BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Pursuant 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 THE DIRECT ACCESS CUSTOMER COALITION AND ALLIANCE FOR RETAIL ENERGY MARKETS ON REMAINING PHASE TWO ISSUES

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August 25, 2014

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SUMMARY OF RECOMMENDATIONS

- Adopt the uniform cost allocation principles proposed by the Direct Access Customer Coalition ("DACC") and the Alliance for Retail Energy Markets ("AReM") for utility costs associated with demand response ("DR") and related programs.
- Direct the utilities to apply these uniform cost allocation principles going forward in all general rate cases, rate design window proceedings, and applications for cost recovery of DR-related costs.
- Direct the utilities to allocate the costs associated with the proposed pilot of the Demand Response Auction Mechanism ("DRAM") to their respective generation revenue requirements, in accordance with the uniform cost allocation principles adopted herein.
- Direct the utilities to allocate the costs of the expert hired to assist the proposed Load Modifying Resource Valuation Working Group to their generation revenue requirements, in accordance with the uniform cost allocation principles adopted herein.
- Determine that the Commission did not adopt a policy to prohibit use of back-up generators for DR resources in Decision 11-10-003, but left the issue open for further consideration.
- Include a commitment to address the appropriate use of back-up generators for DR resources thought a collaborative approach in a new phase of this proceeding or in another proceeding as appropriate.
- Approve the Settlement Agreement filed on August 4, 2014 jointly by multiple parties to this proceeding, including DACC and AReM.

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The Direct Access Customer Coalition[1] ("DACC") and Alliance for Retail Energy Markets[2] ("AReM") respectfully submit this joint opening brief in the demand response ("DR") policy rulemaking pursuant to Rule 13.11 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission" or "CPUC") and the schedule set forth by Administrative Law Judge ("ALJ") Kelly A. Hymes, *E-Mail Ruling Revising Schedule*, issued on July 31, 2014 and *E-Mail Ruling Confirming Issues to be Briefed,* issued on August 13, 2014, which set this date for filing opening briefs on remaining Phase Two and new Phase Three issues. In this opening brief, DACC and AReM focus on remaining Phase Two issues, and reserve the right to file comments in the reply brief on issues raised by parties on the new Phase Three issues.

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

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

I. COST ALLOCATION

A. The utilities should be obligated to use consistent and proper cost allocation for their demand response-related programs.

1. <u>The utilities currently apply disparate and improper cost allocation to their demand response programs.</u>

Examination of the testimony submitted by the investor-owned utilities ("IOUs") and related filings in this proceeding make clear that the IOUs employ different cost allocation approaches for similar demand response ("DR") programs. Parties discussed these differences at the June 9, 2014 DR workshop.[3] The Table below summarizes the DR program types for the three IOUs: Pacific Gas and Electric Company ("PG&E"); Southern California Edison ("SCE"); and San Diego Gas & Electric Company ("SDG&E). The Table also provides the Bridge Funding amounts budgeted for each DR program type in D.14-05-025, the cost recovery accounts that apply, and the customers obligated to pay for each. As is evident, the IOUs' DR-related costs are primarily recovered through the distribution revenue requirement, which is paid for by all customers, including direct access ("DA") customers of electric service providers ("ESPs") and customers of Community Choice Aggregators ("CCAs"). As explained in DACC-AReM's testimony and described below, these IOU DR costs should be properly allocated to the generation revenue requirement.[4] For example, the Bridge Funding decision results in approximately $1 per megawatt-hour of generation-related costs recovered through distribution rates.[5] Such improper cost allocation violates Commission policy on cost causation and creates outcomes that are harmful to the formation of competitive markets.

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[3] *Administrative Law Judge's Ruling Addressing Workshop Report*, R.13-09-011, August 7, 2014, Attachment 1, p. 4.

[4] Exhibit DAC-01, Witness Mara, pp. 11-21.

[5] See discussion in Exhibit DAC-01, Witness Mara, p. 11. This value is calculated as the sum of the three IOUs' requests for 2015 and 2016 ($318.7 million) divided by 2 ($159.4 million per year) divided by 2013 utility retail sales from their respective FERC Form 1's (190 million MWhs).

Table 1. Demand Response Program Cost Recovery Details

Program Categories	Category(ies)	PG&E				SCE				SDG&E			
		Recovered in which Accounts	Recovered in which rates	Bridge Funding ($millions)	Allocated to which customers	Recovered in which Accounts	Recovered in which Rates	Bridge Funding	Allocated to which customers	Recovered in which Accounts	Recovered in which rates	Funding	Allocated to which customers
Dynamic pricing program	n/a	DPMA/ DRAM /2	Dist	U	All	DRBPA G /3,4	Gen/U	U	Bundled /U	DPBA	Gen /1	$92.70 /1	Bundled
IOU Bridge Funding Programs open only to bundled customers (SLR, PTR)	1,2	DRAM	Dist	$0.14	All	DRBPA G	Gen	$3.15	Bundled	AMDRA	Dist	$0.32	All
IOU Bridge Funding Programs open to all customers	1,2,10	DRAM	Dist	$29.30	All	DRBPA D	Dist	$56.56	All	AMDRA	Dist	$14.29	All
AMP/Incentive Contracts	3	DRAM	Dist	$0.79	All	/5		$49.30		AMDRA	Dist	$0.00	All
-- Administration						PAACBA		$1.40	All				
-- Capacity Incentive Payments		ERRA	Gen	U	Bundled	BRRBA D	Dist	$47.90	All				
-- Energy Dispatch (PG&E/SCE); Energy Incentive Payments (SDG&E)		ERRA	Gen	U	Bundled	ERRA	Gen	U	Bundled	ERRA	Gen	U	Bundled
Education, Enabling, Support	4,7,8	DRAM	Dist	$56.89	All	DRBPA D	Dist	$62.07	All	AMDRA	Dist	$20.70	All
EM&V	6	DRAM	Dist	$8.37	All	DRBPA D	Dist	$5.07	All	AMDRA	Dist	$3.81	All
Pilots	5	DRAM	Dist	$5.18	All	DRBPA D	Dist	$0.00	All	AMDRA	Dist	$0.75	All

U = uncertain
Bridge Amounts from D.14-05-025, Attachments 2, 3 and 4
Rate recovery and Accounts from D.12-04-045, pp. 198-202

1/ D.12-12-004: Dynamic pricing for SDG&E Residential and Small commercial collected via generation rates. P 73-4
2/ (DRAM = Distribution Revenue Adjustment Mechanism) Per PG&E Preliminary Statement EX
3/ Per Preliminary Statement Y, Critical Peak Pricing Program costs recovered through generation rates (Sheet 1, footnote 1/) Other programs uncertain.
4/ For SCE DRBPA, G = Generation subaccount, D = Distribution subaccount
5/ SCE AMP cost breakdown from Advice Letter 3089-E, page 4 (implementing D.14-05-025). July 30, 2014.

2. **Inconsistent utility cost allocation is improper, unjustified and creates inequities.**

As shown, the utilities employ inconsistent cost allocation approaches to similar utility-run DR programs. As is evident, the differences are arbitrary and unsupported by any underlying policy rationale. The consequence of such inconsistency is unequal treatment of similarly-situated customers simply because of their location. For example, direct access customers in SCE's service territory pay for the capacity incentive payments made to third-party DR Providers under the Aggregator Managed Portfolio ("AMP") program through their distribution rates, whereas direct access customers in PG&E's service territory do not pay for AMP incentive payments at all. Instead, PG&E recovers the costs of the AMP incentive payments solely from its bundled customers though the Energy Resource Recovery Account (ERRA).[6] There is no rational public policy that can justify such financially divergent outcomes.

The witness for the Office of Ratepayer Advocates ("ORA"), Mr. Sudheer Gokhale, agreed that the current cost allocation of utility-run DR programs was inconsistent, with the same or similar DR programs run by different utilities having differing cost recovery. He recommended that the Commission examine cost allocation mechanisms in this proceeding and require "consistency" among the utilities.[7]

In fact, the Commission previously determined in Decision ("D") 12-04-045 that consistency was needed for the utilities' cost allocation of DR programs and that "overall rules" should be established, which could then be applied in utility applications for cost recovery:

> …[W]e 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 an appropriate forum would be the R.07-01-041 or its successor *to*

[6] See Exhibit DAC-01, Witness Mara, pp.9-10 for discussion of AMP cost allocation by SCE versus PG&E.

[7] Exhibit ORA-01, Witness Gokhale, p. 17.

> *establish overall rules and then those rules can be applied* in the Utilities' respective rate design applications. (Emphasis added).[8]

The Scoping Memo determined this docket would be the proceeding in which these cost allocation issues will be resolved.[9] And finally, the Settlement Parties agreed in the Settlement Agreement that cost allocation will be briefed and decided in this proceeding and that the Commission's determination will apply to utility DR program costs going forward.[10]

DACC and AReM strongly support the Commission's objective to establish "overall rules" for proper cost allocation in this proceeding and have therefore proposed principles set forth in the next section to govern allocation of utility DR procurement and program costs and to apply them uniformly and consistently across the utilities. Once approved by the Commission, the utilities should then be required to comply with these cost allocation principles going forward for all of their DR procurement and programs proposed in individual program applications, general rate cases, or Rate Design Window proceedings. In addition to ensuring uniform treatment of customers, applying uniform, utility-wide cost allocation principles would also reduce Commission Staff and participants' time and resources that would otherwise have to be committed to litigating these contentious issues.

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[8] D.12-04-045, p. 204.

[9] Scoping Memo, *loc. cit.*, p. 9 and Attachment One, pp. 2-3.

[10] See, for example, Settlement Agreement, Section C.7.d: "The allocation of the DRAM-related amounts in 2017-2019 among customers shall be pursuant to the Commission's decision on cost allocation in this proceeding."

B. Current utility cost allocation for DR-related programs adversely affects markets, competitors and customers.

The Commission has, in the past, typically approved the IOUs' requests to allocate the vast majority of their DR program costs to distribution rates. This has several adverse effects, as DACC and AReM described in testimony.[11]

First, improperly allocating costs that should be collected in generation rates to distribution rates artificially lowers utility *generation* rates, thereby creating both harmful market inefficiencies and competitive advantages for the utilities. ESPs and CCAs directly compete with the utilities to provide electric service to retail customers. When current or prospective customers of ESPs and CCAs compare an IOU's generation rate to ESP/CCA prices, they do not see the true cost of the IOU's generation portfolio because the costs of the DR programs have been improperly shifted to distribution. When the generation component of the IOUs' rates, is inappropriately whittled down in this manner, the price comparison that retail choice customers must make between utility rates and competitive prices is artificially skewed, diminishing competitive opportunities and distorting the retail market. As the Commission warned in D.97-08-056, artificially low utility generation rates would "provide competitive advantages, which would stifle competition to the utilities."[12]

Second, utility DR programs funded through distribution rates create barriers to entry for third-party DR Providers, restrict competition, and thereby raise costs for consumers.[13] Specifically, the IOUs are significantly advantaged when their DR program costs are guaranteed cost recovery from all customers through distribution rates with little to no risk of shortfall or

[11] See, Exhibit DAC-01, Witness Mara, pp. 11-13.

[12] See, Exhibit DAC-01, Witness Mara, pp. 5-6 for a discussion of the Commission's determination in D.97-08-056.

[13] See discussion in Exhibit DAC-01, Witness Mara, p. 13, including accompanying cites, particularly The NorthBridge Group report, which discussed the effects of competition on prices, innovation and products for consumers

non-recovery. Third-party DR Providers have neither guaranteed cost recovery nor ratepayer subsidized programs to offer to customers they are seeking to enroll in programs of their own design. When customers who may otherwise elect service through third-party DR programs nevertheless still have to pay for the utility programs, the third-party programs are automatically less competitive than the utilities' subsidized DR programs.[14] Third parties are thus hampered in their ability to enter the DR market when utilities' DR services are underwritten by non-bypassable charges (in this case through distribution rates) that must be paid by all customers. The resulting limited engagement by third parties also stymies innovation in DR programs. Utility offerings tend to be prescriptive, one-size-fits-all programs that do not work well for all customers. As a consequence, the utilities' programs (supported by layers of sales teams, marketing specialists, software and systems, not to mention the direct subsidies paid for through distribution rates) remain the only game in town. In short, the Commission's goal to establish a "new vision" for DR in California[15] is significantly compromised with continued misapplication of DR costs to distribution rates.

C. Uniform utility cost allocation principles should be adopted, as proposed by DACC and AReM.

The sections that follow summarize the proposed uniform principles, explain the policy rational supporting the principles, and describe how they can be applied to current and prospective utility DR program costs.

[14] See: D.12-04-045, pp. 201-202; and *Testimony of Mark E. Fulmer on Behalf of the Direct Access Customer Coalition and the Alliance for Retail Energy Markets Concerning Competitive Issues in the 2012-14 Demand Response Program Proposals,* A.11-03-001 *et al,* June 15, 2011, p. 12-20, as cited in *Prehearing Conference Statement of the Direct Access Customer Coalition and the Alliance for Retail Energy Markets,* R.13-09-011, October 14, 2014, p. 4.

[15] R.13-09-011, pp. 15-16.

1. **Proposed uniform principles for utility cost allocation.**

DACC and AReM presented opening testimony in this proceeding[16] that set forth proposed uniform cost allocation principles to be used to determine proper cost allocation for the IOUs' Supply Resource and Load Modifying Resource DR programs identified in Table 2 of D.14-03-026.[17] These uniform principles can be summarized as follows:

Principle #1: ***Market Integration/Generation Substitute*** – DR-related programs that are integrated with markets operated by the California Independent System Operator ("CAISO") or otherwise function as substitutes for generation should have the associated costs recovered like other generation and procurement costs, from bundled customers through the generation revenue requirement. A program functions as a substitute for generation if it provides (or is expected to provide) Resource Adequacy ("RA") capacity or value,[18] perform other generation-related functions (such as shifting load off-peak), or otherwise affects utility procurement of energy/capacity to meet load.

Principle #2: ***Bundled-Only Tariffs*** – Utility tariffs that are applicable only to bundled customers are to be recovered solely from those bundled customers through the generation revenue requirement.

Principle #3: ***Avoiding Distribution Infrastructure*** -- DR-related programs that are primarily designed to avoid distribution infrastructure additions may be recovered from all customers through distribution rates.

[16] Exhibit DAC-01, Witness Mara, pp. 14-21.

[17] D.14-03-026, Table 2, p. 21.

[18] RA "value" may include, for example, reduced load for RA compliance purposes or peak-shifting.

Principle #4*: *Open Eligibility Without Generation or Procurement Functions – DR programs that do not meet the conditions of Principles 1 through 3 are to be recovered though the distribution revenue requirement if the utility DR program (or any DR-related costs in support of such program) is (a) applicable and available to all customers, (b) not integrated or expected to be integrated with CAISO markets, and (c) does not provide any generation-related value or support any procurement function of the utility.

Principle #5*: *All Program Benefits Flow to the Customers Paying the Costs -- To the extent that bundled customers pay for the utilities' DR program costs, they should retain all associated benefits, such as any applicable RA capacity credit or reduced load forecasts used for RA compliance purposes. Conversely, if all customers pay for the utilities' DR program costs, the associated benefits must be allocated proportionally to all such customers.

2. Policy Rationale Supporting the Proposed Principles.

DACC and AReM provided testimony describing a strong policy rationale to support the proposed uniform principles, which is summarized as follows:

- Utility generation costs must not be allocated to distribution customers to avoid providing a competitive advantage to the utilities and creating market inefficiencies.[19]

[19] Exhibit DAC-01, Witness Mara, pp. 5-6, citing D.97-08-056, p. 8.

- Utility generation costs to be collected through the generation revenue requirement include related costs that are not strictly "generation" to ensure competitive neutrality.[20]
- Utility DR programs are largely used to meet RA requirements or provide RA value by reducing load forecasts used for RA compliance purposes;[21] resources used to meet RA requirements are substitutes for conventional generation and should be recovered like other generation and procurement costs.[22]
- Each load-serving entity ("LSE") has its own RA requirements to meet[23] and there is no statutory obligation that mandates procurement of DR by the IOUs to meet the RA requirements of the ESPs or CCAs.
- Cost-causation principles dictate that costs associated with dynamic pricing tariffs must be recovered from bundled customers through the generation revenue requirement.[24]

[20] Exhibit DAC-01, Witness Mara, pp. 7, citing D.12-12-033, Finding of Fact 136, p. 184, in which the Commission ordered the utilities to collect compliance costs for the cap-and-trade program through the "generation component" of customers' rates to ensure competitive neutrality with ESPs and CCAs.

[21] The IOUs' DR programs receiving RA credits are listed in reports posted on the CPUC web site at the following link: http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/ra_compliance_materials.htm.

[22] Exhibit DAC-01, Witness Mara, p. 20.

[23] Exhibit DAC-02, Witness Mara, p. 13.

[24] Exhibit DAC-01, Witness Mara, pp. 18-20, citing D.12-12-004, pp. 52-53: "We are persuaded by the arguments of the Direct Access Parties that requiring the customers of CCAs and ESPs, who cannot enroll in SDG&E's dynamic pricing tariffs, to pay the costs of implementing those tariffs, is *not consistent with cost causation principles*, and would not be reasonable" and "…we require that the *costs of SDG&E's dynamic pricing decision be recovered from all bundled customers through generation rather than distribution rates.* (Emphases added). See also, D.08-07-045, pp. 41-42, as cited in R.12-06-013, p. 10, in which the Commission determined that dynamic rates should be based on cost-causation principles.

3. Application of these principles to bifurcated DR resources.

In D.14-03-026, the Commission determined that utility DR programs should be bifurcated into two categories: Supply Resources and Load Modifying Resources.[25] The adopted categorization provides a rational and simple basis for application of the uniform cost allocation principles, as follows:

a. *Supply Resources* – The Commission has defined Supply Resources as DR resources integrated into the CAISO's wholesale energy markets.[26] The main benefits of Supply Resource DR are to reduce peak demand on the electrical system, reduce the need to procure new peaking resources, and potentially to help integrate intermittent renewable resources into the grid. In other words, DR Supply Resources directly substitute for conventional generation resources – an understanding shared by the CAISO, Federal Energy Regulatory Commission ("FERC"), Commission Staff and other parties to this proceeding as shown by the following citations to the record:

- Retail DR provided as wholesale products that look and act like generators can be used by the CAISO in the same way as thermal power plants – as part of the total resources available to serve load. [27]
- The CAISO's wholesale DR product, the Proxy Demand Resource ("PDR"), is "treated like generation" in the CAISO's tariff rules.[28]

[25] D.14-03-026, Ordering Paragraph 1, p. 28.

[26] D.14-03-026, Ordering Paragraph 3, p. 28.

[27] 2009 CAISO Annual Report, pp. 18-19, as cited in Exhibit DAC-01, Witness Mara, p. 16.

[28] *Order Conditionally Accepting Tariff Changes and Directing Compliance Filing*, 132 FERC ¶ 61,045, ER10-765-000, July 15, 2010, ¶ 24, as cited in Exhibit DAC-01, Witness Mara, p. 16.

- DR acts as an alternative for generation and is entitled to equal compensation under certain conditions.[29]
- The most significant avoided cost provided by DR resources is the avoided cost of generation capacity.[30]
- Benefits of DR programs primarily accrue to customers in the form of reduced generation costs.[31]
- DR reduces the reserve margin of operating generation resources that provide reserves to respond to system contingencies.[32]
- Testimonies of various utility witnesses that their DR programs function as generation or offset generation procurement requirements.[33]

Put simply, DR Supply Resources are designed to "look and act like generators" in the CAISO's wholesale markets, which means they both substitute for generation resources that would otherwise be called on by the CAISO to meet load and satisfy a procurement obligation for the IOUs. Thus, in accordance with Principle #1, the costs of developing, implementing and operating Supply Resources should be allocated the same way that similar generation and procurement costs are allocated – through the generation revenue requirement.

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[29] *Demand Response Compensation in Organized Wholesale Electric Markets*, 134 FERC ¶ 61,187, March 15, 2011, ¶ 47, as cited in Exhibit DAC-01, Witness Mara, p. 16.

[30] *Administrative Law Judge's Ruling Requesting Comments on Proposed Revisions to the Cost-Effectiveness Protocals [sic],* R.13-09-011, June 23, 2014, Attachment A, p. 31.

[31] Exhibit ORA-1, Witness Gokhale, p. 17.

[32] Attachment A to June 23rd Ruling, *loc. cit.,* p. 39.

[33] Cites in Exhibit DAC-02, Witness Mara, pp. 2-3.

b. *Load Modifying Resources* – Load Modifying Resources are defined by the Commission as DR resources that "reshape or reduce the net load curve."[34] Table 2 of D.14-03-026 provided a preliminary categorization of the IOUs' Load Modifying Resource DR programs, as follows:

Load Modifying Resources[35]
Critical Peak Pricing (CPP)
Time of Use (TOU) Rates
Permanent Load Shifting (PLS)
Real Time Pricing (RTP),
Peak Time Rebate (PTR)

The programs identified as Load Modifying Resources in Table 2 primarily fall into the general category of TOU/Dynamic Pricing Tariffs. Only the Permanent Load Shifting program falls outside of this general category. Each is discussed below.

i. Time-of-Use ("TOU") Rates/Dynamic Pricing Tariffs – Utility TOU tariffs provide incentives for bundled utility customers to reduce their energy consumption during peak periods or at other times designated by the utility. This type of utility tariff also includes Critical Peak Pricing ("CPP"), Peak Time Rebate ("PTR"), and Real Time Pricing ("RTP"). PG&E's Peak Day Pricing ("PDP") and Residential Smart Rates (Electric Schedule E-RSMART) options were not listed in Table 2 of D.14-03-026, but also fit into this category. These utility tariffs are available and applicable solely to bundled customers as either their default tariff by which all of their electricity needs are met or as an optional tariff under which they may choose to take electricity service. As noted above, the Commission has already determined for SDG&E that assigning

[34] D.14-03-026, Ordering Paragraph 2, p. 28.

[35] Excerpted from D.14-03-026, p. 21.

associated costs of such tariffs to non-bundled customers violates cost-causation principles and is unreasonable.[36] Essentially, if the associated bundled tariff costs were permitted to be included in distribution rates, direct access and CCA customers would be forced to subsidize the electricity costs of bundled customers, creating an improper cross subsidy. Therefore, in accordance with Principle #2 above (Bundled-Only Tariffs), the costs of developing, implementing and operating such TOU/dynamic pricing tariffs should be recovered solely from bundled utility customers through the generation revenue requirement. And further, in accordance with Principle #5 above, all program benefits should flow solely to bundled customers.

ii. Permanent Load Shifting (PLS) – Some utility DR tariffs are available and applicable to all customers, including direct access customers, but serve as generation substitutes nonetheless. The utility uses the tariff to procure the resource – a generation substitute – from the suppliers, the retail customers, which may include bundled as well as direct access customers. The PLS program is an example of such a tariff. It is open and available to all customers, and is used to shift load away from peak hours, thereby substituting for generation resources. In accordance with Principle #1 (Market Integration/Generation Substitute), the costs of developing, implementing and operating the program must be recovered through the generation revenue requirement, with any associated RA benefits retained by the bundled customers (Principle #5).

4. Application to other DR-related utility costs.

The five principles listed above are also easily applied to other utility DR programs that were not listed in Table 2 of D.14-03-026. For example, SCE's Summer Discount Plan ("SDP")

[36] D.12-12-004, pp. 52-53.

and Agricultural Pumping-Interruptible Tariff ("AP-I") are examples of tariffs that are open to all customers and receive RA capacity credits.[37] In accordance with Principle #1 (Market Integration/Generation Substitute), the costs of developing, implementing and operating such programs must be recovered through the generation revenue requirement, with the RA benefits retained by the bundled customers (Principle #5).

In addition, the principles adopted in this proceeding should apply to all utility programs going forward. For example, SCE has recently filed Phase 2 of its 2015 General Rate Case and proposed cost allocation for DR-related costs, including additional dynamic pricing rates and costs to integrate its DR programs into CAISO markets.[38] Because this proceeding has just begun,[39] neither SCE nor other parties will be prejudiced by the Commission requiring that cost allocation principles established in this proceeding must apply to SCE's DR-related costs in Phase 2 of its 2015 General Rate Case. In fact, SCE states in testimony that it "proposes to incorporate any authorized changes in revenue requirement or rate design resulting from other proceedings when implementing the final Commission decision in this proceeding."[40] Moreover, DACC and AReM – and other parties -- can avoid unnecessary and contentious re-litigation of issues addressed in this proceeding.[41]

In the Settlement Agreement, parties also specified two additional DR-related costs for which the Commission should determine appropriate cost allocation in this proceeding: the DR Auction Mechanism ("DRAM") Pilot and hiring experts to assist the Load Modifying Resource

[37] As noted in Exhibit DAC-01, Witness Mara, p. 18, the IOUs' DR programs receiving RA credits are listed in reports posted on the CPUC web site at the following link: http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/ra_compliance_materials.htm.

[38] A.14-06-014, June 20, 2014, Exhibit SCE-03, p. 12, to that application.

[39] No prehearing conference has been scheduled thus far.

[40] A.14-06-014, June 20, 2014, Exhibit SCE-03, p. 4, to that application.

[41] AReM and DACC raised the issue of the "correct determination of distribution costs" in their July 25, 2014 response to SCE's Phase 2 application, p. 2.

("LMR") Valuation Working Group. The Settlement provides that the allocation of the DRAM Pilot costs among customers for 2015-16 would be subject to briefing and determination by the Commission in this proceeding and that allocation of the DRAM-related costs among customers for 2017-19 would be subject to this same Commission determination.[42] The Settlement further provides that the allocation of expert costs among customers for 2015-16 would be subject to briefing and determination by the Commission in this proceeding.[43] Each is discussed below.

a. <u>*Cost Allocation for the DRAM Pilot*</u> – The DRAM Pilot is designed to test the feasibility of the IOUs using an auction mechanism to procure RA from DR Supply Resources with third-party direct participation in CAISO markets.[44] Accordingly, Principle #1 applies (Market Integration/Generation Substitute). The costs of the pilot are being incurred to develop mechanisms by which the IOUs can procure RA from third-party DR providers and integrate resources into CAISO markets though an auction mechanism. Further, the DRAM, if found feasible and approved by the Commission, would be a procurement tool solely applicable to the IOUs, and therefore, the costs of all such IOU procurement tools should be recovered like all other procurement costs, through the generation revenue requirement, and the benefits of that procurement should remain with the bundled customers (Principle #5).

b. <u>*Cost Allocation for Experts Hired to Assist the LMR Valuation Working Group*</u> – The LMR Valuation Working Group has a broad mission to determine ways to quantify the value of Load Modifying Resource DR after 2019 and recommend to the CAISO, CPUC and California Energy Commission ("CEC") how this value can be realized by the resource owners.[45] Because this working group seeks new ways to determine value for utility Load Modifying

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[42] Settlement Agreement, Section C.7.d, p. 29.

[43] Settlement Agreement, Section B.6.c.iii, p. 22.

[44] Settlement Agreement, Section C.1, p. 24.

[45] Settlement Agreement, Attachment B, Charter for LMR Valuation Working Group, "Purpose of Working Group," p. 1.

Resources in CAISO markets and through utility procurement of RA, the associated costs to hire experts should be recovered through the generation revenue requirement (Principle #1) with the RA benefits retained by the bundled customers (Principle #5). While the Working Group may also address how to value DR in distribution planning,[46] that is not the primary emphasis of the Working Group and thus does not qualify under Principle #3 (Avoiding Distribution Infrastructure).

D. Specific Commission action requested on cost allocation.

DACC and AReM have consistently raised their concerns in numerous proceedings regarding improper allocation of DR-related costs. With the commitments made by parties in the Settlement Agreement and a Commission determination in this proceeding on uniform cost allocation principles, DACC and AReM believe that litigation on this topic can and should now come to an end. Accordingly, DACC and AReM respectfully request that the Commission take the actions described above in this proceeding.

II. BACK-UP GENERATORS

The Scoping Memo asked parties to address issues regarding back-up generators used to provide DR and how the Commission should set rules consistent with the policy statement in D.11-10-003 if DR programs are bifurcated.[47] As noted in the Scoping Memo, the D.11-10-003 policy statement suggests that RA credit "should not" apply to DR programs using "fossil-fueled emergency" back-up generators.[48] Significantly, however, the policy statement did not *adopt* this

[46] Settlement Agreement, Attachment B, Charter for LMR Valuation Working Group, "Products," p. 1.

[47] Scoping Memo, R.13-09-011, November 14, 2013, Attachment 1, p. 3.

[48] D.11-10-003, p. 30 and Conclusion of Law No. 5, p. 33: "It is reasonable to adopt as a policy statement that fossil-fueled emergency back-up generation resources should not be allowed as part of a demand response program for resource adequacy purposes, subject to rules adopted in future RA proceedings."

policy as some parties asserted,[49] but simply left the issue open for future Commission consideration, as verified in the testimony submitted by the California Large Energy Consumers Association ("CLECA"), PG&E and SCE.[50]

The Commission has been consistent in its goal to maximize DR resources. For example, in establishing this DR rulemaking, the Commission explained that it:

> … intends to build upon the body of work completed to date and retool demand response to align with the grid's needs and *enhance the role of demand response* in our energy policy. (Emphasis added)[51]

As DACC and AReM noted in their response to questions on foundational issues, a prohibition on the use of back-up generation runs counter to this goal by reducing participation of DR in CAISO markets and possibly hampering the development of newer back-up technologies, such as fuel cells, batteries, and other emerging storage technologies that could use natural gas.[52] The use of fossil fuels for back-up generation in certain instances, while creating some emissions, may still be preferable to installing new larger-scale peaking facilities.

In fact, PG&E agreed that limiting fossil-fueled back-up generators from DR participation "could risk losing a significant amount of DR capacity that is being counted on in the IOUs' RA showings."[53] PG&E recommended that the Commission should develop a "robust record" on the use of such generators before it makes a decision on future use.[54] DACC and AReM concur.

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[49] See, for example, Exhibit NRD-01, Witness Bull, p. 3.

[50] Exhibit CLE-02, Witness Barkovich, p. 3; Exhibit PGE-01, Witness Tougas, pp. 7-1 – 7-1; Exhibit SCE-01, Witness Wood, pp. 46-47.

[51] R.13-09-011, p. 15.

[52] *Response of the Direct Access Customer Coalition and Alliance for Retail Energy Markets to Questions on Foundational Issues*, R.13-09-011, December 13, 2013, pp. 11-12.

[53] Exhibit PGE-01, Witness Tougas, pp. 7-4 – 7-5.

[54] Exhibit PGE-01, Witness Tougas, p. 7-4.

In opening testimony, DACC and AReM proposed steps for the Commission to take in this proceeding to determine the conditions under which DR resources supported by back-up generators could qualify as an RA resource, as follows:[55]

- Consider the extent to which the resource is subject to and meets all federal, California Air Resources Board ("ARB") and local air quality management districts' emission standards. If back-up generation meets the low emission standards of the local air quality management district for stationary sources, the unit could be approved for use as an RA resource.
- Allow back-up generation to be bid into CAISO markets as a DR resource (and to receive RA credit) when the unit conducts its required testing.
- Work with ARB to define the acceptable uses of back-up generation for providing DR resources under the plan for reducing greenhouse gas ("GHG") emissions pursuant to Assembly Bill 32.
- Work with local air quality management districts to consider acceptable conditions for waivers of emission requirements to use back-up generation for providing DR resources in CAISO markets. For example, back-up generators can be operated in case of emergencies under most air quality district rules. Therefore, if a request for DR resources is considered an "emergency," the restriction on operations should be removed.

DACC and AReM further noted that the ability of a customer to use back-up generation for any purpose is heavily regulated in California and requested that these policies be reviewed in this proceeding as part of the evaluation of the use of back-up generation by DR resources.[56]

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[55] Exhibit DAC-01, Witness Mara, p. 26.

[56] DACC-AReM December 13th 2013 Response on Foundational Questions, *loc. cit.*, p.

Because of other pressing issues in this proceeding, these proposals by DACC and AReM were not addressed. SCE suggested in its opening testimony that the Commission engage in a "collaborative process" to develop appropriate rules for back-up generators and to include other affected agencies, such as ARB and local air quality districts.[57] DACC and AReM concur with this recommendation and suggest adding the CAISO to the list of affected organizations. This effort could be accomplished as a new phase of this proceeding or in a separate rulemaking. In any event, DACC and AReM request that the Commission devote the necessary attention and resources to define the acceptable use of back-up generators to support DR expansion.

III. SUPPORT FOR THE AUGUST 4, 2014 SETTLEMENT MOTION

On August 4, 2014, a broad group of active parties to this proceeding (the "Settling Parties") filed an uncontested motion for settlement of Phase Three issues ("Settlement Agreement").[58] The Settling Parties have reached agreement on a mutually acceptable outcome on the Phase Three issues identified in the "Joint Assigned Commissioner and Administrative Law Judge Ruling and Revised Scoping Memo Defining Scope and Schedule for Phase Three, Revising Schedule for Phase Two, and Providing Guidance for Testimony and Hearings" issued in this rulemaking on April 2, 2014 ("April 2 ACR"). The settlement complies with all of the requirements specified in Rule 12.1 of the Commission's Rules of Practice and Procedure.

As signatories, AReM and DACC believe that the Settlement Agreement is reasonable in light of the whole record, consistent with law, and in the public interest. Therefore, AReM and

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[57] Exhibit SCE-01, Witness Wood, p. 49.

[58] *Motion for Adoption of Settlement Agreement between and among Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, California Independent System Operator Corporation, Office of Ratepayer Advocates, The Utility Reform Network, California Large Energy Consumers Association, Consumer Federation of California, Alliance for Retail Energy Markets, Direct Access Customer Coalition, Marin Clean Energy, EnerNOC, Inc., Comverge, Inc., Johnson Controls, Inc., Olivine, Inc., EnergyHub/Alarm.Com, Sierra Club, Environmental Defense Fund, and Clean Coalition on Phase 3 Issues,* R.13-09-011, August 4, 2014.

DACC support adoption of the Settlement Agreement; request that the Commission base its decision on all Phase Three issues on the Terms and Conditions of the Settlement Agreement; and therefore do not further address herein the issues that are proposed to be resolved by the Settlement Agreement.

IV. CONCLUSION

DACC and AReM urge the Commission to move forward with the implementation of its new vision for DR in California by taking the following actions:

- Adopt the uniform cost allocation principles proposed by DACC and AReM for DR-related costs.
- Direct the IOUs to apply these cost allocation principles going forward in all general rate cases, Rate Design Window proceedings, and applications for cost recovery of DR-related costs.
- Determine that the DR-related costs in Phase 2 of SCE's 2015 General Rate Case (A.14-06-014), including costs associated with dynamic pricing tariffs, shall be allocated in accordance with the uniform principles adopted by the Commission in this proceeding.
- Find that DRAM Pilot costs are to be recovered through the generation revenue requirement, in accordance with the adopted principles.
- Find that the costs of the expert hired to assist the LMR Valuation Working Group are to be recovered through the generation revenue requirement, in accordance with the adopted principles.
- Include a finding that the Commission did not adopt a policy to prohibit use of back-up generators for DR resources in D.11-10-003, but left the issue open for further consideration.

- Include a commitment to address the appropriate use of back-up generators for DR resources thought a collaborative approach in a new phase of this proceeding or in another proceeding as appropriate.
- Approve the Settlement Agreement filed jointly by multiple parties to this proceeding, including DACC and AReM.

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August 25, 2014