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.	)))	R.12-03-014 (Filed March 22, 2012)

OPENING BRIEF ON TRACK 1 OF

THE CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

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The California Large Energy Consumers Association (CLECA)[1] submits this opening brief pursuant to Rule 13.11 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure and the schedule set by ALJ Gamson in a bench ruling on August 17, 2012.

I. EXECUTIVE SUMMARY

The Commission's core responsibility is to the ratepayers on whose behalf the Commission authorizes the utilities to cost-effectively procure reliable power. In carrying out this responsibility, CLECA cautions the Commission against unintentional abdication of its duty or ceding of its jurisdiction in the context of consideration of the California Independent System Operator's (CAISO) studies and recommendations. The Scoping Ruling sought input on whether the CAISO studies should be modified or if

1 CLECA is an organization of large, industrial electric customers of the three investor-owned utilities, with members taking both bundled and direct access service. The member companies are in the steel, cement, industrial gas, pipeline and beverage industries, and share the fact that electricity costs comprise a significant portion of their costs of production. For all of them, the cost of electricity is a very important element in their cost structure and the competitiveness of their products. CLECA provides an important perspective because it represents both bundled and direct access large power customers. There are no other active parties in this docket representing large power interests of both bundled and direct access customers.

additional factors should be considered in the setting of Local Capacity Requirements; CLECA's input is provided at length below.

In brief, additional factors should be considered in setting LCR needs, the first and foremost of which is cost. Concerns regarding the limited mitigation options considered by the CAISO and its lack of consideration of the costs of added generation bear consideration. Moreover, the CAISO's use of stricter standards than the adopted NERC Reliability Standards is both questionable and costly. In deciding if and how to use the CAISO studies, the Commission should guard against unduly deferring to the CAISO and recognize clearly where its own duty and the responsibilities of the CAISO diverge. CLECA recommends the Commission consider authorizing sequential procurement to meet the LCR need and reject the CAISO proposal to use a 2013 Request for Offer Process to meet the entire need with gas-fired generation.

CLECA also supports continued use of the Cost Allocation Mechanism (CAM) to allot the costs of needed LCR procurement to all benefitting customers. In our view, local reliability is integral to system reliability, and keeping the lights on in the West LA Basin contributes to keeping the lights on in the rest of SCE's service territory. Accordingly, a Commission determination to continue allocating the net capacity costs and the Resource Adequacy credit benefits of LCR resources to benefitting customers through use of the CAM would be appropriate.

II. DETERMINATION OF LCR NEED IN CAISO STUDIES

A. CAISO's LCR and Once-Through Cooling (OTC) Generation Studies

1. The CAISO's Studies Are Neither Exhaustive Nor Definitive

The CAISO's studies are not definitive as to which resources are needed to meet local capacity requirements (LCR) in the West Los Angeles (W LA) local reliability subarea or the Moorpark subarea. The Commission should not adopt the CAISO's assertion that 2,370 or more MW plus another 430 MW of additional gas-fired generation should be procured to replace current generation using once-through cooling (OTC) in these areas.

The CAISO used power flow analyses to determine whether Category C reliability standards[2] could be met under these assumptions. However, its analysis was limited by the assumptions it used and by the narrowly defined set of potential mitigation solutions it studied. The CAISO assessed the level of need based on certain assumptions as to the state of the transmission system and alternatives for replacing current generation using OTC-only with other gas-fired generation; furthermore, it only looked at generation alternatives at existing OTC sites.

> *The lower end of the repowered former OTC range value corresponds to the amount of generation that would be needed if it were located at existing OTC sites that are the most effective at mitigating the identified transmission constraint. The higher end of the OTC range value corresponds to the amount of generation inside the sub-area that would be needed if it were located at existing OTC sites that are the least effective at mitigating the identified transmission constraint.*

Sparks Opening Testimony, ISO-3, p. 6.

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2 North American Electric Reliability Organization (NERC) regulates CAISO compliance with Transmission Planning Standard 003-0a (TPL-003-0a), which sets Category C reliability standards; NERC was delegated jurisdiction over the filing, management and enforcement of Transmission Planning Standards, *e.g.*, TPL-003-0a, by the Federal Energy Regulatory Commission (FERC) pursuant to the Energy Policy Act of 2005. *See generally* 140 FERC ¶61,048 (July 19, 2012).

The CAISO is not a generation planner; it has responsibility for transmission planning. SCE's witness Minick suggested that this represents a limitation in its analysis, when he referred to the CAISO's LCR study for Moorpark:

> *The ISO is not a generation planning entity. They don't know what the options are for adding new generation. So the likely method they used, and I am 99.9 percent sure they did, as they put back Mandalay Unit 1 and found that didn't solve the problem, so they put back Mandalay Unit 2 and that did solve the problem, that simply says the problem requires more than 215 megawatts of generation at the Mandalay site to solve it but might require less than 430 megawatts to solve it.*

SCE-Minick, Tr. p. 1019.

The CAISO has argued that resources within the LCR areas are required to meet the local need. However, even simply considering alternatives within the LCR areas, the CAISO's studies are not comprehensive as they only include gas-fired generation at current OTC sites. The CAISO also fails to include any other non-gas fired generation alternatives or non-generation alternatives at the OTC sites or other sites. Several parties raised the CAISO's failure to consider loading order resources such as energy efficiency (EE), demand response (DR), and distributed generation (DG) as alternatives. CLECA will not address these alternatives, other than DR, since they will be extensively addressed by others.

The CAISO also did not consider possible mitigation from subtransmission and distribution system changes on the grounds that these are not its responsibility. As CAISO witness Sparks said in response to a question from Commissioner Florio regarding the use of a 600 MW load transfer from Mira Loma for mitigation:

> *Q Okay. And that is something that is not yet in a transmission plan but is under review by Edison and ISO?*

A We discussed it with Edison in a couple of conversations. But it's actually a distribution project, so it's difficult for the ISO to lead that process. But we have raised it with Edison.

Q Okay. So as a distribution project, it would not require approval by the ISO as part of a transmission plan?

A No. Only that the operational flexibility of it, we could review it and concur with it sort of like a distribution connection but not –

Q Yeah.

A – the need for it or anything like that.

Q Okay. Do you have – is this in your mind a major undertaking or is this more in the nature of a routine kind of change that happens on the grid all the time?

A My understanding is that it is sort of the master plan that Edison has for their distribution system and that there may be a need to accelerate it and to relieve some transmission constraints.

CAISO-Sparks, Tr. pp. 83-84.

Thus, there are non-generation alternatives involving upgrades to the subtransmission system that were not considered by the CAISO because they are in the purview of the utility. The Commission should be concerned that the analysis of alternatives was not more comprehensive or more closely coordinated between the utility and the CAISO. Further analysis of alternatives for meeting the LCR requirements in this subarea to determine which would be the most cost-effective is needed for a procurement authorization by this Commission to be just and reasonable.

The CAISO's study of the Moorpark subarea requirement is also insufficient for the Commission to determine how the need there should be met. SCE stated during the hearing that the CAISO analysis did not determine the size of the generation resource required to address the Moorpark local area need.

> *Q And your reply testimony, page 18 and 19, line 17, this is having to do with the Moorpark local area, you mention that the two smallest generators are both 215 megawatts. Both had to be added to eliminate the problem. So the entire 430 megawatts is not necessarily needed but it was the only option available for the ISO to test.*
>
> *A Correct.*
>
> *Q Are you saying there that you needed a smaller resource rather than this particular size generator?*
>
> *A What I'm saying is the methodology used by the ISO is to remove OTC or once-through cooling or retire generation, test the system and find where the problems are, then to add generation back in.*
>
> *The ISO is not a generation planning entity. They don't know what the options are for adding new generation. So the likely method they used, and I am 99.9 percent sure they did, as they put back Mandalay Unit 1 and found that didn't solve the problem, so they put back Mandalay Unit 2 and that did solve the problem, that simply says the problem requires more than 215 megawatts of generation at the Mandalay site to solve it but might require less than 430 megawatts to solve it.*
>
> *They didn't do things in between because that wasn't necessarily an option. That's why I'm saying I think we need to study this further. We do need to take a look at are there other options. We need to work with the ISO as a group saying these are other ways to possibly solve this.*
>
> *I think it is a little bit premature, that is what my testimony says, to come to a firm conclusion about this area right now. There's definitely an issue there, but I don't think the ISO spent enough time analyzing it to come to a concise exact answer.*

SCE-Minick, Tr. 1018-1019. The CAISO also failed to study potential changes on the subtransmission or distribution system in the case of

Moorpark. Calpine's witness Calvert presented three transmission upgrade alternatives to the CAISO's proposal for 430 MW of new generation at Moorpark, all of which merited further consideration. Calpine-2, p. 5 *et seq.* and Tr. 1331-1332.

2. The Commission Must Authorize a Process that Considers Cost

The CAISO did not consider the cost of generation alternatives. Indeed, it said it does not know the cost of generation.

> *Q At page 1 you describe your job responsibility as managing a group of engineers responsible for planning to ensure compliance with NERC, WECC, and ISO Transmission Planning Standards in the most cost-effective manner.*
>
> *Would you look at cost-effectiveness in the analysis that is addressed in your direct testimony here?*
>
> *A Yes. That is always something that we are considering when we identify mitigation of NERC criteria standard violations.*
>
> *Q How did you look at cost-effectiveness in this case?*
>
> *A Admittedly, it becomes difficult when generation and transmission are alternatives, because* ***we don't have information on the actual cost of generation.*** *That is confidential information we are not privy to.*

ISO-Sparks, Tr. pp. 98-99 (emphasis added). The Commission's decision in this phase of the proceeding should authorize SCE to pursue a procurement process that will meet the need for local reliability at an appropriate level. The determination of an appropriate level must be based on a thorough evaluation of the cost and effectiveness of non-traditional generation alternatives and non-generation alternatives as well as traditional gas-fired generation. The Commission should order SCE to determine a least-cost best-fit solution among these alternatives. This falls within the CPUC's jurisdiction and its statutory responsibility for adopting just and reasonable retail rates.

3. The Commission Must Consider the Cost of CAISO Standards that Exceed NERC Standards

NERC and WECC Reliability Standards enacted pursuant to the specific delegation of authority by Congress to FERC clearly have the force of law.[3] NERC Reliability Standards become "*mandatory and enforceable upon approval by the Commission*."[4] Violations of the NERC Reliability Standards adopted by FERC can result in assessments by NERC of monetary penalties.[5] Some CAISO standards, however, go beyond NERC and WECC regulations. There are several areas where the CAISO's exhibits show it has developed its own reliability standards which its tariff applies to LCR and the CAISO tariff makes it clear that these standards exceed the adopted NERC Reliability Standards.[6] The Commission should recognize two key

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3 "*All users, owners, and operators of the bulk electric system shall comply with the reliability standards that take effect under this section [referring to §215(b) of the Federal Power Act, added by the Energy Policy Act of 2005].*" 16 USC §824(o)(b)(1). Order 693-A, 120 FERC ¶61,053 at ¶70 states, "*if a standard is approved by the Commission[FERC] under Section 215, compliance is mandatory ....*"

4 *See North American Electric Reliability Corp.,* 116 FERC ¶61,062 (July 20, 2006) (certifying NERC as the Electric Reliability Organization (ERO) pursuant to the Energy Policy Act of 2005); *see also* 119 FERC ¶61,060 (at 4) (approving WECC as a Regional Entity to which NERC may delegate enforcement authority pursuant to the Energy Policy Act of 2005).

5 *See Order on Review of Notice of Penalty*, 140 FERC ¶61,048 (July 19, 2012) (confirming NERC's authority to penalize Southwestern Power Administration for violation of NERC Reliability Standards under §215(e) of the Federal Power Act).

6 40.3.1.1 Local Capacity Technical Study Criteria

> The Local Capacity Technical Study will determine the minimum amount of Local Capacity Area Resources needed to address the Contingencies identified in Section 40.3.1.2. In performing the Local Capacity Technical Study, the CAISO will apply those methods for resolving Contingencies considered appropriate for the performance level that corresponds to a particular studied Contingency, as provided in NERC Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0, **as augmented by CAISO**

Continued on the next page

points here: First, CAISO's claim that violating its stricter standard would be equivalent to breaking the law is questionable. Second, and more importantly, this Commission, not CAISO (and indeed not FERC), bears responsibility for balancing the cost to ratepayers of potential LCR procurement with a determination on the need for LCR procurement.

(a) CAISO Standards vs. Adopted NERC Standards

CAISO standards that exceed FERC-approved NERC Reliability Standards do not appear to have the same force of law attributable to the FERC-approved NERC Reliability Standards. "*Only a Reliability Standard (including a regional Reliability Standard or variance) approved by the Commission is enforceable in the U.S. under section 215 of the FPA.*"[7] Accordingly, we question the accuracy of the CAISO's statements that it cannot violate its own reliability standard because this is "like" violating the law. This does not seem to be strictly correct.

Notably, while NERC Reliability Standards may be differentiated by region, they clearly state where they are differentiated by region.[8] For example, NERC's Reliability Standard TPL-003-0a (which has the force of law since it was adopted by FERC pursuant to §215 of the Federal Power Act) clearly states "*none identified*" under regional differences; similarly, adopted Reliability Standard TPL-004-0 and all the other

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Reliability Criteria in accordance with the Transmission Control Agreement and Section 24.2.1. (Emphasis added).

7 116 FERC ¶61,062, ¶277.

8 *See* Order 693, FERC Statutes and Regulations ¶31,242, Order or Rehearing Order 693-A, 120 FERC ¶61,053 (2007) (referencing six of eight regional differences and stating "*the Commission will continue to rely on NERC's definition of bulk electric system with the appropriate regional differences until Bulk Power System is better defined.*").

TPL standards state "*none identified*" under regional differences.[9] If the CAISO's different reliability standard were adopted pursuant to §215(b) of the Federal Power Act like the NERC and WECC Reliability Standards, its difference would be noted in the NERC Reliability Standards. There is no mention of CAISO's regional difference in NERC's adopted Reliability Standard for transmission planning. It appears that WECC has not submitted, nor has NERC approved, nor FERC approved, any "*regional differences*" for any of the Transmission Planning standards (TPL).

Regional differences among the Reliability Standards can exist, "*if otherwise just and reasonable, not unduly burdensome and in the public interest,*" and if more stringent *AND* necessitated by a regional physical difference in the Bulk Power System.[10] They still must be approved, however, by NERC and then by FERC to become mandatory and enforceable and with violations subject to penalty. It is clear that the more stringent CAISO standards do not meet these criteria. Indeed, CLECA submits that, from the ratepayer perspective, the CAISO's focus on reliability regardless of cost is not reasonable, not in the public interest and is unduly burdensome. Moreover, as discussed further below, this Commission retains its jurisdiction over the determination of reasonableness of the cost of utility procurement of reliability resources; this intersection of jurisdictional boundaries warrants careful consideration.

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9 *C.f.,* the different WECC Reliability Standard for operating limits, WECC Standard TOP-007-WECC-1 that appears to have been adopted by NERC and FERC; while substantively irrelevant, its existence demonstrates that where a Regional Entity (WECC) has an enforceable, mandatory Reliability Standard that is different from the NERC standard, it is clearly published within the NERC standards.

10 116 FERC ¶61,062, at ¶274. Moreover, Regional Entities (*e.g.*, WECC) are discouraged from adopting voluntary rules that detract from Commission-approved Reliability Standards. *Id.*, at ¶281. Arguably, the more restrictive CAISO standard that fails to permit the use of DR in certain instances detracts from the NERC inclusion of DR as a mitigation option in TPL standards.

CAISO's Exh. ISO-19 makes it clear that CAISO reliability rules exceed NERC Reliability Standards for combined line and generator unit outages. The standards state the following:

> *IV. Combined Line and Generator Unit Outage Standards Supporting Information Combined Line and Generator Outage Standard - A single transmission circuit outage with one generator already out of service and the system adjusted shall meet the performance requirements of the NERC TPL standards for single contingencies (TPL002).*

ISO-19, p. 4. In providing further explanation, the CAISO states:

> *The ISO Planning Standards require that system performance for an over-lapping outage of a generator unit (G-1) and transmission line (L-1) must meet the same system performance level defined for the NERC standard TPL-002.* ***The ISO recognizes that this planning standard is more stringent than allowed by NERC,*** *but it is considered appropriate for assessing the reliability of the ISO's controlled grid as it remains consistent with the standard utilized by the PTOs prior to creation of the ISO.*

ISO-19, p. 10, emphasis added.

The use of planning standards in excess of NERC Reliability Standards raises issues about the impact on ratepayers. Establishing a need for additional generation resources or requiring expenditure for additional transmission and distribution resources that are not required by law under adopted NERC Reliability Standards is not costless.

SCE confirmed in hearings that CAISO planning standards exceed NERC standards. In response to cross examination by the Sierra Club, SCE's witness Cabbell stated:

> *Q Does CAISO have additional standards that they consider for LCR?*
>
> *A They have, yes, they have a set of planning standards that they have developed.*

Q Are those different than the NERC standards?

A They are -- they are kind of on top of the NERC standards.

Q Are they more stringent?

A I think in some areas for the contingencies they look at they're more stringent.

Q Can you explain how they're more stringent?

A I think they're considering more of the, as we've been talking about, the Level D contingencies, and the way they actually take the N-1/N-2, one line out and a common load failure. So it's a little more stringent, which the NERC planning standards and NERC allow entities that have more stringent criteria depending on actually application to their system.

Q What would NERC require absent the CAISO standards? They would look at -- what would their requirements be?

A Well, they still look at, they have Level D performance standards, so, but those are typically in a loss of a substation, a loss of an entire corridor. So --

Q They're looking -- sorry.

A Oh, that's okay. Go ahead.

Q So they're looking more at like Level Contingency B?

A Well, yeah. They actually have a Level D, but it's typically, you want to look at the consequences and the risks. And you really -- sometimes you don't have to plan projects for Level D. There is a concern if there's cascading, but you don't have to plan projects for Level D. But for -- then you look at the Level C, which is an N-2, Level B, N-1, which we typically, that's when we plan our projects.

SCE-Cabbell, Tr. pp. 813-814.

(b) Commission Consideration of LCR Criteria Must Weigh Costs

The CAISO's assessment of need for local reliability is based on Category C and

D contingencies, involving two simultaneous outages or two outages with no restoration time in between. This is not explicitly covered by the CAISO's planning standard document, ISO-19. How does the CAISO determine what is needed for LCR?

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

Exh. ISO-3, Sparks Reply Testimony, at 7 (emphasis added).

The Commission should consider whether its adopted LCR criteria, incorporating the CAISO's more stringent reliability standards, are in the best interest of ratepayers. We note that footnote 3 of TPL-003 says that voltage collapse and dynamic instability are not allowed per NERC standards, but TPL-003 leaves it to the transmission planning entity to choose which extreme events to evaluate. ISO-13, p. 21 of 29, fn d. Notably, NERC's TPL-003 does allow for planned and/or controlled load shedding to remedy a multiple outage situation. *Id.*, fn c. TPL-004, covering extreme events, leaves it to the transmission planning entity to perform and evaluate studies "*only for those Category D contingencies that would produce the more severe system results or* *impacts*." ISO-13, p. 25 of 29. As we will show later, Category D contingencies do not require mitigation nor is it clear that the CAISO has an obligation to mitigate a Category C event following a Category B event. *Id*., p. 20. Furthermore, the CAISO has discretion in determining which outage events it concludes must be mitigated in local reliability areas and subareas. The Commission should provide input to the CAISO's process in determining what mitigation is cost-effective for ratepayers.

We understand the CAISO's obligations with respect to grid reliability. However, the CAISO has neither an obligation nor the explicit authority to determine whether the costs of its proposals are just and reasonable from a ratepayer perspective. Indeed, as shown above, the CAISO does not even have the information to evaluate the costs of alternatives. This is the role of this Commission, *i.e*. to determine which resources its jurisdictional entities should procure in a cost-effective manner.

One critical factor that the Commission must consider is the CAISO's conservative position that it would take all necessary measures to procure backstop capacity if the Commission declined to order procurement of sufficient resources to meet the CAISO's own perceived need. In SDG&E's cross-examination of Mr. Millar of the CAISO, the CAISO made its position clear:

> *Q All right. Now, the question I asked of Mr. Sparks under those assumptions essentially was, in lieu of that new generation,* ***what would the ISO -- or does the ISO have other mitigation options in lieu of the addition of the generation you're recommending Edison be authorized to procure?***
>
> ***A Certainly as we got closer over the next few cycles we would have to start exploring the entire range of options both that fall within our current framework and our current authorities as well as should we be seeking additional authorities in order to advance the necessary reinforcements.*** *There's a range of mitigations*

> *that, as, you know, Mr. Sparks pointed out earlier, we think when it comes to transmission alternatives we have captured all of the low-hanging fruit. The alternatives get progressively more intrusive and more costly and more intrusive to the public, landowners, land interests, environmental interests. But we would have to explore all the options available to continue to meet the relevant reliability criteria.*
>
> *We do have once-through cooling generation there now. There is no framework to simply delay compliance with once-through cooling. That was also discussed yesterday. And the fact is that the physical generation would exist, but there is no current framework for making changes in compliance with once-through cooling requirements simply to enable another policy objective to be met. So we would have to look at all of these.*
>
> *I don't believe our current capacity procurement mechanisms address this type of situation specifically. That could also be revisited. But as we get closer to not meeting criteria, we would have to put all options on the table.*

CAISO-Millar, Tr. pp. 449-450 (emphasis added). This is very troubling. The CAISO appears to be asserting that it will utilize its backstop procurement authority or seek to expand that authority to meet standards that are more stringent than NERC requires; moreover, it will undertake these actions if it concludes that the Commission has not ordered the procurement it prefers, based on its clearly limited analysis of the options. This is particularly concerning due to the CAISO assertion that it must have the level and type of procurement it has specified or risk a criteria violation. As we have shown, if the standard it refers to is more stringent that NERC standards, the CAISO has not established that this would represent a criteria violation. When asked about the point, the CAISO's witness Millar said:

> *Q Do you think that this commission should review the relative risks and costs of both oversupply and undersupply in making its decisions in this proceeding?*

A In terms -- it depends which risks we're referring to.

In terms of assessing the risk of accepting a criteria violation, I would say no.

In terms of assessing the risk of proceeding down a procurement path versus delaying to some point in the future, I think that's an issue that the Commission has to consider and will be considering when they're also considering our recommendation.

We believe that this is the right time to start the procurement process, recognizing that new information will be coming in along the way because we see the window closing on some of the options if we don't start now. Whether or not -- how the Commission sees that recommendation and if they agree with us or not is something I see them having to consider in this process.

Q Has the ISO provided any information about the potential costs of oversupply in the event that the forecasts turn out to be far too conservative?

A We haven't tried to perform that kind of analysis, no.

Tr. pp. 501-502. Yet, the CAISO states that violating its own defined criteria is the equivalent of breaking the law.

Q Does a marginal shortage -- does your modeling allow you to estimate the specific loss of firm load that would occur in the case where there's a violation of local reliability criteria?

A Assumptions can be made to take it further into those. It's not part of the routine analysis. Criteria violations are violations that need to be addressed. We can go further if we have to into assessing the amount of risk.

Q So, but a criteria violation doesn't always result in the loss of firm load, does it?

A A criteria violation means we're operating outside of North American Electric Reliability Standards which is not really on the table for discussion to be frank.

Q I understand. But I'm asking you about the statement that equates a marginal shortage to a loss of firm load, and

I'm just trying to understand whether that always occurs.

A No, it does not.

Q And has the ISO attempted to assess or quantify the economic cost associated with losses in firm load in situations where there would be a criteria violation?

A In deciding whether or not to mitigate a criteria violation, no. That is like calculating the cost of breaking the law, and we don't do that.

Tr. pp. 498-500.

There are two key points to be made here. First: shedding load is a legitimate means of addressing a contingency that is acceptable to FERC and NERC. This matter is addressed in further detail below. Second: the CAISO has no responsibility for considering the cost or rate consequences of backstop procurement, which may lead to a decision to pursue a backstop option that would not be perceived as cost-beneficial from the ratepayer perspective.

How does the cost of meeting the need defined by the CAISO get factored into the analysis? The CAISO's transmission planning standards state that it performs a benefit-cost analysis of transmission system additions that reduce the risk of load drop exposure based on its own calculations. ISO-19, p. 14. There is no evidence that it considers all alternatives to such additions. Furthermore, the Commission has had no role in this cost-benefit analysis.

Why is this important in this proceeding? Because statements made by several CAISO witnesses strongly suggest that the CAISO perceives the risk of outages vastly exceeds the cost of additional system reinforcements.

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*.

Sparks Opening Testimony, pp. 5-6. Or, again:

> *In my testimony it asserts that the risk of coming up short and having to interrupt service to customers on a frequent basis is -- the impact of that far outweighs any additional cost that we might incur by perhaps procuring a little bit extra.*
>
> *Q Okay. However, if there is significant overprocurement for whatever reason, you know, there are negative implications of that as well, costs, environmental, whatever, right?*
>
> *A Yes. The degree of the error on both sides, the impact gets -- amplifies.*
>
> *And so significant underprocurement, the impacts are even -- you know, can become political and end up, you know, getting the Governor impeached all the way to --*
>
> *(Laughter)*
>
> *THE WITNESS: -- overprocurement where there can be high rates*.

Tr. pp. 270-271.

It is appropriate for the Commission to consider here whether it or California ratepayers have the same view of risks compared to costs as the CAISO and whether acceptance of the CAISO's view of risk or proposed solution to the perceived risk is necessary. End-use customers face regular outages due to problems on the distribution system. The most stringent 1-in-10 or 100-year outage standard for generation will not change this. Customers, not the CAISO, pay the bills for additional generation and transmission to meet the CAISO's more stringent standards. The CAISO has not considered all the alternatives in its proposal nor has it considered the costs. In terms of its duty to set "just and reasonable rates," the Commission should be concerned by the CAISO's overly conservative position that LCR needs should be met solely through new gas-fired generation, regardless of cost. While the CAISO may see the downside here as simply "*backup insurance*" (Tr. p. 401) or early procurement,[11] ratepayers will pay more.

4. Controlled Load Shed

The issue of when controlled load shed can be used to meet a contingency was raised by CEJA and SDG&E. SDG&E's cross examination focused on a single contingency, where NERC standards on use of involuntary load shed to mitigate contingency risk are said by CAISO's Millar to be unclear. ISO-Millar Tr. 453-454.

However, the NERC Reliability Standards are clear in the case of a double contingency, and they explicitly allow the use of controlled interruption of load to meet a Category C contingency. NERC Standard TPL-003-0a – System Performance Following Loss of Two or More BES Elements (Category C) states:

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

Exh. ISO-13, p. 17 (emphasis added).

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[11] CAISO indicated that if there were more distributed generation than it had forecast, resulting in excess generation when combined with its proposed conventional generation: "*Well, I would expect an increase in costs at least for a little while, but there still is load growth in these areas, and it might mean being a little early….*" Tr. p. 467.

TPL-04-0, entitled System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements, addresses the Category D contingency discussed in the hearing room; TPL-04 discusses an annual evaluation of the risks of such contingencies, not a mitigation. The discussion of a Category D contingency in TPL-003-0a notes that such an event "*may involve the loss of substantial customer Demand and generation in a widespread area or areas*." ISO-13, p. 21 of 29. The point is that not every contingency can be prevented by adding resources and that the costs of attempting to do so may be greater than what customers are willing to pay for the extra insurance.

B. Consideration of Preferred Resources, Including Uncommitted Energy Efficiency, Demand Response, Combined Heat and Power, and Distributed Generation, In Determining Future LCR Needs

The CAISO prematurely concluded that preferred resources cannot provide LCR support. Neither the CAISO nor SCE has appropriately taken into account the capabilities of demand response programs already authorized by the Commission or the additional capabilities that could be added in California to DR programs to allow them to better meet LCR needs. The CAISO admitted it did not know that reliability-based or other DR can or soon will be able to be dispatched on a locational basis, so it did not model it that way. ISO-Rothleder, Tr. 304-305. Furthermore, when asked if DR could be modeled on a day-ahead basis, the CAISO also said no, although there are day-ahead DR programs. ISO-Rothleder, Tr. p. 304.

The lack of knowledge of the locational dispatch aspect of DR programs is surprising since the CAISO was a signatory to a settlement adopted by the Commission in D.10-06-034 that specifically states the following regarding reliability-based DR programs:

> *Once triggered, MWs under this product [the Reliability Demand Response Product] will be dispatchable by location and quantity*.

D.10-06-034, attachment, p. 5. The CAISO under that settlement committed to create this Reliability Demand Response Product. Indeed, Section A of that settlement, which is quoted on page 14 of the decision states:

> *RDRP can be triggered at the point immediately prior to the ISO's need to canvas neighboring balancing authorities and other entities for available exceptional dispatch energy or capacity. Once triggered, RDRP will be economically dispatched by location and quantity through the ISO's Automated Dispatch System (ADS).*

Id., p. 14.

The CAISO also said that DR could not respond in a sufficiently short time to allow for no more than 30 minutes to pass from a contingency to a response. ISO-Millar, Tr. p. 435. However, there are reliability DR programs with 15-minute or less response times (the Summer Discount Program (SDP) for air conditioner cycling and the 15-minute notice option for the Base Interruptible Program (BIP)) and the Commission has authorized the utilities to explore further use of auto-DR that can respond in far less than 15 minutes. The Commission has authorized the continuation of all of these programs for the 2012-2014 DR cycle. D.11-11-002 for SDP, D.12-04-045, p.196 for BIP and p. 144 for auto-DR.

Furthermore, as demonstrated in the testimony of EnerNoc, Regional Transmission Organizations such as PJM permit DR resources to provide ancillary services such as spinning reserve and regulation, which must be provided on very short notice (less than ten minutes). Exh. EnerNOC-2, pp. II-2 through II-7. Thus, it is possible for DR to provide such services, on short notice, in California as well. This could certainly happen by 2020.

SCE says it did not know where DR resources were. SCE-Minick, Tr. p. 979. However, if SCE is going to be able to dispatch on a locational basis, it has to track this information.

We note that NERC's Standard TPL-001-2, covering transmission planning standards, contained in Exh. ISO-13, includes the following provision for action to achieve required system performance:

> *Use of rate applications, DSM, new technologies, or other initiatives.*

TPL-001-2, p. 4, contained in Exh. ISO-13. Thus, there is no NERC prohibition on the use of DR or other new technologies to meet transmission contingencies. The CAISO also admitted that demand-side resources like DG and EE can reduce load and thus the need for LCR; despite this, the CAISO accepted no currently uncommitted demand-side resources. ISO-Millar, Tr. p. 368.

C. Appropriate Assumptions Concerning Retirement of OTC Generation

There is some flexibility as to retirement dates for OTC generation. The State Water Quality Control Board has adopted Resolution 2011-0033, which contained an attachment that went into effect on October 1, 2010 and was updated on July 11, 2011. That attachment details the flexibility built into the OTC retirement dates:

> ***B. Final Compliance Dates***
>
> *(1) <u>Existing power plants</u>* shall comply with Section 2.A, above, as soon as possible, but no later than, the dates shown in Table 1, contained in Section 3.E, below.*
>
> *(2) Based on the need for continued operation of an <u>existing power plant</u>* to maintain the reliability of the electric system, a final compliance date may be suspended under the following circumstances:*

(a) ***Suspension of Final Compliance Date for Less Than 90 Days for Existing Power Plants* Within CAISO Jurisdiction.*** *If CAISO determines that continued operation of an existing power plant* is necessary to maintain the reliability of the electric system in the short- term, CAISO shall provide written notification to the State Water Board, the Regional Water Board with jurisdiction over the existing power plant*, and the SACCWIS. If the Executive Directors of the CEC and CPUC do not object in writing within 10 days to CAISO's written notification, the notification provided pursuant to this paragraph will suspend the final compliance date for the shorter of 90 days or the time CAISO determines necessary to maintain reliability. In the event either CEC or CPUC objects as provided in this paragraph, then the State Water Board shall hold a hearing as expeditiously as possible to determine whether to suspend the compliance date in accordance with paragraph (d).*

(b) ***Suspension of Final Compliance Date for Longer Than 90 Days, or consecutive less than 90 day suspensions, for Existing Power Plants* Within CAISO Jurisdiction.*** *If CAISO determines that continued operation of an existing power plant* is necessary to maintain the reliability of the electric system, CAISO shall provide written notification to the State Water Board, the Regional Water Board with jurisdiction over the existing power plant*, and the SACCWIS. If the Executive Directors of the CEC and CPUC do not object in writing within 10 days to CAISO's determination, the notification provided pursuant to this paragraph will suspend the final compliance date for 90 days. During the 90-day time suspension or within 90 days of receiving a written notification from CAISO, the State Water Board shall conduct a hearing in accordance with paragraph (d) to determine whether to suspend the final compliance date for more than the original 90 days pending, if necessary, full evaluation of amendments to final compliance dates contained in the policy.*

(c) ***Suspension of Final Compliance Date for Existing Power Plants* Within Los Angeles Department of Water and Power (LADWP) Service Area.*** *If the LADWP Commission determines, through a public process, that continued operation of an existing power plant* operated by LADWP is necessary to maintain the reliability of the electric system in the short-term, LADWP shall provide written notification to the State Water Board, the Regional Water Board with jurisdiction over the existing power plant*, and*

the SACCWIS. Within 45 days of receiving a written notice from LADWP, the State Water Board shall conduct a hearing in accordance with paragraph (d) to determine whether to suspend the final compliance date. In considering whether to suspend or amend the final compliance dates the State Board shall consult with the CAISO.

(d) ***State Water Board Hearings on Suspension of Final Compliance Dates.*** *In considering whether to suspend or amend the final compliance dates, the State Water Board shall afford significant weight to the recommendations of the CAISO.*

California State Water Quality Control Board Resolution 2011-0033, pp. 445-446, *"Attachment 1 Statewide Water Quality Control Policy On The Use Of Coastal And Estuarine Waters For Power Plant Cooling."*

However, the CAISO must make the call and it seems reluctant to exercise this responsibility. The CAISO's Millar said:

Q Mr. Sparks yesterday alluded to the ISO's authority under State Water Resources Control Board Resolution 2010-2020 in Attachment 1, Section 2 B 2, Subsections A and B, and these would be the suspension of the final compliance dates for either a short-term period or indefinitely. Might the ISO resort to those measures?

A As I said, all options would have to be considered. The possibility of trading off one environmental goal for another environmental goal is not without consequence. That's not something we consider palatable. The interests that are concerned about the impact of the once-through cooling on marine life are very committed to those initiatives. So I'm sure that would have to be one of those options that's under consideration, but it is not a given and it would not be taken lightly.

ISO-Millar, Tr. p. 475.

We are not suggesting that delaying implementation of the OTC policy is desirable. However, it is an option for some limited period of time if it takes a little longer to implement full mitigation of the LCR consequences of this policy or to resolve some of the uncertainties that are currently driving the expected cost of LCR mitigation. Such a delay might also allow for more time to determine if load growth is slower than forecast due to increased deployment of EE and DG, as several parties have claimed.

D. Transmission and Other Means of Mitigation

Not addressed.

III. DETERMINATION OF LCR NEED SPECIFIC TO LA BASIN AND BIG CREEK/ VENTURA AREA

A. LA Basin

The only need that should be addressed in this phase is the need for new LCR resources for the West Los Angeles Basin Local Reliability subarea. Additional flexibility for renewable integration need is yet to be determined. This need will be addressed by the end of 2013 in the next phase of this proceeding and may include flexibility from existing resources, the total amount of which has not yet been assessed. (This is an issue in the RA case.) Furthermore, it may be possible that additional MW (as well as flexibility) may be available from existing resources. This might meet the need for new LCR resources if the effectiveness factors at the existing sites are high enough.

This phase should set an “up to” level of need, without a floor. The CAISO has proposed a maximum amount of 2370 MW. SCE has proposed authorization for procurement up to this amount. The decision in this phase should also decide if all of the need must be met with generation resources. Since there are non-generation resource options as well as several transmission options that SCE has agreed need to be evaluated, use of such non-generation options should not be foreclosed at this time.

B. Big Creek/Ventura Area

The Big Creek/Ventura need has not been fully established in this phase of the proceeding. SCE pointed out that the CAISO need figure was apparently calculated by taking out existing resources and adding back the exact same amount of capacity from new resources in the same locations, which does not establish the MW of need. Furthermore, this phase has not fully established how any need might be met. Several proposals to meet the identified need through T&D fixes have been proposed and SCE has indicated it intends to study these.

IV. PROCUREMENT OF LCR RESOURCES AND INCORPORATION OF THE PREFERRED LOADING ORDER IN LCR PROCUREMENT

A. Incorporation Of The Preferred Loading Order In LCR Procurement

The Commission's job is to direct SCE to procure resources to meet LCR need subject to four conditions:

1. Minimize cost to ratepayers.
2. Minimize overlap with flexible capacity needs likely to emerge from unfinished renewable integration studies.
3. Look at all alternatives, including transmission and non-generation resources.
4. Take into account the loading order including operational attributes that can be provided from loading order resources, like DR, and reduced need for LCR through load reduction from EE and DG.

The CAISO proposal to meet all of this need through new gas-fired resources does not meet any of these conditions, as discussed above.

B. Other Commission Policies and Consideration Affecting LCR Procurement

As detailed throughout this brief, the key guiding principles should be to minimize costs to ratepayers and conforming procurement to the loading order.

C. If A Need Is Determined, How The Commission Should Direct LCR Need To Be Met

The Commission should direct that the need be met with some flexibility, taking into account the results of an analysis of the benefits and costs of non-fossil generation, non-generation, and transmission alternatives. Such an analysis has not yet been performed.

Based on the record in this proceeding, the CAISO has not considered all alternatives or costs and thus should not be the arbiter of precisely what is needed or how and from where it should be procured. That determination is to be made by this Commission, based on recommendations provided by the entity with the LCR need, Southern California Edison Company, and the full record.

D. Appropriate Method(s) of Procurement

If there is any need for new gas-fired generation, it should be acquired using competitive processes where possible. The Commission should be concerned that while using the cost-of-service approach to procurement at existing OTC sites is an option, it could also be more costly for ratepayers than competitive alternatives, even taking into account effectiveness factors.

E. Timing Of Procurement

1. Start Evaluating Options Now; Consider Procurement Sequentially With Some Up Front if Such Procurement Is Highly Effective and Cost-Effective

The Commission should start evaluating procurement options now, but it should consider sequential procurement. The CAISO's proposal to authorize procurement of gas-fired generation to meet the full need via an RFO during 2013 should be rejected. ISO-Millar, Tr. p. 457. The procurement process should also take into account market power at existing sites.

In contrast to the CAISO's conclusion that gas-fired generation must be used to meet the need and that it must be procured next year, SCE has not asked for the authority to procure that amount of new generation under that time frame.

> *SCE has never said give us the approval to go buy 2400 MW tomorrow; that's never been our case; we do realize that things will change over time; but things get in the way of procuring resources, if we don't start pretty quickly we are going to end up in a situation like 2006 and get a less-than-optimal solution, not lowest cost.*

SCE-Minick, Tr. pp. 942-943.

SCE's testimony made it clear that an evaluation of alternatives will take time and should be followed by an RFO or bilateral negotiations or both. Given that there will be a time lag, the process should be informed by next year's renewable integration studies as results become available.

At the same time, there is a need to look at the ability to improve the performance and flexibility of existing resources when determining incremental need for flexibility. Thus, any procurement should allow for upgrades of existing generation to provide for LCR need as well as additional flexibility to meet renewable integration needs.

The CAISO is worried about uncertainty and the lead-time to get new generation or transmission alternatives built. There are ways of addressing this uncertainty without running the risk of overprocurement. One alternative that should be considered by the Commission is to mitigate this uncertainty by getting plants to the point of construction but only paying for an option to build if necessary. The Commission could authorize development contracts that include permitting and site development but do not include construction, effectively creating an option for expedited development of new generation if and when it is needed.

2. SCE Says Moorpark Procurement Would Be Premature; Delay It Until After Transmission Alternatives Are Explored

SCE's Mr. Minick stated that there were alternatives for Moorpark that were not explored by the CAISO in its analysis. He discussed the fact that the CAISO had not considered generation alternatives other than the two current Mandalay units and did not consider generation amounts at in-between levels or preferred alternatives. SCE-Minick, Tr. pp. 1019-1020. Calpine's testimony presented non-generation alternatives such as changes to the transmission and subtransmission systems. Calpine-2, p. 5 *et seq.* and Tr. 1331-1332. SCE concluded that a decision on Moorpark procurement would be premature in this proceeding. SCE-Minick, Tr. p. 1019. The record supports this conclusion.

V. INCORPORATION OF FLEXIBLE CAPACITY ATTRIBUTES IN LCR PROCUREMENT

A. If A Need Is Determined, Should Flexible Capacity Attributes Be Incorporated Into Procurement

Flexible capacity attributes should be considered, but not as a primary factor as the flexible attributes needed for renewable integration are not yet determined. Procurement of certain resources for LCR and then other resources for renewable integration without taking flexibility into account for both of them would be a very poor strategy from a cost-minimizing perspective.

At the same time, there is a need to look at the ability to improve the performance and flexibility of existing resources when determining incremental need for flexibility. Thus, any procurement should allow for upgrades of existing generation to provide for LCR as well as additional flexibility to meet renewable integration needs.

However, flexibility is not the only consideration. Furthermore, the flexibility requirement will not be determined until the end of Phase 2 of this proceeding. If the Commission believes it must order SCE to procure resources prior to that time for LCR purposes, flexibility should be a consideration but not a requirement until the need is determined. Additionally, it is possible to get more flexibility from existing resources for a price, and therefore upgrades might be more cost-effective than new build. It is also important not to assume that all added resources have to be flexible in the same way.

Moreover, while the loading order is important, the fact is that some preferred resources, like solar PV, can make the flexibility problem worse; this is particularly true when solar PV is installed in a limited geographical area with similar insolation patterns. Thus all of the impacts of loading order resources should also be taken into account.

B. Additional Rules, Not Already Covered By Resource Adequacy (RA) Rules, To Govern LCR Procurement Resources

Not addressed.

VI. COST ALLOCATION MECHANISM (CAM)

A. Proposed Allocation Of Costs Of Needed LCR Resources

CLECA recommends continued use of the CAM to allocate the costs of needed LCR resources. The heightened concern over the growing costs of procurement that increasingly burden ratepayers is shared by bundled and DA customers. CLECA members take both bundled and DA service, so CLECA understands and shares this concern. With the specter of rising procurement costs, all parties, including CLECA, are motivated to seek reasonable reduction of utility procurement costs. We also believe that all parties should bear their fair share of the utility procurement cost burden; this "fair share" concept remains a guiding principle.[12] Indeed, the plain language of Public Utilities Code §365.1(c)(2)(B) states, "*the Commission shall allocate the costs of those generation resources in a manner that is fair and equitable to all customers.*"[13]

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12 *See* D.08-09-012, at 10-11.

13 PU Code §365.1(c)(2)(B).

AReM/DACC/MEA, however, emphasize the statutory language that the Commission ensure generation resources subject to CAM cost allocation "*are needed to meet system or local area reliability needs for the benefit of all customers in the electrical corporation's distribution service territory*."[14] They appear to interpret this as a different "benefit" than the "benefit" in the initial statute and consistently interpreted by numerous Commission decisions.[15]

> *Q So are you effectively saying that only projects used to meet system needs would be eligible?*
>
> *A Unless the local project benefits everyone in the service territory, then it can't be a CAM project if it does not. And it's up to the Commission to determine how to apply that.*[16]

The Assigned Commissioner Ruling included this as an issue, without guaranteeing a specific outcome (*e.g.*, that the CAM would or would not be changed).[17] Critical to this discussion is the indisputable fact that "*the electric grid is interconnected*." SCE-2, Reply Testimony, at 28; *see also* TURN Ex 2, Woodruff, at 3 (*"all share equally in the 'good' of grid reliability.")*. Simply put, maintaining local reliability supports system

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14 Direct Testimony of Mara and Fulmer on behalf of DACC/MEA at 9-10 (*citing* SB 695 and PU Code §365.1(c)(2)(A).

15 *See* D.07-09-044, at 2 (describing the allocation per D.06-07-029 of the capacity benefit as a capacity allotment based on the Load Serving Entities' share of the 12-month service area coincident peak, which is then applicable to the LSE's Resource Adequacy requirement); *see also* D.08-09-012, at 81-82 (discussing the RA credit benefit of the capacity allotment of CAM resources); *see also* D.10-06-018, at 81 Ordering Paragraph 2 (confirming continued application and use of the CAM pending consideration of potential modifications).

16 Tr. p. 1182, DACC/AReM/MEA – Mara.

17 *See* Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge, dated May 17, 2012, at 6.

reliability; all bundled, DA and CCA customers in the service territory benefit from that reliability in interconnected and intangible ways.

As such, the Commission should not change its adopted use of CAM to allocate LCR costs to all benefitting customers, nor should the Commission change its calculation of the CAM or distribution of RA credits; this distribution of benefit is in conjunction with allocation of net capacity costs.[18] The Commission's discussion of the RA credit benefits has not changed over time or since the passage of SB 695. Indeed, D.11-05-005 explicitly confirmed that the Commission's adopted definition of benefitting customer conformed with SB 695. *See* D.11-05-005, at 18, FOF 7. Moreover, D.11-05-005 explicitly addressed the question of benefits: "*The question arises whether this language [in SB 695] is consistent with our prior determinations*." D.11-05-005, at 8. ***"[O]ur prior determinations in D.08-09-012 on customers subject to the nonbypassable charge and the CAM process do not need to be revisited."*** *Id.*, emphasis added.

While D.11-05-005 did pose the question of whether a test of who benefits should be constructed under SB 695, it also clearly decided that "*The Commission's definitions of "benefitting customer" in D.06-07-029 and D.07-11-051, as clarified in D.08-09-012, are consistent with SB 695*." Therefore the Commission has concluded as a matter of law that it does not need to be modified. D.11-0-005, at 18-19, COL 2.

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18 Decision 08-09-012 described the process as follows: "*By D.06-07-029, the IOUs are allowed to recover new generation power purchase agreement (PPA) net costs of capacity (total cost less revenues achieved through an energy auction process) from all benefitting customers in the IOUs' service territories. Customers subject to the D.06-07-029 NBC would be allocated resource adequacy (RA) credits for use in satisfying certain Commission RA requirements*." D.08-09-012, at 5.

B. Should CAM Be Modified At This Time?

No. DACC/AReM/MEA argue that the CAM calculation should be revised in such a way that leads to a lower CAM charge for DA and CCA customers. CLECA joins TURN, PG&E and SCE in opposing this proposal. The criticisms of these parties are founded in the one-sided nature of the proposed changes, the lack of a statutory basis for a cap on CAM costs and the limited market for ancillary services. *See* SCE-2, Reply Testimony, at 32-36; *see also* PG&E-1, Reply Testimony, at 8-9; *see also* TURN Ex 2, Woodruff, Reply Testimony, at 7-13. These criticisms seem well-founded to CLECA. TURN's proposed solution, *"subtract the revenues earned by the CAM resource from the costs of the resource"* seems reasonable. TURN Ex 2, at 13.

C. Should Load Serving Entities (LSEs) Be Able To Opt Out Of CAM?

AReM/DACC/MEA question the "benefits" for DA and CCA customers of procurement of reliability resources and argue that DA and CCA customers should be able to opt out of the CAM. PG&E testified that the proposed opt-out would be complicated, administratively burdensome, and unfair to bundled customers. PG&E-1, Reply Testimony, at 11-13. TURN also noted it would unreasonably burden bundled ratepayers. TURN Ex 2, Woodruff, Reply Testimony, at 8. SCE challenged the legality of the proposed opt-out, in addition to raising concerns regarding equity, implementation difficulties and inconsistent contract terms for LSE's opting out (5 years). SCE-2, Reply Testimony, at 38-41. These concerns are not obviated by the AReM/DACC/MEA proposal in this proceeding. While CLECA has supported and continues to support the concept of an opt-out, CLECA does not support the opt-out proposal by AReM/DACC/MEA here.

VII. OTHER ISSUES

A. SCE Capital Structure Proposal

Not addressed.

B. Coordination of Overlapping Issues Between R.12-03-014 (LTPP), R.11-10-023 (RA), And A.11-05-023

Not addressed.

C. SCE Statewide Cost Allocation Proposal

CLECA recommends that cost and cost-effectiveness be primary considerations in determining which resources should be added and that they should only be added for appropriate LCR needs. It is thus premature to address the matter raised by SCE that if it pays a premium for loading order resources, customers other than its own should pay for this additional cost. Furthermore, this is not a matter exclusive to SCE. The Commission should apply such considerations to its need determination for all utilities.

D. CAISO Backstop Procurement Authority To Avoid Violating Federal Reliability Requirements

As detailed above, CLECA disagrees with the CAISO's conservative position regarding backstop procurement authority. "Reliability at any cost" is not just or reasonable, nor is it in either the ratepayer's interest or the public's interest. As addressed earlier in this brief, we do not believe a violation of federal reliability standards would necessarily result from not having CAISO backstop procurement authority

E. Energy Storage

To the best of our knowledge, there is nothing in the record that demonstrates the cost-effectiveness of energy storage as a reasonable option to meet LCR need. We have the impression that these technologies are simply currently too expensive; if, however, energy storage were to become demonstrably cost-competitive, and if claimed benefits can be audited, it should be considered as an option in the future. It must be recognized that attributes can vary by technology.

VIII. CONCLUSION

For all of the foregoing reasons, CLECA respectfully recommends that the Commission reject the CAISO recommendation to authorize procurement in 2013 of gas-fired resources to meet what it perceives as the LCR need. The CAISO has neither an obligation nor the explicit authority to determine whether the costs of its proposals are just and reasonable from a ratepayer perspective. Yet customers, not the CAISO, pay the bills for additional generation and transmission to meet the CAISO's more stringent standards. Moreover, the CAISO has not considered all the alternatives in its proposal to use its more stringent standard than the NERC Reliability Standards adopted by FERC, nor has CAISO considered the costs. In terms of this Commission's duty to set "just and reasonable rates," the CAISO's overly conservative position that LCR needs should be met solely through new gas-fired generation, regardless of cost is very troubling and should be carefully weighed in the balancing of costs and reliability.

The Commission should thus phase procurement authorization, emphasizing cost-effective resource additions; unlike the CAISO, the Commission must consider cost in its determination of need for LCR resources. Also, the Commission should continue to use the CAM to allocate the costs of the LCR procurement.

Respectfully submitted,

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