Docket:	:	R.13-09-011
Exhibit Number	:	
Commissioner	:	Michael R. Peevey
Admin. Law Judge	:	Kelly J. Hymes
ORA Project Mgr.	:	Sudheer Gokhale
ORA Witnesses	:	Sudheer Gokhale

OFFICE OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

OPENING TESTIMONY OF THE OFFICE OF RATEPAYER ADVOCATES

R.13-09-011

San Francisco, California
May 6, 2014

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I. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

Q. Please state your name and position.

A. My name is Sudheer Gokhale, and I am a Senior Utilities Engineer in the Office of Ratepayer Advocates.

Q. Please summarize the points you will be making in this section of your testimony.

A. The Commission's Office of Ratepayer Advocates (ORA) welcomes this opportunity to present this testimony on the issues and questions posed in the Assigned Commissioner and the Administrative Law Judge's Ruling in the Phase Three of the Demand Response (DR) Rulemaking (R.) 13-09-011. ORA has the following overall recommendations for the Commission:

- ORA supports a cost-effective amount of demand response participation to reduce the need for conventional generation required to integrate renewables and to meet local and system peak loads.
- The Commission should encourage cost-effective procurements of all available load modifying and supply resource DR consistent with the need.
- Reasonableness of the California Independent System Operator (CAISO) integration costs should be judged in terms of the overall cost effectiveness of DR programs.
- Energy Division's (ED) adjustments to ex-ante load impacts used in establishing RA capacity for a DR program are not clearly defined and understood and should not be made in an ad hoc manner. The Commission should provide additional guidance so the Energy Division's adjustments are done in a transparent manner.
- The California Energy Commission (CEC) load forecast is used in determining resource need in the Commission's Resource Adequacy (RA) and Long Term Procurement Planning (LTPP) proceedings. However, there is no well-defined process for determining the amount of conventional generation resources avoided by a load modifying DR response program. The Commission should establish a formal process in collaboration with the CEC to determine how load modifying programs are accounted for in the CEC's load forecast.
- If the Commission authorizes continuation of some of the utility price-responsive DR programs after the bridge funding period ends in 2016, the Commission should ensure that the incentive levels in the utility price-responsive DR programs are sufficiently low so they do not discourage customers to transfer from the current utility programs to the programs procured through the DRAM beginning in 2017.
- The Commission should limit the initial DRAM auctions to three year terms as all participants, DR providers, and other stakeholders are most familiar with the three year DR program cycles.
- The Commission should ensure that DR products procured through DRAM auction are fully utilized for the purpose they were procured. The Commission should ensure DR providers do not provide bids into the CAISO energy markets at very high prices for the sole purpose of avoiding being called.

- The Commission should require that Utilities' DR program tariffs and DRAM contracts to explicitly state that the use of Back-Up Generators (BUGs) for providing DR is prohibited.
- The Commission should use a cost allocation methodology which recovers costs of DR procurement from all customers, including Direct Access (DA) and Community Choice Aggregation (CCA) customers.

II. ORA'S RESPONSE TO PHASE THREE ISSUES AND QUESTIONS

A. Goals for Demand Response

1. Parties should provide what they consider to be past and current goals for demand response so that this proceeding has a complete and accurate history of the goals.

In Decision (D.) 03-06-032 the Commission adopted specific megawatt goals for utility price triggered demand response for the three Investor Owned Utilities (IOUs).[1]

Table 1

Year	PG&E	SCE	SDG&E
2003	150 MW	150 MW	30 MW
2004	400 MW	400 MW	80 MW
2005	3% of the annual peak	3% of the annual peak	3% of the annual peak
2006	4% of the annual peak	4% of the annual peak	4% of the annual peak
2007	5% of the annual peak	5% of the annual peak	5% of the annual peak

In July 2006, California experienced an unusually intense heat wave which at times strained the state's electrical system. This caused the Commission to substantially augment the utility demand response programs for 2007 and 2008 previously authorized in D. 06-03-024.[2] Even with added effort, the Commission's 5% goal was far from being reached by 2008. The rulemaking estimates the current level of price responsive demand response is only about 2.5% of system peak.[3]

In Senate Bill (SB) 1, the California legislature encouraged and established requirements to procure renewable energy to meet 33 percent of California's energy needs by 2020. Subsequently, over the last several years there has been a realization that these large amounts of must-take intermittent renewable resources coming online will require flexible capacity

[1] D.03-06-032, p. 9.

[2] D.06-11-049 augmented utility demand response programs for 2007 and 2008 previously authorized in D. 06-03-024.

[3] R.13-09-011, April 2, 2014 Scoping Ruling, p. 7.

resources to be integrated into CAISO's grid operations. In D. 12-04-045 (authorizing 2012-2014 cycle DR programs), the Commission articulated its goals for demand response in meeting future needs of the grid. The current DR Rulemaking (R. 13-09-011) provides a roadmap for implementing that future vision of DR.

2. Parties should provide recommendations for increasing individual demand response program load impacts and overall participation in demand response programs. If parties consider the current demand response participation level to be appropriate, please explain why.

The future requirements for demand response are changing from providing just peak load reduction when the state's electrical system is strained. Demand response is increasingly looked upon as an important component of meeting the Local and Flexible Resource Adequacy requirements established by the Commission. In addition, demand response is expected to provide ancillary services to the CAISO. Therefore, increasing the megawatt participation in demand response is not as important as getting the program design done properly to enable the specific types of demand response that are most beneficial. Because future demand response products will have specific roles and purposes, demand response must be dependable, consistent and predictable.

It is important for the requirements, incentives, testing, and penalties (for non-performance) to be properly aligned in order to yield the optimum level of participation in a cost effective manner. This suggests the need for a collaborative process between the main stakeholders from the get-go instead of the current more adversarial and litigious process. The recent Petition for Modification (PFM)[4] to implement program improvements for PG&E's Aggregator Managed Portfolio agreements in which the ORA, PG&E, and the aggregators successfully collaborated to take into account each party's interests and concerns is a good example for future effort to get the right type of demand response in the right amount, and in a cost effective manner.

3. Parties should provide recommendations for developing the goals of demand response load (MW) and demand response participation, how those goals should be measured (load impact protocol based on ex post or ex ante, or others), and how often they should be measured to ensure goal achievement (monthly, seasonally, or annually).

As discussed earlier, the Commission's long-standing goal of meeting 5% of the system for price responsive demand response is still far from being reached. Keeping the goal for price-responsive programs at 5% of system peak appears reasonable for now as the current level of price responsive demand response is only about 2.5% of system peak. However, additional amounts of DR may be appropriate in the future to meet any changing needs.

Within the overall 5% of system peak goal, however, the Commission should not lose sight of the need for procuring the most beneficial type of demand response in the right amount in a cost effective manner. It would be useful to identify broad categories of products that are needed and have specific goals for each needed product. This would assist in tracking and

[4] EnerNOC, Inc. (EnerNOC), Energy Curtailment Specialists (ECS), and PG&E jointly filed the petition to modify Decision (D.) 13-01-024. The PFM was filed on December 20, 2013 in proceeding Application (A.) 13-09-004. The petition was approved by the Commission on February 27, 2014.

measuring progress made in meeting future needs identified in D.12-04-045. Initially, such tracking should be done on a monthly basis to help identify and resolve problems if sufficient progress is not made.

The Commission examines the need for conventional generation in its RA and LTPP proceedings. As stated in the Energy Action Plan, the main purpose of demand response as a preferred resource is to obviate the need for conventional generation to the extent possible. To that end, all ratepayer funded demand response programs should be designed to qualify for full credits in the respective RA and LTPP proceedings. ORA supports the cost effective amount of demand response participation to reduce the need for conventional generation required to integrate renewables and to meet local and system peak loads.

The load impact protocols measure ex post and ex ante DR on an annual basis and is used to determine RA capacity credit and so is the only measurement for estimating the reduction in the need for conventional generation. ORA, however, shares the concerns raised by PG&E in its comments on the Energy Division's April 9, 2014 workshop on RA issues.[5] In the comments, PG&E points out that the demand response load impact protocols do not provide a specific methodology for calculating the ex-post load impact of a demand response event. While the protocols do provide some guidelines for this purpose, they are not detailed enough to establish a specific calculation. PG&E also expresses concern that the adjustments the Energy Division recommends for developing RA capacity credit are not clearly defined and understood and should not be made in an ad hoc manner. ORA agrees with PG&E that more transparency is needed on ex-post performance assessment adjustments when calculating DR resource RA capacity.

4. Parties should provide recommendations for programs or activities to ensure equality for load modifying resources and supply resources. Parties should suggest a definition for equality.

To the extent that both load modifying and supply resources are dependable in avoiding conventional generation in a cost effective manner, all available load modifying and supply resources should be procured. The equality between the two types of demand response should be based on cost-effective procurement of both rather than an equal number of megawatts or dollars spent. The Commission should examine and make any necessary changes to properly and accurately reflect both the benefits and costs of demand response resources developed to meet the future needs.

5. Parties should provide a detailed explanation of their resource adequacy concerns, specific to the bifurcation framework adopted in D.14-03-026.

Currently, all demand programs receive RA credit. RA requirements met by DR in effect reduce the need for procurement of an equivalent amount of conventional generation. ORA has two main concerns about the effect of bifurcation on RA credits awarded to DR programs.

First, whether the existing demand response programs that would be classified as supply resource under the bifurcation framework could be modified 1) in time and 2) in a cost effective manner to meet any new RA requirements proposed in the Energy Division's proposals being considered in the RA Rulemaking (R.) 11-03-023. ORA now understands that the new RA

[5] Comments of Pacific Gas and Electric Company On The April 9, 2014, Workshop On Resource Adequacy Issues And Revised Energy Division Resource Adequacy Proposals, dated April 18, 2014.

requirements in the Revised Staff Proposal would not be applicable to the existing demand response programs for the 2015 RA compliance year.[6] However, this concern remains for the 2016 RA compliance year and beyond.

Second, would DR that is considered as a load modifier under the bifurcation framework have the same amount of impact in avoiding procurement of conventional generation resources as it currently does through the RA process? While there is currently a well-defined process for assigning RA credits to a demand response program, there is no such process for determining the amount of conventional generation resources avoided by the load modifying demand response programs. Unless the Commission establishes a similar process for load modifying demand response programs, the current transparency provided in the RA process will be lost for these types of programs after the bifurcation. ORA is also concerned that unless the existing load modifying demand response programs get as much credit as they receive in the current RA process after the bifurcation in avoiding conventional generation, some of the ratepayer investment in the existing programs will be stranded. The Commission should ensure that this does not happen.

B. CAISO Market Integration Costs (as directed by D.14-03-026)

1. Parties should provide their understanding of the costs (in dollars) of the CAISO market participation either through their own direct participation or through the participation of other entities in other markets.

ORA does not have this information. ORA understands that both SCE and PG&E have had some experience with bidding into the CAISO's markets and plans to integrate some DR programs in 2014. ORA understands the incremental costs specific to CAISO integration are primarily related to telemetry, etc. ORA defers to IOUs and other actual market participants to provide this information.

2. Parties should present a range of costs that they would consider to be reasonable. Explain why this range of costs is reasonable and costs outside the range are not reasonable.

Costs should be judged as reasonable only if the benefits of CAISO market participation are shown to be greater than all costs incurred for such participation, in a transparent way. Integration costs for CAISO market participation should be judged in terms of the overall cost effectiveness of DR programs.

3. For costs outside the range and therefore unreasonable, please provide examples of ways to decrease those costs.

See ORA's response to question B.2. above for reasonableness. The CAISO and DR providers should collaborate on finding innovative ways to reduce DR integration costs consistent with the level of visibility of DR resources necessary for operating the grid in a reliable manner.

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[6] "Qualifying Capacity and Effective Flexible Capacity Calculation Methodologies for Energy Storage and Supply-Side Demand Response Resources," Revised Staff Proposal, Resource Adequacy Proceeding R. 11-10-023, Dated Apri l 9, 2014. Energy Division, CPUC p. 2.

4. PG&E provided a list of solutions for decreasing CAISO market integration costs in its December 13, 2013 filing at page 13. Provide comments on the list of solutions.

PG&E's solutions in its December 13, 2013 filing were:

a. Have PDR be called in an "all or nothing" manner (discrete) like RDRR

b. Create a DLAP-level PDR product

c. Simplify telemetry requirements

d. Increase the minimum resource size for telemetry (now 10 MW)

e. Simplify registration for mass market customers

f. Ease master file update requirements for supply-side DR resources

g. Eliminate the requirement to separate PDR participants by LSE

h. Allow customers to be removed or added from a RDRR during a season (no "lockdown" of customers for a season)

i. Reduce the number of subLAPs and have subLAPs rollup to LCAs

It appears that all of these proposed solutions need CAISO's concurrence and approval. CAISO should respond to each proposal in detail so parties can comment. PG&E's proposals lack sufficient discussion and detail in order for ORA to comment. It is also not clear if each proposal by itself will help reduce some of the integration costs or all of these proposals need to be combined to have a meaningful impact. It would help to rank these proposals in terms of their impact on reducing integration costs. If these proposals are workable for the CAISO and significantly reduce DR integration costs, ORA sees no reason to oppose any of them.

The April 18, 2014 CAISO participation workshop[7] discussion was helpful for the CAISO and market participants to better understand each other's concerns. For example, ORA learned that telemetry is required only for Proxy Demand Resources (PDR) aggregated at a level of 10 MW and above and for those providing ancillary services. ORA also learned that CAISO does not require telemetry for Reliability Demand Response Resources (RDRR). One of the issues discussed is the accuracy required by CAISO for Settlement Quality Meter Data (SQMD) submitted by a Demand Response Provider's (DRP) Scheduling Coordinator (SC) to CAISO. Since PDR is made up of multiple smaller resources it was proposed that a wider error band would be useful in reducing costs of providing SQMD. The CAISO indicated they would take the proposal under consideration. CAISO also indicated that it would consider alternative baselines (to the current 10 in 10 baseline) for measuring DR resource performance. CAISO explained that it is subject to the North American Electric Reliability Corporation (NERC) as well as the Western Electricity Coordinating Council (WECC) approved reliability standards whereas many of the Eastern ISOs are subject to NERC only.

[7] April 18, 2014 CAISO Workshop on Requirements for Demand Response Wholesale Market Integration.

C. Supply Resources Issues

1. Parties requested the Commission to analyze the characteristics of each demand response program in order to categorize current and future demand response programs into load modifying resources and supply resources. Provide your list of characteristics that the Commission should use in determining how to categorize a supply resource.

Instead of listing characteristics of DR supply resources, ORA recommends establishing minimum requirements that a DR programs must meet to be classified as a supply resource. The minimum characteristics for DR programs should be the same as those established in current and future RA proceedings. By doing so the Commission will provide a clear bifurcation definition and will also ensure that the DR program provides a supply resource to the CAISO, which is the ultimate purpose of the program. Since the System, Local and Flexible RA will have different requirements to meet, the minimum characteristics for DR programs should reflect the specific RA purpose for which the resource is procured.

2. Using your proposed list of characteristics, describe each demand response program and determine whether that program should be classified as a supply resource, as defined by D.14-03-026. Using your list of characteristics, describe how and whether subsets of customers in existing programs could be sub-aggregated and classified as Supply Resources.

ORA generally agrees with the list of programs shown as "supply resource" shown in Table 2 of the bifurcation decision D. 14-03-026. These programs could potentially meet the RA requirements being established in the current RA proceeding in R. 11-10-023.

Subsets of customers in existing DR programs should be able to be classified as supply resources if they can meet the RA requirements and dispatched accordingly as long as the same customer is not enrolled in more than one program, procurement, or DRAM offer at the same time. ORA defers to the IOUs and other actual market participants supporting this concept to explain how this could be accomplished consistent with the Commission's Direct Participation rules established pursuant to D.12-11-025, D.13-12-029, and Resolution E-4630.

3. Parties are invited to provide their overall comments on the Demand Response Auction Mechanism (DRAM) provided in Attachment B. Parties are asked to respond to the additional questions asked here:

The DRAM proposal for price-responsive DR currently states that the utilities are obligated to procure a minimum amount of price-responsive demand response expressed as a minimum percentage of total system peak for a specific year as part of their system, local and flexible RA requirements. It sets targets for DRAM procurement starting in 2016 at 3% of peak load and increases the target incrementally by 0.5% each year until the 5% target is reached in 2020.[8] ORA agrees that these procurement targets are reasonable if they include a gradual tapering of utility price-responsive DR programs in the overall target.

On April 29, 2014, the Commission's Energy Division (ED) held a question and answer working session on DRAM and provided additional details on targets for DRAM procurement. ED explained that the 3% procurement target for 2016 is for all price-responsive DR, including

[8] Ruling, Attachment B, p. 87.

the utility DR programs. The Ruling states the current price-responsive capacity comprises about 2.5 percent of maximum utility system peak load in 2014 and would continue at that level through the 2016 bridge funding year. So procurement through DRAM in 2016 will be targeted at 0.5 percent of system peak to reach the 3 percent procurement target for 2016 for all price-responsive DR. ED explained that the first DRAM auction in 2016 will be a "pilot" that will help determine if any changes are necessary for subsequent auctions. ORA agrees with ED's view of the first auction. ORA recommends that the first auction be structured as simply as possible in order to focus on any problems with the basic structure of the auction.

ED also stated that the Commission will issue a ruling regarding the level at which the current utility price-responsive DR will continue beyond 2016. Depending on those levels for 2017 through 2020, DR procurement targets for DRAM portion of the price responsive programs will vary accordingly. This could result in the DR procurement target for DRAM portion of the price responsive programs in 2017 to be a full 3.5 Percent of system peak if the entire utility price-responsive DR is discontinued beyond 2016. The Commission should ensure that the incentive levels in the utility price-responsive DR programs are sufficiently low so they do not discourage customers to transfer from the current utility price-responsive DR programs to the programs procured through DRAM beginning in 2017.

i. Are the proposed contract durations of one, two or three years sufficient? Should contracts of a longer duration be included? Why or why not? If yes, what duration(s) is/are recommended?

Some form of long-term contracts could mitigate some of the consequences of the current 'stop/start' nature experienced in the current three-year DR funding cycles. The current three year DR programs cycles have resulted in numerous hastily arranged bridge funding authorizations with little room for making needed changes to the programs. But because of the evolving nature of DR, a longer term contract should ensure there is adequate review and 'off-ramps' for underperforming contracts so that needed changes can be made on a going-forward basis. Cost effectiveness and annual performance still must be evaluated at regular intervals to identify underperforming contracts.

Unlike a physical power plant that is under a long-term contract, the DR aggregators have not provided evidence that they have the ability to recruit and maintain the same customer over a long-term period. There is likely to be a large turnover of customers in a long-term contract. Although long-term contracts might work for providing System RA, they may not be as reliable for providing local and Flexible RA if sufficient customers are not in the right locations over the long term. Long-term contracts may also hamper addressing major developments like the SONGS shutdown and resulting need for targeted DR. ORA therefore recommends the Commission limit the initial DRAM auctions to the three year term as all participants, DR providers, and other stakeholders are most familiar with the three year DR cycles.

Eventually, participants should be able to offer contracts of longer duration if they can reasonably expect to meet the contract requirements for longer period. Conditions under which the contract is considered in default and any liquidated damages for not meeting longer term delivery should be set appropriately.

ii. In addition to the elements listed in this proposal, are there provisions that should be included in a standard contract? Explain the reason for each recommended provision.

The provisions listed in the proposals appear sufficient.

iii. Are there benefits or drawbacks to holding one auction per year for seasonal products (May-Oct; Nov-Apr)? Describe these benefits and drawbacks. How should seasonal products be defined and structured, so as to maximize the potential of demand response in these seasons? If a different approach is preferable, describe in detail.

It is administratively burdensome to hold multiple auctions per year with multiple deadlines for review and approval, especially at the onset of offering an auction. There is no reason why the year-round auction cannot accommodate varying prices and amounts of system, local and flexible resources for each month of the year. It would be best to take a wait-and-see approach for the first auction scheduled in 2015.

iv. The proposed auction schedule is detailed in Attachment B. Provide any comments on the schedule, in recognition of the following desired parameters: a) maximum of six months from RFO issuance to Commission approval, b) up to 60 days for bid selection and contract signing, c) 60 days for Commission review and approval of contracts, and d) alignment with annual resource adequacy showings in October.

The proposed schedule appears to be workable.

v. Is it preferable to have additional minimum eligibility criteria for bids than those listed in this proposal? Please fully describe the recommended criteria and how it should be used to judge bid viability.

The bidding requirements should be consisted with the provisions established in Commission's Rule 24 for SCE and PG&E and Rule 32 for SDG&E. At the April 29, 2014 question and answer working session, ED stated that DRAM is a pure DR capacity auction, so it does not have any pricing triggers. ED stated that the DR products procured through DRAM will be required to meet product-specific RA criteria and must participate in CAISO energy markets by either providing bid or self scheduled under CAISO's Must Offer Obligation (MOO). However, unlike conventional supply resources, DR products do not have any associated incremental costs and can be offered as high as the current CAISO cap of $1000/MWH. ORA is concerned that DR providers could bid at very high prices and avoid being called. This, in practice, could result in a price-responsive program being only called in an emergency. ED stated that they expect DR providers would want to bid and get awarded. ORA is concerned that for some providers though the cost of being called might exceed any energy payment received from the CAISO. The Commission should include some protection in the standard contact to prohibit this type of gaming.

vi. The proposal is to base the capacity cost cap for each auction on the average of bids received, per auction. Are there additional factors that should be considered in constructing a capacity cost cap? Is a different approach preferable? Please describe any recommendations in detail.

The cost cap should be determined based on a weighted average, not average, of bids received.

At the April 29, 2014 question and answer working session, ED stated that there will be a single cost cap developed based on the bids received for System, Local and Flexible RA products, all lumped together. Although a single cost cap is simpler and easier to administer, it could have the unintentional effect of rejecting bids that may truly reflect the cost of providing a product such as Flexile RA.

ED also stated that the DRAM proposal will not make public the amounts of each product type that is being sought under the overall procurement target. ED explained this is intentional to solicit maximum response from the bidders. ORA expressed that if the bidders largely bid for a particular product type, there may be a mismatch between the product need and bids received. Some of the utilities participating in the session indicated that they routinely provide the information on the amounts of products being sought and have no concerns about bidders having this information. ORA agrees that the information on the amounts of various products being sought should be made available to bidders. ED indicated they will take this concern under advisement.

Too few participants could lead to high bids that are not competitive. There should be sufficient off ramps designed to address this scenario. ED indicated the cost effectiveness would be an upper limit going into the auction in addition to the weighted average cost cap based on submitted bids. The Commission should also compare DRAM bids to historical DR program costs to ensure gaming is not occurring.

vii. Emergency demand response resources are included in the DRAM, which means that these resources must receive their capacity payments via a competitive mechanism. Provide specific recommendations on this approach.

It is not clear who will represent the customers in the auction. For example, the customers in the Base Interruptible Program (BIP) are currently compensated by the IOUs based on each customer's own performance in an event. Will these customers be allowed to bid into the auction on an individual basis or must they be bundled together by a DR provider to provide a much larger RDRR product? The Commission should clarify.

viii. This proposal contains the option for the Commission to publish a weighted average of bids received at some point following each auction. Are there competitive, or any other, concerns with this action, should the Commission choose to adopt it? Describe in detail. If another approach or calculation is preferable, describe the recommendation in detail.

If there are too few players in the auction, there is potential for bid information to be gleaned based on the published weighted average bid costs, which in turn could have competitive implications for the next auction. It is not clear that there are any benefits to sharing of this information publicly. Parties involved in oversight should, however, obtain such information after signing appropriate confidentiality agreements. At a minimum, the Commission should not commit to providing the weighted average cost information at the outset. Alternatively, if the Commission decides to publish weighted average bid information it should wait to publish the information on the first auction after the bids are submitted for the second auction to mitigate any anti-competitive impact.

ix. The proposal notes that penalties may apply if deliveries of the DR resource fall below 60% of contracted capacity. Comment on the appropriateness of penalties in addition to capacity derates, and the point at which penalties could or should apply.

The structure of incentives and penalties looks appropriate now but the Commission will need to review how they actually perform under this structure to determine if the penalties provide enough motivation for performance. However, this penalty structure should not be considered in isolation to the other factors of the contract. For example, there should still be provisions to end contracts for consistent under or non-performance, or if it becomes evident that some DRPs are gaming the system.

x. This proposal currently envisions Commission-regulated utilities procuring DRAM capacity on behalf of their own load, and does not include a procurement obligation for other Load Sharing Entities. Comment on whether other Load sharing entities should also have a procurement obligation for DRAM capacity and, if so, how such procurement should be structured. Be as specific as possible.

ORA noticed a typo in the first sentence. The wording should be Load Serving Entities and not Load Sharing Entities.

Other LSEs should be allowed to procure DR through the DRAM if they choose to in order to meet their RA obligations. In any case, the customers of other LSEs should be allowed to participate in DRAM through a DRP of their choice. ORA supports any solution that increases cost effective procurement of DR.

4. In D.14-03-026, the Commission discusses its policy of increasing the amount of demand response integrated into the CAISO market. Provide your thoughts on how we can determine an appropriate annual goal for overall demand response integrated into the CAISO market. Are there terms that we need to identify and define? What should those terms and definitions be?

Under the Energy Division's Revised Staff Proposal [9] for meeting RA eligibility, all supply side DR will have the obligation to bid or self-schedule in CAISO markets and will be subject to CAISO's Must-Offer Obligation (MOO). The annual goal for overall demand response integrated into the CAISO market should be consistent with meeting the RA requirements for that year. All demand response that meets the Commission's RA requirements in a cost effective manner should be encouraged. Furthermore, the Commission should ensure that all supply side DR that is funded by IOUs' ratepayers are eligible for receiving equal RA credit so that ratepayer investment in DR is not stranded.

5. Do we need to improve forecasting with regard to supply resources that will be integrated into the CAISO energy markets? What are methods to improve

[9] Qualifying Capacity and Effective Flexible Capacity Calculation Methodologies for Energy Storage and Supply-Side Demand Response Resources," Revised Staff Proposal, Resource Adequacy Proceeding R. 11-10-023, by CPUC's Energy Division, dated April 9, 2014., p. 2.

the forecasting? What are methods that the Commission can use to modify current demand response programs to meet forecasted needs? What are methods that the Commission can use to design new programs to meet forecasting needs?

ORA understands that both PG&E and SCE are preparing to integrate/bid some or all of their existing DR supply resources in the CAISO energy market in the summer of 2014. Similar to the monitoring of DR program performance done for SCE and SDG&E in 2012, the Commission's Energy Division should monitor and study how these resources performed in 2014 and publish its findings and recommendations.[10]

All future DR supply resources integrated into the CAISO energy markets would be provided through contracts. Accurate forecasting is a contractual issue where aggregators must meet their obligations so that the amount forecasted equates with the contracted capacity and what is actually provided. The contracts should have conditions requiring the aggregators to inform the IOUs if they cannot meet the obligations so that forecasts can be adjusted accordingly.

6. **D.12-04-045 discussed the future of demand response and questioned what the roles of the utilities and third party providers would be in administering future programs. We look at the roles of utilities and third party providers in administering supply resources. Provide your comments on whether a utility centric model for supply resource demand response can meet current and future needs. Provide your comments on the ability of third-party providers to provide supply resource demand response to meet current and future needs. As discussed in D.12-04-045, should the Utilities continue to offer rate regulated supply resource demand response if these services are provided through competitive markets? Should the Commission focus on identifying more of these programs as supply resources, thus facilitating broader competition in the market? Should the utilities' role be solely to oversee the competitive procurement?**

ORA does not understand how the utilities' role in providing rate regulated DR services could be eliminated as long as the utilities remain the sole source of payments for those services. A standard DRAM contract such as the one proposed in this ruling would limit the utilities' role to administering DRAM contracts but the cost recovery of such procurement would still be done by the utilities through their rate regulated mechanisms and proceedings. The utilities should be able to procure cost-effective DR resources, if the utility administered procurement auctions such as DRAM do not solicit sufficient response to meet the Commission's goals for DR.

7. **For supply resources integrated into energy markets without a capacity contract, does the Commission have any role in tracking the resources' load impacts?" If yes, how should the load impacts of these resources be tracked and accounted.**

ORA finds this question confusing. It is not clear how DR supply resources can be integrated into the energy markets without a capacity contract. By definition a "supply"

[10] Commission [CPUC] Staff Report- *Lesson's Learned from Summer 2012 Southern California Investor Owned Utilities'' Demand Response Programs May 1, 2013.*

resource implies the obligation to bid or self-schedule in CAISO markets under the CAISO's Must-Offer Obligation (MOO). The Commission's own definition in D. 14-03-026 for supply resource is even more stringent[11] and would require a resource with capacity obligation under a contract. Does the question mean non-supply resources bidding into energy markets? If so, the Commission would have no obligation or purpose to track the bids; it would be the role of the CAISO to determine performance and payment.

D. Load Modifying Resources Issues

1. Parties requested the Commission to analyze the characteristics of each demand response program in order to categorize current and future demand response programs into load modifying resources and supply resources. Provide your list of characteristics that the Commission should use in determining how to categorize a Load Modifying Resource.

ORA agrees with CAISO that, "a clear bifurcation definition ensures that all parties, most importantly the CEC, CPUC, IOUs and ISO, clearly know how each and every demand response program is classified, or is to be classified, and therefore, treated for load forecasting purposes, because load forecasting implicates all planning and procurement functions, including resource adequacy and long-term procurement plans."[12] As described earlier, linking DR programs to RA requirements provides a clear and workable definition for classification purposes.

However, unlike a Commission-regulated RA proceeding for supply side resources, there has not been a comparable Commission effort or a formal proceeding to examine load modifying DR program requirements. In fact, under the current construct, the CEC would be responsible for determining which DR programs should be classified as load modifiers in its load forecast, what load impacts to be used, and how the load shape will be affected by these programs. The Commission and the CEC should jointly establish a transparent process and protocols to 1) determine program requirements 2) megawatts load impacts to be used, and 3) how different trigger events will influence the shape of the net load. ORA recommends a workshop on this issue.

2. Using your proposed list of characteristics, describe each demand response program and determine whether that program should be classified as a supply resource, as defined by D.14-03-026. Using your list of characteristics, describe how and whether subsets of customers in existing programs could be sub-aggregated and classified as Load Modifying Resources.

ORA generally agrees that programs shown in Table 2 of the bifurcation decision, D. 14-03-026, as "load modifiers" are correct.

Subsets of customers in existing DR programs should be able to be classified as load modifiers if they can meet the requirements for load modifying programs. ORA defers to the

[11] In D.14-03-026, the Commission defines "supply resources" as those DR programs that can be dispatched into the California Independent System Operator's (CAISO) energy markets, when and where needed.

[12] Reply Comments of the California independent system Operator corporation on the Proposed Decision, March 18, 2014, p. 4.

CEC to examine if this concept is workable. The joint effort between the Commission and the CEC should address this issue.

3. How can the Commission improve current programs designated as load modifying resources in order to meet forecasted needs? As we discussed above, does the Commission need to improve forecasting for Load Modifying Resources? How?

The utilities currently provide ex-ante forecasts of load impacts through annual load impact reports which offer recommendations for program improvements and comments on developing more accurate ex-ante forecasts.[13] Additionally, the utilities provide daily forecasts of available load reduction to the CAISO and the Commission.

On May 1, 2013, pursuant D. 13-04-017, the Commission Staff issued a report on "Lessons Learned From Summer 2012 for Southern California" which includes an analysis of SCE's and SDG&E's forecasting methodologies for daily forecasts. On July 16, 2013, the Commission issued D.13-07-003 which adopted findings included in the Staff report. D. 13-04-003 directed SDG&E and SCE, as representatives of the Demand Response Measurement and Evaluation Committee (DRMEC), to file a Tier One Advice Letter reporting forecasting methodologies pursued in 2013 and the results and recommendations for daily forecasting for 2014 and beyond.[14] In response, SCE and SDG&E filed a report in a joint advice letter that showed areas of improvements implemented in daily forecasting.[15]

The Commission should direct Energy Division to provide similar analysis on PG&E's daily forecasting methodologies and offer specific recommendations for improvements. If needed, PG&E should similarly implement changes to their methodologies and file a report.

4. In R.07-01-041, the Commission included in the scope of the proceeding, the intention to set annual goals for load impacts. How should the Commission determine those goals for Load Modifying Resources? Does the Commission have any guidelines in place that it could use as a starting point for establishing rules to comply with these goals?

There should not be any specific load impact goals for Load Modifying Resources. All cost effective DR that can be shown to avoid conventional generation in a transparent manner should be encouraged. The Commissions should ensure that the utilities providing Load Modifying Resources are including all direct, indirect and overhead costs for the programs in their cost effectiveness evaluations. Additionally, demand response resources not selected in the DRAM auctions but which could still participate as load modifiers should be allowed to do so.

5. D.12-04-045 discussed the future of demand response and questioned what the roles of the utilities and third party providers would be in administering future programs. We look at the roles of utilities and third party providers

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[13] D.08-04-050, as modified by D.10-04-006, requires SCE, SDG&E, and PG&E to perform annual studies of their DR activities using the adopted load impact protocols, and to file reports consistent with Protocol 26 annually on April 1 of each year.

[14] D.13-07-003 Ordering Paragraphs 4 and 5, pp. 39-40.

[15] Jointly filed Advice Letters SCE AL 3000-E and SDG&E AL 2572-E, dated January 31, 2014.

in administering load modifying resources. Provide your comments on whether a utility-centric model for load modifying resource demand response can meet current and future needs. Provide your comments on the ability of third-party providers to provider Load Modifying Resource demand response to meet current and future needs. As discussed in D.12-04-045, should the Utilities continue to offer rate-regulated load modifying resource demand response if similar services are provided through competitive markets? Should we limit the utilities' role in providing load modifying resource demand response? How?

In general, customers participating in utilities' Load Modifying programs (TOU, CPP, PTR etc.) do not receive any capacity payments from the utility for their participation. On the other hand, third-party providers typically require some level of capacity payments to cover their costs and make a profit.

Conceptually, if all of the costs a utility incurs in providing Load Modifying programs are considered, it may be possible to offer a capacity payment to third-party providers while not exceeding the costs incurred by the utility. Alternatively, if third-party providers can provide "value-added" Load Modifying programs that modify the net load on the system in a more specific and beneficial way, a separate capacity payment may be justified. The Commission should explore these options in small incremental steps to gauge their feasibility.

E. Program Budget Application Process

1. **In the OIR, the Commission discussed the idea of longer budget cycles. Provide your comments on why the Commission should consider longer budget cycles. Provide justification for the specific length of the budget cycle.**

2. **If the Commission approves longer budget cycles, i.e. 5 or 10 years, should there be regular reviews of the budgets in between the application approval. How often should the reviews occur and what level of scrutiny should be involved and why? How can evaluation, measurement, and verification (EM&V) processes be leveraged to improve demand response programs in longer budget cycles?**

Some form of longer-term contracts may mitigate some of the consequences of the current 'start/stop' cycles. The current three year DR programs cycles have resulted in numerous hastily arranged bridge funding authorizations with little room for making needed changes to the programs. Though, because of the evolving nature of DR, a longer term contract should ensure there is adequate review and 'off-ramps' for underperforming contracts so needed changes could be made on a going-forward basis. Cost effectiveness and annual performance still must be evaluated at regular intervals to identify underperforming contracts.

Unlike a physical power plant that is under a long-term contract, the DR aggregators have not provided evidence that they have the ability to recruit the same customer over a long-term period. There is likely to be a large turnover of customers in a long-term contract. Although long-term contracts might work for providing System RA, they may not be as reliable for providing local and Flexible RA if sufficient customers are not in the right locations over the long term. Long-term contracts also may hamper addressing major developments like the

SONGS shutdown and resulting need for targeted DR. ORA therefore recommends the Commission limit the initial DRAM auctions to the three year term as all participants, DR providers, and other stakeholders are most familiar with the three year DR cycles.

Eventually, participants should be able to offer contracts of longer duration if they can reasonably expect to meet the contract requirements for longer period. The liquidated damages for not meeting longer term delivery should be set appropriately.

III. PHASE TWO REMAINING ISSUES AND QUESTIONS

A. Back-Up Generators

1. **In D.11-10-003, Ordering Paragraph No. 3, the Commission adopted a policy statement that any demand response program, whether operated by a Commission-regulated Utility or another entity, that uses fossil-fueled emergency back-up generation (BUG) for demand reduction should not count towards resource adequacy obligations for any Commission-jurisdictional load shedding entity. Provide your understanding of the status of the Utilities' compliance with this policy statement.**
2. **How should the Utilities collect data on the customer's use of fossil-fuel emergency BUG during the demand response events? Identify the amount of demand response provided by BUG on an on-going basis?**
3. **How can this policy be further implemented for the Utilities' existing and new demand response programs as Supply Resource and Load Modifying Resources? What methods should the Commission use to exclude demand reduction provided through the use of BUG?**
4. **Should the Commission require on-site sub-metering for BUG and/or should the Commission require self-certification with the inclusion of data regarding the intended use of BUG during demand response events? If on-site metering is preferred, how should the costs of the metering be recovered?**

ORA provided extensive comments in its December 13, 2013 Opening Comments and December 30, 2013 Reply Comments on the foundational issue of the use of BUGs. ORA summarizes the main points here from those comments that are relevant to the questions here.

Utilities' DR program tariffs should explicitly state that the use of BUGS for providing DR is prohibited. Utilities are the main data collectors on their customers' usage of electricity. However, third-party aggregators probably have the more intimate knowledge of DR strategies employed by the customers involved in DR programs. Therefore, there should be financial consequences for the Demand Response Providers (LSEs or third-party) for either knowingly allowing or ignoring a customer's use of BUGs in providing DR.

B. Cost Recovery

1. **Provide a summary of each of the Utilities' current demand response program cost recovery and provide citations for the decisions authorizing this recovery method.**

2. Should the current cost recovery policy be changed? Please describe your proposed alternate cost recovery methods for the Supply Resource and Load Modifying Resource demand response programs in the future?

3. Are there fairness issues that the Commission should consider for Commission-regulated utilities and other Load Sharing Entities? Please describe these issues in detail, with specific recommendations for resolving and/or avoiding these issues.

ORA provided extensive comments in is December 13, 2013 Opening Comments and December 30, 2013 Reply Comments on the foundational issue of cost recovery. ORA summarizes main points here from those comments that are relevant to the questions here.

The current Cost Recovery accounting mechanisms are not consistent across the three IOUs, even for the same or similar programs. Unless there are specific reasons for different mechanisms, the Commission should require consistency.

Currently, there is no clear Commission guidance on cost recovery and consequently the three IOUs can recover program implementation costs differently for the same DR program. PG&E uses cost causation principles that ensure DR program costs are recovered via distribution rates from all customers who either participate in or benefit from the programs.[16] SCE's method recovers costs only from those customers who are able to participate in a given DR program.[17] Both DACC and AReM argue that costs associated with utility programs should be recovered through generation rates that are paid by the utilities' bundled customers only.[18] So, depending on the program, costs are recovered from either the bundled customers or all customers.

Cost recovery should follow benefit allocation. ORA recommends that costs should be recovered from all customers, including DA and CCA customers, unless a party is able to show with clear evidence that a DR program benefits only a certain group of customers. In such cases, costs could be recovered from only those customers who benefit from the DR program. Reliability benefits impact all users of the distribution system, as they reduce system resource adequacy costs and prevent outages affecting all distribution customers.

ORA recommends DR implementation costs be allocated to all customers using a calculation method that reflects total revenues. Using the equal percent of revenues allocation is a balanced approach recognizing that DR benefits primarily accrue to customers in the form of reduced generation costs and secondarily as reduced transmission and distribution costs. This method also recognizes that all customers benefit from DR programs. Therefore, this method is fair to both the the Commission-regulated utilities and other Load Sharing Entities.

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[16] *Joint Assigned Commissioner and Administrative Law Judge Ruling and Scoping Memo ("Scoping Memo")* in R. 13-09-011. PG&E's Opening Comments, p. 14.

[17] *Joint Assigned Commissioner and Administrative Law Judge Ruling and Scoping Memo ("Scoping Memo")* in R. 13-09-011. SCE's Opening Comments, p. A-7.

[18] *Joint Assigned Commissioner and Administrative Law Judge Ruling and Scoping Memo ("Scoping Memo")* in R. 13-09-011. The Direct Access Customer Coalition (DACC) and Alliance for Retail Energy Markets (AReM) (DACC-AReM), Opening Comments p. 5.