procurement authorizations based on the results of these longer-term studies.

SPECIFIC CONCERNS WITH CAISO METHODOLOGY

Q. What are the major concerns with the CAISO's recommendation that you feel the Commission should consider before reaching a final conclusion?

A. There are at least three basic issues that deserve the Commission's attention before it authorizes any LCR procurement:

- LCR needs, especially longer-term needs, are "moving targets."
- The CAISO is not honoring the state's energy planning goals in its recommendations.
- The CAISO appears to be proposing the Commission adopt more stringent standards for LCRs than the Commission has previously adopted.

I anticipate that other parties will also raise additional issues worthy of Commission consideration before it acts in this case.

- *LOCAL CAPACITY REQUIREMENTS ARE A 'MOVING TARGET'*

Q. What is your first concern about adopting the CAISO's recommendations?

A. Over the several years the CAISO has performed LCR studies, the results of such studies that focused on needs several years in the future have been "moving targets," that is, the projected LCRs in future years have varied significantly over time.

Q. What is the significance of projected LCRs being moving targets?

A. The tendency of LCR estimates to change over time means that Commission adoption of a fixed number at this time poses the risks of either under-procurement or over-procurement of capacity in select portions of Edison's territory.

Q. Do you have some examples of longer-term LCR studies varying to a significant degree over time?

A. Yes. There is one example of particular relevance to the Commission's consideration in this docket. The Sparks Testimony forecast that LA Basin LCRs for 2021 would range from 10,743 MW to 12,165 MW, depending on the RPS scenario.[8]

But in December 2010, the CAISO issued a *2013-2015 Local Capacity Technical Analysis* which said:

"Due to the numerous transmission projects modeled, in 2015 timeframe, the Western LA Basin sub-area will become the most stringent and binding local area constraint. At that time it is envisioned that the LA Basin local area will be eliminated and the Western LA Basin local area will become a new local area."

As a result, in this study, the LCRs shown for the LA Basin dropped from 11,304 MW in 2013 to 5,988 in 2015.[9]

The potential for actual LCRs to deviate from forecast LCRs is thus quite significant and makes authorization of new capacity to meet LCRs a financially risky proposition for customers. The Commission should consider such risks in its deliberations in this docket.

Q. Are you suggesting that the Commission ignore the CAISO long-term LCR studies?

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8 Sparks Testimony, Table 1 (p. 6) and Tables 2 to 6 on following pages.

9 The salient pages from this study are provided as Attachment 2. The complete study is available at http://www.caiso.com/Documents/2013-2015LocalCapacityTechnicalAnalysisReport.pdf. This study consistent with the *2011-12 Transmission Plan*, still found LCR needs in the Western LA Basin and Ellis sub-areas.

A. No. CAISO LCR studies no doubt have significant value in highlighting local reliability issues in portions of Edison's territory. But the Commission should recognize that such studies are forecasts of needs, and thus prone to the same frailties as all forecasts. As such, it may be appropriate for the Commission to reach findings and conclusions and direct procurement that differs from the results of the CAISO's modeling.

- *THE CAISO IS NOT HONORING THE STATE'S ENERGY PLANNING GOALS*

Q. Why do you say the CAISO is not honoring the state's energy planning goals?

A. The CAISO has taken a very aggressive stance that it does not wish to rely on this Commission's long-term planning goals in deciding whether new generation should be built to meet local needs. In particular, the CAISO states it did not include in its reliability modeling any amounts of uncommitted estimates of demand response (DR), energy efficiency (EE) and combined heat and power (CHP).[10]

Q. Is the CAISO correct that the above targets might not be achieved?

A. Yes.

Q. Is concern over achieving targets a sufficient reason to not consider such targets – that is, discount them to zero – in planning?

A. No. If the Commission acquiesces to this assumption, then its program targets may never be achieved. Moreover, the programs themselves rely on cost-effectiveness calculations that assume economic value tied to the displacement of new conventional generation capacity. Reliance on the CAISO approach is tantamount to concluding that these DR, EE and CHP programs are not expected to provide any capacity value. This would not be an acceptable outcome given the amount of funding the Commission is lavishing on such programs.

[10] See Sparks Testimony, 15:20-30 and Sparks Supplemental Testimony, 4:6-5:5.

Q. Does the CAISO's stance on this matter extend beyond merely ignoring the Commission's plans and goals?

A. Yes. The CPUC and California Energy Commission (CEC) adopted an Energy Action Plan (EAP) that features a "loading order" expressing preference for meeting future needs by "conservation and energy efficiency" and "renewable and renewable energy resources and distributed generation" before "additional clean, fossil fuel central-station generation".[11] The CPUC cited the loading order positively as recently as April in D.12-04-046.[12] To my knowledge, the CAISO has previously expressed support for the EAP's goals and has not publicly rejected the "loading order" so forcefully.[13]

Q. What are the implications of the CAISO's stances on the state's energy planning goals?

A. The CAISO may have legitimate concerns about the achievement of the state's energy planning goals and of any failure to achieve such goals on its operation of the system. But abandoning such goals is not consistent with state policy and the CAISO's past stances. The Commission should chart a course in this case that honors its own goals and the state's energy planning goals in general.

- *THE CAISO APPEARS TO BE ADOPTING MORE STRINGENT LCR STANDARDS*

Q. Why do you say the CAISO appears to be adopting more stringent LCR standards than the Commission has previously approved?

A. The CAISO's recommendations appear to be based on two applications of NERC standards that go beyond what the Commission has adopted before in its annual LCR decisions.

Q. What is the first of these apparently new applications of NERC standards?

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11 Attachment 3 to this testimony provides the pertinent page from the original EAP.

12 See D.12-04-046, p. 43.

13 Attachment 4 is a joint presentation of the CPUC, CEC, CAISO and the California Air Resources Board that expressed support for goals similar to the loading order. See page 5 in particular.

A. The first issue is the NERC "Category" of contingency that the CAISO is using to set LCRs.

Q. Please explain what you mean by "NERC Category".

A. The NERC is the North American Electrical Reliability Corporation (NERC) and is charged with setting reliability standards for electric system operators throughout the U.S. The NERC Categories define the types and timing of contingencies operators must manage to avoid shedding firm electric load. According to the CAISO's *2013 Local Capacity Technical Analysis*:[14]

> "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." (pp. 10, 17)
>
> "Generally, Category C describes system performance that is expected following the loss of two or more system elements." (pp. 11, 17)

Further, NERC defines Category D as an "extreme event – loss of two or more elements" (p. 17).

Q. What NERC Categories are relevant for setting LCRs?

A. In adopting the LCR program several years ago, the Commission decided – based on the CAISO's recommendation – to implement LCRs sufficient to allow the CAISO to mitigate Category C contingencies. In doing so, the Commission explicitly decided against adopting procurement based on the less stringent Category B contingency.[15] To my knowledge, there has been no consideration in Commission LCR decisions about local procurement to meet Category D contingencies. The CAISO's *2013 Local*

14 Attachment 5 hereto provides excerpts from the CAISO's *2013 Local Capacity Technical Analysis*, including the pages discussing NERC contingencies As noted above, this report's LCR recommendations were adopted by the Commission June 21, 2012, in D.12-06-025 in R.11-10-023; the report was previously submitted to the Commission on May 2. The study is also available on the CAISO's website at http://www.caiso.com/Documents/Final2013LocalCapacityTechnicalStudyReportApr30_2012.pdf.

15 D.06-06-064, pp. 16-22.

Capacity Technical Analysis contains text stating it is imposing performance criteria only to "Performance Level B & C".[16] And the *Analysis's* only other reference to Category D contingencies implied that such contingencies were not relevant to setting 2013 LCRs.[17]

Q. What NERC Categories did the CAISO use as criteria for setting LCRs in its *2011-2012 Transmission Plan*, and thus Mr. Sparks's Testimony?

A. In response to Questions 7 and 9 of TURN's First Data Request, the CAISO said it developed its recommendations using Category C events except for the Ellis and Moorpark sub-areas. For those areas, the CAISO said its recommendations are both based on "a NERC Category D event that can cause uncontrollable voltage collapse". These answers are provided in Attachment 6.

Q. What is the significance of the CAISO's use of Category D events to set recommended LCR procurement targets in the Ellis and Moorpark sub-areas?

A. It is possible that the use of Category D events led to higher estimates of LCR and thus procurement needs.

Q. Do you oppose the Commission's implementation of LCR procurement based on Category D contingencies in this case?

A. Not necessarily. But I do oppose the application of the Category D criteria without a full vetting of the basis for doing so and its implications for procurement targets. The CAISO needs to explain why it seeks to deviate from Commission policy on this matter.

Q. What is the second application of NERC standards that you believe is new in this case?

A. CAISO witness Sparks contends that new local resources "should have flexibility characteristics similar to the OTC generation".[18] In response to Question 14 of TURN's First Data Request, the CAISO contended that new generation should be flexible so that

[16] See Attachment 5, p. 7

[17] See Attachment 5, p. 3.

[18] Sparks Testimony, 17:15-16.

it can be started or ramped within 30 minutes.[19] The NERC criteria appear to be written with this standard for responding to outages.[20] However, I do not believe that the CAISO actually applies this requirement to set LCR procurement targets when it conducts LCR studies.

More importantly, the Commission does not now require local capacity that meets LCR needs to be flexible. Thus inflexible capacity such as nuclear units, many Qualifying Facility resources, and other renewable generation all count equally with flexible capacity in meeting LCR procurement targets. The CAISO's interpretation of this aspect of the NERC requirements thus seems to be new and different in this case and, if applied to annual LCR procurement, could cause a significant change in that program.[21]

It thus appears the CAISO is using this portion of the NERC standard as a convenient means to argue that new local capacity should be flexible generation. The Commission should explicitly consider whether it wishes to adopt this seemingly new interpretation of the NERC criteria and its possible implications for annual LCR procurement.

Q. Do you disagree that any capacity the Commission authorizes in this docket should be flexible?

A. No. I generally agree that, all else being equal, flexible resources are superior to inflexible resources, largely for the same reasons the CAISO cites. But I do not think that the state's energy policy goals should be abandoned in pursuit of such flexibility. And I am concerned that the Commission should consider the implications of this apparently new application of the NERC standards to set LCR procurement requirements.

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19 This response is provided as Attachment 7.

20 See Attachment 5, p. 16.

21 Pursuant to D.12-06-025, Section 3.2.2, the Commission will be considering proposals that will require LSEs to meet some targets for procuring flexible capacity to meet general system needs in upcoming phases of R.11-10-023.

CAISO ARGUMENTS ABOUT 'ASYMMETRIC' RISK IMPROPERLY MAKE ALL ISSUES PIVOTAL

Q. What does the CAISO mean what it says that a certain risk is "asymmetric"?

A. In justifying the CAISO's position that it is inappropriate to rely on the Commission's uncommitted EE assumptions, CAISO witness Sparks argues that the risks of such reliance are "asymmetric", contending that the CAISO uses "[d]eliberately conservative forecasts" because "[a] marginal shortage means the loss of firm load, which puts public safety and the economy in jeopardy, whereas a marginal surplus has only a marginal cost implication". [22]

Q. Do you agree with Mr. Sparks that relying on uncommitted EE is an asymmetric risk?

A. No. Mr. Sparks has implicitly made assumptions in that argument that merit challenging. For example, he suggests "a marginal surplus has only a marginal cost implication," but no offers no evidence to support this assertion. If a new power plant is built to provide that last increment of surplus, it could actually be quite expensive. His prior statement that "[a] marginal shortage means the loss of firm load" suggests that such loss of load would be more than marginal, but again, there is no evidence to support this assumption. Losses of load could be minimal. Further, such losses of load could be much less if uncommitted EE achieves even part of its objectives, rather than the zero value Mr. Sparks assumed.

A more balanced analysis would at a minimum consider a range of possible outcomes for uncommitted EE results, their implications for interrupting service to firm load in terms of MW, and the costs of the capacity needed to prevent such interruptions. Consideration of the other factors affecting local reliability should also be made, such as the probability of the high loads used for local reliability planning and the likelihood of the

[22] Sparks Supplemental Testimony, 4:21-5:2.

contingencies used to set LCRs. Unfortunately, the standard methodology for setting LCRs does not lend itself to more nuanced analyses.

Q. Do you believe that there are risks to reliability that may be asymmetric, that is, that their adoption provides a very high value to customers?

A. Possibly. But proving that any risk is asymmetric requires more analysis than the CAISO has provided.

Q. Is the CAISO making arguments that there are other asymmetric risks to reliability that must be addressed?

A. Yes. The CAISO is applying this theme to risks related to renewable integration. For example, in his CEO Report of August 18, 2011, CAISO President and Chief Executive Officer Steve Berberich said that "aggressive forecasts of new energy efficiency and demand response preferred by the CPUC" create asymmetric risk.[23] The CAISO made similar arguments about the need for forward procurement of flexible capacity, as shown in Attachment 9, a portion of the CAISO's presentation from its June 14 stakeholder call on its latest proposal on this topic.[24]

Q. Are there risks to acting on poorly-supported claims regarding "asymmetric risks"?

A. Yes. As discussed above, there is potential for the Commission to authorize substantial new investments that will not be economic or consistent with state policy if it accepts and acts on such arguments about asymmetric risk without critical review.

Q. How do you believe the Commission should consider claims that multiple different risks are all asymmetric?

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[23] The CEO's Report is provided as Attachment 8. See page 2. The complete document is available on the CAISO website at http://www.caiso.com/Documents/110825CEOReport.pdf. Mr. Berberich made this report to the CAISO Board barely two weeks after the CAISO entered the Settlement Agreement in R.10-05-006, as discussed below.

[24] The complete presentation is available on the CAISO website at http://www.caiso.com/Documents/Presentation-FlexibleCapacityProcurement-RevisedStrawProposal.pdf.

A. Multiple arguments that specific risks are asymmetric are mutually self-rebutting. That is, the more risks the CAISO claims are asymmetric, the less credible each such claim is.

Q. How should the Commission evaluate each such claim that a risk is asymmetric?

A. The Commission should evaluate each such claim based on consideration of the range of possible outcomes, good and bad, for taking the risk.

COMMISSION SHOULD CONSIDER CAREFULLY ANY ARGUMENTS BASED ON SONGS RETIREMENT SCENARIOS

Q. Should the Commission consider the current outage of the San Onofre Nuclear Generating Station (SONGS), its implications for the units' long-term operation, and the implications of SONGS retirement in its decision in this docket?

A. The current SONGS outages and its possible early retirement or reduction of capacity may present additional challenges to maintaining reliability in both the Edison and SDG&E service territories. But the Commission should make decisions in this docket based on such concerns only to the extent it has the opportunity to review evidence in this proceeding. The Commission must be wary of acting in response to press accounts or to incomplete assessments. Since the situation is quite fluid, any information presented today may no longer be relevant in a matter of weeks or months. It is therefore inappropriate to make long-term decisions until the future availability of SONGS is more settled.

RECOMMENDATIONS REGARDING LOCAL CAPACITY PROCUREMENT

Q. What actions should the Commission take as to authorizing local capacity procurement at this time?

A. Because of my above concerns, I do not have a specific recommendation for the amount of local capacity in Edison's territory that the Commission should authorize at this time.

Based on my discussion below under "Contracting for Local Resources," I do have the following recommendations to consider when the Commission decides such issues:

- Provide minimum and maximum procurement targets (a) to ensure some truly needed minimum amount is procured, (b) to prevent procurement of capacity that will not necessarily be needed, and (c) to provide purchaser(s) flexibility when negotiating with bidders.
- Prioritize procurement in the most logistically challenging areas first, such as the Ellis and Moorpark sub-areas.

RENEWABLE INTEGRATION 'NEEDS'

Q. Briefly summarize your interpretation of the CAISO's recommendations in this case regarding resource procurement to meet of renewable integration needs.

A. CAISO witness Rothleder does not appear to be suggesting that any additional MW be added to Mr. Sparks's recommended procurement targets for local reliability needs. His testimony instead argues that any procurement for local needs be focused on procuring flexible capacity.[25] Unlike Mr. Sparks, however, Mr. Rothleder is recommending that such capacity be flexible to fill a need for such capacity to integrate growing quantities of renewable resources into the CAISO grid.

Q. What evidence does Mr. Rothleder cite that there may be significant needs for new flexible generation to support renewable integration?

A. Mr. Rothleder offers modeling results suggesting that the CAISO will have significant needs for new generation to integrate renewable resources and that authorization of the new local resources the CAISO is requesting in this case could meet most of such needs – if such local needs are met by flexible generation.[26]

[25] Rothleder Testimony, 7:17-21.
[26] Rothleder Testimony, 3:17-6:19.

Q. Do you have particular concerns with the modeling Mr. Rothleder has submitted in this case?

A. Yes. I have not analyzed the specific modeling Mr. Rothleder cites in his testimony. But I am greatly concerned that this modeling was based on a study the CAISO performed last year and submitted in its testimony in the last LTPP on July 1, 2011. That study, based on a "high load" scenario specified by the Commission's Energy Division, found that an additional 4,600 MW of new flexible generation might be necessary to integrate a 33 percent level of renewable resources into the CAISO grid. I thus label that scenario as the "4600 study".

Q. Do you any concerns about Commission reliance on the 4600 study?

A. Yes. I have several serious concerns about the Commission relying on the 4600 study.

The CAISO's 4600 study has never been analyzed in detail by this Commission. Major parties to the last LTPP, including TURN, settled the case before any party could file testimony to challenge that particular scenario. For example, I noted in my testimony supporting the settlement that I had several major criticisms that I chose not to develop in light of the settlement.[27]

Further, the 4600 study was only one of several scenarios the CAISO and Investor-Owned Utilities (IOUs) submitted in that docket, most of which found there was no additional need for new generation to integrate renewables.

Given these widely-shared concerns, most parties to the case reached a Settlement Agreement that stipulated:[28]

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27 Prepared Direct Testimony of Kevin Woodruff on behalf of The Utility Reform Network regarding Tracks I and III, submitted in R.10-05-006 August 4, 2011, 2:7-14. Exhibit 1504.

28 "Settlement Agreement between and among..." numerous parties, including CAISO and TURN, August 3, 2011, R.10-05-006.

"The resource planning analyses presented in this proceeding do not conclusively demonstrate whether or not there is need to add capacity for renewable integration purposes through the year 2020, the period to be addressed during the current LTPP cycle. The Settling Parties have differing views on the input assumptions used in, and conclusions to be drawn from the modeling. There is general agreement that further analysis is needed before any renewable integration resource need determination is made." (p. 5)

Pursuant to the Settlement, since last summer the CAISO has reviewed its methodology in detail with a working group and is developing another approach to estimating renewable integration need for use in Track II of this case. However, that methodology is not complete yet.[29]

Q. Have you been involved in the working group envisioned by the Settlement Agreement?

A. Yes. I have followed the working group's efforts closely. As Mr. Rothleder stated, the CAISO has been making considerable effort to review its approaches to estimating need and developing an alternative. As a result, the CAISO is planning to revise its approach for estimating renewable integration needs for the studies to be considered next year by this Commission in this docket. This CAISO documented its planned changes in a presentation to a workshop in this docket on June 4, 2012. The most salient portion of that presentation is provided as Attachment 10.

Q. What are the implications of the Settlement Agreement and the CAISO's ongoing review of renewable integration study methodologies for this case?

A. The CAISO is basing its estimates of flexibility need in this case on a high need scenario based on a study methodology it will not use in the next phase of this case. This is not a strong basis for its testimony in this case.

Q. Should the Commission afford the 4600 study or any derivative study any particular evidentiary value in this case?

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[29] Rothleder Testimony, 2:21-3:5 and 7:4-8.

A. No. The 4600 study is not necessarily invalid, but it is only one of a number of analyses on renewable integration need that the Commission received in testimony last summer. As such, the Commission may treat the 4600 study as a study – but the Commission should not consider it or any of its derivatives as "the study" that defines procurement needs for renewable integration purposes.

Q. Do you have any other concerns about the CAISO's use of the 4600 study in this and other forums?

A. Yes. I am concerned that the CAISO's continued use of the 4600 study is an exercise of bad faith to the settlement process in last year's LTPP. At a minimum, when presenting the 4600 study or any derivative study in the future, the CAISO should note for the Commission and others' sake that the CAISO and other major parties agreed last year that studies did not "conclusively demonstrate" a need and that it is now reviewing and revising its methodology.

CHALLENGES TO CONTRACTING FOR LOCAL CAPACITY IN SOUTHERN CALIFORNIA

Q. Do you believe the procurement of any capacity needed to meet LCRs in Edison's territory presents challenges to the Commission?

A. Yes. There are some unique challenges to developing local capacity to meet needs in some areas of Edison's service territory. For example, in two of the areas the CAISO identified as having needs – the Ellis and Moorpark sub-areas – a single company owns all of the OTC assets. If these areas have needs that can only be effectively met by generation at existing OTC sites, these two sites' owners will likely possess significant market power in any solicitation for replacement capacity.[30]

[30] These companies are AES – which owns the Huntington Beach plant in the Ellis sub-area – and GenOn – which owns the Mandalay and Ormond Beach plants in the Moorpark area. All these units have a deadline for complying with OTC regulations of December 31, 2020.

Managing the refurbishment or replacement of existing OTC generation in these two sub-areas may also present challenges. If such existing units are critical to sub-area reliability, they likely cannot be razed while replacement capacity is built. The replacement of such capacity will likely need to be carefully phased. This may further limit capacity buyers' options, enhancing sellers' market power.

Finally, I do not anticipate that any OTC asset owners will replace or refurbish their capacity without a long-term contract, especially given the careful coordination that such efforts will require.

Q. Do you think there are also market power issues in the Western LA Basin area?

A. Possibly. AES owns substantial capacity in the Western LA Basin – including the Alamitos and Redondo Beach plants, along with Huntington Beach –totaling close to 4,000 MW.[31] But there appears to be significantly more existing generation sites in this larger area, which may mitigate market power.

COMMISSION SHOULD ADAPT SPECIFIC POLICIES FOR PROCUREMENT IN THIS TRACK OF THIS DOCKET

Q. Do you think that to address these issues, the Commission should adopt generalized procurement policies in this track or instead adopt specific procurement policies focused on the specific purpose of this track?

A. The Commission should adopt a procurement approach tailored to the specific circumstances of the needs it identifies in this track. The adopted approach should not be precedential in later tracks in this proceeding or in other dockets.

31 This total excludes the 440 MW of capacity at Huntington Beach Units 3 and 4, which were returned from retirement this year to address concerns with the prolonged SONGS outage. The Alamitos and Redondo Beach units also have an OTC compliance deadline of December 31, 2020.

Q. How do you propose to address the challenges of supporting the development of any new local capacity the Commission believes should be built in Edison's territory?

A. I will start with the long-term contracting challenge first. Current Commission policy has already enabled the only realistic alternative for providing OTC replacement capacity developers a long-term contract on competitive terms. That approach is for Edison to contract for the capacity and allocate the costs among ratepayers when the plant becomes operational. Edison has the desired skills in system planning, asset valuation, and contract negotiation and management to conduct such a solicitation. Edison has also successfully conducted long-term solicitations for new capacity previously.

Q. What other options are available to the Commission to facilitate procurement of replacement OTC resources, including managing market power?

A. The Commission should adopt one or more of the following policies to help Edison manage the procurement of any needed local capacity.

- Holding RFPs to seek the most competitive replacements for OTC resources, even in sub-areas in which there are currently no known alternatives to an OTC unit, to ensure that all potential options are considered. In addition to conventional generation, such RFPs should also solicit non-fossil alternatives for meeting specific area or sub-area needs, such as Demand Response.
- Providing minimum and maximum procurement targets (a) to ensure some truly needed minimum amount is procured, (b) to prevent procurement of capacity that will not necessarily be needed, and (c) to provide purchaser(s) flexibility when negotiating with bidders.
- Implementing some type of "circuit breaker" mechanism to allow procurement of lower amounts of capacity – such as the lower end of a range of capacity need – should prices of one or more bids greatly exceed a reasonable cost.
- Providing OTC unit owners in sub-areas with cost-of-service contracts for development and operation of needed resources.

- Prioritizing procurement in the most logistically challenging areas first, such as Ellis and Moorpark sub-areas.

OTC SITE OWNERS SHOULD BE VIEWED AS POSITIVE PARTICIPANTS IN PROCESS OF ADDRESSING LOCAL CAPACITY ISSUES

Q. Do you believe the OTC site owners have a desire to solve local reliability issues in Edison's territory in a constructive and timely manner?

A. Yes. Not only do OTC site owners possess assets of potentially great value in meeting local reliability, I anticipate that such owners understand better than anyone the steps they need to take adapt their sites and power plants to meet such needs and are prepared to take such steps. Commission policy should anticipate OTC site owners will attempt to play a positive role in addressing local needs.

Q. Are you suggesting that the owners of existing OTC sites be denied the value of their investments in OTC generation, including the potential future value of the OTC sites?

A. No. I recognize that the OTC site owners want to earn a reasonable return on their investments and that Commission policy should enable them to make such returns.

Q. Are you suggesting that the owners of existing OTC sites are planning to exercise whatever market power they have?

A. No. I am not trying to suggest the OTC site owners have plans to enrich themselves unduly at Edison ratepayer expense. But I still want the Commission to adopt policies to prevent this from happening.

COST ALLOCATION

Q. How should costs of any procurement the Commission authorizes to meet local capacity requirements in the Edison service territory be allocated?

A. The net costs of such capacity should be allocated to all benefiting customers, pursuant to Senate Bill 695, Senate Bill 790 and other Commission policies. Other than this general principle, I am not making any more detailed recommendations at this time.

CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

ATTACHMENT 1

Resume of Kevin Woodruff

RESUME

Kevin Woodruff
Principal, Woodruff Expert Services

EXPERIENCE

WOODRUFF EXPERT SERVICES 1100 K Street, Suite 204 Sacramento, California 95814 916-442-4877 (voice) 916-442-2029 (fax) kdw@woodruff-expert-services.com November 2002 –	**PRINCIPAL** Analyze complex policy and business issues faced by electric utilities, generators, customers, and other industry players. Communicate to clients analytic findings and corollary recommendations for action. Help clients communicate findings and recommendations to other parties, including preparing expert testimony for and supporting litigation efforts.
HENWOOD ENERGY SERVICES, INC. (aka Ventyx and acquired by ABB May 2010, previously aka Global Energy Decisions) April 1988 – November 2002	**PRINCIPAL CONSULTANT (as of July 1992)** Helped manage Henwood's transition into leading supplier of electric power system and market analytic software by managing complex software development and implementation projects and managing the development, marketing, and sales of software products. Helped develop Henwood's power market analysis consulting practice into national leader by managing individual projects, managing and developing other staff to provide such services, identifying and developing new and enhanced services, and marketing and selling services to new and existing clients. Provided variety of consulting services to clients with interests in energy utility industry, including preparing expert testimony and supporting litigation efforts, analyzing, modeling, and forecasting operations of power systems, power markets, and individual generating units, forecasting utility and project revenues, costs, and rates, and analyzing and consummating business transactions.
CALIFORNIA STATE UNIV, SACRAMENTO September 1994 – May 1995 (part-time)	**LECTURER IN MANAGEMENT** Taught upper division courses in Finance.
SIERRA ENERGY AND RISK ASSESSMENT May 1986 – April 1988 November 1985 – May 1986 (part-time)	**STAFF CONSULTANT** Provided clients analysis of gas and electricity project economics and utility revenues, costs, and rates.
PRIOR EXPERIENCE	Five years with private legislative reporting firm; California state economic development, regulatory, and tax agencies and Legislature; and labor organization.

EDUCATION

A.B., Economics, University of California, Berkeley, 1976
M.B.A, California State University, Sacramento, 1990

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ADDENDUM 1

to Resume of Kevin Woodruff

EXPERIENCE WITH WOODRUFF EXPERT SERVICES

CLIENT	PROJECTS
THE UTILITY REFORM NETWORK 115 Sansome Street, Suite 900 San Francisco, CA 94104 415-929-8876 Mr. Bob Finkelstein, Legal Director Mr. Matt Freedman, Staff Attorney	**ANALYZE IOUs' PROPOSALS TO DEVELOP OR ACQUIRE POWER PLANTS. Sep 03 – present.** Review, analyze, comment, and testify on California Investor-Owned Utilities' (IOUs') various plans to purchase output from or acquire specific power plants, both conventional and renewable. **MONITOR CALIFORNIA IOUs' SHORT- AND MID-TERM ELECTRIC PROCUREMENT. Aug 03 – present.** Review, analyze, and comment on California IOUs' short- and mid-term electric power procurement and related activities by participating in their confidential Procurement Review Groups. **ANALYZE ELECTRIC RESOURCE PLANNING AND ADEQUACY POLICIES. May 03 – present.** Review, analyze, comment and testify on California electric resource planning issues, including Resource Adequacy policies, the development of new power plants, and the integration of renewable resources. **MONITOR INITIATIVES TO CHANGE CALIFORNIA TRANSMISSION PLANNING PROCESSES. Feb 04 – Aug 05 and Jul 08 – present.** Review, analyze and comment as appropriate on California state agencies' various initiatives to change transmission planning and evaluation processes.
OFFICE OF THE ARKANSAS ATTORNEY GENERAL, CONSUMER UTILITIES RATE ADVOCACY DIVISION 323 Center Street, Suite 200 Little Rock, AR 72201 501-682-1321 Mr. M. Shawn McMurray, Senior Assistant Attorney General Mr. Emon Mahony, Assistant Attorney General	**ANALYZING PROPOSAL TO INSTALL ENVIRONMENTAL CONTROLS ON COAL POWER PLANT. Mar 12 – present.** Analyzed proposal of Southwestern Electric Power Company and other owner to install environmental controls at the coal-fired Flint Creek Power Plant (APSC Docket No. 12-008-U). **ANALYZING ENTERGY ARKANSAS, INC. FUTURE SYSTEM PLANNING AND OPERATION OPTIONS. Jun 10 – present.** Analyzing alternatives for Entergy Arkansas, Inc. (EAI) to plan and operate its electric generation and transmission systems upon its withdrawal from the Entergy System Agreement (APSC Docket No. 10-011-U). **ANALYZED TRANSMISSION PLANNING ISSUES. Feb 09 – Aug 09.** Analyzed proposals to restructure Entergy's transmission planning processes (APSC Docket No. 08-136-U). **ANALYZED TRANSMISSION COST RECOVERY ISSUES. Mar 10 – Apr 10.** Analyzed utility proposals to expedite recovery of transmission and related costs (APSC Docket Nos. 09-074-U and 09-084-U).

CLIENT	PROJECTS
ARKANSAS ATTORNEY GENERAL (continued)	**ANALYZED PROPOSAL TO INSTALL ENVIRONMENTAL CONTROLS ON COAL POWER PLANT. Mar 09 – Dec 09.** Analyzed proposal of EAI and other owners to install scrubbers and low NOx burners at the coal-fired White Bluff Steam Electric Station (APSC Docket No. 09-024-U). **ANALYZED UTILITY PROPOSAL TO PURCHASE POWER PLANT. Nov 07 – Jun 08.** Analyzed EAI proposal to purchase Ouachita (combined cycle power) Plant and related wholesale resale, cost allocation and ratemaking issues (APSC Docket No. 06-152-U).
MAINE PUBLIC ADVOCATE OFFICE 112 State House Station Augusta, ME 04333-0112 207-287-2445 Mr. Richard Davies, Public Advocate Ms. Agnes Gormley, Senior Counsel	**ANALYZED PROPOSED TRANSMISSION LINE. Aug 10 – Sep 10.** Performed review of feasibility and cost-effectiveness of Algonquin Power Corporation's proposed Northern Maine Interconnect.
AVONDALE GLEN ELDER NEIGHBORHOOD ASSOCIATION (c/o LEGAL SERVICES OF NORTHERN CALIFORNIA) 515 – 12th Street Sacramento, CA 95814 916-551-2150 Mr. Colin Bailey, Attorney Mr. Stephen Goldberg, Attorney	**ANALYZED NEED FOR PROPOSED GAS STORAGE PROJECT. Dec 10 – Jan 11.** Reviewed, analyzed and testified on need for proposed Sacramento Natural Gas Storage Project.
ATTORNEY GENERAL OF WASHINGTON, PUBLIC COUNSEL SECTION 800 5th Street, Suite 2000 Seattle, WA 98104-3188 206-389-3055 Mr. Simon J. ffitch, Senior Assistant Attorney General, Section Chief	**ANALYZED UTILITY POWER SUPPLY COST FORECAST AND PROPOSED POWER CONTRACT. Feb 09 – Dec 09.** Analyzed proposal of Avista to assign to Avista Utilities a Power Purchase Agreement (PPA) and related contracts related to the Lancaster (combined cycle) Generating Facility and other aspects of Avista's forecast of its 2010 power supply costs.
DIVISION OF RATEPAYER ADVOCATES of the CALIFORNIA PUBLIC UTILITIES COMMISSION 505 Van Ness Avenue San Francisco, CA 94102 415-703-1418 Mr. Scott Logan, Regulatory Analyst	**ANALYZED COST-EFFECTIVNESS OF PROPOSED TRANSMISSION LINES.** **Dec 06 – Jan 09.** Led team of consultants analyzing cost-effectiveness of San Diego Gas & Electric Company's proposed Sunrise Powerlink. **Aug 05 – Jan 07.** Led team of consultants analyzing cost-effectiveness of Southern California Edison's proposed Devers–Palo Verde No. 2 Transmission Line Project (DPV2).

CLIENT	PROJECTS
MAINE PUBLIC UTILITIES COMMISSION 242 State Street, State House Station 18 Augusta, ME 04333 207-287-1394 Mr. Chuck Cohen, Hearing Examiner	**ANALYZED COST-EFFECTIVENESS OF PROPOSED TRANSMISSION LINE. Oct 08 – Jan 09.** Initiated analysis of cost-effectiveness of Maine Public Service and Central Maine Power Company's proposed Maine Power Connection.
NEVADA OFFICE OF THE ATTORNEY GENERAL, BUREAU OF CONSUMER PROTECTION 555 E. Washington Avenue, Suite 3900 Las Vegas, NV 89101 702-486-3129 Mr. Eric Witkoski, Chief Deputy Attorney General	**ANALYZED COST-EFFECTIVNESS OF PROPOSED GENERATION AND TRANSMISSION RESOURCES.** **Jun 07 – Sep 07 and Jul 08 – Aug 08.** Reviewed and analyzed resource plans and amendments filed by the Nevada Power Company and Sierra Pacific Power Company. **Jun 06 – Nov 06.** Led team of consultants analyzing proposals to build significant new generation and transmission resources made by the Nevada Power Company and Sierra Pacific Power Company in their 2006 Integrated Resource Plan filings.
TEXAS OFFICE OF PUBLIC UTILITY COUNSEL 1701 N. Congress Ave., Suite 9-180 Austin, TX 78701- 512-936-7500 Mr. Clarence L. Johnson, Director, Regulatory Analysis (retired)	**ANALYZED REASONABLENESS OF EL PASO ELECTRIC COMPANY'S POWER PURCHASES. Feb 05 – Mar 06.** Reviewed and filed testimony regarding reasonableness of three contracts signed by El Paso Electric Company in 2001 for delivery of power in 2002.
UTILITY CONSUMERS' ACTION NETWORK 3100 5th Ave., Suite B San Diego, CA 92103 619-696-6966 Mr. Michael Shames, Executive Director	**ANALYZED SAN DIEGO GAS & ELECTRIC PROPOSAL TO DEVELOP NEW POWER PLANTS. Sep 03 – Sep 06.** Review, analyze, and testify on SDG&E's plan to purchase Palomar power plant, contract for power from Otay Mesa power plant, and make other transactions. (*Joint effort with TURN.*)
PASADENA WATER AND POWER 150 S. Los Robles Ave., Suite 200 Pasadena, CA 91101 Contact Woodruff for reference.	**ESTIMATED HISTORIC GAS COSTS. Apr – May 03.** Reviewed, analyzed, and provided testimony to Federal Energy Regulatory Commission regarding the gas costs facing Pasadena Water and Power during the period from October 2000 to June 2001.
NORTHERN CALIFRONIA POWER AGENCY 180 Cirby Way Roseville, CA 95678 916-781-3636 Mr. Don Dame, Assistant GM, Power Management Mr. Thomas S.W. Lee, Mgr, Portfolio Planning	**CONFIDENTIAL PROJECT. Feb – Apr 03.**

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ADDENDUM 2

to Resume of Kevin Woodruff

EXPERIENCE RELATED TO ELECTRIC RESOURCE PLANNING AND ASSET VALUATION

Woodruff Expert Services
Sacramento, California
November 2002 to present

- Analyze and provide expert testimony regarding cost-effectiveness of California Investor-Owned Utilities' (IOUs') specific proposals to contract for or acquire electric generating projects, both conventional and renewable.
- Analyzing alternatives for Entergy Arkansas, Inc. (EAI) to provide or procure electric system planning and operation services following its withdrawal from the Entergy System Agreement.
- Analyzing proposal of Southwestern Electric Power Company and other owner to install environmental controls on coal-fired Flint Creek Power Plant.
- Analyzing California's electric Resource Adequacy Requirement and electric IOUs' long-term electric resource plans and short-term procurement and risk mitigation plans.
- Analyze and provide comments procurement and risk mitigation strategies as part of each California IOU's Procurement Review Group.
- Monitor development of estimates of renewable transmission and other integration costs in California.
- Analyzed proposals to restructure Entergy's transmission planning processes.
- Analyzed potential value of Algonquin Power Corporation's proposed Northern Maine Interconnect.
- Analyzed proposal of Avista to assign to Avista Utilities a Power Purchase Agreement (PPA) and related contracts related to the Lancaster (combined cycle) Generating Facility.
- Analyzed proposal of EAI and other owners to install scrubbers and low NOx burners at the coal-fired White Bluff Steam Electric Station.
- Led effort to assess value of San Diego Gas & Electric Company's proposed Sunrise Powerlink on behalf of Commission's Division of Ratepayer Advocates (DRA).
- Initiated analysis of cost-effectiveness of Maine Public Service and Central Maine Power Company's proposed Maine Power Connection transmission project.
- Analyzed proposal of EAI to purchase the Ouachita (combined cycle power) Plant.
- Led effort to assess value of Southern California Edison's proposed Devers-Palo Verde No. 2 Transmission Line Project (DPV2) on behalf of DRA.
- Led analysis of proposals to build significant new generation and transmission resources made by the Nevada Power Company and Sierra Pacific Power Company in their 2006 Resource Plan filings.
- Analyzed and provided analysis regarding California state agencies' initiatives to develop consistent process for planning for and evaluating new transmission projects.

Henwood Energy Services, Inc.
Sacramento, California
April 1988 to November 2002

- Modeled and analyzed long-term resource planning issues of California electric IOUs
- Modeled and analyzed short-term operations of California electric IOUs
- Prepared resource plan for municipal utility
- Managed and assisted public power entity's power supply Request for Proposal (RFP) processes
- Helped generation plant owners respond to California IOU and other RFPs for electric power
- Sold, conducted, and/or managed forecasts of power market operations and prices and related valuations of generating assets
- Prepared analyses of IOU and municipal utility revenue requirements, stranded costs, and rate design
- Managed projects to develop and implement software for electric plant and system operations, electric system forecasting and planning, risk quantification, and asset valuation
- Sold and managed projects to develop and implement maintenance planning software for vertically-integrated utilities
- Helped electric generators buy gas commodity and pipeline capacity rights
- Prepared and defended expert testimony on behalf of applicants and interveners in Commission proceedings in California and Montana

Sierra Energy and Risk Assessment
Sacramento / Roseville, California
May 1986 to April 1988 (full-time)
November 1985 to May 1986 (part-time)

- Assisted analysis for CPUC advocacy staff regarding SCE's proposed Devers-Palo Verde 2 transmission line.

ATTACHMENT 2

Excerpt from

CAISO's *2013-2015 Local Capacity Technical Analysis*

December 30, 2010

California ISO
Your Link to Power

California Independent
System Operator

2013-2015
LOCAL CAPACITY TECHNICAL ANALYSIS

REPORT
AND STUDY RESULTS

December 30, 2010

Local Capacity Technical Analysis
Overview and Study Results

I. Executive Summary

This Report documents the results and recommendations of the 2013 and 2015 Long-Term Local Capacity Technical (LCT) Study. The LCT Study objectives, inputs, methodologies and assumptions are the same as those discussed in the 2011 LCT Study and already adopted by the CAISO and CPUC in their 2011 Local Resource Adequacy needs.

Most LCR requirements trend down by about 1 %/year mainly due to slight load forecast decrease. However overall they significantly decrease (about 5,000 MW between 2013 and 2015) mainly due to new transmission projects. For comparison below you will find the 2011, 2013 and 2015 total LCR needs.

2011 Local Capacity Needs

	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**

2013 Local Capacity Needs

	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	57	179	236	142	0	**142**	191	0	**191**
North Coast/ North Bay	133	728	861	861	66	**927**	861	72	**933**
Sierra	1057	759	1816	786	12	**798**	1468	300	**1768**
Stockton	226	259	486	211	0	**211**	282	187	**469**
Greater Bay	1210	5296	6506	3770	0	**3770**	3974	0	**3974**
Greater Fresno	485	2434	2919	2053	0	**2053**	2053	49	**2102**
Kern	699	9	708	328	0	**328**	465	21	**486**
LA Basin	4401	8136	12537	11304	0	**11304**	11304	0	**11304**
Big Creek/Ventura	1142	4110	5253	2753	0	**2753**	2923	0	**2923**
Greater San Diego/ Imperial Valley	186	4295	4481	3312	0	**3312**	3312	35	**3347**
Total	**9596**	**26205**	**35803**	**25520**	**78**	**25598**	**26833**	**664**	**27497**

2015 Local Capacity Needs

	Qualifying Capacity			2015 LCR Need Based on Category B			2015 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	179	236	147	0	**147**	197	0	**197**
North Coast/ North Bay	133	728	861	861	71	**932**	861	74	**935**
Sierra	1057	759	1816	874	13	**887**	1523	350	**1873**
Stockton	227	259	486	234	0	**234**	287	204	**491**
Greater Bay	1210	5296	6506	3924	0	**3924**	3951	0	**3951**
Greater Fresno	485	2434	2919	2025	0	**2025**	2025	50	**2075**
Kern	699	9	708	349	0	**349**	486	21	**507**
LA Basin*	4401	8136	12537	5988	0	**5988**	5988	0	**5988**
Big Creek/Ventura	1143	4110	5253	2480	0	**2480**	2872	0	**2872**
Greater San Diego/ Imperial Valley	186	4295	4481	3435	0	**3435**	3435	43	**3478**
Total	**9598**	**26205**	**35803**	**20317**	**84**	**20401**	**21625**	**742**	**22367**

* - Area needs to be redefined as Western LA Basin in 2015 therefore loads and especially qualifying capacity will decrease (see detail description).

Overall, the LCR trended is downward due to numerous transmission projects. It is worth mentioning the following areas: (1) Sierra, where the LCR was reduced mostly due to the installation of the Table Mountain-Rio Oso 230 kV Reconductor and Tower Upgrade, Palermo-Rio Oso 115 kV Reconductoring, Rio Oso #1 and #2 230/115 kV Transformer Replacement, Gold Hill-Missouri Flat #1 and #2 115 kV line Reconductoring and Gold Hill-Horseshoe 115 kV line Reconductoring; (2) Stockton, where the LCR was reduced mostly due to the installation of the Tesla 115 kV Capacity Increase, Tesla-Schulte. Lammers-Kasson & Schulte-Lammers Tower Raise, Weber 230/60 kV Transformer #2&2A Replacement and Weber-Stockton "A" #1 and #2 60 kV Reconductoring; (3) Greater Bay Area, where the LCR was reduced mainly due to the installation of Moraga #1 and #2 230/115 kV Transformer Replacement, Tesla Pittsburg 230 kV Reconductoring, Contra Costa-Las Positas 230 kV Reconductoring, Contra Costa-Moraga #1 and #2 230 kV Reconductoring and Tesla-Ravenswood 230 kV Reconductoring; (4) Fresno Area, where the LCR was reduced mainly due to the installation of Herndon #3 230/115 kV Transformer; (5) LA Basin, where the 2015 LCR was greatly reduced due to the installation of the Colorado River-Devers #2 500 kV line and the Vincent-Mira Loma 500 kV line (part of Tehachapi Transmission Project).

The North Coast/North Bay area LCR needs have increased mainly due to projected retirement of Pittsburg sub-area once through cooling generation. The LCR needs for Humboldt and Kern are steady whereas Big Creek/Ventura and San Diego are slightly going up due to load growth. It is worth mentioning that due to the new most limiting contingency the San Diego area boundary has been moved to Imperial Valley and the new area name is Greater San Diego/Imperial Valley.

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 the 2012-14 Long-Term LCR study and this study.

24239	MALBRG1G	C1	11
24027	COLDGEN	1	11
24060	GROWGEN	1	11
24120	PULPGEN	1	11
28951	REFUSE	1	11
28005	PASADNA1	1	9
28006	PASADNA2	1	9
28007	BRODWYSC	1	9

Western LA Basin Sub-area:

For 2013, the most critical contingency is the loss of one of the Serrano – Villa Park 230 kV line followed by the loss of the Serrano – Lewis 230 kV line, which would result in thermal overload of the remaining Serrano – Villa Park 230 kV line This limiting contingency establishes a local capacity need of 6090 MW (includes 836 MW of QF and wind, 392 of Muni and 2246 MW of nuclear generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Due to the numerous transmission projects modeled, in 2015 timeframe, the Western LA Basin sub-area will become the most stringent and binding local area constraint. At that time it is envisioned that the LA Basin local area will be eliminated and the Western LA Basin local area will become a new local area.

For 2015, the most critical single contingency is the loss of the Sylmar-Gould 230 kV line with SONGS #3 unit out of service, which would result in thermal overload of the Sylmar-Eagle Rock 230 kV line. This limiting contingency establishes a local capacity need of about 5988 MW (includes 836 MW of QF and wind, 392 of Muni and 2246 MW of nuclear generation) as the minimum capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

There are numerous other combinations of contingencies in the area that could overload a significant number of 230 kV lines in this sub-area/area and have slightly less LCR need. As such, anyone of them (combination of contingencies) could become

ATTACHMENT 3

Excerpt from

Energy Action Plan

Adopted

STATE OF CALIFORNIA

CONSUMER POWER AND CONSERVATION FINANCING AUTHORITY

ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION

PUBLIC UTILITIES COMMISSION

ENERGY ACTION PLAN

California is a diverse and vibrant society. The fifth largest economy in the world, California's population is expected to exceed 40 million by 2010. California's economic prosperity and quality of life are increasingly reliant upon dependable, high quality, and reasonably priced energy. Following the biggest electricity and natural gas crisis in its history, the state is well aware of the need for stable energy markets, reliable electricity and natural gas supplies, and adequate transmission systems. Looking forward, it is imperative that California have reasonably priced and environmentally sensitive energy resources to support economic growth and attract the new investment that will provide jobs and prosperity throughout the state.

California's principal energy agencies have joined to create an Energy Action Plan. It identifies specific goals and actions to eliminate energy outages and excessive price spikes in electricity or natural gas. These initiatives will send a signal to the market that California is a good place to do business and that investments in the more efficient use of energy and new electricity and natural gas infrastructure will be rewarded. This approach recognizes that California currently has a hybrid energy market and that state policies can capture the best features of a vigorous, competitive wholesale energy market and renewed, positive regulation. This approach will be ever mindful of the need to keep energy rates affordable, and is sensitive to the implications of energy policy on global climate change and the environment generally.

While this Plan lays out specific actions, it is a living document. It is a blueprint that is subject to change over time. The agencies will use it to give their efforts direction, focus, and precision, but some of the specific actions cited are subject to further proceedings so may need to be fine-tuned or changed to best meet the overall goals.

step in identifying future statewide energy needs. The agencies will participate in this process, assessing demand growth and available supply, and balancing various state policy objectives to determine the combination of conservation and infrastructure investments that best meet California's short- and long-term needs. The Public Utilities Commission and the Power Authority will carry out their energy-related duties and responsibilities based upon the information and analyses contained in the assessment.

The Action Plan envisions a "loading order" of energy resources that will guide decisions made by the agencies jointly and singly. First, the agencies want to optimize all strategies for increasing conservation and energy efficiency to minimize increases in electricity and natural gas demand. Second, recognizing that new generation is both necessary and desirable, the agencies would like to see these needs met first by renewable energy resources and distributed generation. Third, because the preferred resources require both sufficient investment and adequate time to "get to scale," the agencies also will support additional clean, fossil fuel, central-station generation. Simultaneously, the agencies intend to improve the bulk electricity transmission grid and distribution facility infrastructure to support growing demand centers and the interconnection of new generation.

Energy Services are Growing, are Essential, and the Delivery Systems are Complex

As a context for this plan, Californians must understand the essential and complex nature of the state's energy resources. Currently the state uses 265,000 gigawatt-hours of electricity per year. Consumption is growing 2 percent annually. Over the last decade, between 29 percent and 42 percent of California's in-state generation used natural gas. Another 10 - 20 percent was provided by hydroelectric power that is subject to significant annual variations. Almost one third of California's entire in-state generation base is over 40 years old. California's transmission system is aging also. While in-state generation resources provide the majority of California's power, California is part of a larger system that includes all of western North America. Fifteen to thirty percent of statewide electricity demand is served from sources outside state borders.

Peak electricity demands occur on hot summer days. California's highest peak demand was 52,863 megawatts and occurred July 10, 2002. Peak demand is growing at about 2.4 percent per year, roughly the equivalent of three new 500-megawatt power plants. Residential and commercial air conditioning represent at least 30 percent of summer peak electricity loads.

California's demand for natural gas also is increasing. Currently the state uses 2 trillion cubic feet of natural gas per year. Historically the primary use of this fuel was for space heating in homes and businesses. Electricity generation's dependence on relatively clean-burning natural gas now means that California's annual natural gas use by power plants is expected to increase. Overall, natural gas use is growing by 1.6 percent per year. Eighty-five percent of natural gas consumed in California is supplied by pipelines from sources outside the state.

ATTACHMENT 4

Presentation of “Unified Vision”

by CPUC, CEC, CAISO and CARB

at December 15, 2009, Energy Action Plan Meeting

California Environmental Protection Agency
AIR RESOURCES BOARD

Unified Vision

- California Public Utilities Commission – Pete Skala
- California Energy Commission – Melissa Jones
- California ISO – Phil Pettingill
- California Air Resources Board – Kevin Kennedy

Energy Action Plan Meeting
December 15, 2009

Vision Scope

ffi Encompass preferred resource types and magnitudes required by law or agency policy decisions

ffi Address system elements needed to ensure system reliability with an increased penetration of preferred resources

ffi Encompass concrete objectives for supply, demand, storage and transmission

ffi State-wide, IOUs and POUs, WECC-wide

ffi Focused on 2020, with consideration of system requirements and constraints after 2020

The Plan

- Roadmap from present to 2020
- List of current processes, how they fit together, what is missing
- Identify key milestones for elements of Vision and determine critical path items
- Capture interdependencies and uncertainties among Vision objectives
- Potential update of Energy Action Plan that explicitly focuses on GHG-reduction goals

Tracking and Reporting

- Ongoing tracking, updating, and reporting of results
- Identification of additional opportunities
- Updates on how previously identified barriers are being addressed and identification of any new barriers
- Common metrics across the agencies
- Enhancements to current CAT “report card” information

Vision Elements

- Demand in 2020
  - Efficiency standards, programs, market
  - Demand response
  - Distributed generation / Cogeneration
  - Electrification of transportation coupled with a cleaner energy supply
- Supply in 2020
  - Statewide 33% renewables target
  - Meet environmental goals and ensure reliability
  - Natural gas generation
  - Carbon capture and storage

Vision Elements

- Transmission, Distribution, & Operations in 2020
  - Transmission planning and permitting advancements
  - Advanced metering and smart grid technologies
  - Energy storage
- Additional Supporting Processes
  - Multi-sector state, regional, and/or federal GHG cap-and-trade program
  - Emerging technologies and R&D
  - Climate change adaptation
  - Engage and partner with California's citizens

ATTACHMENT 5

Excerpt from

CAISO's *2013 Local Capacity Technical Analysis*

April 30, 2012

California ISO
Shaping a Renewed Future

2013
LOCAL CAPACITY TECHNICAL ANALYSIS

FINAL REPORT
AND STUDY RESULTS

April 30, 2012

* 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

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:	
ffi 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.
ffi 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
ffi Load Forecast	Uses a 1-in-10 year summer peak load forecast
Methodology:	
ffi 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.
ffi 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.
ffi 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:	
ffi 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:	
ffi 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.

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[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

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

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

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

c. CAISO Statutory Obligation Regarding Safe Operation

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

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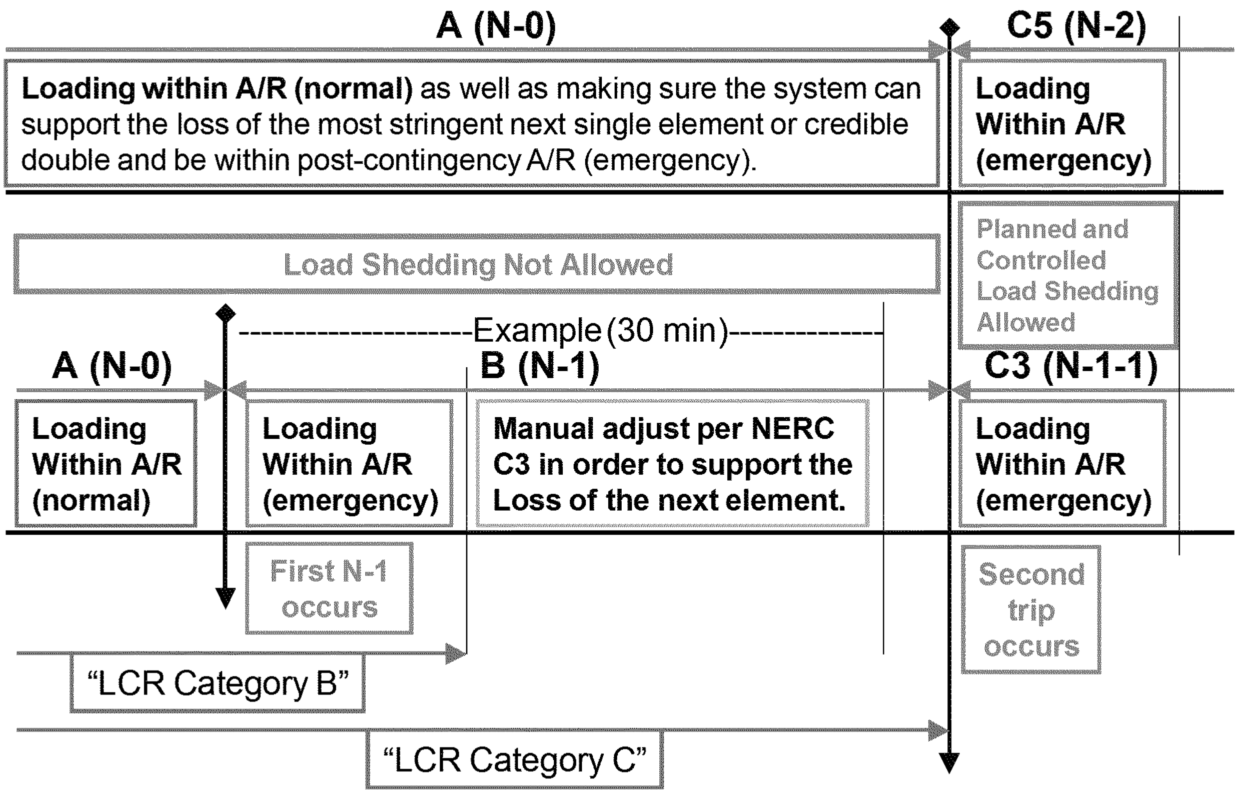
additional generation and permits operators to effectively prepare for the next event as well as ensure security should the next event occur. However, these systems have their own risks, which limit the extent to which they could be deployed as a solution for grid reliability augmentation. While they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

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



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

Applicable Rating:

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

Normal rating is to be used under normal conditions.

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

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

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

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

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

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

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

Controlled load drop:

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

Planned load drop:

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

Special Protection Scheme:

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

System Readjustment:

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

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

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

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

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

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

4 Evaluate for risks and consequence, per NERC standards.

ATTACHMENT 6

CAISO Response to

Questions 7 and 9 of TURN's 1st Data Request

Request No. 7

7. For each of the contingencies listed on Tables 2 to 5 and described on pages 9 and 10 of the May 23 Testimony of Robert Sparks, state whether addressing the contingency is considered as meeting a NERC "Category B" system reliability criterion, a "Category C" criterion or some other criterion.

ISO RESPONSE TO No 7

They are all NERC Category C events except for the Ellis sub area which is a NERC Category D event that can cause uncontrollable voltage collapse.

Request No. 9

9. For each of the contingencies listed on Tables 7 to 10 and described on pages 13 and 14 of the May 23 Testimony of Robert Sparks, state whether addressing the contingency is considered as meeting a NERC "Category B" system reliability criterion, a "Category C" criterion or some other criterion.

ISO RESPONSE TO No 9

They are all NERC Category C events except for the Moorpark sub area which is a NERC Category D event that can cause uncontrollable voltage collapse.

ATTACHMENT 7

CAISO Response to

Question 14 of TURN's 1st Data Request

Request No. 14

14. Is Mr. Sparks's statement at 17:15-16 of his May 23 Testimony "replacement OTC generation should have flexibility characteristics similar to the OTC generation" based on his own analysis or upon Mr. Rothleder's May 23 Testimony? If this statement is based on Mr. Sparks's own analysis, provide such analysis and supporting workpapers.

ISO RESPONSE TO No 14

Mr. Sparks' statement is based on his own analysis of the resource characteristics needed to reliably operate the transmission system following contingency events. The contingency conditions establishing the need for local capacity are described in pages 6-17 of Mr. Sparks' May 23 Testimony. In every local area requiring OTC replacement, the contingency event is a scenario where after an initial contingency, the ISO must be prepare for the next worst contingency to ensure the reliable operation of the system. Based on NERC transmission operating standards this must be done within 30 minutes *because the system is in an insecure state until these system adjustments can be made. These system adjustments require the starting or ramping up of the replacement OTC generation within 30 minutes. Requiring all local generation to be running prior to the first contingency is likely to be inefficient and an uneconomic use of resources.*

ATTACHMENT 8

CAISO "CEO Report"

August 18, 2011

California ISO
Shaping a Renewed Future

California Independent
System Operator Corporation

Memorandum

To: ISO Board of Governors

From: Steve Berberich, President and Chief Executive Officer

Date: August 18, 2011

Re: **CEO Report**

This memorandum does not require Board action.

Operations Update

Summer conditions remain mild. We continue to experience abnormally low demand for the summer because of below normal temperatures. Based on long term forecasts, those conditions are expected to continue.

Renewable generation continues to grow in our footprint. We have been setting new records regularly over the summer as new resources come online. The current footprint records are 2,517 MW for wind set June 10 at 23:29 and 514 MW for solar set on July 18 at 12:21.

Valley Electric Association

We are pleased to announce that we have executed a memorandum of understanding with Valley Electric Association outlining the framework for the Nevada member-owned utility to join the ISO. Valley Electric is located in the southwest portion of Nevada adjacent to and within the eastern edge of California's Inyo County. By joining the ISO, California and Nevada solar projects located inside Valley Electric will be better positioned to deliver power to the California grid. In addition, the ISO will benefit by gaining access to additional import capability from Valley's transmission rights at the Mead Substation.

The MOU will be presented to the ISO Governing Board at this meeting. If authorized by the Board, the ISO will enter into a transition agreement based on the MOU. This agreement will then be filed with FERC for approval along with any limited waivers of the ISO tariff necessary to support the transition process. We appreciate the working relationship we have developed with Valley Electric's leadership and look forward to helping them achieve their long term goals.

Governor's Conference on Local Renewable Energy Resources

The Governor's office held a distributed generation conference at UCLA on the July 25 and 26. The ISO appreciated the opportunity to participate in this important conference. I served on a panel moderated by CEC Chairman Weisenmiller while several of you helped host the conference and moderate panels. Implementing the governor's ambitious goal of 12,000 megawatts of distributed generation was discussed at length with it being clear that work will have to take place on making the generation visible, managing the costs and strategizing how best to deploy it.

Convergence Bidding on the Ties

ISO Management is recommending that the Board of Governors eliminate convergence bidding on the interties in an action at this meeting. By way of background, the ISO imports a large amount of power from out of state resources. The scheduling of those resources is done west-wide on an hourly basis and requires administrative setup 75 minutes before real time. This results in the pricing of imports in advance of the pricing of instate resources in the five-minute real time dispatch market. As a result, differences in prices can be arbitraged through the convergence bidding process. Related costs are borne by load with no operational benefit to the ISO or its ratepayers.

Management does not make this recommendation lightly. Philosophically, we support a deep market with a variety of products, and removing functionality should always be approached with caution. In this case, however, we worked with market participants to find other ways to remove the arbitrage opportunity but were unable to find any beyond a fundamental re-design of the real time market. A re-design is under consideration, but no decision has been made. In any case, such an effort would require a major investment of staff and dollars, and could not be implemented before 2013. In the meantime, Management believes that it is necessary to eliminate the arbitrage opportunity inherent in the current market design.

Renewable Integration Needs

California's 33% renewable portfolio standard, signed into law earlier this year by Governor Brown, has led to vigorous competition among hundreds of renewable energy projects seeking to contract with the state's utilities and other load-serving entities. The ISO is actively preparing for the increased levels of renewable generation that will result from these projects and others already in development. Our immediate concerns have to do with having sufficient flexible generation available to manage the variability of weather-dependent wind and solar resources at the same time that we face the possible retirement of coastal power plantsfacing restrictions on the use of once-through cooling technology.

To that end, the ISO has performed extensive studies to define the system flexibility needs driven by this transformation of the state's resource mix, and has presented them in the long-term procurement proceeding pending at the California Public Utilities Commission. The ISO is presenting a memo at this Board meeting outlining our assessment. Under the ISO's preferred scenario, approximately 4,700 MW of additional flexible generation is needed before 2020, 2,000 MW of which could be provided by generation also needed to maintain local reliability. Our findings do not incorporate aggressiveforecasts of new energy efficiency and demand response preferred by the CPUC. We support these policies, but are concerned about the asymmetric risk these assumptions create. The risk arises because failing to act today to initiate long-term procurement to meet needs means that we will be unable to maintain reliable electric service if energy efficiency and demand response programs fail to materialize. On the other hand, procuring more generation adds additional costs but ensures reliability.

The ISO looks forward to working with the CPUC, utilities, renewable and conventional generations, and other stakeholders in the months to come. This effort is critically important to the success of the state's policies, which depend in part on the ability of the ISO to maintain reliability.

ATTACHMENT 9

Excerpt from CAISO June 14, 2012 Presentation

Flexible Capacity Procurement: Risk of Retirement

California ISO
Shaping a Renewed Future

Flexible Capacity Procurement: Risk of Retirement

Revised Straw Proposal

June 14, 2012

Karl Meeusen, Ph.D.
Market Design and Regulatory Policy Lead

SB_GT&S_0210696

Defining the Need for Flexible Capacity Risk of Retirement Designations

- Asymmetric risk for reliable grid operations
  - If a flexible or local resource needed four or five years in the future retires in two years, it can take several more years to replace that needed capacity, leaving grid operations in jeopardy
  - The potential costs of insufficient capacity could be far greater than the costs of preventive measures
- The ISO proposes to use a five year outlook to assess need for resources at risk of retirement
- Addresses flexible and local resources

ATTACHMENT 10

Excerpt from CAISO June 4, 2012, Workshop Presentation

2012 LTPP Operating Flexibility Analysis, Process Update

R.12-03-012: 2012 LTPP
Operating Flexibility Analysis

Nathaniel Skinner

Senior Analyst, Generation & Transmission Planning

California Public Utilities Commission

June 4, 2012

California ISO
Shaping a Renewed Future

Process Update

SB_GT&S_0210700

Where We Have Been

- CAISO has been using PLEXOS to estimate need for new resources to integrate renewables
  - Develop detailed data inputs for hourly production simulation
    - Loads, renewable profiles, etc.
    - Regulation and Load Following Requirements (Step 1)
    - Import capabilities
  - Run PLEXOS to simulate hourly production
  - Log "violation" when resource stack is insufficient to meet load, reserve, regulation and LFU requirements
  - Add resources until no more violations

Where We Are Now

- CAISO is now proposing to supplement our modeling with a different type of analysis to address those factors unrelated to integration need, as a new step in the process
  - Reliability modeling that calculates Loss of Load Probability (LOLP) and Loss of Load Expectation (LOLE)
  - PG&E and E3 have been developing models to conduct this analysis
  - CAISO has also developed a stochastic analysis approach that to test simultaneous ramping capability
  - CAISO has not yet decided which model to use in this case

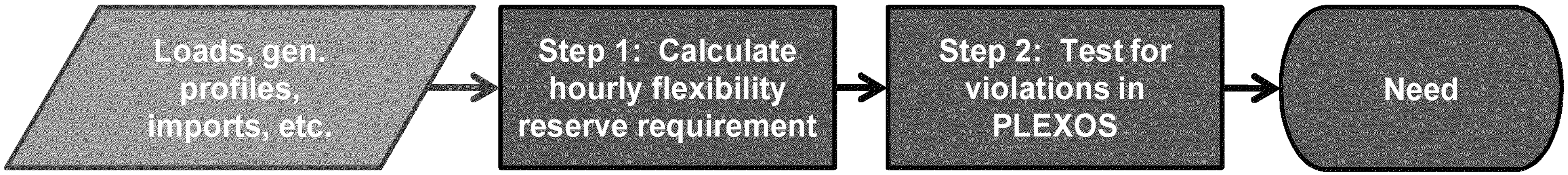
Two Types of Renewable Integration Need

1. Capacity Need:
   - **Resources needed to serve load reliably** using traditional reliability metrics such as Planning Reserve Margin (PRM) and Loss of Load Expectation (LOLE)

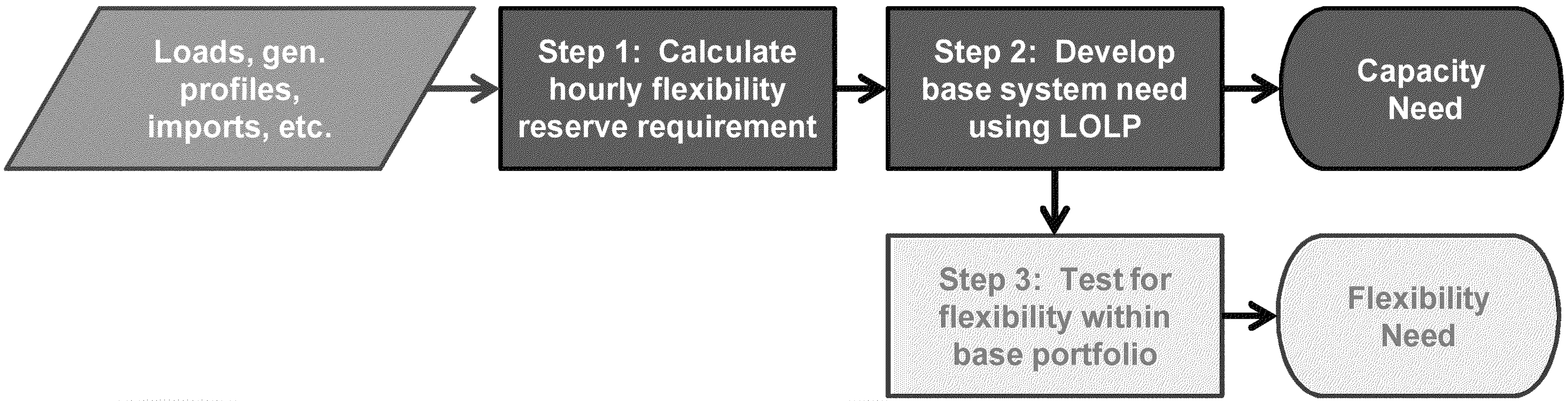
2. Flexibility need:
   - Resources needed to meet 10-minute, 20-minute and hourly ramp requirements

CAISO Proposed New Approach

Previous Methodology



Current Proposal



Step 1 of Proposed New Approach

- **Calculate Regulation and Load Following Requirements associated with variability** and uncertainty of load, wind and solar for each resource portfolio
- Unchanged from previous approach

Step 2 of Proposed New Approach

- Conduct LOLP modeling to determine need for new capacity to meet a reliability standard of 1-day-in-10-years
  - Calibrate model to reflect 17% PRM under All-Gas Case
  - For each portfolio, calculate change to PRM needed to achieve same reliability as All-Gas Case
    - Expected renewable production will be different from NQC
    - Incremental increase in Reg. and LFU requirements due to renewable penetration
  - Add resources as needed to meet the updated PRM to reflect changes from All-Gas case

Step 3 of Proposed New Approach

- Test for flexibility within portfolio that comes from Step 2
  - Includes any resources added to meet reliability standard
- Need for ramping capability is not the same thing as need for new resources
  - Conversion of existing resources to something more flexible could solve a ramping problem without changing the PRM
- Stochastic component estimates the probability of having a ramping capacity shortage based on distribution of hourly ramps
  - Within-hour ramps also assessed through incorporation of Step 1 results
- PLEXOS runs to test operability of portfolio that comes from Step 3

Stochastic Simulation

- Purpose
  - To incor porate uncertainties in key input assumptions in determining need for capacity
- Scope
  - May apply to all cases
  - May be used together with Plexos simulation
- Study Approach
  - Probabilistic simulation
  - Loss of Load Probability (LOLP)
  - Assess probability of flexibility shortage

Flexibility needs analysis bridges planning and operational needs