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)

TRACK III COMMENTS OF THE ALLIANCE FOR RETAIL ENERGY MARKETS AND THE DIRECT ACCESS CUSTOMER COALITION

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In accordance with the directives provided in the March 21, 2013, Administrative Law Judge's Ruling Seeking Comment on Track III Rules Issues ("Ruling") and the ruling issued by Administrative Law Judge David M. Gamson on March 28, 2013 by electronic mail setting this date for filing comments, the Alliance for Retail Energy Markets[1] ("AReM") and the Direct Access Customer Coalition[2] ("DACC") respectfully submit these joint comments on Track III issues.

I. Executive Summary

AReM and DACC recommend as follows:

- As part of their bundled procurement planning, the investor-owned utilities ("IOUs") should be obligated to forecast departing load for direct access ("DA") and community choice aggregation ("CCA") customers with all such forecast load exempt from non-

[1] AReM is a California non-profit mutual benefit corporation formed by electric service providers that are active in the California's direct access ("DA") market. This filing represents the position of AReM, but not necessarily that of a particular member or any affiliates of its members with respect to the issues addressed herein.

[2] DACC is a regulatory alliance of educational, commercial, industrial and governmental customers who have opted for direct access to meet some or all of their electricity needs. In the aggregate, DACC member companies represent over 1,900 MW of demand that is met by both direct access and bundled utility service and about 11,500 GWH of statewide annual usage.

bypassable charges ("NBCs"), just as forecast municipal departing load ("MDL") is exempt today.

- The Cost Allocation Mechanism ("CAM") may not be applied to any IOU procurement of resources needed to meet bundled load.
- Any procurement authorized in other Tracks of the Long-Term Procurement Plans ("LTPP") proceeding, which is used to meet bundled load requirements, either in total or in part, does not confer any automatic CAM treatment, and will be governed by the Commission's decision on these issues in this Track 3 proceeding.
- This proceeding should become the venue for addressing how non-IOU load-serving entities ("LSE") will be given an opportunity to fulfill System or Local reliability needs and avoid CAM procurement by the IOUs. This LSE Self Fulfillment Option would both reduce the need for CAM and encourage investment by non-IOU LSEs.
- The Commission should refine the current guidelines and requirements for the energy auctions and the proxy calculation used when there is no auction because they rely on the short-term value of energy to produce an imputed capacity value from a long-term contract price, which can create results that may not accurately reflect the value of the energy associated with the PPA, causing the net capacity costs to be higher than they should be.
- AReM and DACC recommend that the Commission direct the staff to conduct workshops with the goal of evaluating alternative proposals to address each of these issues, understand the differences in parties' positions, and work out details. Each of

these recommendations is explained in more detail below in response to the applicable question.

II. Comments on Track III issues

The Ruling directed that parties could file comments on a series of Track III issues. In the following, AReM and DACC respond to some, but not all of the questions. As a result, the numbering below is not sequential. Additional issues may be addressed in reply comments that are due on May 10, 2013.

1. Maximum and minimum limits on IOU forward purchasing of energy, capacity, fuel, and hedges

a. Should the Commission modify the Assembly Bill (AB) 57 bundled procurement guidelines to indicate minimum and maximum limits for which the three IOUs must procure for future years? If so, should these minimum and maximum limits address energy, system resource adequacy (RA), local RA, and/or flexibility?

Yes. In particular, the Commission should establish <u>minimum</u> limits for IOU procurement to comply with the requirements of AB 57[3] to procure energy, capacity and reserves sufficient to serve their bundled loads over the long term. As the Commission has previously determined and is detailed below, AB 57 reaffirmed the IOUs' statutory obligation to serve their bundled customers over the long term, required the IOUs to submit bundled procurement plans, and established requirements for those bundled plans that the Commission must enforce on the IOUs. IOU procurement to meet their bundled load requirements is not subject to the cost allocation mechanism ("CAM").

While there is no approved compendium of "AB 57 bundled procurement guidelines," previous decisions set forth the Commission's evaluation of AB 57 requirements and how they should be applied to the IOUs, as follows:

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[3] Stats 2002, Ch 835.

- AB 57 and other state statutes impose an obligation on the IOUs to serve their bundled customers.[4]
- The IOUs' obligation to serve includes procurement to meet reserve requirements.[5]
- The "obligation to serve" and AB 57 require the IOUs to procure long term.[6]
- The approved AB 57 plan must "enable the utility to fulfill its obligation to serve its customers,"[7] which would include meeting the customers' long-term needs.
- AB 57, as codified in Public Utilities ("P.U.) Code Section 454.5, requires each IOU to prepare and file a procurement plan that meets "specified requirements,"[8] which include a "diversified portfolio" of "both short-term and long-term electricity-related products."[9]
- AB 57 procurement plans have previously included authorization to procure long term to meet the needs of bundled load.[10]

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[4] D.02-10-062, Conclusion of Law No. 2: "Consistent with Pub. Util. Code Sections 451, 761, 762, 768, 770 and proposed 454.5(a), the utilities have an obligation to serve." D.04-01-050, pp. 93-94: "The utilities themselves are the ones responsible and accountable for meeting the loads and energy requirements of the customers in their service areas."

[5] D.02-10-062, Finding of Fact No. 19: "It is reasonable to require the utilities to meet a reserve requirement, as part and parcel of their obligation to serve."

[6] D.02-10-062, p. 14, referring to Section 454.5(a), which was added by AB 57: "[A]s required by Section 454.5(a), we adopt herein each of the utilities' plans, as modified by this decision and the utilities' more recent filings. … While we recognize the urgency of having a procurement plan in place by January, we also understand the importance of beginning longer-term (up to 20-year) resource planning now. Therefore, we adopt an ongoing two-part procurement planning process to cover short-term and long-term needs, as detailed further in this decision."

[7] D.04-01-050, p. 9.

[8] D.04-01-050, p. 8.

[9] D.04-01-050, footnote 8, p. 8.

[10] D.04-12-048, p. 5: "In summary, that is the purpose of this decision: to give the three IOUs authorization to plan for and procure the resources necessary to provide reliable service to their customer loads for the planning period 2005 through 2014." And, p. 107: "It is reasonable to extend the IOUs' procurement authority on a rolling 10-year basis, given that the long-term procurement plans cover a ten-year period and they will be updated and reviewed every two years. We will diligently oversee how the utilities are using this authority. Therefore we authorize the utilities to enter into short-term, mid-term, and long-term contracts, with contract delivery start dates through 2014, provided that the IOUs submit the necessary compliance filings." See also, Ordering Paragraph No. 14.

As indicated above, the Commission's determinations are clear that AB 57 and related statutes require the IOUs to procure long term to meet their bundled customer loads. However, since the time of these seminal decisions, the IOUs' planning process pursuant to the AB 57 requirements has been bifurcated into "system/local" and "bundled" plans.[11] In fact, AB 57 contains no requirement for such bifurcation. While "system plans" can certainly be pursued by the IOUs and the Commission, "system plans" cannot replace or supersede the IOUs' obligation to prepare and seek approval for a bundled plan that includes long-term procurement.

Moreover, in the previous LTPP Rulemaking ("R.") 10-05-006, the Scoping Memo, at the IOUs' behest, restricted their bundled procurement plans to consideration of short-term and medium-term options only.[12] The ruling stated that the restriction was necessary to "reach a decision in a timely fashion."[13] While this was perhaps an expedient element for that round of the LTPP, that shorter-term focus for bundled procurement plans is not a restriction imposed by AB 57 requirements. Nevertheless, the bifurcation of system/local requirements and bundled procurement has made it all too easy for the IOUs to claim that all long-term procurement must be addressed only *outside* of the IOUs' bundled plans, and that everything approved in the system/local tracks meets reliability needs and is therefore subject to CAM. However, as explained throughout these comments, the statutory framework for CAM simply does not permit the Commission to endorse this overly simplistic interpretation.

In addition, bundled procurement needs include meeting bundled load growth and required reserves, as well as procurement to replace expiring contracts, retiring power plants, and

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[11] The first such bifurcation we could find appears in R.10-05-006, pp. 2 and 9.

[12] Scoping Memo, R.10-05-006, January 3, 2011, p. 3: Track II Bundled Procurement should "focus solely on the "short-to-medium term operational needs of the utilities, and should not result in construction of new generation facilities."

[13] Scoping Memo, R.10-05-006, January 3, 2011, p. 1. At the same time, R.10-05-006, pp. 2-3, stated that the Commission intended that the bundled plan be informed by the results of the system planning effort.[13]

bundled peak load requirements. Bundled load growth is driving the need for new generation[14] in California and the long-standing principle of cost causation[15] requires that bundled load should therefore be responsible for the associated costs and new generation required to serve it. The Commission expressed concern in Decision ("D.") 07-05-052 that the CAM might be used "inappropriately" because the new resources were actually needed to meet bundled load.[16]

Put simply, AB 57 and proper application of cost causation principles dictates that approved bundled procurement plans include minimum limits for procurement to meet the IOUs' bundled load long term, including procurement of new generation needed to meet bundled peak load growth, to replace expiring power contracts or retiring power plants, and to fulfill associated flexibility requirements. As the Commission has previously noted, under P.U. Code Section 454.5, the IOUs are not free to procure whatever they choose and the Commission would be abdicating its responsibility under the law if it allowed that to happen.[17] Track 3 of this proceeding provides the opportunity for the Commission to address IOU bundled procurement plans to meet these statutory and Commission requirements. A necessary first step would be for the Commission to recognize that the longer-term commitments for new and/or repowered generation or other supply that it requires of the IOUs through the now separate system/local tracks of LTPP are not and should not be exempt from being categorized as intended to meet the IOUs' bundled load.

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[14] This issue arose as early as R.06-02-013. See D.07-05-052, p. 117, citing AReM's testimony, which referred to Southern California Edison's filed procurement plan: *Southern California Edison's 2006 Procurement Plan, Volume 1A (Public Version)*, December 11, 2006, at pp. 22-23.

[15] In R.12-06-013, the Commission is examining the IOUs' residential rate structure. The Rulemaking states: "Developing equitable rates based on the principle of cost causation is one of the underlying goals of the Commission's ratemaking process." (p. 13, issued June 28, 2012)

[16] D.07-12-052, p. 118.

[17] D.12-01-033, pp. 10-11.

b. **How may the Commission best balance issues regarding departing load in any future requirements for procurement?**

The Commission has repeatedly affirmed the benefits of the competitive retail market in California, while acknowledging that non-bypassable charges ('NBCs"), be they stranded costs or CAM, harm that market.[18] In fact, the Commission has in the past limited application of certain NBCs over the objections of IOUs.

For example, the Commission determined that the Cost Responsibility Surcharge ("CRS"), which recovers the above-market costs of the power contracts entered into by the California Department of Water Resources during the Energy Crisis, would <u>not apply</u> to direct access customers who were served solely by electric service providers ("ESPs") (*i.e.,* continuous DA customers). In making this determination, the Commission also rejected the IOUs' claims that the CRS should apply to all customers because indirect societal benefits of the procurement accrue to all.[19]

Another active area of Commission inquiry has been addressing the accuracy of the IOUs' long-term load forecasts and the significant role that such forecasts play in IOU bundled procurement and creation – or avoidance – of NBCs for departing load. An extensive discussion of this topic appears in D.08-09-012.[20] In that decision, the Commission established two pivotal rules:

[18] See, for example, D.06-07-029 on CAM, pp. 24-25 and D.02-07-032 on the Cost Responsibility Surcharge, p. 110: "Yet, we have also set forth our policy in D.02-03-055 that there is value in maintaining the DA market. To guard against DA contracts becoming uneconomic, we stated in D.02-07-032 that "there should be a cap on the total surcharge levels imposed on DA customers (including the impact of any changes to PX credits)."

[19] See, D.02-11-052, p. 57: "Attempting to assign a charge to DA customers *based solely on indirect societal benefits* would be arbitrary and speculative. Moreover, it would be *unfairly discriminatory* to assess a uniform bond charge among DA customers when some of them had actually consumed DWR power *while others had consumed none.*"(Emphasis added.)

[20] D.08-09-012, pp. 11-36.

> [W]hen costs are incurred on its behalf, that customer must pay its fair share of the costs, and the corollary rule: if no costs are incurred on its behalf, then the customer's fair share can be determined to be zero.[21]

The Commission then applied the rule in the proceeding and determined that municipal departing load ("MDL") and customer generation departing load ("CGDL") should not be responsible for any NBCs, including stranded costs (pursuant to D.04-12-048) or CAM (pursuant to D.06-07-029), because their associated loads were excluded from the load forecasts used as the basis for the IOUs' long-term procurement plans:

> Such departing loads have been forecasted and are not included in the load forecasts used in determining the need for those resources. Those resources are therefore not procured on behalf of these departing load customers for any time period and their fair share of the costs should be zero. (Emphasis added.)[22]

The Commission further determined that there was no cost shifting associated with this approach:

> Also, since there are no resources or associated costs in the forecast year related to the load departing in that year, there is no cost shifting to bundled customers when these departing customers leave. (Emphasis added).[23]

This same approach should be applied to DA and CCA departing load. The IOUs, with information provided by the California Energy Commission ("CEC"), should be required to estimate reasonable levels of expected DA/CCA departing load over the 10-year term of the bundled plans. The IOUs should then exclude this load from their future resource plans and procurement activities. Having been excluded from the planning scenarios, the forecasted

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[21] D.08-09-012, Finding of Fact No. 3, p. 95.

[22] D.08-09-012, p. 23. See also, D.08-09-012, Conclusion of Law No. 3, p. 104: " Imposition of the D.04-12-048 and D.06-07-029 NBCs is not necessary or appropriate for MDL or CGDL customers, since MDL and CGDL is factored into … the CEC load forecasts for the IOUs … and therefore the fair share of these customers should be zero upon departure."; and Ordering Paragraph No. 2, p. 107: "[B]ecause … CGDL and MDL are excluded, as classes, from the adopted load forecasts on which … LTPPs are based, CGDL and MDL customers are excluded from having to pay the D.04-12-048 and D.06-07-029 NBCs, including any above market costs related to RPS contracts ..."

[23] D.08-09-012, pp. 24-25.

departing DA and CCA load would not be subject to any NBCs, either stranded costs or CAM,[24] for procurement costs incurred by the IOUs after approval of the bundled plans. This elegant solution would both mitigate the competitive harm created by NBCs and promote retail markets. In fact, the Commission previously suggested a similar approach for CCAs in its post-AB 57 decision adopting the IOUs' long-term LTPPs in R.04-04-003.[25]

AReM and DACC recommend that the Commission order a workshop in which staff facilitates a discussion among the IOUs and other interested parties to develop the details of this approach and submit their recommendations to the Commission for approval in this proceeding.

3. Long-term contract solicitation rules

a. Should the Commission adopt a rule that explicitly indicates that existing power plants may bid upgrades or repowers into new-generation RFOs?

iv. How should cost allocation issues be addressed?

LSEs are responsible for meeting their own customers' loads.[26] As a consequence, LSEs must continually seek new procurement contracts to serve their customers' load and replacement contracts for expiring contracts or retiring power plants. If an IOU has a power plant under contract to serve its bundled load, cost causation principles dictate that the associated costs must be recovered from those bundled customers. Likewise, the costs of any replacement contracts or other contract modifications should be borne by those same bundled customers presuming that the IOUs' forecasted bundled load (exclusive of DA or CCA load) warrants replacement. While

[24] Stranded costs are currently "vintaged" so that customers only pay for the procurement costs incurred before departure. CAM is not vintaged and applies to all DA load.

[25] D.04-12-048, Ordering Paragraph No. 9, p. 239. See also, discussion on pp. 53-55 of the decision: "We hereby direct the IOUs, along with interested CCAs, to develop such an agreement. The agreement should specify a date at which the IOU's planning responsibility for the CCA load terminates and the CCA will be responsible for this function, so that the CCA's customers will not bear the stranded costs responsibility for utility procurements entered into after the agreed upon date." (p. 55)

[26] D.04-01-050, Ordering Paragraph No. 2, p. 199.

this procurement may take place by allowing upgrades or repowers to bid in what have recently become the new generation RFOs conducted as part of the system/local tracks, there is no rational basis for seeking subsidies from non-bundled customers for such procurement through application of the CAM. As detailed above, AB 57 requires the IOUs to procure to meet bundled load long term and does not provide any authority for the IOUs or the Commission to sidestep this requirement, nor should the Commission allow the fact that a particular procurement authorization is granted through the system/local procurement decisions create an automatic CAM designation for such authorizations.

Furthermore, these questions implicate issues pertaining to stranded costs and not solely the CAM. As noted in the petition for a rulemaking that is currently pending before the Commission:

> The initial concept of recovery of "stranded costs" by the IOUs originated in Assembly Bill 1890, the electricity restructuring bill enacted in 1996. The Legislature intended that most of the stranded costs were to be recovered by December 31, 2001[fn] or foregone by the IOUs. Nevertheless, subsequent Commission decisions, beginning with Decision ("D.") 08-09-012, [fn] have vastly expanded the types of costs that could be considered to be "stranded" and recovered from departing load customers beyond what AB 1890 contemplated. As a consequence, significant stranded cost charges continue to this day and burden the customers (even those who departed IOU service since the beginning of DA back in 1998) who do not receive generation service from the IOUs and the CCA and DA providers which serve them. Petitioners are concerned that the same interminable fees will be imposed on their customers for unspecified durations.[27]

Many of the existing gas-fired plants and plants for which repowering is an option under consideration have been included in the stranded cost charges that have been imposed on

[27] November 30, 2012, Petition To Adopt, Amend, Or Repeal A Regulation Pursuant To Pub. Util. Code § 1708.5 Of Marin Energy Authority, Alliance For Retail Energy Markets, City And County Of Santa Cruz, Climate Protection Campaign, Constellation NewEnergy, Inc., Direct Access Customer Coalition, Direct Energy, LLC, Energy Users Forum, IGS Energy, Retail Energy Supply Association, Sam's West, Inc., Shell Energy North America (Us), L.P., South San Joaquin Irrigation District, Texas Retail Energy, LLC, And Wal-Mart Stores, Inc. ("Petition"), at pp. 10-11.

departing load customers for over fifteen years. Making the replacements to or the repowered versions of these plants now subject to CAM would be blatantly unfair, particularly if the energy is needed to meet bundled load. The Commission should insist that the costs of all such upgrades and repowerings are to be recovered solely from the bundled load customers who require these plants to serve their load.

5. Changes to the Commission's adopted Cost Allocation Mechanism (CAM) per Senate Bill (SB) 695, SB 790, Decision 11-05-005 and relevant previous decisions.

a. Is the CAM currently implemented in a manner that is sufficiently transparent or least cost?

No. The CAM process is both unclear and opaque, especially to the retail choice customers that must pay the CAM charges and the ESPs that supply their power and must accept the allocations of net capacity that CAM creates. This is due to several reasons. First, there is no process for distinguishing between system and bundled resource needs, which the Commission previously identified as a critical gap that could lead to DA/CCA customers subsidizing bundled customers.[28] Neither is there a realistic test to determine "who benefits" from IOU procurement, as required under SB 695 in order for CAM to be used at all. Under current practice, the utilities make vague pronouncements to the effect that "everyone benefits" from their procurement activities and a share of costs is then ladled out to DA and CCA customers who have no idea as to the validity or reasonableness of the charges. This approach has consistently failed to acknowledge that DA and CCA customers, whose energy needs are being met by another

[28] OIR, R.08-02-007, February 14, 2008, Attachment A, Preliminary Scoping Memo, pp. A-27-A-28: " In D.07-12-052, we acknowledged comments from parties identifying gaps in the Commissions' rules with regard to the extent to which IOUs can elect the cost allocation mechanism (CAM) for new generation. The Commission heard at least two major concerns in the absence of a standard methodology or consistent practices for identifying system vs. bundled resource needs. … In other words, energy service provider (ESP) load may grow at a different rate than bundled load and there should not be a cross-subsidy between the two." (p. A-27)

supplier from whom they are legally entitled to take service, most certainly receive no benefit from duplicative IOU procurement.[29]

Unfortunately, the existing CAM Group process is simply not structured to provide meaningful guidance in this regard. Pursuant to D.07-12-052, the Commission established the CAM Groups for each utility as an adjunct to the existing Procurement Review Group ("PRG") process, whereby utility procurement for which the utility intends to seek CAM treatment is reviewed by the CAM Group, which consists of a few DA and/or CCA representatives in addition to the full PRG Group.[30] However, the CAM Group has no ability to oppose or reject the utility's proposed CAM application, and strict confidentiality requirements preclude them from sharing any insights they gain from their participation with similarly-situated DA or CCA customers.

One potential solution would be to give the PRG and the CAM Group greater authority to reject utility procurement that, in their opinion, is not economic or that does not represent the least-cost option for all ratepayers. Such an approach, if properly implemented, could lead to overall lower costs by imposing additional discipline on utility procurement. AB 57 has led to a system where utility prudence reviews, which used to discipline utility procurement, are a thing of the past. However, giving the PRG and CAM Groups the right to reject uneconomic deals and to require that certain least-cost standards be met could provide another form of procurement discipline that is sorely needed.

Furthermore, there needs to be far more rigor with regard to providing directives to the IOUs as to what they can procure under their respective procurement plans. For example, as

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[29] While CAM procurement provides an allocation of RA to the DA/CCA customers, this "RA credit" is neither desired nor desirable because it severely limits the DA/CCA customers' ability to choose own RA supply portfolio.

[30] D.07-12-052, Ordering Paragraph No. 8, p. 301.

discussed above, the Commission needs to emphasize that the IOUs should only plan to procure for their bundled load and not to procure on behalf of other LSE's. Step two of the Track III process directs that, "the Commission will require the IOU to file <u>bundled</u> procurement plans."[31] IOUs are not required to file "CAM procurement plans." By making it expressly clear to the utilities that they are to reasonably forecast bundled load and anticipated departing load and to plan for serving solely the former, the Commission would go a long way towards eliminating this constant discussion about CAM and when or if it should be applied.

b. Should the Commission reform the CAM energy auctions? If so, how?

Allocation of net capacity costs and benefits to "benefiting customers" was first approved in D.06-07-029. In this Decision, the Commission determined that benefiting customers would pay for the net cost of capacity defined as "a net of the total cost of the contract minus the energy revenues associated with dispatch of the contract."[32] The Commission found that "the energy and capacity from any new resources should be unbundled, with the costs and benefits of the RA capacity component socialized to all customers connected to the utility's distribution system, and the costs and benefits of the energy component assigned to those that value the energy the most, as demonstrated through an auction or similar mechanism."[33] This policy decision resulted in D.07-09-044, which established the energy auctions underlying the CAM charge.

In Track 1 of this LTPP, AReM, DACC and the Marin Energy Authority ("MEA") (filing jointly) and San Diego Gas and Electric ("SDG&E") both filed testimonies raising concerns and suggesting potential improvements with how the net capacity costs should be calculated, whether through the energy auctions or through the proxy calculation when there is no auction. While

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[31] *Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge*, R.12-03-014, May 17, 2012, p. 11 (emphasis added).

[32] D.06-07-029, p. 26.

[33] D.06-07-029, p. 31.

D.13-02-015 specifically rejected AReM's recommendations with respect to the improvements to the calculations of the net capacity costs, it further stated:

> We have stated an openness to revisit the energy auction mechanism adopted in D.07-09-044. [fn] Toward that end, we appreciate the suggestions from parties in the current proceeding to consider improvements toward the current auction mechanism structure, including valuing net capacity costs. The record, however, fails to provide an adequate basis upon which to comprehensively consider and adopt any potential changes to the auction mechanism. We may consider taking a more focused look at these issues in the future.[34]

AReM and DACC's fundamental concern with the energy auction and the proxy calculation used when there is no auction is that they rely on the short-term value of energy to produce an imputed capacity value from a long-term contract price. By design, the imputed capacity value will be inversely related to energy price. When examined in the short term, this can create results that may not accurately reflect the value of the energy associated with the PPA, with the result that the net capacity costs are higher than they should be. In the event that limited capacity is available, the costs of the PPA will likely be high; the energy value of the output from that PPA should reflect the higher value of that output, so that the net capacity costs are calculated more accurately. This is not the case under the current CAM methodology.

D.07-09-044 requires that the back-to-back toll product available for the energy auction be limited to a term not to exceed five years.[35] AReM and DACC believe that the Commission should consider modifying this restriction to allow the auction products of a longer duration. Furthermore, the Commission should consider implementing a longer minimum term (currently at one year). Longer-term tolling products would better reflect the incremental hedging value of the PPA.

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[34] D.13-02-015, p. 110

[35] D.07-09-044, Appendix A, p. 5.

AReM and DACC recommend that the Commission convene a workshop of interested parties for the purpose of determining if different term requirements are appropriate and developing modifications to the auctions so that they might result in better, more accurate results regarding the determination of capacity values. The goal of the workshop would be to refine the current guidelines and requirements for the energy auctions (or develop new ones) that would improve the product definitions so that the full value of energy and other products is netted from the contract price to calculate the net capacity cost.

Second, AReM and DACC believe that Joint Parties' Proposal, used when there is no energy auction, should be reexamined so that the full value of energy and other products is netted from the contract price. In particular, the calculation of the value of products and services that the plant may provide should consider expected revenues from not only the long-term value of the energy, but also from all applicable ancillary services products in the markets operated by the California Independent System Operator ("CAISO"), the imputed value derived from the use of the plant for self-provision of ancillary services by the IOU (if applicable and then at the value of the CAISO products), and the revenues expected from any additional products that become available. However, the Joint Parties' Proposal in current use includes only one ancillary service, non-spinning reserves. All four currently-traded ancillary services, plus consideration of additional products when they become available, such as flexible capacity and renewable integration value, should be considered in any proxy calculation. As noted above, AReM and DACC recommend that a workshop be held to consider such modifications to the Joint Parties Proposal currently in use.

The energy auction methodology for calculating the net capacity cost of a resource does not solely apply to utility PPAs. SB 695 added sections to the P.U. Code that state that net capacity costs can, upon approval by the Commission, be calculated for UOG resources. The statute says to determine net capacity costs "by subtracting the energy and ancillary services value of the resource from the total costs paid by the electrical corporation pursuant to a contract with a third party or the annual revenue requirement for the resource if the electrical corporation directly owns the resource."[36] In the Commission's interpretation of this provision, it is important that the annual revenue requirement associated with UOG be analogous to the total costs paid by the electrical corporation associated with a PPA.

As noted in their testimony in Track I of this proceeding, AReM and DACC's concern with using the annual revenue requirement is that the imputed capacity costs of a utility-owned generating asset changes over time as the plant is depreciated.[37] In the early years of a UOG plant's life, the revenue requirement associated with capital costs is higher, while in latter years it is lower. While this makes accounting sense, directly using this changing revenue requirement distorts the imputed value of the plant's capacity as defined by the proxy calculation. A plant's depreciation schedule should not impact the value of the capacity it is providing. Given a typical depreciation schedule, during the early years of a plant's life the residual capacity value (and hence associated CAM charge) would be skewed high while during the later years it would be skewed low.

In Track 1 of this proceeding, AReM and DACC recommended levelizing the plant's fixed revenue requirement.[38] While this solution was rejected in D.13-02-015, it is undoubtedly not the only way to address the issue. As such, AReM recommends that the workshop recommended above also consider whether the dramatically changing cost of UOG resources

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[36] P.U. Code Section 365.1 (c) (2) (C).

[37] LTPP Track 1 Testimony of AReM, DACC and the MEA, R.12-03-014, June 25, 2012. pp. 44-47.

[38] LTPP Track 1 Testimony of AReM, DACC and the MEA, R.12-03-014, June 25, 2012. P. 46.

creates inequities between bundled and departing load customers and if so, how they could be addressed.

c. How does the capacity allocation interact with other allocated costs such as energy efficiency and demand response funding?

It is not clear to AReM and DACC that there is any particular interaction *per se* between the capacity allocation associated with the CAM and the cost allocation of other utility costs such as energy efficiency and demand response.

However, AReM and DACC do have a significant concern that all ratepayers, including DA and CCA customers who must pay for CAM projects, energy efficiency and demand response programs, are being double charged when utility procurement authorizations are predicated upon forecasts that presume energy efficiency and demand response will not make the expected contribution to load reductions. In short, for customers to pay for a certain level of energy efficiency and demand response, only to have the load forecasts upon which traditional generation procurement is based omit or discount those contributions to load reductions, is tantamount to double-charging. Moreover, there is no better way to ensure the failure of energy efficiency and demand response than by explicitly stating that you expect the programs to fall short in terms of delivering what is being paid for.

To remedy this problem, one of two things needs to happen. Quit paying for energy efficiency and demand response that is not performing, or ensure that what you are paying for actually performs. In either event, the forecasts that dictate the level of needed generation should be based on inclusion of precisely the amount of energy efficiency and demand response that is being paid for – not more and not less.

It is time that this Commission policy, which reflects applicable state law, is reflected in the LTPP process and made a fundamental element of the procurement forecast process. By consistently under-estimating anticipated energy efficiency and demand response, the utilities are exacerbating the CAM issue and increasing costs for all the state's ratepayers.

d. At what stage in procurement should procurement be deemed CAM eligible, and what criteria should govern Commission decision regarding CAM allocation?

AReM, DACC and MEA provided joint testimony in Track 1 in this proceeding proposing criteria for approval of CAM projects and a process for determining when CAM should apply to a particular project that complied with statutory and Commission requirements.[39] The proposed criteria and process were rejected in the Track 1 decision, because the Commission found that they failed to improve upon the "fairness" of the current allocation method.[40] No other party proposed a set of comparable criteria to govern Commission decisions approving CAM treatment. Instead, the IOUs supported, and the Commission has to date endorsed, a simplistic approach for such determinations, *i.e.*, "All IOU Procurement Is CAM Procurement," as discussed in the AReM, DACC and MEA Opening Brief in Track 1.[41] In fact, the relevant statutes do not support the notion that "all IOU procurement is CAM procurement." SB 695 and SB 790 could have said just that, but they did not. Moreover, the Commission previously determined in D.11-05-005 that SB 695 required adoption of criteria[42] or a "benefits test" to ensure compliance with the statute.[43]

While the statutes say, in summary, "all who benefit must pay," this cannot be read in isolation. The reality is that any new generation project or upgrade brings reliability benefits to the grid. But that does not mean that customers who are served by non-IOU suppliers benefit

[39] LTPP Track 1 Testimony of AReM, DACC and the MEA, R.12-03-014, June 25, 2012. pp. 30-34.

[40] D.12-03-015, p. 107.

[41] LTPP Track 1 Reply Testimony of AReM, DACC and the MEA R.12-03-014, July 23, 2012, pp. 3-7.

[42] D.11-05-005, p. 7.

[43] D.11-05-005, p. 16.

from the procurement by the IOU when that customer's own supplier has already complied with all existing procurement requirements. Indeed, that customer most certainly receives no benefit from the IOU's duplicative procurement. In short, the fact that a project contracted for or built by the IOUs improves reliability does not and should not mean that all customers benefit from it, any more than utility customers would (or should) be considered to benefit from projects brought on line by an ESP or CCA. In fact, as noted above, the Commission has previously determined that existence of indirect societal benefits alone is insufficient rationale for allocating costs to all who benefit and may be unfairly discriminatory.[44]

Indeed, the Commission has acknowledged the anticompetitive effects of CAM.[45] With virtually no exceptions, ESPs have met all of the Commission's requirements for LSEs, including resource adequacy ("RA"), renewable portfolio standards ("RPS") and greenhouse gas ("GHG"). Yet, CAM authorizations continue unabated. This is a fundamental issue of fairness in competitive markets where additional cost is imposed on some players, without satisfying any of their needs. Over time, indiscriminate application of the CAM will simply make DA a mirror image of bundled service and therefore meaningless as a competitive alternative.

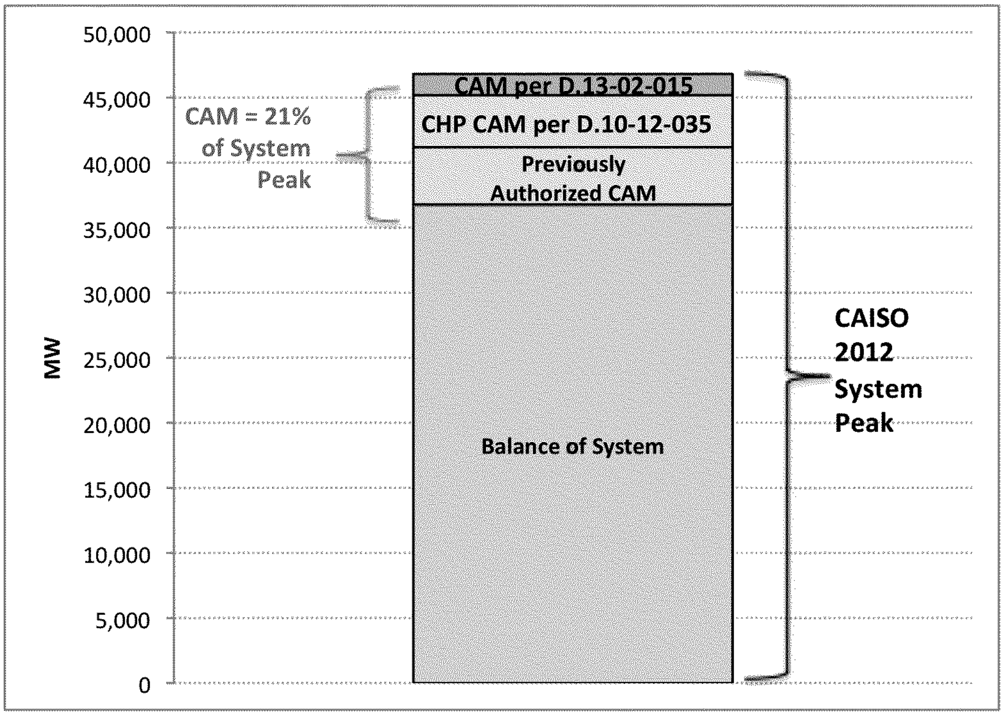
Indeed, time is running out to put in place appropriate criteria and a reasonable process for determining when CAM should be authorized. The startling reality is that authorized CAM procurement now exceeds 10,000 MW,[46] equivalent to 21% of the CAISO system peak in 2012.[47]

[44] D.02-11-052, p. 57.

[45] D.06-07-029, pp. 24-25.

[46] Not included is the 45 MW of CAM recently approved by the Commission for SDG&E in D.13-03-029?

[47] 2012 CAISO System Peak listed in *State of the Grid 2012*, CAISO, September 2012, p. 11; D.13-02-015 authorized CAM listed on p. 82 of decision; previously approved CAM is listed in AReM, DACC, MEA Track 1 Reply Testimony, R.12-03-014, July 23, 2012, Attachment. Not included in this number is the recent CAM procurement approved for San Diego Gas & Electric Company in D.13-03-029.



At a minimum, the Commission must set clear guidelines that procurement to meet bundled load is not CAM procurement. As discussed above, the IOUs are required to procure long term to meet their bundled load, which includes procurement of new generation and procurement of replacement generation. Thus, some or all of the capacity associated with new generation resources authorized in the bifurcated system/local tracks of the LTPP proceedings is logically necessary and required to meet such bundled load and load growth – to say that no new generation is needed for bundled loads significantly strains credulity. As such, AReM and DACC recommend that the Commission establish a burden of proof whereby all IOU procurement is deemed to be needed to meet IOU bundled load and not subject to CAM, unless the IOU can demonstrate through testimony and evidence that the procurement is needed solely to meet system requirements – put another way, a reasonable guiding principle the Commission should adopt is that CAM procurement should be the exception, rather than the rule. The statute requires the Commission to set appropriate criteria and the time has long passed for the Commission to comply.

As a reminder, AReM and DACC note the Commission itself has recognized the need for such criteria in a prior decision. In D.11-05-005, the Commission found that:

> This decision narrowly modifies our existing rules and processes to ensure compliance with the resource adequacy provisions of SB 695. In doing so, it is clear that there are some issues that remain to be resolved, including:
>
> 1. The development of policies and processes for distinguishing between system and bundled resource needs, and related cost allocation.
>
> 2. Whether there should be a test of "who benefits" under SB 695, and if so, the construction of such a test.[48]

To date, the Commission has so far failed to accomplish either of these objectives and this Track III would be a convenient vehicle to do so. AReM and DACC suggest that a manner of achieving this would be for the Commission to direct that: (1) procurement required to meet bundled customer needs is not subject to CAM; (2) the only procurement that may be afforded CAM treatment is that which is specifically ordered by the Commission for reliability purposes and that has been demonstrated to benefit <u>all</u> customers; and (3) determination of whether customers who are served by ESPs or CCAs receive any benefit from IOU procurement must include an assessment of whether the customer's competitive supplier is already providing reliable service to those customers and meeting all the regulatory and system requirements as a load serving entity. Such a policy would in fact be in harmony with Section 365.1(c)(2)(B), which was added to the California Public Utilities ("P.U.") Code as part of SB 790 and requires that:

> If the commission authorizes or orders an electrical corporation to obtain generation resources pursuant to subparagraph (A), <u>the commission shall ensure</u>

[48] D.11-05-005, at p. 16.

> that those resources meet a system or local reliability need in a manner that benefits all customers of the electrical corporation. The commission shall allocate the costs of those generation resources to ratepayers in a manner that is fair and equitable to all customers, whether they receive electric service from the electrical corporation, a community choice aggregator, or an electric service provider. (Emphasis added).

This statutory excerpt has two important elements that support the AReM/DACC recommendation. First, the Commission must "authorize or order" a utility to obtain generation resources; and second, the Commission must ensure that the procured resources actually "meet a system or local reliability need in a manner that benefits all customers…" Without both of these findings, the following sentence dealing with the allocation of the costs to all customers is not relevant. However, to date the Commission has not fully implemented the statute, instead relying on vague representations that "all customers benefit" without probing to verify that such a claim is in fact accurate. Without such an examination and without the prerequisite that the procurement must be done at the express order of the Commission, CAM treatment should not be afforded.

e. How should the Commission address flexibility in regards to the CAM?

Along with ensuring that the application of CAM takes into account whether an ESP or CCA is already meeting the reliability needs of their customers, and therefore should be exempt from CAM, another element of CAM "flexibility" the Commission should consider would be to afford ESPs and CCAs the opportunity to self-fulfill their System or Local reliability needs and avoid CAM charges based on IOU procurement. With CAM, the IOUs end up in control of a portion of the ESP's/CCA's energy portfolio and dictate a portion of their costs. In short, CAM hampers the ability of ESPs and CCAs to meet the energy needs and desires of their own customers in accordance with their own plans and strategies and discourages investment in resources of their own. The anti-competitive effects of this arrangement cannot be overstated.

The Commission registered concern about the anti-competitive effects of CAM procurement in D.06-07-029, noting that CAM might afford "too much price guarantee and risk protection for the IOUs" that could "undermine the development of a more competitive market."[49] A mechanism by which LSEs could demonstrate that they have fulfilled a portion of System or Local reliability needs would counterbalance some of the anti-competitive effects by providing LSEs with a way to avoid the CAM charges for their customers and control their own RA portfolio resources and costs. Permitting this LSE Self-Fulfillment Option would provide ESPs and CCAs with a tool to control their own RA portfolio costs and with enhanced incentives to invest in resources. In short, the LSE Self-Fulfillment Option provides market incentives to ESPs and CCAs to enter into multi-year contracts for RA capacity. The current CAM approach provides no such incentives.

In the Track 1 LTPP proceeding, AReM, DACC and MEA submitted specific proposals on this topic,[50] which were rejected by D.12-02-015.[51] At the same time, the Commission found that AReM, DACC and MEA had "raised legitimate issues regarding the equity of the current CAM structure."[52] The decision sought more clarity on how the proposal would adequately ensure investment in new resources and could be implemented without undue administrative burden.[53] AReM and DACC believe that consideration of the proposals was hampered by the testimony and hearing format in Track 1. However, the legitimate equity issues remain and have intensified owing to continued calls from the IOUs for new CAM procurement.

[49] D.06-07-029, pp. 24-25.

[50] LTPP Track 1 Testimony of AReM, DACC and the MEA, R.12-03-014, June 25, 2012. pp. 51-66.

[51] D.13-02-015, p. 112.

[52] Ibid.

[53] Ibid.

In order to advance the discussion of how to implement the LSE Self-Fulfillment Option, AReM and DACC recommend and urgently request that the Commission direct the IOUs and interested parties to submit their own proposals on this topic and to order consideration of the proposals in a Track 3 workshop devoted to that topic. In other words, the Commission should firmly inform participants in this Track III that the question to be answered is not "whether" there will be an LSE Self-Fulfillment mechanism, but "how" the mechanism will work. Proposals submitted by interested parties can be stand-alone separate proposals, or can be stated in terms of changes that the party recommends to the mechanism put forth by AReM and DACC in Track 1 of this proceeding.[54]

f. Should the CAM rules be differentiated to best account for benefit and cost allocation among community-choice aggregators and electric-service providers, based on their different business models or portfolio of other contracts? If so, how?

If the guiding principles and recommendations made herein are included in the deliberations that will take place in this Track 3, CAM rules can and will be developed that are fair for all customers and their suppliers, regardless of whether they are bundled utility customers, or are served by ESPs and CCAs.

[54] LTPP Track 1 Testimony of AReM, DACC and the MEA, R.12-03-014, June 25, 2012. pp. 51-66.

III. Conclusion

AReM and DACC thank the Commission for its attention to the discussion of LTPP Track III issues that is contained herein.

Respectfully submitted,

Sue Mara

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