Written comments with CAISO reply
Submitted after the
March 10 Stakeholder Meeting regarding the
2011 Local Capacity Requirement (LCR) Results

BAMx Comments on

CAISO Draft 2011 Local Capacity Technical Study Results

BAMx[1] has reviewed the CAISO Draft Study Results dated March 10, 2010, and offers the following comments.

First, BAMx thinks that more attention should be paid to evaluating projects that will reduce the need for local capacity. The ISO may wish to report on such assessments in the longer-term Local Capacity studies or in its transmission expansion plan, but the economics of potential transmission upgrades to reduce LCR requirements should be assessed.

ISO response: ISO will continue to investigate economic driven projects (for areas or sub-areas without a deficiency) and/or reliability driven projects (for areas or sub-areas with an LCR deficiency), in order to decrease LCR needs. All proposed new transmission projects must follow the ISO's Order No. 890 Transmission Planning Process.

Second, BAMx would like to reiterate the issue that we raised last year in our comments in response to the 2010 draft Local Capacity Technical Study results. While the CAISO, in response to BAMx earlier comments, stated that it is in the process of standardizing the write-up and presentation on its use of Category B and C needs such that the needs for the Sub-areas are clearly stated, we continue to be concerned that the nomenclature used by the CAISO makes it harder to understand the results. This year, the CAISO has still not produced a table that clearly indicates the Category B and C needs for

[1] BAMx consists of Alameda Municipal Power, City of Palo Alto Utilities, and City of Santa Clara, Silicon Valley Power.

the Sub-areas. We have included a sample table based on 2010 LCR in Attachment 1. We request the ISO to develop and include a similar table for 2011 LCR in the final report.

ISO response: The ISO believes the confusion arises from the fact that both sets of numbers are published in the report. In order to avoid confusion in the future the ISO is contemplating the elimination of Category B vs. Category C write-up by only publishing the most limiting contingency regardless of category. The sub-areas do not have a stable or fixed boundary definition like the larger LCR areas do, and most often they overlap. As such, their requirements are more volatile and could change rather significantly from one year to the next depending on the most limiting contingency and are highly driven by new transmission or generation projects. Due to this fact the ISO does not see the benefit of providing a different table for them as the one provided for LCR areas.

Humboldt Area

It seems strange that as you add generation, the local generation requirements go up. We assume that whoever designed the switchyard for PG&E at the new power plant was not aware of or did not consider how the design of the interconnection of the generators to the grid would affect the local capacity requirement.

They may not have assumed the ISO would treat a short interconnection within the generator property as a transmission line. We suggest that the CAISO exclude such a facility from a classification of a transmission line; at the very least it should be excluded from the list of category C contingencies. When the CPUC ruled on the type of events/contingencies that are used to fix the LCR requirements for category B or C events, we do not believe they would have included such short interconnections for generation that is internal to the load pocket.

ISO response: The classification of this contingency is not important, (G-1), (T-1) or (L-1). What it is important is that for a fault on any one of the three generators or any one of their three step-up banks, or the small collector line, the "consequential" loss is all of them together. Therefore they should be treated as a "single contingency".

North Bay (Lakeville Sub-area)

There was some discussion concerning whether the CAISO should assume a runback of the DC cable for the Category B contingency of the simultaneous outages of Vaca Dixon-Lakeville 230 kV line and DEC power plant. There was no discussion of any reliability problems that would result from such a scheme. If it creates none, BAMx recommends the CAISO utilize the runback to alleviate the adverse impact the Cable has on the local capacity requirements in the Lakeville Sub-area.

ISO response: The outage described is not a simultaneous one. DEC power plant out followed by system readjustment and then Vaca Dixon-Lakeville 230 kV out is a category B contingency, whereas the Vaca Dixon-Lakeville 230 kV line out followed by system readjustment and then DEC out is a category C event. The runback recommendation will be taken under advisement in preparing the final 2011 LCR Results.

Stockton

The ISO presentation on Stockton area indicates a new "Weber" Sub-area. Please elaborate on the formation of this new Sub-area that did not exist earlier. What has caused its appearance this year?

ISO response: The Weber LCR sub-area was identified first last year through the 2012-2014 Long-Term LCR report: http://www.caiso.com/2495/2495c63b23450.pdf. This sub-area is rather small and the two existing resources are QF/self gen. The spectrum for a

contract conversion with potential of unit retirement has triggered the need to include this sub-area in the LCR report. After the completion of two ISO approved transmission projects, expected in 2011 and 2013, this sub-area will most likely be eliminated from LCR.

Thank you for the opportunity to provide comments on the draft 2011 Local Capacity Technical Analysis report and for responding to BAMx's prior submitted comments.

Comments of Southern California Edison on Draft 2011 Local Capacity Requirements Study Results

In accordance with the California Independent System Operator's (CAISO) request at its Local Capacity Requirement (LCR) stakeholder meeting held March 10, 2010, Southern California Edison Company (SCE) hereby submits comments on the draft 2011 LCR Study results. SCE appreciates the opportunity to provide input prior to CAISO's completion of the Study.

The primary focus of SCE's comments are with regard to the CAISO's methodology and application of Category D standards in the 2011 LCR Study. Specifically, SCE does not agree with the approach of creating the Santa Clara/Moorpark, Barre/Ellis, and El Nido/La Fresa sub-areas by enforcing Category D standards. In most LCR Study scenarios, generators in sub-pockets are status-off in the base cases. Layering in the next L-1-2 outages (Category D) seems unrealistic and too stringent. Furthermore, if Category D is expected to occur, then all associated thermal and voltage violations should be mitigated. The requirement to only mitigate voltage collapse problems is questionable. SCE recommends that the LCR study criteria and study methodology be revised to be consistent with Western Electricity Coordinating Council and North American Electric Reliability Corporation (WECC/NERC) reliability standards relative to Category D violations (i.e., for information only).

ISO response: The ISO held a stakeholder meeting on November 24, 2009 in order to discuss the criteria, methodology and assumptions for the 2011 LCR study. The results

of that meeting are posted at: http://www.caiso.com/18a3/18a3d40d1d990.html. The ISO cannot unilaterally change the LCR criteria; however there will be another meeting to talk about this issue in the fall when the kickoff meeting for the 2012 LCR study is held. If agreement is reached, then the ISO would also need to change the ISO Tariff since the LCR criteria is included in the ISO Tariff. The generators being out does not count as a contingency because the scope of the study is to come up with the "minimum" LCR requirement, so all units not needed in order to meet the criteria (not required to be purchased) are off-line. The ISO acknowledges that the L-1 followed by an L-2 is a category D; however, the concern here is that immediately after the first single contingency the ISO should be in position to readjust the system in order to support the next worst contingency. All the ISO intends to do is make sure there are enough resources in other to avoid dynamic instability and voltage collapse.

In addition, as SCE noted in the 2009 LCR study process, it is not necessary or prudent for LSEs to have a local capacity procurement "requirement" in sub-areas. In particular, CAISO Tariff Section 40.3.2c states that, for California Public Utilities Commission (CPUC) load serving entities (LSE), "the CAISO will allocate the Local Capacity Area Resource obligation based on an allocation methodology adopted by the CPUC." The CAISO has also previously acknowledged that: (1) the CPUC has not previously enforced sub-area requirements as procurement obligations, and (2) the CAISO does not expect the CPUC to enforce sub-area requirements for the 2009 Local Resource Adequacy (RA) program. If the CPUC chooses to include a discussion of sub-area study findings as it develops the 2010 Local RA requirements for its jurisdictional LSEs, then in addition to the technical findings, potential procurement implications should also be

discussed. SCE therefore recommends that the CAISO's draft 2011 LCR Study clearly identify the sub-area analyses as study "findings," rather than "requirements," as it did in the 2009 LCR Study Report.

ISO response: The ISO will not change the word "requirement" from the sub-area LCR needs. The ISO has an obligation to meet the LCR criteria for all sub-areas and will use its backstop procurement authority in case these resources are missing from the aggregate of LSE showings. So this is not a requirement for any specific LSE, but is a requirement to the aggregate of LSE showings.

Conclusion

SCE requests that the CAISO remove the mitigation requirements for Category D in its LCR study criteria to be consistent with WECC/NERC Reliability Standards. SCE is ready and willing to provide any assistance that the CAISO may need to implement these changes.

CPUC's Comments to the 2011 Draft LCR March 24, 2010

The CPUC staff wishes to thank the CAISO for providing detailed draft 2011 LCR results, then explaining them during the stakeholder meeting held on March 10th. The CPUC staff offers limited comments, restricted solely to the North Coast/North Bay Local Area study results. The CPUC staff recommends that the analysis of the North Coast/North Bay Local Area LCR model the mitigation provided by ramping down the Transbay DC Cable, and the final LCR study reflect this analysis as the suggested LCR level.

The North Coast Local Area and the Greater Bay Local Area are interconnected; the same contingency (loss of generation capacity near Pittsburg) can affect both Local Areas. Because the procedure of ramping the Transbay cable will be used in the event of this contingency, the CPUC staff considers it reasonable to model this mitigation for both local areas, and suggests the lower Local RA requirement in the North Coast/North Bay Local Area at least through 2011.

The CPUC staff believes that suggesting an LCR number without the ramping procedure would be overly conservative, given that this mitigation exists. The CPUC staff believes it very unlikely that this particular contingency (the Category B contingency listed for North Coast/North Bay) will occur alongside additional Category C contingencies in the Greater Bay Local Area. Therefore, the

CPUC staff requests that the CAISO suggest the lower LCR value for North Coast North Bay Local Area.

The overlap in contingency mitigation highlights the changing nature of grid topology. Due to future transmission improvements that may complicate the maintenance of static boundaries between Local Areas, the CPUC staff requests the final LCR report in 2011 provide some analysis of the criteria and trigger points the CAISO proposes to use to change boundaries of Local Areas to reflect the changing transmission and generation topology. The CPUC staff believes that any possible changes in the Local Area boundaries should be published to market participants as early as is reasonably feasible.

ISO response: The runback recommendation will be taken under advisement in preparing the final 2011 LCR Results. The changes in local area boundaries are rather rare and they are based on new transmission and/or new resources coming on-line in future years. Please read the latest long-term LCR study the "2012-2014 Long-Term LCR report": http://www.caiso.com/2495/2495c63b23450.pdf, for latest updates.

J.P. Morgan Comments on CAISO Draft 2011 LCR Study Results

J.P. Morgan Ventures Energy Corporation and BE CA, LLC (collectively, "J.P. Morgan") appreciates this opportunity to provide comments on the California ISO's (CAISO's) Draft 2011 Local Capacity Requirements ("LCR") Study Results and the issues discussed at the CAISO's March 10, 2010, LCR stakeholder meeting.

J.P. Morgan provides the following limited comments on the draft study results:

1) **Load Forecast Assumptions and Distribution** – As discussed at the March 10, 2010, meeting, for purposes of conducting the draft 2011 LCR study the CAISO used a load forecast provided by the California Energy Commission and then distributed load to specific areas based on load distribution factors provided by the Participating Transmission Owners (PTOs). Based on the fact that, under the CAISO's analysis, certain local reliability areas show an increase in load, while other local reliability areas show a decrease in load, J.P. Morgan requests that the CAISO provide more detailed information on the load distribution factors employed by the CAISO in its study. In addition, J.P. Morgan requests that the CAISO identify differences with the load distribution factors employed by the CAISO in its market software. While J.P. Morgan understands that the CAISO markets use more real-time data and the LCR studies are based on a year-ahead forecast and projection, differences between the load distribution factors are important and could give rise to important difference between planning assumptions and operational realities.

ISO response: The base cases used in the 2011 LCR study are posted on the ISO secure web site and they include all loads within WECC including the ISO control area. There is a case for each "local peak" and load distribution factors can be retrieved by stakeholders directly. In real-time, load distribution factors vary hour by hour and minute by minute and a correlation between this and static year-ahead 1-in-10 local area by local area load forecast projection would be difficult with questionable results. It is important to mention that there is a correlation between the two; the load forecast is based on actual real-time data (SCADA) at the time of each local area's peak. Then new customer data and scaling factors are applied in order to reach the future forecasted value.

2) **Modeling of Generating Resources** – Referring to the presentation for the LA Basin study results, slide 14 states that "17 small resources have been modeled." Can the CAISO please clarify whether those resources are existing or new resources, the location and capacity (MW) of those resources, and whether they were included in the local capacity resource list on pages 67-71 of the 2010 Local Capacity Technical Analysis (found at http://www.caiso.com/23a1/23a186dd41f50.pdf). In addition, J.P. Morgan requests that the CAISO clarify the impact of modeling those generating resources on the net LCR requirements for the LA Basin and the related sub-area requirements.

   Finally, as J.P. Morgan recalls, at the March 10, 2010, meeting the CAISO stated that certain Western Electricity Coordinating Council (WECC) requirements necessitated a change in the way certain generating resources are modeled in the CAISO's planning and operational studies. In addition to the information requested above, J.P. Morgan

requests that the CAISO provide further background and detail on the WECC modeling issue.

ISO response: These resources are all small existing resources QF and/or self-generation that were not modeled explicitly in the previous base cases but rather were load netted. This new modeling change should have no impact on the relative need for resources in the LA Basin or elsewhere.

3) **Local Sub-Area Boundaries** – The CAISO's draft LCR study for the LA Basin identifies the following sub-areas: the Barre-Ellis sub-area; the El Nido-La Fresa sub-area; and the Western LA Basin sub-area. (See slides 10-12 for the LA Basin). Consistent with the manner by which it defines each larger local capacity area, J.P. Morgan requests that the CAISO provide detail regarding both the geographic and transmission-facility defined boundaries of the aforementioned sub-areas. In addition, J.P. Morgan requests that the CAISO identify the local capacity resources that fall within the defined sub-areas and, as appropriate, the effectiveness factors of those resources in addressing the contingencies that give rise to the sub-area requirements.

ISO response: The sub-areas do not have a stable or fix boundary definition like the larger LCR areas do; and most often they overlap, as such their requirements are more volatile and could change rather significantly from one year to the next depending on the most limiting contingency and are highly driven by new transmission or generation projects. Due to this fact the ISO does not have a geographic or transmission limited definition for their boundaries. However the ISO has defined in the report all the local capacity resources that fall within each sub-area and, as appropriate, the effectiveness factors of

those resources in addressing the contingencies that give rise to the sub-area requirements.

J.P. Morgan appreciates the opportunity to provide these comments and looks forward to continued participation in the CAISO's LCR study effort.

SDG&E's COMMENTS ON THE CAISO'S

2011 DRAFT LCR RESULTS STAKEHOLDER MEETING

SDG&E appreciates the opportunity to comment on the CAISO's March 10, 2010 presentation entitled Local Capacity Requirements (LCR) for Year 2011.

SDG&E is providing comments on five items:

1. Demand Side Management (DSM) is not contained in the results.
2. The South Bay power plant is not needed for LCR in 2011.
3. Encina generation will remain fully deliverable in 2011
4. The maximum import limit is 2500 MW with SWPL out of service
5. Separate, additional LCR study is necessary to determine seasonal local capacity obligations

Demand Side Management (DSM) is not contained in the results

The results presented by the CAISO could mislead stakeholders because they do not address the fact that DSM is a resource that can and will be used to meet LCR. DSM will be able to provide from 85 MW to 228 MW of capacity to meet the LCR in the San Diego area in 2011. The exact amount will be determined around the middle of this year, but will not be lower than the 85 MW allowed to satisfy 2010 LCR. This is because a number of existing programs are growing and several new programs are starting up and will be available for use in 2011.

The CAISO's stated San Diego area Maximum Qualifying Capacity of 3421 MW must be increased for DSM by at least 85MW to a minimum of 3506 MW while awaiting the development of the final 2011 DSM numbers.

ISO response: DSM has never been included in the Maximum Qualifying Capacity table. The ISO does agree that DSM is allowed to count as a Resource Adequacy resource for local RA as specified by the CPUC or other local area regulatory agencies. The ISO believes that any RA resource should have an ISO market ID and should be scheduled in the market. DSM currently does not meet these requirements and as such is not listed in the NQC list or the ISO LCR report and stakeholders should be aware of this fact because it has been done consistently from the inception of the RA program.

The South Bay power plant is not needed for LCR in 2011

The CAISO's stated San Diego area Maximum Qualifying Capacity of 3421 MW would be 3110 MW without any capacity from South Bay power plant. This becomes a minimum of 3196 MW when the low estimate of DSM for 2011 of 85 MW is added. The CAISO's stated LCR need of 3146 MW results in a surplus of 50 MW of resources for meeting the 2011 San Diego LCR without South Bay power plant.

Attached is a spreadsheet that summarizes why South Bay is not needed to meet San Diego's 2011 LCR. Rounding can cause a difference of 1 MW between various numbers and should be ignored. However, there appears to be a 2 MW difference between the CAISO's numbers and SDG&E's numbers. This small difference can not be resolved until more detail of the CAISO's numbers becomes available with the draft final report on

April 8, 2010. Also some historically based QF NQC and DSM values are not yet final, but should increase the San Diego area resource surplus.

ISO response: ISO acknowledges SDG&E's opinion; however this LCR study does not fully address the question of the RMR need for South Bay power plant. As you know, the ISO has other on-going studies with SDG&E to address this question. The ISO will assess the 2011 RMR need designation for South Bay before October 1, 2010. The reliability need in San Diego without South Bay Power Plant cannot be determined solely by Load and Resource spreadsheet calculation, but is also dependent on the results of other technical evaluations such as power flow and voltage stability to comply with WECC reliability standards. At this time, the ISO and SDG&E are performing additional in-depth studies, including investigating study assumptions to ensure that all angles are thoroughly examined before decision to release South Bay Power Plant from RMR status. The ISO will also examine and validate future on-line resources that have an RA contract (showed by all LSEs through the September preliminary RA showings), as well as any required transmission mitigation measures, to ensure that they will be available for 2011 time frame.

Encina generation will remain fully deliverable in 2011

Slide 97 of the CAISO's 3/10/2010 presentation indicated on-going studies at the CAISO were evaluating the deliverability of Encina generation. Since the meeting, the CAISO indicated it believed certain outages or combinations of outages could impact Encina's deliverability. Mitigations for all these situations have been found. These include turning off capacitor banks, utilizing 30 minute emergency ratings, and special protection

schemes. All necessary mitigations will be in place before 2011, and SDG&E posits that Encina generation will remain fully deliverable.

ISO response: ISO acknowledges SDG&E's opinion, and encourages the submission of all these mitigation measures for review and approval by the ISO. Please provide these mitigation plans as soon as possible to the ISO. These mitigation plans, if concurred by the ISO, would need to be in place by the end of September 2010 prior to final decision on South Bay RMR status.

The maximum import limit is 2500 MW with SWPL out of service

Slide 97 of the CAISO's 3/10/2010 presentation also indicated on-going studies at the CAISO were evaluating the maximum import on WECC Path 44 under the SWPL out condition. The CAISO has shared some preliminary study results with SDG&E. Nothing definitive has been shown that would warrant changing the current 2500 MW WECC Path 44 rating. The 2011 LCR study should continue to use a 2500 MW maximum import limit into the San Diego area with SWPL out of service.

ISO response: The ISO is not challenging the 2500 MW WECC Path 44 rating with SWPL out of service, but rather suggesting that it may not be achieved in all system conditions and that either a nomogram, operating procedure or system protection system may be needed. The ISO is currently working with SDG&E to validate these study results and review potential mitigation measures in order to address Category C reliability concerns if warranted.

The CAISO should undertake a separate, additional LCR study to determine seasonal local capacity obligations

SDG&E requests the CAISO enhance its annual assessment by determining each LSE's local capacity obligation on a seasonal basis. This enhancement will significantly improve the accuracy of local procurement obligations and result in lower capacity-related costs for LSEs. Additionally, a seasonal LCR will mitigate or avoid unnecessary availability penalties for generators during non-summer months.

The debate over seasonal and annual local capacity requirements has ebbed and flowed since the Commission first established local RA obligations. At bottom, the push for a seasonal LCR assessment was designed to avoid unnecessary over-procurement in low-load months. In the run up to D07-06-029, however, the CAISO opposed consideration of a seasonal LCR, arguing that technical hurdles, operational impacts, and programmatic issues made seasonal LCR studies difficult. An early proponent of seasonal local requirements, SDG&E begrudgingly accepted the CAISO's arguments due to the lack of empirical data showing that this simplified approach increases cost to ratepayers.

However, recent operational experience makes clear that the current rules result in unnecessary costs to market participants. The annual requirement forces LSEs to over-procure local capacity for most of the year, particularly during non-summer months. In these months, SDG&E and other LSEs must carry surplus local capacity with no means to sell the excess to the market. The lack of precision in the annual LCR obligation thereby increases ratepayer cost.

ISO response: The fact that LSEs cannot sell excess capacity during non-summer months is a good indicator that the resource owners will not be able to sell either.

Resources needed to meet the LCR criteria have to recover their annual fix costs or else they will retire. There is no increase in ratepayer cost if they recover the same amount across three or six months versus 12 months under the existing local RA system. However these units are critical to local system operation and in the non-summer month are extensively used for transmission and local generation maintenance. If these units are not made available to the ISO in the non-summer months, then most likely they will be procured through the backstop mechanism, ICPM, in order to allow maintenance to the transmission and/or other local area generation, and they will actually increase costs to ratepayers.

The recently implemented SCP initiative, when combined with the annual obligation, further increases costs to ratepayers. Under the SCP framework, units on forced outage can avoid availability penalties if they can locate substitute capacity from a non-RA resource. However, current rules require each generator used to satisfy the annual LRA requirement must be declared as an RA unit every month of the year, even when load requirements are well below annual peak loads. Further complicating the matter in SDG&E's service territory, all available local resources are committed to satisfying the current annual obligation. In other words, there are no non-LRA resources in SDG&E's resource constrained load pocket. Thus, unlike other areas in California where unit substitution is available, every non-exempt or non-grandfathered generator that is forced out in SDG&E's system is exposed to availability penalties for the foreseeable future, with no option to mitigate damages. The SCP, combined with the current annual LCR obligation, expose SDG&E to potentially hundreds of thousands of dollars in penalties –

penalties that are avoidable in other areas of the state. This disparate treatment favors some suppliers and penalizes others based solely on geography, and is unacceptable to SDG&E.

SDG&E believes a workable solution calls for the CAISO to perform a more detailed LCR study each year to determine separate local obligation for each of the summer, fall, winter and spring seasons. SDG&E anticipates that lower loads in the non-summer months would produce a lower LCR obligation and allow market participants to avoid unnecessary costs. In addition, the lower obligation would free up units to substitute for those on forced outage, thereby avoiding unnecessary penalties and further reducing costs.

ISO response: Any local area that heavily relies on local generation is exposed to these higher charges "because they don't have extra non-RA resources" in their territory. The LCR Report has this information listed in table 5 and any local area that relies on more than 90% of resources for their local need are in the same position. These costs can be eliminated by further investments into new transmission and/or local generation.

The SCP gives an opportunity to provide replacement capacity not a requirement. The ISO agrees that there is higher "exposure" for these local areas that are low on non-RA local resources; however, SDG&E has not provided any economic justification that purchasing "additional RA resources local or not" to cover for the "substitute" local capacity that is out on outage is less costly then the charges imposed. As discussed at previous LCR stakeholder meetings regarding the "LCR criteria, methodology and assumptions" SDG&E needs to propose solutions to the technical problems related to the seasonal LCR studies like: number of transmission elements on "maintenance" in the non-summer months before the LCR criteria is applied, RA resource outage in the non-summer

months, deliverability of all resources in the non-summer months. The ISO believes the current process achieves the right balance between granularity of local area requirements and study/regulatory expectations.

COMMENTS OF THE ALLIANCE FOR RETAIL ENERGY MARKETS

ON 2011 LOCAL CAPACITY REQUIREMENTS

The Alliance for Retail Energy Markets (AReM)[2] provides the following comments on the CAISO's *2011 Draft LCR Results*, which was issued March 3, 2010 and discussed at the March 10th stakeholder meeting.

1. Concerns With The Current Process For Local Capacity Requirements

2011 will mark the fifth compliance year for Local Capacity Requirements (LCRs). LCRs were established to ensure Resource Adequacy (RA) in Local Capacity Areas (LCAs) that have transmission constraints. By identifying the location of the constrained LCAs and the megawatts (MWs) the load-serving entities (LSEs) are required to procure the necessary capacity resources, and identification of the constraints is supposed to inform the transmission planning process so that necessary infrastructure is developed to relieve the constraints and reduce the LCRs, where cost-effective. The Table below shows the year-to-year changes in the statewide LCR.

Local Capacity	2006	2007	2008	2009	2010	2011	% Change	% Change

[2] AReM is a California non-profit mutual benefit corporation formed by electric service providers that are active in California's direct access market. These comments represent the position of AReM, but not necessarily that of any particular member or any affiliates of its members with respect to the issues addressed herein.

Require-ments (LCR)	LCR (MW)[3]	LCR (MW)[4]	LCR (MW)[5]	LCR (MW)[6]	Final LCR (MW)[7]	Draft LCR (MW)[8]	2006-2011	2010-2011
TOTAL	23,420	22,934	28,030	27,915	27,727	28,154	20	1.5
MWs Defic.[9]	385	466	767	907	652	974	153	49
# of Deficient Areas	3	4	5	4	5	6	--	--

Since the first LCR calculation issued in September 2005, LCRs have increased more than 20% for the CAISO grid. The number of deficient areas has also increased. Even accounting for the addition of the LA Basin LCA in the 2008 compliance year, which added 3,700 MW to the LCRs, the trend is, at best, steady state. Further, while California is experiencing a major recession beginning in 2008, the LCRs are still increasing, by 1.5% from 2010 to 2011.

[3] CAISO, *Local Capacity Technical Analysis, Overview of Study Report and Final Results*, September 23, 2005, p. 12.
[4] CAISO, *2008 Local Capacity Technical Analysis, Report and Study Results,* April 3, 2007, p. 4.
[5] *Ibid.*
[6] CAISO, *2009 Local Capacity Technical Analysis, Final Report and Study Results*, May 1, 2009, p. 2.
[7] *Ibid.*
[8] CAISO, *2011 Draft LCR Results*, issued March 3, 2010, slide 5.
[9] In 2006 and 2007, all of the deficient LCAs (Sierra, Stockton and Fresno with Kern added in 2007), were in "Other PG&E," which is composed of six aggregated Local Capacity Areas (LCAs). As of 2008, San Diego became deficient as well. In 2009, Fresno was no longer a deficient area in "Other PG&E." In the final report for 2010, North Coast/North Bay was added as a deficient area in "Other PG&E." In the draft for 2011, North Coast/North Bay was no longer deficient, but Humboldt and Greater Bay Area were added as deficient LCAs. So, the 2011 deficient LCAs were: Sierra, Stockton, Kern, San Diego, Humboldt and Greater Bay Area.

AReM requests that the CAISO explain how the impacts of the current economic downturn are reflected in the LCRs for 2011. AReM further requests that the CAISO include in the report whether there are specific transmission projects under development or under consideration that are intended to alleviate the transmission constraints contributing to the LCRs.

ISO response: The impact of the current economic downturn is reflected in the latest CEC forecast, used by the ISO in these studies, located at: http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-SF-REV.PDF. The ISO will be listing all transmission projects with LCR implications operational by June 1, 2011 in this year's report. For additional transmission project and their effect on LCR please read the latest long-term LCR report the "2012-2014 Long-Term LCR report": http://www.caiso.com/2495/2495c63b23450.pdf.

2. Need for Checks On Load Data

During the March 10th meeting, the CAISO explained that the Participating Transmission Owners (PTOs) distribute the load data provided by the CEC to the transmission busses in each sub-area in the LCA. The CAISO uses these distributed data in their modeling to determine the LCRs. In some cases, the 2011 results showed significant increases in load over the 2010 data. When asked, the CAISO staff admitted that the information received from the PTOs does not contain explanations for any significant increases in the load distribution. Given the current economic downturn, AReM requests that the CAISO follow-up with the PTOs on this issue, report back to stakeholders on the

results of these discussion at the next stakeholder meeting, and include in their LCR report explanatory statements on the rationale and analysis that backs up load pocket load increases..

ISO response: The only areas with load increase in 2011 are LA Basin <1% and Kern that has a rather large percentage increase. Per the CEC forecast the total load for the Big Creek/Ventura and LA Basin combined have actually decreased from last year. The Kern area is part of PG&E's Valley South coincident peak recorded data, in order words load forecast is trying to mimic real time data for a total combined load between Yosemite, Fresno and Kern. The first two combined represent the Greater Fresno LCR area and being much bigger then Kern they drive the day and hour of the actual peak. The Kern LCR area is small and it is apparent from previous year fluctuations that at the recorded peak (driven overall by Yosemite and Fresno) is not consistent from one year to the next. PG&E is to investigate if it would be better if two different base cases are build one for the Greater Fresno peak and another for the Kern peak. Since the Kern LCR area already has enough units under long-term contract, the ISO believes that this change in load forecast will not impact overall local RA procurement.

3. <u>Need for Advance Warning Of Increased LCRs</u>

AReM has previously raised the issue of the need for advance warning of significant increases in procurement requirements. The 2008 addition of the new LA Basin LCA was the first such RA procurement surprise. This year, the CAISO has calculated an increased LCR for the LA Basin of more than 850 MW or 9%. The March 8th slide

presentation revealed to the LSEs for the first time that a major 230-kV transmission line will be out of service for 2011, which apparently created the significant increase.[10] We have several questions about this case and the process:

1. When did the CAISO approve the plan for removing the line from service?

2. Who requested to take the line out of service?

3. Did the CAISO consider the effect on LCRs from this transmission outage at the time of the request?

4. Were alternatives considered that would lower or eliminate the impact on the LCR?

The CAISO should be actively evaluating the effect on LCRs of any request for long-term transmission line outages. Further, LSEs need to know that alternatives were considered to reduce the LCR increase. Otherwise, LSEs and their customers may be forced to bear an unnecessary and unfair cost burden.

In the future, AReM requests that CAISO engage the LSEs early in the process, either in a stakeholder forum or through working groups, to discuss the outage plan, the effect on LCRs and the alternatives considered. Indeed, AReM urges the CAISO employ this process in the future when it first learns of *any* significant change to the LCRs, rather than waiting for its annual draft report in March of each year.

[10] This revelation appeared as one bullet on p. 14 in the LA Basin/Big Creek slide presentation.

ISO response: 1. Both the ISO and the CPUC have approved the removal of this line from service when the Tehachapi Renewable Transmission Plan was approved. 2. This line needs to be completely eliminated in order to make room for a new 500 kV line. 3. The new 500 kV line to Mira Loma adds great benefits to ratepayers, it allows for renewable integration and it also eliminates significant amount of LA Basin LCR (see the long-term LCR study for more information). The 2011 situation is but a temporary one until the new 500 kV gets built. 4. Alternatives to this line being rebuild at 500 kV have been discussed in the CPUC proceeding.

4. No Unilateral Change To RA Schedule

The CAISO's March 10th presentation included a schedule that would require the LSEs to submit *final* RA showings by the week of October 2.[11] This would represent a significant change to the current RA schedule, which has been in place since 2007. The LSEs are now required to make their annual RA showings at the end of October. The CAISO's change in schedule would necessitate an *earlier* RA decision (now scheduled for June) and an *earlier* LCR allocation (which is released in July) to allow LSEs at least 90 days to procure. The CAISO must propose any such changes through the CPUC stakeholder process, which has already concluded for Phase 1. AReM suggests that the CAISO raise this issue in Phase 2 of R.09-10-032.

ISO response: The ISO cannot unilaterally change the CPUC schedule. However in order to finalize the ISO process as required by the ISO Tariff the ISO needs to treat all

[11] Overview presentation, Slide 7.

resource showings received by the first week of October as the showing used to determine whether there are deficiencies in year-ahead local procurement.

The LSEs do not need to wait for a CPUC RA decision or a LCR allocation in order to start local RA procurement for next year. Once final results are published on May 1 (ISO final report) the LSEs can simply take their last year's allocation (by TAC) and multiply it by the ratio of the 2011 LCR needs in each TAC vs. the 2010 LCR needs in the same TAC. A request for proposal can be sent out based on this data; such that by the time the CPUC comes up with a decision and the actual final year-ahead allocation is submitted the LSE is ready to sign the contract. The process of signing contracts should be contained to 30-60 days and as a result procurement can be finalized by the end of August or September.