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.	R.13-09-011 (Filed September 19, 2013)

OPENING BRIEF OF PACIFIC GAS AND ELECTRIC COMPANY

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Pursuant to the schedule established by the Presiding Administrative Law Judge's July 31, 2014 ruling, Pacific Gas and Electric Company (PG&E) submits its opening brief on issues identified for briefing in the Settlement filed August 4, 2014 (Settlement). There are two Phase 2 issues and one Phase 3 issue identified for briefing in the Settlement: 1) allocation for demand response (DR) costs among bundled and unbundled customers, 2) potential limitations on the use of fossil-fueled back-up generators (BUGs) for DR, and 3) participation in the Demand Response Auction Mechanism (DRAM) Pilot and the potential interaction of other types of Supply Resource DR solicitations with the DRAM Pilot.

I. ALLOCATION OF DEMAND RESPONSE COSTS ARE EQUITIBLY RECOVERED FROM ALL CUSTOMERS VIA DISTRIBUTION RATES

In this rulemaking, the California Public Utilities Commission ("CPUC" or "Commission") is presented with the question of whether to continue or modify the rules for the recovery of IOU DR program revenue requirements. The two primary positions on this issue are:

1) Continue allocating program revenue requirements to bundled and unbundled customers, which would apportion DR program costs via electric distribution charges to all customers regardless of energy supplier. This position is supported by PG&E, San Diego Gas and Electric Company (SDG&E), and the Office of Ratepayer Advocates (ORA). (Haertle, PGE-01. p. 8-4, ll. 6 to 16; Fang, SGE-06. pp. GK-2, l.19 to GK-3, l. 20; accord, Gokhale, ORA-1, p. 17, ll. 22-27.) since all customers benefit from DR.

2) Change allocating DR revenue requirements only to electric generation charges, which would assign costs solely to bundled customers. This position is supported by the Direct Access Customer Coalition and Alliance for Retail Energy Markets (DACC/AReM), who provides energy supplies to PG&E's unbundled distribution service customers. (Mara, DAC-01, p. 3, ll. 19-20.)

The Commission should continue to recover DR revenue requirements via distribution charges. Doing so ensures that DR program costs continue to be recovered equitably by reflecting cost causation and the benefits that all customers on the electric system receive from the IOUs' DR programs.

A. Should Cost Allocation Principles for Demand Response Costs be Decided Here?

The cost allocation issue in this case is whether Direct Access (DA) and community choice aggregation (CCA) customers should help pay the costs of the IOUs' DR programs, or whether they should be exempted, by placing all DR costs in generation rates which only bundled customers pay. The answer to this question involves factors such as the benefits of DR, cost causation, eligibility to participate in the programs, equity and fairness. A careful review of these factors for particular programs could depend on the programs' use and characteristics under the future framework for DR at the Commission and CAISO. Such a review could occur in future proceedings, where the IOUs present the programs for evaluation and approval by the Commission and DR program cost recovery could be based on the facts and policy then applicable. SCE witness Aldridge states:

> . . . any change in policy should be based on the specific costs for which the utility is seeking recovery and should be specific to each utility funding application. The Commission should refrain from establishing a strict method for DR costs and thereby prejudge all future DR applications.

(Aldridge, SCE-01, p. 45, ll. 18-20.) (see, Besa, SGE-04, p. AB-6, ll. 17-28; c.f. Haertle, PGE-03, p. 4-7, l. 21 to p. 4-8, l. 5.) In light of the changing environment for DR, the IOUs' role in procuring and delivering DR in the future, and the evolving CAISO and Commission framework for DR, PG&E respects SCE's position, but is amenable to having the issue decided in this proceeding.

The November 14, 2013 Joint Assigned Commissioner and Administrative Law Judge Ruling and Scoping Memo raises possible revisions to DR program cost allocation in relation to bifurcating DR into demand-side and supply-side DR in this case. (Nov. ACR, attachment 1, pp. 2-3.) In response to the ACR, DACC/AReM assert that a final decision should be reached now on whether or not DA/CCA customers should be exempt from bearing any costs for IOU DR programs, instead of the current allocation of DR costs to both bundled and unbundled customers. (Mara, DAC-01, p. 3.)

Since the Commission may decide to resolve the issue of whether DA/CCA customers should or should not help pay for DR programs in its decision here,[1/] the IOUs and other parties have sponsored testimony explaining their principles for cost allocation, how DA/CCA customers benefit from DR programs, and why they should not be exempt from paying for them. The following sections of this brief address these topics.

B. Principles For Allocation Of DR Costs To Bundled And Unbundled Customers

To ensure an equitable allocation of DR program costs between bundled and unbundled customers, PG&E has identified underlying principles for DR cost allocation. Specifically, DR cost allocation should reflect and consider the following attributes:

- Customer eligibility to participate in DR programs.
- Benefits of the DR programs.
- Cost causation
- Equity and fairness.

The use and consideration of these principles and attributes – in the context of bundled and unbundled customers – DR programs and costs, IOUs and other load serving entities like DACC/AReM and Marin Clean Energy (MCE), the Commission's DR policies, and the

1/ In D.12-04-045, page 204, the Commission indicated that question of cost allocation between DA/CCA and bundled customers should be considered in a rulemaking: "We agree that these issues should be considered in a consistent manner across all three utilities and thus are best handled in one proceeding. We think that the most appropriate forum would be the R.07-01-041 or its successor to establish overall rules and then those rules can be applied in the Utilities' respective rate design applications."

California Independent System Operator's (CAISO) needs, merits thoughtful and careful consideration. When the facts are reviewed from these perspectives, the Commission should conclude that all customers, whether bundled or unbundled, should pay for DR programs.

C. PG&E Makes Almost All DR Programs Available to All Customers And Incurs DR Costs On Behalf Of Program Participants, Regardless Of Energy Supplier.

1. PG&E's DR Programs And Distribution TOU Rates Are Open To All Customers. Only Dynamic Generation Rates Are Unavailable For DA/CCA Customers

PG&E's DR programs, except for Dynamic Pricing Programs that are based on the generation rate component, are open to all customers, regardless of whether they are supplied by an IOU, Energy Service Provider (ESP), or CCA. When a customer is eligible for a DR program, PG&E incurs the costs (including administrative and incentive costs) to make the program available to them.

All PG&E DR programs approved in its DR application cycle in D.12-04-045 are available to unbundled and bundled customers on the same basis. These programs are the Base Interruptible Program (BIP), Optional Binding Mandatory Curtailment, Scheduled Load Reduction Program (SLRP), Capacity Bidding Program (CBP), Demand Bidding Program (DBP), Aggregator Managed Portfolio (AMP), SmartAC, Auto DR, Technical Incentives, DR Emerging Technology and Permanent Load Shifting. (Haertle, PGE-03, p. 4-4, Table 4-1.) SLRP is capped at 0 MW, so neither unbundled nor unbundled customers can participate in it (*Id.*, footnote a.).[2/] MCE complains that many IOU-run DR programs such as Air Condition Cycling (AC Cycling) are ill-suited for many of its ratepayers due to their location, asserting "MCE's customers derive little value in participating in PG&E's AC Cycling program because they reside in a mild costal (sic) climate and have limited air conditioning-related electricity

2/ Marin Clean Energy (MCE) noted that SLRP is not open to CCA customers (Waen, MCE-01. p. 6, l. 1-2), but Mr. Waen neglected to mention that SLRP is also unavailable for bundled customers. So Mr. Waen's assertion is irrelevant since unbundled and bundled customers are treated the same, just as they are for the other PG&E programs in D.12-04-045.

usage." (Waen, MCE-01, p. 6, ll. 3-7.) MCE's customers, however, are in the same position as PG&E bundled customers who live in mild coastal climates, like the central coast or Humboldt County. AC Cycling is available for both MCE and PG&E customers on the same terms, but whether it makes sense for individual customers depends on the customer's situation.

Since DA and CCA customers do not pay the IOUs' generation rate component, they do not participate in Dynamic Pricing Programs that only involve that rate component. However, when time-varying pricing is part of a distribution rate, DA and CCA customers participate, either on an opt-in or mandatory basis. DACC/AReM claims that unbundled customers cannot participate in TOU (Mara, DAC-01, p. 15), but that assertion is completely wrong in connection with distribution rates. PG&E'S agricultural time-of-use (TOU) rates include time-varying distribution rate components that apply at different times of the day and year: peak summer, part-peak summer, off-peak summer, part-peak winter and off-peak winter. (e.g. Electric schedule AG-4, sheet 7; Electric schedule AG-5, sheet 7.)[3/] Residential TOU rates have summer peak, part-peak and off-peak distribution components, and winter part-peak and off-peak distribution components. (Electric schedule E-6, sheet 3.)[4/] The small commercial general TOU rates have peak summer, partial-peak summer, off-peak summer, partial-peak winter and off-peak winter distribution components. (Electric schedule A-6, sheet 4.)[5/] Actually, the only PG&E TOU distribution rate components that do not have time-varying components are A-1 TOU and A-10 TOU. All the other PG&E TOU schedules have time-varying distribution rate components, and they are open to DA and CCA customers.[6/] [7/]

3/ http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_AG-4.pdf.
For PG&E's TOU schedules, Distribution and New System Generation charges are combined for presentation on customer bills. However, the distribution rates are separate and time-varying in the TOU schedules. http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_AG-5.pdf.

4/ http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_E-6.pdf.

5/ http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_A-6.pdf.

6/ DA and CCA customers are not eligible for the Peak Day Pricing or SmartRate provisions in PG&E's TOU tariffs because PDP and SmartRate are generation rate components, but DA and CCA customers may take service pursuant to the rest of the provisions in the TOU tariffs. Distribution and New System Generation.

7/ For industrial Schedules E-19 (sheet 5) and E-20 (sheet 4), time-varying distribution is reflect in the demand charges based on maximums for peak demand summer, part peak demand summer, The question of cost causation applies to the distribution system and the loading at the time of a power line's peak. PG&E's distribution rate components do vary based on TOU period. Therefore, unbundled and bundled customers taking service on these rate schedules participate in time-differentiated distribution pricing. Furthermore, Commission rate design is not set in concrete. For the future, no one should be surprised if the Commission continues to explore the use of TOU or dynamic rates (or DR programs) to signal time-differentiated costs for the delivery function.[8/]

2. Program Participation, In And Of Itself, Should Not Be The Sole Basis For Allocating DR Program Costs

MCE's position is that DR revenue requirements should only be allocated to ratepayers who are allowed to participate in the associated DR program and when the LSE derives the primary benefit from the DR program. (Waen, MCE-01, p.4.) This argument also appears in DACC/AReM's testimony in connection with dynamic pricing tariffs. (Mara, DAC-01, p. 15.) Trying to use that principle, however, would also require changing cost allocation within the bundled customer group, because eligibility to participate in a DR program is not just simply defined by "unbundled" versus "bundled" status.

PG&E has demonstrated in previous testimony before the Commission that program participation, in and of itself, is not the sole basis for allocating DR program costs. In both Application (A.) 08-06-003 and A. 11-03-001, PG&E noted that bundled residential, small commercial, small agricultural and streetlight customers were not able to participate in the Base Interruptible Program, yet they have funded this program via distribution rates. (Haertle, PGE-03, p. 4-6, ll. 11-17.) And as discussed below, DR helps all customers, including those who do not participate in DR programs, by serving the goal of grid reliability, which benefits DA and

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demand summer, part-peak demand winter and demand sinter. Since all distribution costs on E-19 and E-20 are collected either through customer charges or demand charges, these two rate schedules do not have volumetric per kW distribution charges.

8/ The Commission is considering possible changes in policy for TOU residential rates in its OIR into residential rate structures, R.12-06-013.

CCA customers as well. This benefit supports continuing the current approach of having all customers contribute to DR cost recovery.

DACC/AReM cites D.12-12-004 from SDG&E's most recent GRC II case for the proposition that eligibility to participate should be the controlling factor to allocate DR program costs. DACC/AReM identifies Dynamic Pricing as a program with costs that should be allocated to generation rates under D.12-12-004 guidelines.[9/] (Mara, DAC-01, p. 18, l. 11 to p. 19, l. 2.) That SDG&E decision, however, is inapplicable to PG&E's DR program costs. First, all PG&E DR programs are open to both DA and CCA customers, except for Peak Day Pricing (PDP) and SmartRate, which are unavailable to DA customers because those customers do not take generation from PG&E. (Haertle, PGE-03, p. 4-4, table 4-1.) Cost recovery authorization for PG&E's PDP and SmartRate implementation also occurred long ago. PG&E's SmartRate implementation costs were addressed in its AMI case, D.06-07-027, and governed by cost recovery established there. PG&E's PDP cost recovery was authorized in D.10-02-032, which allocated the costs to distribution rates. (Haertle, PGE-03, p. 4-7, ll. 26-34.) Currently, PG&E's on-going Dynamic Pricing customer service costs are part of PG&E's general rate case proceedings—not its DR program applications. (*Id.*)

Moreover, R.13-09-011 is where all stakeholders are litigating the issue of DR program cost allocation between unbundled and bundled customers. This is the proceeding where all the parties have presented evidence and are making their arguments. SDG&E's GRC II did not have the breath or depth of representation and participation that is present for litigating the issue in this proceeding, and D.12-12-004 should not be given any weight.

In addition, the Commission continues to develop policies for DR that change eligibility for DR programs, which undermines the basis of "participation" as a determining factor in DR cost allocation. For instance, under the direct participation rule for demand response approved

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9/ DACC/AReM also identified SmartAC as a program only open to bundled service customers. That is incorrect. PG&E's rebuttal testimony, (Haertle, PGE-03, p. 4-4), shows that SmartAC is open to all customers including DA and CCA customers. However, the commercial SmartAC program is closed to new customers, whether bundled or unbundled.

earlier this year (Electric Rule 24/32), third party DR providers can use bundled IOU customers to bid directly into the CAISO wholesale market.[10/] However, Rule 24 requires that IOU customers who register at the CAISO for direct participation cannot also participate in IOU DR programs. That condition applies to bundled customers as well as unbundled customers. (Rule 24, C.2.d, sheet 9.)[11/] Moreover, bundled customers on dynamic pricing such as PDP, must be removed automatically from PDP when they are registered at the CAISO. (*Id.*, sheet 10.) Consequently, bundled customers will become ineligible for IOU DR programs by participating in the CAISO market under Rule 24.

Evolving DR policies, including changes in eligibility rules, demonstrate why eligibility to participate in a DR program is not a sound basis for DR cost allocation. "Participation" is too narrow a basis for cost allocation in this environment. Commission developments in demand-side notification and outreach, as discussed in the section 3 below for *Flex Alerts and Energy Upgrade California*, also illustrate the need for a more holistic approach. The Commission itself has stated. . .our intent is to move away from separately authorized marketing and outreach programs and budgets for statewide demand response, energy efficiency . . . and other statewide demand-side program efforts." (D.12-05-015, p. 301.)

The existing principle of allocating DR costs to all IOU customers provides a more simple and holistic foundation for cost allocation in this environment.

3. DR Programs That Are Not Participation-based, Such as *Flex Alerts* And Marketing, Education And Outreach For The Commission's Demand-Side Umbrella Brand *Energy Upgrade California* Benefit Californians In General And Are Supported By PG&E DR Funding

In addition to funding explicit DR programs in which customers directly participate, some DR funding is allocated to statewide notification and marketing efforts that benefit all

10/ For SDG&E, direct participate is covered in Rule 32.

11/ The ALJ ruling issued on August 14, 2014 in A.14-06-001, et. al directed that cost recovery for Rule 24 implementation will be litigated in that proceeding The discussion of Rule 24 in this brief is to illustrate the fact that the Commission continues to address new policies and requirements for DR.

customers (including unbunblded customers). Funding for the two notification or outreach programs for communicating with the general public about CAISO system conditions and CPUC jurisdictional demand-side programs is partially recovered through the IOUs' DR budgets. The CAISO system condition notification is the *Flex Alert* program and the outreach program is for statewide (SW) marketing, education and outreach (ME&O) for the Commission's *Energy Upgrade California* umbrella brand (*EUC*) for demand-side matters, including DR. Both *Flex Alerts* and the *EUC* SW ME&O program benefit everyone, regardless of unbundled or bundled status.

Flex Alert is an emergency alert program for use during system emergencies or power shortages. (D.13-04-021.) *Flex Alerts* are called by the CAISO, and are broadcast to Californians in general. The *Flex Alert* budget is funded by the IOUs, and for 2013 and 2014, the annual budget has been $10 million. (*Id.* OPs 1, 2, and 3.) PG&E's share of *Flex Alert* costs are paid in the same proportion as the authorized statewide ME&O revenue requirements, with 35.5 percent from DR. (*Id.*, p. 18 and OP 7.) This use of DR funds benefits the general population of California, not only bundled customers.

The Commission also directed the IOUs to fund its *EUC* umbrella brand for energy information and demand-side management actions by residential and small business customers. (D.13-12-038.) The *EUC* program is run by the Commission's designated provider, the California Center for Sustainable Energy (CSE), under a contract which the Commission first ordered PG&E to enter into with CSE in D.12-05-015, and continued under D.13-12-038.[12/] (D.12-05-015, p. 304 and OP 123; D.13-012-038, OP 27, vii.)[13/] The amount for the two years (2013-2014) is approximately $43.5 million in aggregate for the IOUs. (Letter Reporting Updated Budget Information in Compliance with OP 16 in D.13-12-038, served on all parties.)

12/ CSE recently changed its name from "California Center for Sustainable Energy" to "Center for Sustainable Energy."

13/ The government structure for *EUC* is described in D.13-12-038, OP 27, which begins by identifying the CPUC as the owner of the *EUC* brand, with overriding authority on all decisions.

PG&E's share of the SW ME&O costs is funded in part through DR, since D.13-12-038, OP 20 approved PG&E's proposal to allocated 35.5 percent to DR.

The CSE SW ME&O plan approved for the Commission's *EUC* brand is for all residential and small business customers, without regard to whether the customers are unbundled or bundled. Similarly, the *Flex Alert* program increases awareness and understanding by all Californians and is another example of why DR activity and costs should be viewed more broadly than on a narrow bundled versus unbundled basis. Unbundled customers should continue to bear DR costs along with bundled customers to benefit all California energy consumers.

4. DA And CCA Customers Currently Participating in PG&E DR Programs Realize A Subsidy From DR Program Costs Recovered Via Generation Rates

DA and CCA customers can and do participate in PG&E's Aggregator Managed Portfolio (AMP) program. DR providers in the AMP program can sign up customers to provide DR in the DR provider's portfolio whether or not the customer is bundled or unbundled. AMP program costs include incentives (about $10 million annually), which are recovered via generation rates, and administration expenses (about $0.4 million annually), which are recovered via distribution rates. (Haertle, PG&E-02, p. 4-5, ll. 22-32.) DA and CCA customers, who do not pay IOU generation rates, effectively avoid what would otherwise be their share of approximately 96 percent of AMP program costs each year and are, therefore, enjoying a subsidy borne by bundled customers. Since unbundled customers can and do participate in AMP, they should share the costs with bundled customers.

5. Cost Causation Supports Allocating DR Program Costs To Unbundled and Bundled Customers, Both Of Which Benefit From Grid Reliability and DR Programs

Unbundled customers give rise to costs for DR programs and or the grid that is protected by DR. With respect to the former, the costs paid for their participation in the AMP program discussed in the preceding section is undeniably a cost directly attributable to unbundled customers. The same is true for amounts paid for unbundled customers in the other DR programs, such as BIP, CBP, DBP, Auto DR, Technical Incentives, DR Emerging Technology and Permanent Load Shifting. In addition, administrative costs to run these programs and make them available to unbundled and bundled customers are also attributable to unbundled customers, as well as bundled customers. The same is true for administering distribution TOU rates, whether they are opt-in or mandatory.

The need to protect system and local grid reliability is due to the combined effect of all users, including unbundled customers. That is why protecting grid reliability benefits both unbundled and bundled customers, as discussed in the following sections. Since all customers use the grid, everyone contributes to causing the costs needed to protect grid reliability. Thus these costs, including DR costs protecting grid reliability, are caused as much by unbundled customers as by bundled customers. And unbundled customers should share in paying those costs.

D. DR Program Operations Provide Benefits To All Electric Customers Through Grid System Reliability And Wholesale Market Prices

DR programs provide system and local grid reliability benefits (as some programs may be called locally), and may reduce the market clearing prices. Enhanced grid reliability and lower market clearing prices benefit all customers, including unbundled customers not participating in DR programs. DR load reductions can defer or avoid the construction of generation units and/or electric transmission facilities, to the benefit of all electric customers.

1. DACC/AReM Completely Misrepresents PG&E Testimony By Claiming Mr. Abreu Equates DR And Generation

DACC/AReM recommends that all DR program revenue requirements be recovered via generation rate components. DACC/Are asserts that DR programs are a near-perfect substitute for electric generation supplies, which can be dispatched by the CAISO in their wholesale markets. DACC/AReM cites PG&E Witness Abreu's testimony to claim that he equates DR with generation, but that completely mischaracterizes his testimony. (Mara, DAC-02, pp. 2-3.)

DACC/AReM quotes and misuses Mr. Abreu's comparison of the "IOU's role in competitively procuring DR . . . [as] analogous to their role in procuring generation resources". (*Id.*) The quoted text is about the IOUs' role on how it conducts competitive procurement; it does not equate DR and generation resources. DACC/AReM also mischaracterizes Mr. Abreu's statement about IOU procurement of supply-side DR to meet "LSE's obligations". (*Id.*) That statement is in Answer 18, at PG&E-01, pages 4-14 to 4-15, where Mr. Abreu discusses the IOU obligations to provide rate options, energy efficiency, integrated approaches for customers; to own and operate the distribution systems; to own and participate in transmission planning; and to incorporate DR into transmission and distribution (T&D planning and operations to capture cost-effective DR).[14/] Question 18 is about the roles of utilities and third-party providers in administering future programs, including the IOUs' obligations to offer rate regulated supply resource demand response through competitive markets, (*Id.* p. 4-14, ll. 1-12.) As Mr. Abreu's Answer to the question shows, the passage that DACC/AReM referenced is about the IOU's obligations as a regulated utility subject to the Commission's jurisdiction. His point is that procuring DR is an obligation that the IOUs have in the context of Commission regulation of

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14/ The relevant portions of Answer 18 (Abreu, PG&E-01, p. 4-14, l. 26 to 4-15, l. 9) read as follows:

IOUs have several characteristics that make it appropriate for them to continue to provide DR through rates, tariffs and contracts. IOUs are LSEs and as such they will have rates. Providing their customers DR options as part of their rate offerings is an efficient way to capture DR. IOUs also offer energy efficiency and other products, and it is efficient to offer DR as part of an integrated approach to customers. IOUs also own and operate the distribution systems, own the transmission systems, and participate in transmission planning (together, T&D), so incorporating DR into T&D planning and operations is a unique opportunity to capture cost-effective DR. IOUs are also procuring supply-side resources to meet their LSE obligations and having DR as a tool in the portfolio will allow a more robust portfolio.

The Commission should not "focus on identifying more of these programs as supply resources," but should allow utilities, aggregators and customers the flexibility to decide how best to capture the value of DR.

The IOUs' role in competitively procuring DR should be analogous to their role in procuring generation resources. The utilities currently conduct the procurement of generation and manage the contracts, and they should similarly be able to do the same for DR.

their activities. Thus, DACC/AReM's characterization of Mr. Abreu's testimony as equating DR with generation very seriously mischaracterizes and misrepresents his testimony.

2. DR Benefits All Customers By Supporting System Reliability, And CAISO Transmission Grid Planning

The ability of DR to support grid reliability is a central reason that all customers, both bundled and unbundled, should pay the costs of DR. The use of DR for grid reliability resonates in the CAISO's testimony. CAISO witness Neil Millar, the CAISO Executive Director, Infrastructure Development, discussed how its transmission planners can use supply-side DR to offset the need for conventional generation or transmission investments in local capacity areas. (Millar, ISO-01, p. 2, ll. 7-10.) Mr. Millar generally identified the characteristics that the CAISO requires to analyze the effectiveness of DR for satisfying local capacity area needs, i.e. response time, duration, availability. This analysis has started in southern California and as part of the CAISO's current transmission planning cycle.[15/] (*Id.*, p.2, l. 17 to p. 5, l. 2) Mr. Millar emphasizes that knowing the location of supply-side DR is "particularly important in addressing local reliability requirements". (Millar, ISO-02, p. 5, ll. 22 to p. 6, l. 4.) He further explains,

> Aggregating supply-side DR within a sub-LAP that is contained within a local capacity area may suffice at a minimum for planning purposes in addressing known limitations, but the CAISO must know with confidence the distribution of these resources within the sub-LAP to a nodal level for testing **the integrity of the system within the local capacity area**.

(*Id.*, p. 6, ll. 12 to 16, emphasis added.) CAISO witness Goodin also indicates that DR can help maintain grid reliability when stating that properly configured DR may provide services that support grid reliability. (Goodin, ISO-4, p. 19, ll. 15-20.) CLECA testimony further points out that DR "is 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." (Barkovich, CLE-02, p. 22.) DACC/AReM's attempt to lump DR with generation and claim

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15/ The CAISO transmission planning process concerns how to protect system integrity and provide the ability to dispatch and reposition the system to prepare for the next contingency within 30 minutes. "When a transmission contingency occurs, they have to be able to reconfigure the transmission system within 30 minutes to be ready to meet the next contingency [N-1-1], if it were to occur. Draft Workshop report, section H. 6. p. 41.)

that DR does not benefit unbundled customers ignores the system reliability benefits of DR discussed by Mr. Millar, Mr. Goodin and Dr. Barkovich.

When utility DR is dispatched to address transmission and distribution (T&D) conditions, it is reducing customer loads to remedy the problem. It is serving its core objective of influencing and reshaping customer load that customers place on the system to provide a benefit to all customers.[16/] (Silsbee, SCE-02, p. 9, ll. 19-22.) SCE witness Silsbee adds,

> Simply because DR is dispatched in a manner integrated with CAISO markets does not make DR a generation function asset. There are numerous trade-offs between generation, transmission and distribution, so that one functional asset can reduce reliance on another asset class. For instance, CAISO local capacity areas have limited capability to import sufficient power to serve local needs, and such local requirements can generally be met with local generation, a transmission upgrade, or DR in the local area. Neither generation built to meet such local needs or DR are transmission assets, simply because they are an alternative to transmission.

(*Id.*, p. 9, l. 24 to p. 10, l. 6.) Mr. Silsbee reminds us that protecting the grid involves different tools (transmission, DR, generation, distribution) which may be alternatives under some circumstances. However, the potential for them to be alternatives does not change their function and should not change cost allocation.[17/]

3. The RA Benefits From DR, Whether Supply-Side Or Load Modifying, Will Flow To All LSEs In The Service Area And Their Customers

MCE asserts that 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. MCE thinks that if a DR program results in reductions of RA obligations for only the IOU, then the DR program should be deemed a procurement-related program and collected through the generation rate. (Waen, MCE-01, p. 4, ll. 4-5 and ll. 10-13.) However, RA from IOU DR programs are allocated to all LSEs within the IOU's service area, as

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16/ DR programs began in the early 1980's to help customers control their energy costs and bills. They provided optional programs and rates to customers to reduce their peak demand in exchange for financial incentives. And that assistance to customers continues to be the focus of PG&E's DR programs. (Haertle, PGE-03, p. 4-6, l. 24 to p. 4-7, l. 3.)

17/ For instance, the potential for a transmission project to be an alternative to generation does not mean that the transmission project costs should be recovered through generation rates. Nor does it mean that the generation costs should be recovered through transmission rates.

MCE acknowledges. (*Id.,* ll. 7 to 10.) The RA credit is assigned to all LSEs on a load ratio share basis. (Barkovich, CLE-01, p. 44.) The principle of allocation to LSEs on a load share basis was established in D.09-06-028. (D.09-06-028, pp. 27-28; Barkovich, CLE-02, p. 8.) Since supply-side DR would continue to get RA credit, bifurcation of DR would not change this approach to RA credit allocation among LSEs.

How load-modifying DR will be valued remains to be seen, since the Settlement establishes working groups to address load-modifying DR. The reality, however, is that load-modifying DR will produce resource adequacy benefits. The CAISO states:

> . . . a load serving entity can procure a load modifying resource, which can help the load serving entity reduce the need for resource adequacy capacity. Both types of demand response have resource adequacy benefits – supply resources can satisfy a resource adequacy <u>requirement</u> and load modifying resources can reduce the resource adequacy <u>need.</u>

(Goodin, ISO-03, p. 4, l. 23 to p. 5, l. 2, emphasis in original.) That reduction in need will benefit all LSEs. SDG&E explains that "load modifying DR reduces the system peak and therefore reduces the Resource Adequacy (RA) requirements of <u>all</u> Load Serving Entities (LSE). Load-modifying DR does indeed lower procurement from generation but it lowers it for all entities with RA obligations, both IOUs and other LSEs." (Fang, SGE-06, p. GK-3, ll. 1 to 4.)

SDG&E witness Fang also testifies that load-modifying DR lowers energy prices for all entities in the relevant market. She quotes from Federal Energy Regulatory Commission (FERC) Order 745 that "it is just and reasonable to allocate demand response costs proportionally to all LSEs that benefit—all entities that purchase energy from the relevant market."[18/] (*Id.*, ll. 5-14.)

18/ In *Electric Power Supply Association, et al. v. Federal Energy Regulatory Commission* (D.C. Cir. Nos. 11-1486, et. al; May 13, 2014), the US Court of Appeals for the District of Columbia Circuit vacated Order 745 in its entirety as ultra vires agency action, on the grounds that Order 745 directly regulated the retail electric market. (D.C. Cir. 2014) 753 F.3d 216.) The court also struck down the FERC directive that grid operators pay demand response providers the same amount for a DR negawatt as they pay generators for a MW of additional supply. The FERC petitioned for rehearing *en banc* of the decision on the jurisdictional issue. Petition of Respondent Federal Energy Regulatory Commission for Rehearing *En Banc*, (D.C. Cir. Nos. 11-1486, et. al; July 7, 2014).

The fact that resource adequacy benefits from IOU DR programs will be shared among the IOUs and other LSEs, adds to the reasons that the costs of IOU DR must be recovered from unbundled as well as bundled customers. The effect on the CAISO market price is yet another benefit that lends weight to cost recovery from all customers. And as discussed below, only the IOUs have the obligation to support DR. The DA and CCA intervenors maintain that the Commission has no power over their procurement, including DR. (Mara, DAC-01, p. 27, ll. 8-15.) Assuming that the regulatory obligation to obtain DR is unique to the IOUs, the IOUs are the only entities that the Commission can mandate to implement its DR policies and acquire DR to support the system. That is an additional reason for allocating the costs to all customers, including DA/CCA customers.

E. The Principle Of Sharing Costs Involving Unbundled Customers Has Already Been Established In LTPP For New Generation Resources That Serve The System

Dr. Barkovich testifies that DACC/AReM has already lost the argument that DR is the equivalent of a generation resource for which costs should be allocated only to bundled customers. In the long term procurement planning proceeding (LTPP), utility generation procurement costs for new generation resources that serve the entire system are partly recovered from DA and CCA customers under Section 365.1(c)(2) (A-B) of the Public Utilities Code. (Barkovich, CLE-02, p. 21.) Although ESPs have many parallel obligations to IOUs for procurement, including the renewable portfolio standard (RPS) and storage, "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." *(Id.)* ESPs also claim that they have no obligation to procure DR. The DA and CCA representatives in this case have opined that the IOU DR costs cannot be imposed on them through the CAM. (Mara, DAC-01, p. 27, ll. 8-15; Draft Workshop report, Section A. 3. (e), p. 9.) Nevertheless, the principle of spreading the costs of resources that benefit the system to unbundled and bundled customer loads, applies by analogy as well as based on other facts and analyses in the record.

F. Costs to support the Demand Response Auction Mechanism (DRAM) Are Appropriately Recovered In Distribution Rates

Recovery of Demand Response Auction Mechanism (DRAM) costs should come from all customers, bundled and unbundled. In the DRAM Pilot contained in the Settlement filed August 4, 2014, the IOUs will conduct two auctions to obtain only RA tags from third-party DR providers. The DRAM winners will then be responsible for bidding DR using customer load, without bundled versus unbundled restrictions, directly into the CAISO market, under a standard contract. Thus, the DRAM Pilot will provide capacity payments to the winning bidders to support their direct participation in the CAISO market, and will provide reliability benefits to the grid. PG&E sees no reason to treat DRAM cost recovery differently from DR programs. PG&E will incur these costs to provide DR services and benefits to all customers. And similar to the current AMP contracts, both DA/CCA and bundled customers would be eligible to participate. In contrast, however, DACC/AReM and MCE maintain that they cannot be compelled to conduct DRAM auctions, so they will not be providing DR benefits or supporting the grid that way. (Mara, DAC-01, p. 27, ll. 9-15; Waen, MCE-01, p. 8, l. 24 to p. 8-2, l. 3; see Barkovich, CLE-01, p. 36.)

G. Competitive Neutrality And Fairness Require That DA/CCA Customers Participate In Paying The Costs Of IOU DR

1. Unbundled Customers Can Participate And Get Financial Incentives Under The IOU DR Programs And Should Not Be Able To Avoid The Cost Of The Programs

DACC/AReM's proposal to allocate DR costs solely to the generation rate component would be unfair because DA customers participate in DR programs and receive DR payment incentives, but would escape paying any of the costs since the generation rate component is only paid by bundled customers. Information in this case shows that 51% of SDG&E's industrial customer class (over 500kW) are Direct Access (DA), while 20% of its commercial class load is

DA. (Katsufrakis, SGE-02, p. GK-7, ll. 20-23; Barkovich, CLE-02, p. 20.) For PG&E, the 2013 Olivine report shows that PG&E's potential Base Interruptible Program (BIP) resources are 185.73 MW from unbundled customers (40.5%) versus 240.68 MW (59.5%) from bundled customers.[19/] [20/](Gerber, PGE-02, Appendix E, p. E-24, Table 5, total row.) For PG&E's Capacity Bidding Program (CBP), unbundled load is 1.41 MW while bundled load is 5.53 MW, or approximately 20% unbundled.[21/] (*Id.*, p. E-26, Table 6, total row.) And for PG&E Aggregator Managed Portfolio (AMP), the unbundled MWs for day-of are approximately 15% (17.19 MW unbundled versus 93.68 MW bundled), while the day-ahead unbundled resources are approximately 35% of the total (25.31 MW unbundled versus 46.94 MW bundled) (*Id.*, p. E-27, Table 7, total row.) This information clearly establishes that unbundled DA customers actually participate in IOU DR programs, and receive financial incentives for doing so. DACC/AReM want this significant unbundled customer load to collect the financial benefits available under the IOU DR programs, while completely escaping any responsibility for the costs, and foisting all the costs to bundled customers. This result would be highly inequitable. DACC/AReM's cost allocation proposal must be rejected.

2. DACC/AReM's Proposal Is NOT Competitive Neutrality, And Instead Would Burden Bundled Customers With Subsidies For DA/CCA Customers

DACC/AReM claims that DR programs are a substitute for procurement of generation, and on that basis asserts that allocating all DR costs to unbundled customers is anti-competitive. (Mara, DAC-01, pp. 5-6; Mara, DAC-02, pp. 2-4.) Based on its assumption that DR equates to generation, DACC asserts that the generation rates for the IOUs' bundled electricity service are suppressed when DR costs are shared with unbundled customers instead of falling entirely on bundled customers. (Mara, DAC-01, p. 12, ll. 9-12.) This rationale is the basis for DACC's

19/ BIP incentives in the tariff are described in Schedule E-BIP, sheet 5, section 6, and vary between \$8.00/kW per month to \$9.00/kW per month.

20/ Approximately 18 percent of PG&E's BIP customers have non-PG&E LSEs. (Abreu, PGE-03, p. 2-7, ll. 18-20.)

21/ CBP capacity payment incentives are described in Schedule E-CBP, sheet 5, and vary between \$2.17/kW per month in winter to \$24.81 /kW per month in August.

competitive argument that "[t]his results in an unfair competitive advantage to the IOUs and is a disadvantage to the ESPs and CCAs who directly compete with the IOUs for customers." (*Id.,* ll. 13-14.) DACC/AReM sees the DR costs in distribution rates as a subsidy, which it claims would prevent DA and CCA customers from seeing "the true cost of the IOU's generation portfolio." (*Id.*, ll. 15-21.) PG&E disagrees with DACC/AReM. Shifting all DR costs to bundled customers in the generation rate instead would subsidize DA and CCA customers, give DA and CCA providers an unfair advantage, inflate bundled customers' generation rates, and harm bundled customers.

The debate over competitive issues needs to recognize the benefits that DA and CCA customers receive through the IOU DR programs, to wit:

- DA and CCA customers can participate in PG&E's DR programs authorized in its DR decisions, on the same terms as PG&E's bundled customers. DA customers have opted into P&E's DR programs for industrial/commercial customers, where they are a significant portion of the load; and through these programs, they can manage their loads, receive the financial incentives paid under the DR Programs, and reduce their bills.

- DA and CCA customers can participate in PG&E's TOU rate schedules, where there are distribution rates that are time-varying. For E-19 and E-20 customers, time-varying distribution elements are in the demand charges.

- DA and CCA customers are part of the audience for *Flex Alert* and the Commission's *EUC* state-wide brand ME&O program (conducted by CSE, not the IOUs). Those notification and awareness marketing programs are for the benefit of DA and CCA customers as individuals and entities that need to know the information conveyed, and through improved reliability of the grid.

- DA and CCA customers, and their ESPs, benefit from protection of grid reliability provided by DR programs like BIP or AMP, which are called for local capacity area reliability needs, or even for the entire system, as occurred on February 6, 2014.[22/]

- DA and CCA customers, and their ESPs, benefit from using DR in the CAISO transmission planning process to determine what transmission upgrades and additions are needed, and what can be acceptably deferred or avoided.

22/ Barkovich, CLE-01, p. 16; Draft Workshop Report, p. 28.

- DA and CCA customers, and their ESPs, will receive benefits from load-modifying DR because it will reduce the RA requirement overall, which benefits everyone.

- DA and CCA customers, and their ESPs, receive RA benefits from supply-side DR through which the RA credits are allocated among ESPs based on load shares.

DACC/AReM's cost allocation proposal would keep all of these benefits for DA and CCA customers (and their ESPs), but would shift all the DR program costs that produce the benefits entirely onto bundled customers. That result would be highly inequitable, and would force bundled customers to subsidize DR-related benefits for DA and CCA customers, and their ESPs.

The Commission's underlying objective should be to treat utility and non-utility LSEs the same.[23/] Competitive neutrality requires no less. If the Commission has the authority, this can be achieved by imposing the same requirements on all LSEs, such as generally occurs with the 33 percent RPS. (Silsbee, SCE-02, p. 10, ll. 10-13.) However, DACC and MCE unequivocally maintain that the Commission has no authority to review or approve procurement by the ESPs, including DR procurement. (Mara, DAC-01, p. 27, ll. 8-15; Waen, MCE-01, p. 8, l. 24 to p. 8-2, l. 3; see Barkovich, CLE-01, p. 36.) In essence, DA and CCA ESPs see themselves as completely free to do what they want, including continuing not to pursue DR.[24/]

So DACC/AReM's position comes down to:

23/ The Commission has recognized that the goal of maintaining competitive neutrality is founded on the underlying principle of equal treatment of LSEs. (Silsbee, SCE-02, p. 10, ll. 18-19, citing D.12-12-033, mimeo p. 67.)

24/ In the context of direct participation, Olivine reports that non-utility LSEs have been reluctant to support their customers' participation in DR. (Gerber, PGE-02, p. B-8, l. 18 to p. B-9, l. 3.)

1) keeping the benefits of IOU-funded DR programs for DA and CCA customers, through DA and CCA participation in the IOUs' programs, the RA benefits, and improved grid reliability,

2) making bundled customers subsidize DA and CCA customers by paying all IOU DR program costs through generation rates, and

3) remaining free of any obligation to procure DR themselves.

These outcomes amount to a free ride for DA and CCA that places the bundled customers and IOUs at a disadvantage. Trying to obfuscate the inequity of this set of DA and CCA objectives by calling DR a generation substitute ignores the true balance of benefits and responsibilities for DR. PG&E agrees with SCE that if DACC/AReM and MCE are correct that the Commission cannot impose an obligation to procure DR on non-utility ESPs, then the Commission must require DR costs to be recovered from all customers, especially in light of the benefits that unbundled customers reap from IOU jurisdictional DR programs. (Silsbee, SCE-02, p. 10, ll. 14-19.) The Commission must reject DACC/AReM's cost allocation proposal, and approve PG&E's proposal.

II. GUIDANCE FOR BACK-UP GENERATORS' USE FOR DR SHOULD NOT BE CHANGED NOW

A. There Is No Prohibition On The Use Of BUGs In Connection With DR

NRDC's testimony wrongly accuses the IOUs of being out of compliance with provisions in D.11-10-003 regarding customers' use of fossil-fueled emergency back-up generators (BUGs) during DR events. (Bull, NRD-01, pp. 2-3.) NRDC goes on to urge the Commission to establish penalties to deter customers' use of their on-site BUGs. (*Id.*, pp. 3-4.) NRDC takes this position despite recognizing that the Commission may not have any authority:

> [T]he Commission has **no jurisdictional authority** if an on-site BUG owner or DR aggregator with BUGs in its portfolio can fully bypass RA and instead enroll these resources via "direct access" within the definitional frame of a "Supply Resource" into a California Independent System Operator (CAISO)-run reliability market.

(*Id.*, p.3, emphasis added.) NRDC's penalty suggestion applies to "all the parties involved", including the customer and third-party DR aggregators. This penalty suggestion conflicts with

NRDC's statement that the Commission has no jurisdiction. If there is no jurisdiction, there would not be any authority to impose penalty rules. So NRDC's overall position is not sustainable. Furthermore, NRDC ignores whether any requirement has actually been imposed on the IOUs, the DR aggregators and/or the customers. In fact, the Commission has not prohibited the use of fossil-fueled BUGs for DR.

Decision 11-10-003, OP 3, directs the IOUs to work with the Energy Division to gather data on the use of fossil-fueled BUGs for DR. Details on the process evaluation and policy recommendations were deferred to the future. (D. 11-10-003, p. 30; Tougas, PGE-01, p. 7-2, l. 28 to p. 7-3, l. 2.) However, the Commission deferred making a decision about use of fossil-fueled BUGs for DR to a future RA proceeding. (D.11-10-003, p. 30; Tougas, PGE-01, p. 7-3, ll. 3-10.) Consequently, NRDC misconstrues the Commission decision when it accuses the IOUs of non-compliance with D.11-10-003; there is no compliance issue with D.11-10-003. (Wood, SCE-1 and SCE-01A. p. 46, l. 18 to p. 47, l. 10; Barkovich, CLE-02, p. 3; Tougas, PGE-03, p. 3-1, l. 26 to 3-2, l.3.

1. It Is Premature To Limit The Use Of BUGs For DR Programs

NRDC cites a 2010 KEMA report to assert that 45% of respondents enrolled in IOU emergency DR programs used their BUGs for a DR event.[25/] CLECA witness Barkovich responded with reasons that the KEMA report should not be used to draw any conclusion about the use of BUGs by customers participating in IOU DR programs. Dr. Barkovich informs us that air quality regulations for BUG have changed since 2010, and there were permitted uses under those regulations for BUG in 2009 or early 2010 for DR. She reports,

> For example in 2009-2010, diesel BUG could be used for participation in an Interruptible Service Contract (the predecessor of BIP. (ftn: California Air Resources Board: Airborne Toxic Control Measures for Stationary Compression

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25/ KEMA, (2010) *California Statewide Process Evaluation of Selected Demand Response Programs*. Prepared for the Demand Response Measurement and Evaluation Committee (DRMEC) on behalf of San Diego Gas and Electric Company, study ID: CPU0025.01. page 2-93cited by NRDC witness Bull, NRC-01, p. 2 to assert that the customer respondents were in violation of D.11-03-003 Since the KEMA study involved a period well before D.11-03-003 was issued, NRDC's assertion is meritless on its face. (Barkovich, CLE-02, p. 3.)

> Ignition Engines, Effective 10-18-2007 at 9 and 29-31.) Federal regulation of BUG for participation in DR programs only started in 2010 and the federal rules went into effect in 2013. (ftn: 40 CFR Part 63 [Subpart ZZZ].) These limit the uses of 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.

(Barkovich, CLE-02, p. 2.) Dr. Barkovich also points out that the KEMA report did not ask how much of the customer's load the BUG represented, i.e. the BUG may have been to support safety requirements, as opposed to the customer's whole DR commitment. (*Id.*, p. 3.) Thus, Dr. Barkovich cautions that the KEMA report should not be relied upon for the purpose used by NRDC.

The data collection and analysis required under OP 3, D.11-10-003, has not commenced yet. There is no evidence in the record on whether use of BUGs for DR would or would not reduce emissions overall. DACC/AReM states that even the use of fossil fuels for back-up generation, while creating emissions that would be avoided if the DR resource avoided all consumption of power, "may still be preferable to the construction of new larger-scale peaking facilities." (Mara, DAC-01, p. 25, ll. 15-18.) A ban on BUG use for DR also may not reduce the number of hours they are used, if the customer uses the DR event to meet annual testing requirements in its air permits. (Tougas, PGE-01, p. 7-4, ll. 1-10.)

In connection with this question, there is no information in the record to indicate how a prohibition or limitation on using fossil-fueled BUGs for DR would impact the amount of DR. Given the lack of information and knowledge, PG&E maintains that if the purpose of a limit or prohibition on using BUGs is to reduce air emissions, the Commission should first determine if prohibiting them would have a substantive impact on emissions, as well as determining the likely consequences of its action.[26/] (Tougas, PGE-01, p. 7-4, ll. 9-12; cf. DAC-01, p. 25, ll. 18-21.) A full record would be needed on the use of BUGs before the Commission makes any decision on limiting their use in connection with DR. (Tougas, PGE-03, p. 3-1, ll. 20-22; c.f. Mara, DAC-01, p. 25, ll. 15-21.) Moreover, if a significant amount of DR would be impacted by a limitation on

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26/ DACC/AReM requests the Commission to address how to use BUGS to enhance, not hinder, DR expansion. (Mara, DAC-01, p. 26, ll. 11-22.)

fossil-fueled BUG use, the Commission could risk losing a significant amount of DR capacity that is being counted on to support the grid today and in the future. (Tougas, PGE-01, p. 7-4, l. 26 to p. 7-5, l. 6.)

2. The IOUs (And Third DR Providers) Should Not Be Ordered To Collect Information On The Use Of BUGs By Their DR Customers

CLECA asserts that there is no reason why anyone other than the customers themselves or their air quality regulators should determine when and how the customers' generators can be used. Dr. Barkovich observes that the customers are all subject to appropriate air quality regulations (which can and do change over time), and "[i]t is not the CPUC's jurisdictional responsibility to enforce air quality regulations at either the state or the federal level. (Barkovich, CLE-01, p. 43.) Enforcement of the rules mandated by the other state and federal authorities should not be the IOU's responsibility. (Katsufrakis, SGE-02, p. GK-10, ll. 15 to GK-11, l 7.) PG&E agrees with SDG&E and CLECA on these points.

PG&E assumes that if the Commission were to take action on limiting use of BUGs that limitation would apply to third party DR providers, as well as the IOUs. However, the Commission has also been circumspect about its exercise of jurisdiction over third party DR providers. Decision 10-12-060, Order Modifying Decision (D.) 10-06-002, And Denying Rehearing Of Decision, As Modified, states the Commission's intent "that our exercise of jurisdiction (over non-IOU DR providers) be narrowly tailored to focus on developing protections that relate to our interest in ensuring safe and reliable electric service for IOU customers". (D.10-12-060, p. 7.) In D.12-11-025, page 26, the Commission states ". . . we clarify that we will take a light touch approach to the regulation of non-Utility DR providers serving medium and large commercial industrial bundled customers." Before limiting or prohibiting use of fossil-fueled BUGs for IOU and DR providers' customers, the Commission should determine if its intervention would be consistent with the "narrowly tailored focus" and "light touch approach" and explain its reasoning.

If the Commission were to impose limitations and require data collection, third party DR providers would be more appropriate than the IOU to obtain the BUG usage information from the DR providers' customers. However, PG&E maintains that neither the DR providers nor IOUs are in a position to obtain the customers' BUG usage information.[27/] That expertise, along with the individual customer's air quality permit requirements, resides with the state and local air quality regulators (the California Air Resources Board and the Air Quality Management Districts).[28/] The IOUs do not have the knowledge, the expertise or resources to collect the air quality data or understand air quality permit conditions for individual customers' BUGs, nor is there any funding for the significant effort that would be required. The IOUs should not be tasked with collecting data for which the legislature has vested other agencies with the responsibility for comprehensive air pollution control. (Wood, SCE-01, p. 48, ll. 10-23.

III. THE SETTLEMENT INSTITUTES A DRAM PILOT TO EXPLORE AN AUCTION MECHANISM FOR PROCUREMENT OF SUPPLY RESOURCE DR PLACING LIMITATIONS IN IOU DR PROGRAMS WITH THE GOAL OF ENCOURAGING DRAM PILOT PARTICIPATION IS UNNECESSARY AND WOULD BE COUNTERPRODUCTIVE

The Settlement, Section II. C. 3. j., page 27, recites that

> the Settling Parties discussed various methods to encourage participation in the DRAM Pilot and the potential interaction of the IOU solicitations for Supply Resources with the DRAM Pilot but did not come to agreement. Parties agreed that the narrowly scoped additional question of whether the DRAM should be a preferred means of procuring Supply DR and if so, with respect to encouraging participation in the DRAM Pilot, the potential interaction of IOU solicitations for Supply Resources with the DRAM Pilot with respect

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27/ NRDC has proposed that the Commission require real-time tracking devices, such as sub-meters, to track BUG operation, with the cost of the sub-meters assigned to the BUG owner. Both SCE and PG&E argue that this would be an unfair cost burden to the large number of DR customers who do not use BUG to respond to DR events. (Wood, SCE-02, p. 17, ll. 3-8; Tougas, PGE-01, p. 7-5, l. 22-29.

28/ The California Code of Regulations contains specific Recordkeeping, Reporting, and Monitoring requirements for information to be provided to the District Air Pollution Control Officer (APCO) for stationary compression ignition engines. The regulations are extensive, (Cal. Code Regs., tit. 17, §§ 93115.10 - 93115.14.) The regulations on the substantive requirements for stationary compression ignition engines include, without limitation, California Code of Regulations, title 17, sections 93115 to 93115.9.

> to encouraging participation in the DRAM Pilot and possible limitations on the IOUs' solicitations for Supply Resources, will be briefed. . .

The ALJ ruling issued August 13, 2014, confirmed that this issue would be included in the briefs due August 25, 2014 in this proceeding. This passage from the Settlement identifies the following questions for briefing:

- Should the DRAM Pilot be a preferred method of acquiring Supply Resource DR?
- If the answer were to be "yes", should limits be placed on other methods to acquire Supply Resource DR?

The second question could involve other DR programs, tariffs, or contracts, such as requests for offers (RFO), MW, and/or geographic limits based on sub-Load Aggregation Points (subLAPs). However, the second question is moot if the Commission decides that the DRAM Pilot should not be a preferred method of acquiring Supply Resource DR.

PG&E does <u>not</u> support making the DRAM Pilot a preferred means of obtaining Supply Resource DR, and would oppose placing any limitations on other DR programs, tariffs or contracts for the purpose of giving preference to the DRAM Pilot. The DRAM is a new and untested concept for DR in California, and the DRAM Pilot is for the purpose of testing the concept, in phases. It is definitely not ready to be considered a preferred vehicle for Supply Resource DR procurement.

1. The Purpose of the DRAM Pilot Is To Test Feasibility And Will Only Procure RA Tags, Without Any Other Product

The Settlement provides that a DRAM Pilot will be conducted in 2015 and 2016 to test two things:

> (a) the feasibility of procuring Supply Resources for Resource Adequacy with third party direct participation in the CAISO markets through an auction mechanism, and
>
> (b) the ability of winning bidders to integrate their provision of DR into the CAISO market.

(Settlement, Section C. 1., p. 24.) The DRAM Pilot basically will assess the feasibility of using an auction process to create opportunities for Supply Resource DR. It will be an educational process, and the Settlement provides that "lessons learned" will be presented in a report evaluating the DRAM Pilot. (*Id.*, Sections C. 5. and 6., p. 28.)

Consistent with initial feasibility testing, the scopes of the DRAM Pilot auctions are carefully specified. The first auction, in 2015, is only for System RA tags. The second auction, in 2016, can include Local and Flexible RA tags as well as System RA tags. No other DR products would be included. (*Id.*, Sections C.3. g., p. 26, and C.4.a.-b, p. 27.) Structuring the DRAM Pilot to acquire the most uncomplicated product in the initial auction (System RA), while the second auction is still limited to RA products (albeit more types of RA tags), moves the DRAM forward in a careful step-by-step process. The DRAM Pilot will test the market interest in RA tag-only products, as opposed to other DR products. While the DRAM Pilot is testing the water for RA tag products, there are other types of DR products that can and should continue to be obtained through the IOUs' other DR programs.

The MW amounts designated for the two DRAM Pilot auctions are relatively modest because the DRAM is a preliminary concept that has yet to be developed. The statewide minimum target is 22 MW in each auction, with 10 MWs each allocated to PG&E and SCE, and 2 MWs to SDG&E. Those IOUs may acquire more MWs in the DRAM Pilot, but the minimum targets are at levels that represent a "toe-in-the-water" approach, as opposed to a "cannon-ball" dive. This approach is necessary because the DRAM Pilot has not yet been designed and there is no evidence to indicate how successful the auction or the delivery on the contracts will be. For instance, no one knows how bidding directly into the CAISO market by the winning bidders will go, but to judge from Mr. Gerber's testimony and the Olivine report, there will be many hurdles to overcome. (Gerber, PGE-02, pp. B-1 to B-12, and Appendix E.)

2. There Is Considerable Uncertainty Surrounding Implementation For Bidding Retail Customer Load Into The CAISO Market As Demand Response

Under the circumstances, trying to make DRAM a preferred method of acquiring Supply Resource DR would make no sense. Designating the DRAM Pilot as preferred over other DR procurement, such as established tariffs, programs, or RFOs, would likely inhibit the amount of DR procured. (See, Binz, Sierra Club, SLC-01, p. 15, ll. 12-17.) The problem would be severely compounded if limitations were placed on DR programs, tariffs and RFOs, in a mistaken attempt to make the DRAM Pilot auctions more attractive by reducing other DR options for customers. Instituting limitations likely would reduce the amount of DR, as customers and aggregators could see existing DR options limited or cut off in favor of DRAM Pilots with all the unknowns of trying to bid and provide DR under CAISO processes and requirements. (Abreu, PGE-3, p. 2-11, ll. 24-25.) Given that the Commission is encouraging growth in the amount of DR and the amount of Supply Resource DR, it would be counterproductive to limit any type of DR.

Moreover, the DRAM Pilot is only for RA tag products. Other IOU DR programs involve other types of products. Maintaining opportunities to obtain other DR products under existing DR programs, tariffs, and through new IOU non-DRAM RFOs is critical for increasing the amount of DR, and keeping DR providers and customers engaged in DR in California. DR providers and customers for whom participation in the DRAM Pilot is not sufficiently compelling will want other options to participate in DR programs.[29/]

Before the Settlement was negotiated, TURN suggested that all existing DR programs be terminated over the period 2016-2018, in favor of the DRAM. (Hawiger, TRN-02A, p. 15, ll. 3-10.) PG&E responded that for TURN's recommendation to work without reducing the amount of available DR, all customers participating in existing DR programs would need to be willing to participate in DR resources through DRAM contracts, and the DRAM design and implementation would need to be successful. There is no factual evidence in the record to support the notion that either condition would be met. (Abreu, PGE-03, p. 2-10, ll. 21-28.) Instead, the evidence indicates that DR would decline. For instance, Mr. Abreu testified that DR procured through the DRAM would be subject to the CAISO must-offer obligation (MOO),

29/ In addition, if a DA customer's ESP will not cooperate to let the customer be part of direct participation, an IOU program may be the customer's only way to provide DR. (See, Gerber, PGE-02, Appendix E, pages E22-E23) which existing DR customers may not accept. (*Id.*, p. 2-10, l. 31 to p. 2-11, l. l5) Dr. Barkovich cautions

> 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.

(Barkovich, CLE-02, p. 15.) Furthermore, Mr. Gerber's testimony shows that a major portion of PG&E's DR portfolio would be lost, if all were required to bid into the CAISO market. (Abreu, PGE-03, p. 2-11, ll. 8-11.) Based on the Olivine report, Mr. Gerber testifies that out of 795 MW considered, only approximately 20 MW realistically could be bid into the CAISO market under current CAISO processes, with the lower number influenced by manual processes for management of registrations and CAISO resources. (Gerber, PGE-02, p. B-11, l. 25 to B-12, l. 4, and Appendix E.)

The concern over the market uncertainties and DRAM procurement are widespread in this case. SCE highlights the number of activities and proceedings which will potentially have a significant impact on the use of DR resources and the CAISO processes. First, PG&E has proceeded with bidding into the CAISO markets this summer, and third-party DR providers are expected to begin direct participation in the CAISO markets in 2015. Second, the Commission only recently determined flexibility requirements that would apply to LSE portfolios, including what performance attributes DR resources would need to qualify as flexible resources. Third, the Commission is considering a Joint Reliability Plan (JRP) that would impose a multi-year forward procurement obligation for RA resources, which would potentially change the value of DR resources in the market. (Silsbee, SCE-01, p. 33, ll. 10-20.) CLECA mentions "the many complexities and costs to participation in the CAISO's markets, including must offer obligations and integration costs." (Barkovich, CLE-02, p. 15.) In addition, the CAISO's Reliability Services Initiative is currently underway, which will determine the Must-Offer Obligations for DR providing Local and System RA. (Draft Workshop report, section E. 4., pp. 24-25.)

3. There Is No Evidence That The DRAM Should Be A Preferred Means Of Procuring Supply Resources DR, Instead The Evidence Indicates Many Concerns About The DRAM

The Settlement itself is a product of the parties' new understanding of the uncertainty involved in direct participation in the CAISO markets. The Settling Parties' August 4, 2014 Motion for Adoption of the Settlement Agreement stated at page 10:

> Specifically, the Settling Parties learned many critical things about what is necessary to increase demand response successfully in a future world where DR Supply Resources are bid directly into the CAISO market by third-party DR providers, as well as the utilities. It became apparent to the Settling Parties that rushing into bifurcation implementation without addressing and solving valuation, integration, process, and cost questions that emerged in both the workshops and settlement discussions in June and July 2014 will set back and diminish demand response and not improve and increase DR as expected by the Commission. In fact, consistent with the Commission's stated intentions in D.14-03-026, such a result (a decrease or diminishment of DR) would clearly be an unintended consequence that should be addressed and avoided.

Thus, in the current circumstances, it is uncontroverted that placing limitations on existing DR programs, tariffs and non-DRAM RFOs will reduce the number of DR MWs. That result would be contrary to the expressed goals of the DR OIR:

> Another goal of this proceeding is to increase the penetration of demand response programs by doing a close examination of how we frame the programs, how they are offered, procured, and reduce barriers to entry for new customer participation.

(R.13-09-011, p. 15.) In D.14-03-026, at pages 2 and 7, and as reflected in Finding of Fact 4, the Commission states "We reiterate that the Commission's goals are to improve the efficiency of demand response and increase the use of all demand response programs."

DRAM is modeled on the Renewable Auction Mechanism (RAM). (April 2, 2014 ACR, p. 4.) RAM, however, is not a preferred method to procure renewable resources. There are no limits placed on other forms of renewable procurement in order to favor RAM. Thus, if DRAM is to be modeled on RAM, there is no justification for making it a preferred procurement method.

The Settlement recognizes that going ahead full steam with the DRAM is likely to produce unintended, undesirable effects. The Settlement's DRAM Pilot provisions are designed to gain the experience and information that stakeholders (DR providers, customers, IOUs, the Commission, and the CAISO) will need to shape DRAM to succeed in the longer run. However, maintaining a healthy environment for DR means that DRAM should not be made a preferred resource, and no limitations should be placed on other methods for the IOUs to obtain DR.

4. Participation In The DRAM Can Be Encouraged Without Placing Limits On Other DR Programs

The DRAM pilots should be designed with their own direct mechanisms to encourage participation. The DRAM Pilots may very well take a cue from PG&E's IRM2 Pilot where a significant outreach and recruitment effort was made to bring participants into the pilot. This included a workshop where all known potential participants were invited and the pilot was explained and "training" workshops that were provided to ease the transition to bidding into the CAISO markets. The IRM2 Pilot had an outreach effort to seek new participants and to answer questions that potential participants might have. A solid outreach, education and recruit plan as a part of the DRAM Pilot will be a positive way to encourage participation, without restricting other Supply Resource DR and risking reducing DR overall.

IV. CONCLUSION

For the reasons discussed in this pleading, the Commission should take the following actions:

1. Decide that costs of DR programs, including incentives, should be allocated to all customers, whether bundled or unbundled, through distribution rates; and should reject DACC/AReM's proposal to allocate all the costs only to bundled customers through generation rates.

2. Determine that before making any decision about the use of BUGS in connection with DR, a robust record about the use of BUGs is needed, but under no circumstances should the Commission order the IOUs to collect air quality data in connection with the use of BUGs by their customers.

3. Decline to make the DRAM Pilot a preferred method for obtaining Supply Resource DR, and refrain from placing any limitations on IOU DR programs with the idea of encouraging participation in the DRAM Pilot.

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Respectfully submitted,

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