BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements.	Rulemaking 13-09-011

REPLY TESTIMONY OF DR. BARBARA R. BARKOVICH
ON BEHALF OF THE
CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

May 22, 2014

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements.	Rulemaking 13-09-011

REPLY TESTIMONY OF DR. BARBARA R. BARKOVICH
ON BEHALF OF THE
CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

I. Introduction

Q1. Please state your name and business address.

A1. My name is Dr. Barbara R. Barkovich. My business address is Barkovich & Yap, Inc., P.O. Box 11031, Oakland, CA, 94611.

Q2. Did you provide direct testimony in this proceeding?

A2. Yes, I did on May 6, 2014 on behalf of the California Large Energy Consumers Association (CLECA).

Q3. What is the purpose of your reply testimony in this proceeding?

A3. The purpose of my testimony is to rebut parts of the testimony of several other parties who served direct testimony on May 6, 2014, in this proceeding.

Q4. How is your testimony organized?

A4. I respond to the testimony of each of several parties in a separate section below.

II. Pacific Gas and Electric Company (PG&E)

Q5. To which part of PG&E's testimony do you reply?

A5. I reply to the Testimony of Luke Tougas in Chapter 7 of PG&E's direct testimony. My reply focuses only on pages 7-3 and 7-4 of Mr. Tougas's testimony and his discussion of the KEMA report cited in a footnote on page 7-4. This report is entitled "Final Report California Statewide Process Evaluation of Selected Demand Response Programs: Process Evaluation of PG&E, SCE, and SDG&E's Critical Peak Pricing and Base Interruptible Programs" dated April 7, 2010.

Q6. What is your concern about this testimony?

A6. I am concerned by the apparent conclusion drawn about the number of customers participating in DR with back-up generation (BUG) based on the KEMA report. The KEMA report should not be used to draw any conclusions about the use of BUG by either customers participating in the Base interruptible Program (BIP) or investor-owned utility (IOU) dynamic pricing programs. There are two reasons for this. First, the air quality regulations for BUG have changed since 2010 and there were permitted uses for BUG in 2009 or early 2010 for demand response. For example, in 2009-2010, diesel BUG could be used for participation in an Interruptible Service Contract (the predecessor of BIP).[1] Federal regulation of BUG for participation in DR programs only started in 2010 and the federal rules went into effect in 2013.[2] These limit the uses to 100 hours per year at the equivalent of a Stage 2 emergency. Since the KEMA report was completed in April 2010, it would reflect legitimate use of BUGs for DR or CPP in 2009.

Second, the report asked customers if they had and used BUG, not how much of the customer's load the BUG represented. The report nowhere

---

1 California Air Resources Board: Airborne Toxic Control Measure for Stationary Compression Ignition Engines, Effective 10-18-2007 at 9 and 29-31.

2 40 CFR Part 63 (Subpart ZZZZ)

indicates, for example, if a customer with a 10 MW load had BUG of 300 kW to support safety requirements. Thus, for both reasons, the KEMA report "information" should be given no weight in this proceeding.

III. Natural Resources Defense Fund (NRDC)

Q7. To which points in NRDC's testimony do you wish to respond?

A7. NRDC cites the same KEMA report that was cited by Mr. Tougas for PG&E.[3] For all the reasons I have already discussed, this report should be given no weight. Furthermore, NRDC argues that in early 2010, when the report was issued, the utilities were in violation of a policy statement in D. 11-10-003, adopted in October 2011.[4] This is clearly absurd on its face. Lastly, and more importantly, also in D. 11-10-003, the CPUC stated that it did not intend to implement the cited policy statement:

> **At this time, we will not make *<u>any</u>* change to the RA rules to implement our policy statement regarding RA treatment of back up generation.** We recognize parties' concerns regarding lack of data or analysis to the extent that customers use their BUGs for DR and enforcement related issues. Therefore, we will defer the RA rule change to a future RA proceeding when further studies or analysis become available.[5]

Thus, there is no rule or policy currently in force for which the utilities can be found in violation.

IV. San Diego Gas & Electric Company (SDG&E)

Q8. To which SDG&E testimony do you reply?

A8. I reply to the testimony of David Barker.

---

3 NRDC Testimony, at 2.

4 NRDC Testimony, at 3.

5 D. 11-10-003, at 30 (emphasis added).

Q9. What are your concerns about Mr. Barker's testimony?

A9. I have several. The first is his statement that "the CPUC decided it wanted to phase out emergency DR like BIP in favor of price-responsive supply-side DR".[6] He provides no citation to support this statement; indeed there is none. In D. 10-06-034, the Commission capped the amount of emergency (aka reliability-based) DR to two percent of ISO system load effective in 2014. However, the Commission has never stated an intention to eliminate emergency DR. Indeed, without reliability-based DR, as I noted in my opening testimony, the ISO would have had considerable difficulty serving load on February 6 of this year. Thus, there is no reason to eliminate reliability-based DR, just the opposite – BIP should be retained and maintained.

Q10. What other concerns do you have about Mr. Barker's testimony?

A10. Mr. Barker states that there should be no multiplier to the avoided generation capacity cost in the DR cost-effectiveness methodology.[7] This existing multiplier reflects the fact that a load reduction reduces the need for resources to serve that load and an incremental amount of resources to provide the planning reserve margin. His reason for not having this multiplier is that it can create a bias toward load modifying DR. However, a reduction in load does result in a reduction in the amount of capacity needed to meet the planning reserve margin as well, so the multiplier is appropriate. Mr. Barker also states that customers should not be allowed to provide both supply DR and load

6 SDG&E Barker Testimony at 7.

7 SDG&E Barker Testimony at DBT-20.

modifying DR or to dual participate in two programs of load modifying DR.[8] If SDG&E considers the Demand Bidding Program (DBP) to be load modifying DR, I strongly disagree. Dual participation in an energy-based DR program and a capacity-based DR program is permitted by several CPUC decisions.[9] Furthermore, the Reliability Demand Response Resource (RDRR) is set up to allow BIP customers to also participate in DBP in the CAISO energy markets.

V. Environmental Defense Fund (EDF)

Q11. To what parts of the testimony of Stephen Moss for the EDF do you respond?

A11. I respond to three of his points. The first is his proposal that Peak Time Rebates be a supply DR resource.[10] I fail to see how a dynamic pricing program can qualify as a supply resource since it does not meet my criteria that it must be dispatched by the CAISO and that it is cost-effective to do so. Perhaps this is just an oversight on his part. The second is his proposal that the Commission consider allowing utilities to include the costs of developing and operating their DR programs in rate base.[11] I strongly disagree with this proposal. With the exception of possible capital assets, which are few in managing DR programs, there is no ratemaking basis to include DR in rate base. Most of the costs are for program management, incentives, and evaluation, measurement and verification. These are not capital assets. Furthermore, this proposal would appear to raise significant competitive issues, since third party DR suppliers have no rate base option. While I take issue with some of the alleged

---

8 SDG&E Barker Testimony at DBT-25.

9 D. 09-08-0-27 at 154-158 and D. 12-04-045 at 47-48 and 54-56.

10 EDF Moss Testimony at 20.

11 EDF Moss Testimony at 30.

competitive issues raised in direct testimony of Marin Clean Energy (MCE) and the Alliance for Retail Energy Markets/Direct Access Customer Coalition (AReM/DACC) elsewhere in this reply testimony, I would share such a concern on this point.

The third point to which I respond is his proposal for geographically de-averaged rates. Using a model about which very little information is provided, he claims that there is significant variability in service costs by region.[12] He then concludes that there would be benefits from having rates vary by location.

> Geographic-specific time variant rates that are based on marginal (i.e., forward-looking) costs would reflect the expense associated with forecasted demands, and as a result create a better market for load modifying programs to meet these needs.[13]

Mr. Moss may not be familiar with the stakeholder process at the CAISO, which found compelling reasons for not pursuing generation pricing for load at a level below the default load aggregation point (D-LAP).[14] Both the CAISO and stakeholders determined that the drawbacks outweighed any benefits. Indeed, one of the points was that DR in the wholesale markets already settles at the sub-LAP level.

Geographically de-averaged rates will significantly complicate cost allocation and revenue recovery. Only PG&E develops marginal costs for distribution below the system level, for example, and it re-averages them for setting rates. Furthermore, locational rate-setting will necessitate load forecasting on a locational basis, which significantly increases uncertainty, a point made by the

---

12 EDF at 24.
13 EDF at 26.
14 Load Granularity Refinements Stakeholder process.

utilities in the CAISO stakeholder process. As for the distribution cost variation cited by Mr. Moss, this is not a focus of DR, although DR programs can be dispatched to resolve loading problems on the distribution system. In addition, geographically de-averaged rates typically raise equity concerns. This is a reason why the Commission eliminated them in 1975. Marginal costs, cost allocation and rate design at this level of detail are a matter for phase two of a general rate case, where rates are set, rather than a DR rulemaking. For all these reasons, the Commission should not pursue this proposal here.

VI. Marin Clean Energy (MCE)

Q12. What are your concerns about the testimony of Mr. Jeremy Waen for MCE?

A12. Mr. Waen raises several issues that he claims result in competitive concerns. He says that if a DR program results in reductions of resource adequacy (RA) obligations for only the IOU, the costs of this DR program should be recovered in generation rates.[15] His concern appears to be that at present, all DR counts for RA and RA value is shared with all LSEs. If I understand correctly, he is saying that if load modifying DR does not count for RA in the future, only IOU customers will benefit via a reduction in load leading to a lower RA obligation and non-IOU LSEs would get no RA credit. If the latter, like MCE, get no RA credit, they do not want to pay for the DR program.

Fortunately, there is a way in which non-utility LSEs can get credit for DR that does not count explicitly for RA as a supply resource, i.e. load modifying DR. Before 2013, DR was subtracted from load by the Energy Division to create a

15 MCE Waen at 4.

net demand for RA procurement purposes on a load ratio basis for all LSEs whose customers supported the DR, called a capacity credit. D. 09-08-026 says:

> We affirm the established principle that DR program capacity credits should be allocated to LSEs in proportion to the funding that their respective customers provide toward DR programs. The proposed alternative of basing the allocation on relative participation rates of bundled and DA customers in a DR program fails to account for the fact that customers decide to enroll in DR programs because of the direct benefits of doing so. Since bundled service ratepayers generally provide funding for those DR program benefits, they effectively procure DR capacity. It would be inequitable to bundled service customers to assign DR capacity credits to LSEs on the basis of who participates in the DR program, without regard to how it is funded.
>
> The PG&E/TURN proposal to allocate DR credits associated with IOU DR programs whose costs are recovered in ERRA exclusively to the IOUs that administer them, along with PG&E's clarification that credits for DR programs whose costs are recovered through distribution rates should be allocated on a load share basis, are consistent with our adopted allocation principle, reflect current practice, and are hereby affirmed.[16]

There is no reason that this cannot be done again. In this way, all LSEs whose customers are paying for DR would receive RA value.

His proposal for load modifying DR to be paid for as a generation cost and thus exclusively by bundled customers is not the answer. Customers of non-IOU LSEs are permitted to participate in most IOU DR programs. Mr. Waen himself says:

> DR program cost recovery should be directly correlated with the ratepayers who are allowed to participate in the DR program and the LSEs which derive the primary benefit from the DR program.[17]

If some current DR programs in which DA and CCA customers can participate become load modifying DR, perhaps because the costs of integration into the

---

16 D. 09-08-026 at 27-28.

17 MCE Waen at 4.

CAISO markets render them cost-ineffective, a return to the prior treatment of DR for RA would provide those load modifying DR programs with RA value. Treating them as generation costs to be paid only by bundled customers would be inappropriate.

As for dynamic pricing that may be treated as load modifying DR, Mr. Waen states that his CCA customers "are prohibited" from participation in IOU dynamic pricing programs.[18] The issue is not so much that these customers are prohibited per se, which implies that they are denied an important opportunity, but that their rate designs are set by the CCA, not by the CPUC. He argues that only bundled customers should pay for these programs. I disagree. If CCAs want to have their own dynamic pricing programs, there is no reason why they cannot do so. CCAs use utility billing systems now to bill their own customers. There is no reason why these systems could not be used to allow them to have their own dynamic pricing programs. Since CCAs use these billing systems, there is not a good argument that they should be able to avoid the costs of those systems if they do not have dynamic pricing. Furthermore, even if CCA customers do not have dynamic pricing, they would benefit from any changes to the system load shape resulting from dynamic pricing by IOUs or other LSEs; a smoother system load shape resulting from dynamic pricing would reduce the overall costs of serving load, for example by reducing ramping requirements, improve the system efficiency and reduce costs to serve all load, not just bundled load.

18 MCE Waen at 5.

Mr. Waen also makes the argument that his CCA customers live in a mild climate zone and are not well-suited for air conditioner (A/C) cycling programs.[19] First of all, not all Marin customers lack A/C. Napa, which is considering joining MCE, certainly has A/C. Second, why is this any different from any other customer living in a mild climate having to pay for an A/C cycling program that provides demand response when needed to support the entire system? Air conditioner use increases peak loads for the entire grid and affects all customers through higher costs, even those without air conditioning load. Thus, all benefit from reductions in peak load from A/C cycling. There is no merit to the argument that this is anti-competitive.

Q13. Are there any other parts of Mr. Waen's testimony to which you would like to respond?

A13. Yes, there are two. The first is his proposal that DR programs that do not exclusively provide RA benefit to IOUs or that are open to all customers should be funded like EE program funding, i.e. by all LSEs, and that CCAs be permitted to make proposals to use such funding.[20] Since the only DR programs that are only open to bundled customers are dynamic pricing programs, I assume he refers to traditional, non-dynamic-pricing DR programs.

This proposal may have some merit. If CCAs can propose DR programs for their own customers, and these have value, the Commission should consider whether they should receive some DR funding, paid for by customers of all LSEs, to run such programs. However, these LSEs should not deny their customers

---

19 MCE Waen at 6.
20 MCE Waen at 4.

the ability to participate in IOU DR programs, if the latter work for their customers. As Mr. Waen himself states: "CCA customers should not be prohibited from participating in IOU-run DR programs purely because these customers are not receiving IOU generation services."[21] It may be that some bundled customers will want to participate in CCA programs, if they are located in that CCA's service territory, and this could also be permitted.

The second point, and this is also an issue in the testimony of Ms. Sue Mara for the Alliance for Retail Energy Markets and the Direct Access Customer Coalition (AReM/DACC), is the apparent presumption that recovery in delivery charges means that the costs are also allocated on a distribution basis. This is not necessarily the case. Recovery in delivery charges means that non-bundled customers are also charged. However, it does not mean that the costs are allocated in any particular way.

VII. Clean Coalition

Q14. To which points made by Ms. Wang of the Clean Coalition would you like to respond?

A14. Clean Coalition uses a graph in its testimony from a study by Lawrence Berkeley National Laboratory (LBNL) that I also cited in my direct testimony.[22] While Clean Coalition refers to this as a graph of capacity, it is actually a graph of daily energy availability. However, the main point is that Clean Coalition claims that this graph shows "the projected 2020 availability of loads, by type, that will be

21 MCE Waen Testimony at 6.

22 Daniel J. Olsen, et al., *Grid Integration of Aggregated Demand Response, Part 1: Load Availability Profiles and Constraints for the Western Interconnection*, Lawrence Berkeley National Laboratory and National Renewable Energy Laboratory, September 2013.

available to respond to grid services needs on an hour-by-hour basis in the Western Interconnection. The chart below from this study shows projected hourly capacity of 26 different types of major loads in the Western Interconnection in 2020."[23] This graph shows less than 1000 MW of load available for such uses across the entire Western Interconnection, not just California, more than half of which load is for cooling and thus not available on a year round basis. This graph thus does not support the argument that DR will be able to provide substantial flexibility to the CAISO-only markets.

VIII. EnergyHub

Q15. To which points made by EnergyHub in its testimony would you like to respond?

A15. There are two. The first is EnergyHub's call for:

> "**(2)** Low-friction end-user enrollment process, **including such seemingly simple** tactics as eliminating the need for customers to enter account numbers during the enrollment process, by providing an automated system for looking up account or meter numbers based on the customer's address (provided the aggregator has obtained the customer's consent to do so)"[24]

This proposal is not compatible with the Commission's process for assuring privacy of customer energy use data. The Commission put great effort into the requirement that each customer fill out and submit a Customer Information Service Request (CISR) through which the customer provides its own account number and authorizes a third party to receive a copy of its billing data. Third parties should not

---

23 Chart from Daniel J. Olsen, et al., *Grid Integration of Aggregated Demand Response, Part 1: Load Availability Profiles and Constraints for the Western Interconnection*, Lawrence Berkeley National Laboratory and National Renewable Energy Laboratory, September 2013, at Appendix E, page 86.

24 EnergyHub Testimony at 7, emphasis in original.

be given the ability to download account or meter data without going through this established process.

The second point is EnergyHub requests to have utilities pay aggregators to sign up customers for DR programs.[25] I have serious concerns about this idea. The Austin program cited provides an incentive to a DR aggregator for signing up a customer onto a DR program and an additional incentive for each year the customer remains on the program. There is no mention in the EnergyHub testimony of a requirement for the customer to stay on the program and no mention of any requirement to perform. This is in contrast to existing IOU DR programs that have a one-year requirement and an annual opt-out window. Mr. Frader-Thompson provides no mention of rules to ensure that customers are provided with accurate information as to their potential obligations as DR participants. If an aggregator signs up a customer, does that customer have any ongoing relationship with the aggregator, or is this just a bounty program?

In current California IOU aggregator-managed programs, the aggregator takes a share of the incentive provided by the utility. For example, SCE's Capacity Bidding Program (CBP) has two sets of customer incentives, and they are lower for aggregator-managed programs because the aggregator is compensated with part of the incentive money. To the best of my knowledge, the aggregator does not receive a payment simply for signing up a customer. For some aggregator-managed programs, aggregators are paid under (confidential) contractual agreements with utilities for providing load reductions, not just for signing up customers.

25 EnergyHub Testimony at 8.

Aggregators must sign up enough customers to provide the agreed-upon load response and meet their financial objectives. If they lose customers, they must replace them, and that is a cost of doing business. If an aggregator were paid just to sign up customers, there would be an enormous incentive for churn and little incentive to ensure performance.

IX. TURN

Q16. To which points made in TURN's testimony would you like to reply?

A16. I will respond to both Mr. Hawiger and Mr. Woodruff. I will begin with Mr. Hawiger. He states in his testimony that he is concerned that there has been no decline in the cost of DR.[26] It is not clear why he thinks there should be such a decline. Mr. Hawiger has provided no information as to changes in the costs to customers to participate in DR programs. The costs of the utility system in general have not declined. If the Commission is considering expanding the amount of DR, as it has indicated, and wants to integrate DR into the CAISO markets with corresponding significant integration cost, there is no reason to assume that DR costs would decline. Quite the contrary.

Q17. What is your response to Mr. Hawiger's statement[27] that all supply resource DR should participate in the CAISO markets by 2018?

A17. I find it curious that TURN, which is generally concerned about electric costs and rates, should take such a blanket position without considering whether the costs of integration into the CAISO markets will render DR cost-ineffective. Unless and until the integration problems pointed out in my direct testimony

---

26 TURN Hawiger at 12.
27 TURN Hawiger at 14.

and the direct testimony of PG&E are resolved in a cost-effective manner, the Commission should reject this proposal.

Q18. What is your response to Mr. Hawiger's proposal that all existing DR programs be terminated in 2017?[28]

A18. He provides no justification and I can see none. Existing DR programs are successful, both the reliability-based and the price-based programs. The response of DR to the February 6 event demonstrates that it delivers load reductions when needed, even without air conditioning load, and without integration into the CAISO's markets. The Scoping Ruling discusses securing additional DR through the proposed DR Auction Mechanism, not replacing existing DR. Furthermore, the DRAM is completely untested and numerous parties have raised concerns in their direct testimony in this proceeding, including my own.

Mr. Hawiger should not assume that all or even most existing DR will transition to the DRAM or to supply resource status. There are many complexities and costs to participation in the CAISO's markets, including must-offer obligations and integration costs, which are not necessarily commercially feasible for all existing DR.

Furthermore, it is not clear if Mr. Hawiger includes dynamic pricing in his proposal to terminate all existing DR programs. In my mind, this would clearly be a mistake. Not only is dynamic pricing beneficial and just in the

---

[28] TURN Hawiger at 15.

process of being implemented, but it has no substitute that can be provided by third parties or offered into the CAISO's markets.

Q19. What is your response to Mr. Hawiger's claim that the costs of DR are higher than the costs of RA?[29]

A19. Mr. Hawiger is mixing apples and oranges. The cost of RA is not the average annual market price of an RA contract. It should include the cost of long-term contracts with new generation, including those struck for meeting the Renewable Portfolio Standard (RPS), and utility-owned generation, all of which provide RA value, all of which are procured through long-term RFOs, and none of which are procured through the bilateral RA market to which Mr. Hawiger refers. Furthermore, given the way Mr. Hawiger had the utilities calculate the costs he cites for the DR programs, i.e. the costs of DR budgets used in the TRC test, the RA "cost" should also include the costs of the utility procurement departments. His comparison is meaningless.

Q20. Do you have any comments on the testimony of Mr. Woodruff?

A20. Yes. First of all, Mr. Woodruff never addresses the impact of CAISO integration costs on participation in the DRAM in his apparent support of the DRAM concept. This is a major oversight. Second, Mr. Woodruff incorrectly characterizes the role of the Net Benefits Test (NBT). He says that the NBT could mitigate his concerns that winning bidders in the DRAM would submit high energy price offers into the CAISO's markets.[30] He is mistaken. The NBT assures that bids into the CAISO's markets will exceed the NBT, in order to be able to

[29] TURN Hawiger at 10.
[30] TURN Woodruff Testimony at 7.

receive LMP. It does not lower them. Indeed, the Commission has directed that all bids must be at or above the NBT.[31] The NBT for the CAISO for April 2014 over \$70/MWh[32], thus assuring energy offers from DR significantly in excess of the current average market prices. The NBT sets no upward limit on energy price offers by DR other than the offer cap.

Q21. Do you have any other concerns about points made by Mr. Woodruff?

A21. Yes. He says that an alternative perspective on cost-effectiveness for DR could come from looking at current or recent prices for RA capacity.[33] As I noted in my response to Mr. Hawiger, this is not an appropriate comparison.

X. California Independent System Operator (CAISO)

Q22. Do you have any response to the direct testimony of the CAISO?

A22. Yes, I have several responses to both Mr. Millar and Mr. Goodin. I begin with Mr. Millar. Mr. Millar's testimony actually adds confusion and additional complexity to the concept of using DR to provide local RA. I have no idea how the Commission could design an auction to procure DR for this purpose when his testimony provides additional layers of uncertainty as to how DR would have to be configured to provide this service.

He starts by saying that there are three characteristics of DR that are important for local RA, namely duration, availability and response time.[34] However, he also states that requirements for DR to provide local RA will vary

---

31 D. 12-11-025, Ordering Paragraph 1.

32 DemandResponseNetBenefitsTestResults-April2014.pdf.

33 TURN Woodruff Testimony at 9.

34 Millar Testimony, p. 4.

by location, will have varying duration, and will vary over time.[35] He says that the Commission should consider how to assess DR products in this uncertain and changing environment[36], including buying changing products over time. However, he provides no clarity as to how the Commission can accomplish this without some more specific information from the CAISO as to the need to be met, i.e. the product to be purchased. The only specific point he makes is that DR for local reliability would be needed within 30 minutes, although even here he provides an alternative, which is that it will be needed whenever the CAISO might want to use it.[37]

For DR with day-ahead notice, he simply states that the CAISO will have to consider this in its Transmission Planning Process, if it becomes an issue. However, since that process will result in no decisions until 2015, its outcome will be too late to inform this proceeding.

Mr. Millar also insists on integration of DR into the CAISO's markets with no consideration for costs. Indeed, he argues that manual dispatch is "completely untenable"[38], although it worked fine on February 6, because the CAISO is going to develop more complex systems to address the uncertainty of distributed generation. Indeed, he argues that DR must be incorporated into the CAISO's enhanced contingency modeling initiative[39], a subject that the CAISO has never raised at the CPUC before with respect to DR. This initiative involves

---

35 Ibid., pp. 4-5.
36 Ibid., p. 5.
37 Ibid, p. 6.
38 Millar Testimony at 7.
39 Millar Testimony at 8.

a major increase in the complexity of the CAISO's market and dispatch to reduce exceptional dispatch and other "manual" processes for post-contingency dispatch.[40] This is still merely a proposal. Various stakeholders have raised serious concerns about the efficacy of the proposal and the costs that would actually be avoided if this initiative were to be completed, adopted, and implemented.[41] Furthermore, this insistence by the CAISO on participation by DR in ever-more complex CAISO markets seems to undermine the ability of DR to be a supply resource. It certainly raises serious questions about the ability to have an auction that can simultaneously procure system, local, and flexible supply resource DR in any meaningful way.[42]

Q23. What is your reply to Mr. Goodin?

A23. Mr. Goodin says that "load modifying DR is generally enacted through voluntary and behavioral changes", implying it cannot be counted on to perform.[43] Yet this position does not adequately or fairly capture the excellent performance of DR on February 6, when it was not integrated into the CAISO markets, and thus would have fallen under the "load modifying" category definition. If the terms and conditions of a DR program are correctly established, there is ample evidence that load modifying DR can be predictable and reliable.

In his discussion of load modifying DR, Mr. Goodin fails to acknowledge that its value is a function of its appropriate reflection in operational as well as

40 SecondRevisedStrawProposal-ContingencyModelingEnhancements.pdf.

41 StakeholderCommentsMatrix ContingencyModelingEnhancementsStrawProposal.pdf.

42 Millar Testimony at 8-9.

43 Goodin Testimony at 8.

planning decisions. The RA value he discusses is a planning issue. However, there is also a value of load modifying DR on the operational side. The CAISO does not make day-ahead and real-time procurement decisions in its markets based on the load forecasts of the utilities, whose load the DR will modify. Instead, it uses its own load forecasts. If the effect of DR, including dynamic pricing, is not incorporated into the CAISO's load forecasts, the CAISO will over-procure. Furthermore, although the CAISO devotes much attention to the optimization it attempts to achieve through its markets and its wish for transparency, its daily load forecasting process is far from transparent.

XI. AReM/DACC

Q24. On which points do you wish to respond in the testimony of Ms. Sue Mara on behalf of AREM/DACC?

A24. I wish to respond to numerous points. AReM/DACC's testimony focuses on cost allocation issues for DR. Although Ms. Mara claims to analyze the nature of both types of DR, load modifying and supply resource, her entire testimony is a justification for having bundled customers pay for all IOU DR programs. This would include having bundled customers pay for DR Programs in which Direct Access (DA) customers can and do participate. Indeed, as noted in SDG&E's testimony, roughly 51% of its industrial load is DA and 20% of its commercial load is DA.[44] Thus, it is reasonable to infer that a significant portion of DR from the commercial and industrial sectors is provided by DA customers. Under her proposal, these customers would have no responsibility to help pay for the costs

[44] SDG&E, Katsufrakis Testimony at GK-7.

of the programs they actively participate in. Indeed, I would argue that her proposal creates its own anti-competitive consequences, since bundled customers would have to pay for DR incentives received by non-bundled customers.

Ms. Mara attempts to make the argument that DR is the equivalent of a generation resource and thus the costs of utility DR programs should be allocated as generation costs, i.e. to bundled customers. DACC/AReM has already lost the argument in the long term procurement planning proceeding; that is, that utility generation procurement costs for new generation resources that serve the entire system should not be partly recovered from DA and CCA customers under Section 365.1(c)(2)(A-B) of the P.U. Code.[45] ESPs have many parallel obligations to IOUs for procurement, including RPS and storage. However, they have no obligation to procure new long-term generation supply assets, and the cost of new generation resulting from IOU contracts or ownership that provides benefits to the system is allocated to them under the Cost Allocation Mechanism. ESPs have no obligation to procure DR, but it benefits the system too. While Ms. Mara argues that ESPs would prefer to have their own DR programs and that paying a share of the costs of IOU DR programs makes that impossible, ESPs are under no obligation to have DR programs and could instead meet their RA requirements by signing RA contracts with generators at relatively low costs in a market with excess capacity. The requirement for utilities to have DR programs thus could be argued to put the

45 D. 14-03-004, pp. 119-120.

bundled customers at a competitive disadvantage. The ESP case for excluding DA customers and themselves from any cost responsibility for IOU DR programs would be stronger if they had a legislated mandate to have their own DR programs similar to the RPS requirement.

Ms. Mara cites the CAISO and FERC as support for her assertion that DR is equivalent to generation.[46] However, she ignores the fact that DR is also used to prevent or mitigate emergencies on the transmission and distribution systems that serve all customers, whether bundled or not. This is not a generation function.

In her discussion of load modifying DR, Ms. Mara only includes dynamic pricing programs and permanent load shifting, referring to Table 2 in D. 14-03-026.[47] That table is a *proposed* bifurcation of DR programs and was not adopted by the Commission in that decision. Indeed, the decision on how to bifurcate existing DR programs is a matter for *this phase* of the proceeding. It has no evidentiary weight. Thus her apparent assumption that no other DR programs will be found to be load modifying in this proceeding is unfounded. As I have pointed out, this assumption ignores the very real likelihood that many current DR programs, in which DA and CCA customers can participate, will remain load modifying DR because the costs of integration into CAISO markets are too great. In this case, non-bundled customers should share in the costs of this DR.

---

[46] AReM/DACC Testimony at 16.
[47] AReM/DACC Testimony at 18.

She claims, as does MCE, that in return the non-IOU LSEs should receive RA credit for this DR[48] and that load modifying DR that does not receive RA credit should be treated as generation. I have already stated, in response to MCE, that if load modifying DR does not count for RA, it can be used to reduce RA requirements of the LSEs whose customers pay for it, as has been the case in the past.

Ms. Mara claims that recovery of DR costs in distribution rates is inappropriate. The reason for recovery in delivery charges/distribution rates is that only these charges are paid by all customers, whether bundled or not. Such recovery does not mean that the costs are allocated on a distribution basis. Some are, and some are not. If the concern were the allocation, these costs could be allocated on the basis of some combination of generation and distribution costs, with ESP and CCA generation costs imputed, as is done for other allocations. The real issue is that treating these costs as generation costs means that only bundled customers would pay for them.

Ms. Mara also makes the argument that California markets discourage third party DR providers.[49] The participation of DR aggregators in utility aggregator-managed programs would seem to belie that point, unless she is referring to ESPs as third parties. She provides no support for her claim that a greater role for third party suppliers would drive down costs. Nor does she provide support for her claim that existing utility DR programs do not meet

---

48 AReM/DACC Testimony at 20.
49 AReM/DACC Testimony at 13.

customer needs. If that is the case, she has provided no information as to what types of DR programs would meet these needs. Her assertions are simply that.

Q25. Does this complete your reply testimony?

A25. Yes, it does.