BEFORE THE PUBLIC UTILITIES COMMISSION
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Application of Pacific Gas and Electric Company (U39E) for Approval of Demand Response Programs, Pilots and Budgets for Program Years 2018-2022.	Application 17-01-012 (Filed January 17, 2017)
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RESPONSE OF THE CALIFORNIA ENERGY STORAGE ALLIANCE
ON THE ADMINISTRATIVE LAW JUDGES' RULING REQUESTING RESPONSES TO QUESTIONS

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In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), the California Energy Storage Alliance ("CESA")[1] hereby submits this response to the *Administrative Law Judges' Ruling Requesting Responses to Questions* ("Ruling"), filed by Administrative Law Judge ("ALJ") Kelly A. Hymes and Administrative Law Judge Nilgun Atamturk on June 15, 2018. Pursuant to ALJ Hymes' procedural email

[1] 8minutenergy Renewables, Able Grid Energy Solutions, Advanced Microgrid Solutions, AltaGas Services, Amber Kinetics, American Honda Motor Company, Inc., Axiom Exergy, Brenmiller Energy, Bright Energy Storage Technologies, Brookfield Renewables, Carbon Solutions Group, Centrica Business Solutions, Consolidated Edison Development, Inc., Customized Energy Solutions, Dimension Renewable Energy, Doosan GridTech, Eagle Crest Energy Company, East Penn Manufacturing Company, Ecoult, EDF Renewable Energy, ElectrIQ Power, eMotorWerks, Inc., Enel, Energport, ENGIE, E.ON Climate & Renewables North America, esVolta, Fluence Energy, GAF, General Electric Company, Greensmith Energy, Ingersoll Rand, Innovation Core SEI, Inc. (A Sumitomo Electric Company), Iteros, Johnson Controls, Lendlease Energy Development, LG Chem Power, Inc., Lockheed Martin Advanced Energy Storage LLC, LS Power Development, LLC, Magnum CAES, Mercedes-Benz Energy, NantEnergy, National Grid, NEC Energy Solutions, Inc., NextEra Energy Resources, NEXTracker, NGK Insulators, Ltd., NRG Energy, Inc., Parker Hannifin Corporation, Pintail Power, Primus Power, Range Energy Storage Systems, Recurrent Energy, Renewable Energy Systems (RES), Sempra Renewables, Sharp Electronics Corporation, SNC Lavalin, Southwest Generation, Sovereign Energy, Stem, STOREME, Inc., Sunrun, Swell Energy, True North Venture Partners, Viridity Energy, Wellhead Electric, and Younicos. The views expressed in these Comments are those of CESA, and do not necessarily reflect the views of all of the individual CESA member companies. (http://storagealliance.org).

communication to the service list for A.17-01-012, *et al*. on June 22, 2018 granting an extension for filing responses, CESA timely files its responses here on July 20, 2018.

I. INTRODUCTION.

CESA appreciates the Commission's leadership in addressing some of the key policy questions around dual participation as it relates to demand response ("DR") programs, including for technology incentive programs such as the Automated Demand Response ("ADR") Program. The Commission recognized the importance of dual participating in previous Decisions that found that dual participation promoted increased DR participation from customers and that it would be inconsistent with Commission priorities to "limit customers" ability to reduce peak demand simply because it might result in some customer overpayment in rare circumstances."[2] CESA agrees, and if a customer is willing and able to provide multiple grid services by participating in multiple DR programs or contracts, the Commission should encourage customers to do so by removing barriers for dual participation while setting reasonable parameters and rules that avoid overcompensation, reliably address the underlying grid needs, and allow for reliable scheduling of load. In doing so, DR resources will deliver more value to ratepayers, customers, and the grid, as well as foster further customer choice by increasing the utilization of ratepayer investments.

However, after reviewing past Commission decisions and participating in the February 13, 2018 workshop on current dual participation rules, CESA finds that dual participation and compensation rules have changed multiple times, effectively reframing the incrementality definition and leading to confusion by DR service providers. Table 1 in the Ruling summarized the current rules for participating in more than one DR program as follows:[3]

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[2] *Decision Adopting Demand Response Activities and Budgets for 2009 Through 2011*, D.09-08-027, issued on August 20, 2009, pp. 149-150, 154-155.

[3] Ruling, p. 6.

- Customers are not paid twice for the same load reduction;
- One program is day-ahead and the other is day-of;
- Only one of the two programs may pay a capacity payment;
- If both programs offer energy payments, one of the energy payments must be withheld for simultaneous events; and
- Critical Peak Pricing rate is a day-ahead energy program.

CESA believes that it is important to ensure that the rules for participating in multiple DR programs advance the state's policy goals while also evolving to remain in step with the transition of customer loads to alternative load-serving entities ("LSEs") and an increasing focus on cultivating greater third-party competition in providing DR services. In order to facilitate this transition, dual participation rules require re-evaluation and modification to enable fair competition among third-party providers. This includes rules for DR programs that are likely to be developed by Community Choice Aggregators ("CCAs") and direct-access energy service providers ("ESPs").

In this response, CESA provides our views on how dual participation rules should evolve to address operational concerns, which appears to be the focus of questions in this Ruling. CESA also proposes that the dual participation rules be adapted to a new incrementality framework that was developed in the Energy Storage Multiple-Use Applications ("MUA") Working Group,[4] which is relevant and important in discussions around compensation and eligibility for dual participation in multiple DR programs and participation models. Though the MUA Working Group arose out of R.15-03-011, the incrementality framework proposed by industry stakeholders is applicable to any distributed energy resource ("DER") technology and should be incorporated into

[4] CESA notes that the MUA Working Group Final Report will be filed on August 9, 2018. As of July 13, 2018, a draft version of that report has been circulated with the R.15-03-011 service list. CESA does not attach the report here because it is still in draft form but encourages the Commission staff and stakeholders in this proceeding to refer to that report once finalized.

the policy development for dual participation of DR resources.[5] Specifically, this framework defines incrementality in two main categories:

- **Planning and procurement incrementality** determines incrementality for an identified grid need during the planning and solicitation processes. This *ex ante* incrementality is a determination of how much energy and capacity of a resource is incremental to address an identified grid need and how much of that incremental energy and capacity should be reflected in procurement contracts, tariffs, and programs. This is particularly relevant for whether and how DR should participate in DR programs that count toward either supply-side Resource Adequacy ("RA") capacity and/or load-modifying RA capacity reductions.
- **Compensation and service incrementality** assesses *ex post* incrementality that may not be factored into contracts and settlement mechanisms at the time of procurement and contract execution. If the planning and procurement phase fully accounts for the incrementality of actual services rendered, then there may not be a compensation and service incrementality issue. But there may also be other markets where resources do not need to be solicited through a procurement and separately contracted (*e.g.*, energy markets) but rendering of actual services is measured through performance evaluation methodology or governed by tariffs. This is particularly relevant to baseline evaluation methodologies and concerns of dual participation resources.

CESA recommends that the Commission and stakeholders consider in this proceeding how the above incrementality framework could be adapted to the dual participation rules to ensure that DR resources are appropriately compensated for their incremental services and to prevent 'value from being left on the table' by not fully utilizing the grid-service capabilities of DR resources. For example, the current dual participation rules do not neatly apply to new applications of DR resources to provide local capacity and distribution deferral capacity. However, in the case where a DR resource is providing both local capacity and distribution deferral, while the current rules say that the same load reduction should not be paid twice, CESA argues that some non-zero incremental compensation is warranted for the same load reduction that delivered both local RA

[5] The energy-storage-specific sections of the report pertain to metering, settlement, and resource performance, but the incrementality principles should apply not only to the DR proceeding but also to the Integrated Distributed Energy Resources ("IDER") proceeding (R.14-10-010).

capacity and distribution capacity, which are two distinct values (*i.e.*, providing generation capacity versus deferring a distribution capital investment). Distribution capacity in this example would have otherwise required the investor-owned utility ("IOU") to procure and pay for that distribution capacity from a different resource, meaning that the DR resource would be providing the distribution capacity for 'free'.

In addition to the above incrementality categories, policy discussions around dual participation may also benefit from importing the "capacity-differentiated", "time-differentiated", and "simultaneous" multiple-use concepts that address many of the operational and compensation concerns of dual participation. Rather than enforcing an outright prohibition of dual participation in two capacity programs, as the current rules state, it may be more reasonable to consider the times during which capacity in the two programs must be delivered – *i.e.*, allowing dual participation in two time-differentiated capacity programs. It may be possible that there are very few periods of overlap in the capacity needs. For example, DR resources that wish to participate in both the Demand Response Auction Mechanism ("DRAM"), which has regular must-offer obligations and dispatches, as well as the Base Interruptible Program ("BIP"), which is rarely called upon, would be outright prohibited from dual participation under current rules due to the "no two capacity programs" rule. This prohibition does not consider whether the two capacity needs are time differentiated or whether a partial or reduced payment could be made for periods where the capacity needs happen to align to some degree.

Similarly, the "one day-ahead, one day-of" rule may also not be needed as the Commission moves to integrate many of its DR programs into the California Independent System Operator ("CAISO")markets, which come with day-ahead and real-time obligations, thus allowing careful consideration of must-offer obligations and/or dispatch periods to manage and count scheduled load drops. Blanket prohibitions against dual participation eligibility and compensation therefore may not be needed because clearer obligations may help make a more nuanced determination on whether two DR programs are incremental, avoid double counting, and warrant incremental compensation.

CESA understands that there are operational realities in how DR resources are notified, scheduled, dispatched, and compensated, which may require some of these multiple-use or dual-participation rules to be modified to accommodate these differences for DR resources. However, CESA believes that the above incrementality and multiple-use *principles* still apply. Thus, as the Commission moves forward in this proceeding, CESA highly encourages the Commission to consider and incorporate the applicable recommendations from the MUA Working Group to guide policy discussions around dual participation for DR resources.

II. RESPONSES TO QUESTIONS ON STRAW PROPOSAL FOR DEMAND RESPONSE PILOT PLANS TO BENEFIT DISADVANTAGED COMMUNITIES.

CESA does not have specific responses to the questions posed in the Ruling on this topic, but generally supports the Commission's intent to focus DR programs on disadvantaged communities ("DACs"), which aligns with the Commission's recent policy decisions for the Net Energy Metering ("NEM") Program and Self-Generation Incentive Program ("SGIP") to focus those customer programs on DACs with dedicated funding and/or customized programs and tariffs. Based on our experience with SGIP and studies[6] on the unique challenges to deploying DERs to low-income and disadvantaged communities, CESA encourages a careful consideration of the customization of program design, incentive levels, marketing and outreach, and safeguards needed

[6] *SB 350 Low-Income Barriers Study, Part A - Commission Final Report*, published by the California Energy Commission ("CEC") on December 16, 2016.

to support these customers. CESA thus generally supports the Commission's approach to begin with pilot DR programs targeted to DACs.

III. RESPONSES TO QUESTIONS ON DUAL PARTICIPATION.

As noted in the Ruling, CESA does not respond to the questions directed specifically to the IOUs (*i.e.*, Questions 2-5) or third-party providers (*i.e.*, Question 1) but is looking forward to reviewing and responding to insights that can be gained from statistical trends on dual participation and approaches/barriers to dual participation.

Question 6: What approach would you recommend to allow for the visibility needed by the Utilities regarding what is bid and awarded into the CAISO market while ensuring that customer choices are not decreased? Describe the approach and explain how the approach fulfills both needs. Provide cost estimates for this approach.

CESA recognizes the complications of forecasting load drops and scheduling load due to dual participation of DR programs, although the magnitude of these impacts may be relatively small relative to the total load. This reflects an operational complexity where load drops may be double counted that requires the IOUs and other LSEs to be able to have visibility into which and how much DR resources are participating in the CAISO markets. CESA understands that inaccurate forecasts due to overestimation of scheduled load drops presents a potential grid reliability concern that must be addressed in dual participation rules.[7]

In D.09-08-027, the Commission established some general criteria to minimize the likelihood of double counting DR resources and identified how San Diego Gas and Electric Company ("SDG&E") has been able to manage dual participation among IOU customer

[7] At the July 18, 2018 Load Shift Working Group meeting, CESA learned that the CAISO uses its own forecasting methodologies to manage real-time operations and that there are other factors that go into uncertainties and/or errors between forecasts from the day-ahead to real-time markets, which the CAISO's Day-Ahead Market Enhancements Initiative is intended to address to some degree.

participants by creating internal controls that limited the possible combinations of DR programs to avoid conflicts in triggers and that established a 'payment hierarchy' in the event of overlapping triggers. However, in CESA's view, one of the key barriers that prevent dual participation for customers in third-party-administered DR programs or portfolios is the single DR provider ("DRP") requirement. The Rule 24 tariff established that customers requesting DR service may not partition the electric loads of a service account among different DRPs, meaning that the entire reduction of a service account's electricity demand for a DR program must be registered to only one DRP. Customer service accounts are not precluded from enrolling and participating in multiple DR programs with a single DRP, since internal controls such as those established by SDG&E can manage any conflicting dispatches/triggers and have visibility into its DR customers. As a result, third-party DR customers are prohibited from simultaneously enrolling and participating in the event-based DR programs of more than one DRP. CESA raises this as a 'level playing field' issue in this proceeding because, currently, customers in IOU-administered programs can participate in multiple other IOU-administered programs, but the same dual participation allowance is not granted to customers in third-party-administered programs.

To address this issue, a Rule 24 tariff reassessment is warranted. In cases where there are two DRPs, such as when a customer wishes to participate in the third-party-administered DRAM in addition to the IOU-administered BIP, some platform and process to share information on the dual-participating DR resource is needed to allow the different DR providers to plan dispatches, schedule load, and verify/compensate load drops. Once authorized by the third-party DR provider to make its information available, a 'centralized scheduling matrix' or data sharing platform (*e.g.*, a "green button" type of mechanism) could potentially enable the IOU to more accurately forecast load drops by limiting the likelihood of double counting load drops. By adhering to the established "one day-ahead, one day-of" dual participation rule, the IOU should be able to avoid overlapping schedules and count a specified load drop to one DR program, not multiple, and then be able to identify and dispatch other DR resources within its portfolio to provide the needed load drop if a third-party DR resource cannot commit to do so.[8] Finally, with this data sharing, DR program administrators should be able to conduct for *ex post* verification of load reduction against a baseline and make the associated payments.

The actual technical solutions and details by which such data sharing can be done between IOUs and third-party DRPs likely requires technical working groups in this proceeding to dive into the feasibility and implementation issues. Furthermore, CESA acknowledges that the Rule 24 'firewall' must also be reassessed. CESA understands that the firewall, whereby IOU staff who hold "DRP responsibilities" are prevented from accessing confidential and competitive information from third-party DR providers, was established in order to protect confidential and competitive information.[9] This firewall, which was intended to protect competitive third-party dispatch strategies and customer acquisition, would need to be eliminated in order to allow IOU DR staff to incorporate third-party dispatches into the baseline calculations for their IOU-administered DR program. CESA recognizes that this firewall may need to be removed if dual participation is desired between IOU-administered and third-party-administered DR programs, and dual-participating third-party DR providers may need to accept that fact. At a minimum, this competitive neutrality issue could be addressed through some form of non-disclosure agreements among IOU individuals involved to maintain confidentiality of third-party data and practices. In

[8] Depending on the program, CESA acknowledges that non-performance within a DR program may come with incurred charges or reduced payments. It is incumbent on the DR provider to optimize their DR resource around that and identify DR programs where their DR resource may minimize or avoid such conflicts and overlapping service requirements.

[9] Rule 24 Tariff Section C.1.a(3).

addition to the firewall issue, CESA also recognizes that there are policies for performance evaluations and DR systems and registration that must be worked out at the CAISO in order to allow multiple DR resources behind a single retail service account to participate with different DRPs.

CESA does not comment on cost estimates of the data-sharing solutions discussed above, as other parties such as the IOUs and third-party DR providers may be better positioned to address these questions.

<u>**Question 7**</u>**: What changes to Rule 24/32 do you recommend to allow dual participation between Critical Peak Pricing and a third-party demand response provider program? Justify why these changes are needed. What changes, if any, do you recommend to address the firewall issue described in Section C.1.a.(3) of Rule 24/32? Justify why these changes are needed?**

CESA views the prohibitions around dual participation in Critical Peak Pricing ("CPP") and in a third-party DRP program to be a major challenge to ensuring a competitive DR marketplace, especially as many IOU commercial and industrial customers move toward default CPP rates. Currently, CPP is defined as an IOU-administered, default, day-ahead, energy program that provides customers the ability to opt out. According to Rule 24, these CPP customers would be required to disenroll from CPP rate in order to participate in, say, the DRAM because of the prohibition against customers enrolling in DR programs with more than one DRP. At the same time, when customers are enrolled in multiple DR programs administered by the same DRP, these customer are allowed to dual-enroll, so long as several other conditions for dual participation are met. CESA thus agrees that Rule 24 must be amended, as detailed in our response to Question 6.

Unlike CAISO-integrated DR programs, the CPP is a *voluntary* and *retail-only* DR program where the energy payments are economically determined by DRPs rather than based on bids into the market. As a result, CESA believes that the prohibitions against dual participation between CPP and third-party-administered DR programs (*e.g.*, DRAM) may be easier to address than it may be with other dual-participation use case varieties. For example, dually-enrolled CPP and DRAM customers should be able to deliver the same load reduction as intended by these two programs while only forgoing the energy payment from the DRAM contract during those coincident event periods – *i.e.*, adhering to the rule where only one of the energy payments must be withheld for simultaneous events. As CESA sees it, double compensation is not an issue in this case.

Rather, the applicable language in Rule 24 could be modified to reflect the fact that CPP is not a CAISO-integrated DR program with market obligations that would allow for such dual participation. CESA understands the original intent of Rule 24 as supporting compliance with Federal Energy Regulatory Commission ("FERC") Order Nos. 719 and 719-A, which are intended to focus on direct DR participation bid into the CAISO's market. Given this, CESA offers our suggested simple modification to eliminate the limits to "additional enrollment" for all customers participating in any IOU-administered event-based DR program, regardless of whether said DR program participates in the CAISO's markets:

> "***Under the CAISO's rules, a customer is not allowed to simultaneously enroll load associated with the same service account number with more than one DRP that directly participates in the CAISO market***. A customer already enrolled in a DRP's DR service who chooses to enroll in another DRP's DR service must un-enroll from the current DRP's DR service. The DRP that is losing the customer must un-enroll the customer's load from the DRP's PDR or RDRR registration at CAISO. It is both the new and existing DRPs' responsibility to ensure the unenrollment in a timely fashion.
>
> ***A customer who participates in a [PG&E/SCE/SDG&E] event-based demand response program that is bid into CAISO's markets and chooses to enroll in any DRP DR service where [PG&E/SCE/SDG&E] is not the DRP, must un-enroll from any and all of [PG&E/SCE/SDG&E]'s event-based demand response programs subject to any contractual or program tariff obligations***. [PG&E/SCE/SDG&E] will notify the customer who will be switched to

> an otherwise applicable rate schedule (OAS) when the un-enrollment from the [PG&E/SCE/SDG&E] demand response program becomes effective [***emphasis added***]."

By making the edits above, the "one DRP" requirement under Rule 24 would be inapplicable for CPP customers that wish to enroll with third-party DRPs, though it would still represent a barrier for other dual-participation use cases. Furthermore, information sharing and double-counting avoidance can be readily implemented due to the voluntary, day-ahead, and energy-only nature of the CPP. To illustrate, if the IOUs are notified of dual participation in CPP and DRAM, which have known and frequent must-offer obligations delineated in contracts pursuant to RA requirements, the IOU should be able to only count on the load drop based on the RA capacity obligations. Especially as CPP events are known on a day-ahead basis, the IOUs should be able to accurate schedule load on a day-ahead basis based on expected load drops from the DRAM resource while not counting any duplicate load drops from the same resource for being also part of the CPP Program. As noted before, the energy payments would be dropped and only the capacity payment would be made, adhering to the existing dual participation rules.

In sum, CESA believes that modest Rule 24 changes could readily open the potential for CPP customers to be dual-enrolled in third-party DR programs that ensures that competition is fair between IOU and third-party DR providers. While CESA believes that the MUA principles and incrementality definitions should be used to redefine dual participation rules, modest changes to Rule 24 should immediately allow this one dual-enrollment use case that is feasible and reasonable in the near term.

IV. <u>RESPONSES TO QUESTIONS ON AUTOMATED DEMAND RESPONSE INCENTIVE POLICY</u>.

The Ruling provides a procedural overview and history of the ADR incentive policy discussion, including the February 20, 2018 set of guidelines proposed by the IOUs, April 20, 2018 webinar, and May 8, 2018 in-person workshop. In this overview, the Ruling notes that "battery storage technology was not present in the marketplace at the time the Auto Demand Response program was established,"[10] leading to questions around whether battery storage controls should qualify for ADR incentives. In CESA's view, it is important to not only narrowly consider the eligibility of energy storage technologies in ADR incentive eligibility but also to consider the role of the ADR program in achieving the state's policy objectives. Although the ADR incentive program has been around for more than a decade, developments and dynamics on the grid have made clear both the importance of the ADR program and the need for expanding it to assist in achieving the state's ambitious greenhouse gas ("GHG") emissions reduction and renewable energy objectives. For such reasons, CESA believes that the Commission required that "the Utilities shall offer Auto Demand Response technology incentives to customers *of all supply-side programs/activities* not subject to cost-effectiveness analysis…[including but not limited to] the Demand Response Auction Mechanism, and where applicable, pilots" [*emphasis added*].[11]

CESA believes that there are four 'touchstones' that should undergird the Commission's actions on ADR. First, the Commission should strive to facilitate as much, if not all, behind-the-meter ("BTM") energy storage to be considered ADR compliant. In the study prepared by the

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[10] Ruling, p. 14.

[11] *Decision Adopting Demand Response Activities and Budgets for 2018 Through 2022*, D.17-12-003, issued on December 14, 2017, pp. 78-79. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M202/K275/202275258.PDF

Lawrence Berkeley National Laboratory ("LBNL"), the focus should be on making investments in buildings so that it will be less expensive for them to join DR programs in the future and "future-proof" them in order to enable a building or end-use customer with the control and communication systems necessary for it to provide DR to the grid.[12] The introduction of smart meters when there was little or no residential time-of-use ("TOU") rates in effect serves as an apt analogue of a necessary infrastructure investment that made it possible for the *future* general application of residential TOU rates, which now is positioned to serve as an important tool to shape demand to mitigate 'duck curve' impacts and create economic opportunities like DR. Similarly, with the creation of the ADR incentive program that promotes the wide deployment of ADR technologies, the future distribution system will be equipped with DR resources with ADR capabilities going forward. While not all BTM energy storage will be equipped with ADR capabilities, the ADR incentive program, as with other preferred resources such as energy efficiency and renewables, should strongly encourage ADR capabilities to assist customers in making investment decisions for the needs of tomorrow.

Second, and relatedly, the Self-Generation Incentive Program ("SGIP") should reasonably complement the ADR program and serve to encourage the implementation ADR technologies. This can be achieved by not outright prohibiting the eligibility of SGIP projects to receive ADR incentives to encourage ADR compliance. Supporting synergies and alignment between SGIP and ADR programs will enable energy storage resources to more effectively provide (and optimize) grid support, customer services, and GHG emissions reduction.

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[12] Alstone, Peter et al., *2025 California Demand Response Potential Study: Charting California's Demand Response Future*, published on March 1, 2017, Sections 8.2 and 9.3. http://www.cpuc.ca.gov/General.aspx?id=10622

Third, as noted in our responses to dual participation, incrementality is an issue that must be carefully considered for BTM energy storage resources. Many of these incrementality concepts and principles are being developed in the Energy Storage proceeding (R.15-03-011) through the MUA Working Group that should be broadly applied to DR programs. When considering the eligibility of energy storage systems that claim ADR incentives and also claim SGIP incentives and/or participate in different DR programs or participation models, CESA recommends that incrementality be assessed on the specific services being assumed or contracted and differentiate it with what can be reasonably assumed (in terms of capacity impact and operational profile) as a condition of receiving ADR/SGIP incentives. As actual performance of those services are being measured and compensated, it will again be imperative to make an incrementality determination to ensure resources are properly compensated and, inversely, not over-compensated.

Finally, CESA believes that it is important for the Commission to align the state's vision for decarbonization, grid modernization, and reliability to align its DR programs and rules to work together to advance this vision. By providing this vision, the Commission may also have the guidance to ensure that DR providers are provided with the continuity and regulatory certainty that investment decisions today are not put at risk – *e.g.*, by prohibiting third-party energy storage projects claiming SGIP or contracted under Local Capacity Requirements ("LCR") contracts or Preferred Resources Pilot ("PRP") from also claiming ADR incentives – despite policies and rules previously in place that allow for such dual participation. As ADR guidelines are being developed, it will be important to ensure that they consistently align with the broader state policy objectives over the long term.

Below, CESA provides its responses to questions posed in the Ruling that are of particular concern and interest to our members and reserves the right to respond in replies to questions that are more directed to the IOUs (*i.e.*, Questions 8, 11-12) or non-energy-storage providers (*i.e.*, Questions 4 and 9).

<u>Question 1</u>: Do you agree with the matrix provided by the Utilities (see Attachment B)? Explain any disagreement.

CESA observes that the matrix does not fully capture the scope of DR programs and pilots that are available to technology incentive programs. Specifically, while not a "program" or "pilot" *per se*, LCR contracts and PRP represent a supply-side resource that participates in wholesale markets by providing supply-side DR. The matrix should reflect whether LCR and PRP resources that provide supply-side DR should be eligible for technology incentive programs. CESA's view is that the Commission already determined that DR resources that bid into the market are "supply-side resources"[13] and that all supply-side DR programs should be eligible for ADR incentives.[14] Thus, CESA believes that the matrix should reflect LCR and PRP resource eligibility for technology incentive programs when providing local capacity as a supply-side DR resource.

<u>Question 2</u>: Do you agree with the definition of an Auto Demand Response control, as developed during the workshop? Explain any disagreement.

CESA generally agrees with the definition of ADR control as developed at the workshop: "the ability to receive an automated DR signal to enable the customer to participate in a DR event for current models of DR without any manual customer intervention."

<u>Question 3</u>: Explain why you do or do not agree with the following criteria for controls eligible for auto demand response incentives: a) In the case of all three classes of customers (residential, commercial & industrial, and small & medium businesses) the control must be able to receive an Open Auto Demand Response compliant Auto Demand Response signal; b) For commercial and industrial customers, the customer must also be able to provide the anticipated kilowatts expected from the end uses equipped with the control as that is what determines the calculated incentive for that class of customers; and c) In the case of the small &

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[13] D.17-12-003, p. 40.

[14] *Ibid*, p. 75.

medium business customer class and residential customers receiving incentives for thermostats, the criteria depend upon the type of Auto Demand Response in which the customer is enrolled, deemed incentive based on the average kW load drop for that control in that sector.

CESA generally agrees with the criteria for controls eligible for ADR incentives. As discussed later, CESA's concerns revolve around the broad prohibition of ADR incentive eligibility when participating in SGIP, as part of a DR resource outside of a DR program, or part of a potential permanent DRAM in the future. Rather than taking a resource-specific approach, CESA argues that a nuanced and specific look at the specific controls and components of the resource that are eligible for ADR incentives be considered when making an eligibility and incrementality determination in relation to other funding and sourcing mechanisms for the same DR resource.

<u>Question 5</u>: Should a base interruptible program (a reliability program) customer bidding into the demand response auction mechanism pilot as a Reliability Demand Response Resource be eligible for Auto Demand Response control incentives? This question is only asked in terms of the pilot and not in terms of whether the pilot becomes a permanent mechanism; that question is premature.

CESA understands that the BIP is predicated on 15-minute and 30-minute notice options prior to an event by which customers must reduce their energy consumption to their firm service level. Based on this understanding, BIP resources would only qualify for ADR incentives if the resources plan to incorporate an automated, pre-programmed DR response, even as BIP allows for notification periods when emergency events are triggered by the CAISO or IOU.

<u>Question 6</u>: Should the Cost Causation Principle apply to Auto Demand Response incentives? If a Community Choice Aggregator or a Direct Access energy service provider offers auto demand response incentives to their customers does this qualify as a "similar" demand response program?

Yes, the Cost Causation Principle should apply to ADR incentives since it is a DR program that is recovered from all customers through distribution rates. By satisfying the requirements laid out in D.17-10-017 around "similar programs" including the offering the same type/number of customers, adhering to the prohibited resources policy, and allowing for third-party DR provider participation, the applicable CCA or ESP should be eligible to develop their own ADR incentive programs and then begin the process of ceasing marketing and cost recovery of the similar IOU program. As CCAs and ESPs serve a greater proportion of customer load, it will be important to ensure that DR programs such as ADR incentives continue to be offered through a "similar" technology incentive program.

A key policy discussion, however, is needed as the decision determined that the Cost Causation Principle is not applicable to the DRAM, which is designed to allow third-party direct participation in the CAISO markets and is not a DR program *per se*. There is lack of clarity around how ADR incentives *are* eligible for DRAM resources, according to matrix included in Attachment B in the Ruling, due to ADR incentives being eligible for pilot programs, which are not required to be analyzed for cost-effectiveness, but they may not be eligible according to a strict interpretation of the Cost Causation Principle due to DRAM being more of a participation model rather than a DR program.[15] Similar ambiguities apply when looking at ADR incentive eligibility for LCR resources for CCAs that provide DR. Broadly, even if DRAM becomes a permanent supply-side DR procurement mechanism, it is unclear whether ADR incentive eligibility would apply for DRAM resources since, pursuant to D.17-12-003, they are not analyzed for cost-effectiveness (as costs are bid in and least-cost offers are selected). The interplay between DRAM and LCR project eligibility for ADR incentives and how those would translate to similar CCA and ESP programs need to be addressed as well.

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[15] *Decision Adopting Steps for Implementing the Competitive Neutrality Cost Causation Principle, Requiring an Auction in 2018 for the Demand Response Auction Mechanism, and Establishing a Working Group for the Creation of New Models of Demand Response*, D.17-10-017, issued on November 1, 2017, p. 31. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M198/K319/198319901.PDF

Question 7: **If a community choice aggregator or direct access provider develops its own critical peak pricing or real time pricing program, should the customers of these programs be eligible for Auto Demand Response incentives if the investor owned utility does not receive the resource adequacy credit for the load modifying demand response benefit? Does the amount the customer pays in distribution charges fairly compensate for the customer's participation? Should there be a carve-out/set-aside or a cap on the Auto Demand Response incentive budget for these customers? How would the Commission determine that carve-out/set-aside or cap?**

Assuming similar CPP and Real-Time Pricing ("RTP") programs pursuant to D.17-10-017, CESA believes that these CCA and ESP customers should also be eligible for ADR incentives made available through the IOU's ADR program. As long as ADR programs continue to be funded through distribution rates, CCA and ESP customers should also have access to these technology incentives. This in turn will encourage maximum customer participation in DR programs from all service providers in accordance with longstanding Commission policy.[16] Additionally, in line with the dual participation rules and our responses to the questions in Section III, CESA believes that CCA and ESP customers who participate in their CPP and RTP programs would be disadvantaged otherwise as compared to IOU customers due to their inability to participate in two DR programs under two DR providers.

Question 10: **For demand response resource contracts external to the demand response portfolios and budget applications, should the Commission permit the customers of these contracts to receive auto demand response incentives for the controls? If the Commission determines it should allow these incentives, should such an allowance apply only to future procurements, or should it also apply to past procurements such as those with competitive bids that included all costs? If the Commission does not approve this policy, should the entire contract project site be ineligible for Auto Demand Response incentives including additional capacity in the battery storage or only the procured capacity resource and its controls? If the Commission determines it should permit these contracts to receive incentives, how**

[16] See D.09-09-047, p. 214: "Statewide IDSM Program is pivotal in promoting and achieving clearly defined goals and objectives for integrating demand side technologies and program offerings across the IOU portfolios."

should the Commission address the future funding issue since the 2018-2022 demand response budget for the incentives has already been authorized? If the Commission were to allow these customers to receive the incentives, should the Commission consider a carve-out/set-aside or a cap on the incentives?

Yes, customers with DR contracts to meet LCR needs outside of DR programs should be allowed to receive ADR incentives for any incremental capacity that is not tied to the LCR contract. Incrementality principles should apply here in determining whether there is any capacity or time differentiation to determine the incremental capacity of an energy storage system. A portion of the system may be participating in an LCR contract while another portion of the system may be participating in other DR programs, which should not be precluded from ADR incentives as a result. ADR incentives should thus be allowed for both past and future procurements.

Given that this new guidance is just now being developed, CESA recommends that any past procurements where bidders developed and proposed their LCR resources with ADR eligibility being reasonably assumed at the time should be granted ADR eligibility. In general, retroactive changes to regulatory policy harms industry confidence and certainty to make DER investments and thus it will be important in ensuring that past procurements are not subject to new guidance that were not applicable at the time.

Question 13: Should adding or enhancing Open Auto Demand Response capability to battery storage controls for participation in event-based demand response programs as a secondary service be approved as eligible to receive incentives? Is the incremental benefit provided by storage participating in demand response as a secondary service greater than the incremental cost of the incentive?

By creating an incentive for energy storage systems to become ADR compliant, the Commission advances the state's objective of better integrating renewable resources and reducing GHG emissions, opens up the opportunity for greater grid reliability, and enhances customer value by enabling customers to participate in the CAISO energy markets. As noted, this infrastructure will also future proof California's grid as the need for DR resources increases with rising levels of intermittent renewable resource penetration. By affording ratepayers the opportunity to actually upgrade their systems they not only help to strengthen the distribution system (which they pay for) but also enable themselves to yield some benefit from their investment, making it a "win-win" for both the grid and customers.

Importantly, ADR capabilities are not typically developed for energy storage systems that only serve customer load through retail bill management. The advanced and automated communication and response capabilities that come with ADR compliance are features that would enhance the customer-sited energy storage system to provide various grid services through DR programs – thus constituting an incremental benefit. It may also be a mischaracterization for ADR capabilities and DR program participation to be labeled as a "secondary service" given that grid service obligations, such as in LCR contracts, are considered priority applications that have contractual and legally binding must-offer obligations and high performance requirements. While customer bill management is also a primary service, DR providers have demonstrated the feasibility of co-optimizing energy storage assets and customer loads around these two primary services, which demonstrates the significant incremental benefit of not only delivering customer bill savings but also local capacity needs.

Question 14: If the Commission determines that the list of controls eligible to receive Auto Demand Response incentives should include Open Auto Demand Response capability to battery storage controls, what hardware and software costs should the incentives subsidize?

ADR incentives should be intended for the sole purpose of enabling the customer to pull signals directly from their LSE (regardless of whether it is an IOU, CCA, or ESP) in order to enable the it to direct the energy storage equipment to deliver pre-programmed load reduction in response to an LSE- or CAISO-initiated DR event, and to do so without manual intervention by the customer or reliance on third-party vendors or aggregators. Customer-sited energy storage systems should be eligible to receive ADR incentives for the applicable costs for the following components:

- Industrial computer
- Communication signal (*e.g.*, Gridlink Switch)
- Modem
- Enclosure box
- Connectors
- Software
- Design costs
- Installation materials and labor

The above list is not intended to be an exclusive or exhaustive list. As technology advances, there may be additional items that should be added to this list. In addition, for each of the above, the ADR incentives should cover the *applicable* costs for making the energy storage system or any other potential DR resource to *become ADR compliant*. This is important in determining the incrementality of what the ADR and SGIP incentives respectively cover if a resource is applying for funds in both programs, as discussed further in our response to Question 16. Similarly, the same guidance applies to LCR resources seeking ADR incentives, where it will be important to determine what specific costs are covered to pay for specific capabilities and services.

<u>Question 15</u>: Currently the Auto Demand Response program uses a $200 per kilowatt incentive level and calculates the incentive amount based on a building end use load shed test, with the customer eligible for incentives up to 75 percent of the project cost if their building performs adequately. Would this be an appropriate incentive design for battery controls and if not, what other design would you propose? (*e.g.*, fixed or flat rate per hardware device, etc.) Based on the exact costs identified above as appropriate, should the Commission adopt a maximum amount for battery storage control incentives, and why? (*e.g.*, should the incentive be bounded by the incremental value the battery storage is providing for demand response above and beyond its primary load management services?

The incentive design for energy storage controls should be the same as other technologies in the ADR program. Storage controls for the purpose of ADR are not standard energy storage system components. In other words, these controls would not be installed for all energy storage systems if not for participation in the ADR program. Therefore, if the applicant incurs costs for the ADR program, they should be eligible to receive ADR incentives up to 75% of the project cost if their building performs adequately.

<u>Question 16</u>: Given that battery storage is eligible to receive incentives for controls from other publicly-funded programs, such as SGIP, what requirements should be in place to enable utilities reviewing incentive applications to prevent incentivizing the same equipment cost a second time?

Both programs already require the applicant to provide a cost breakdown and/or invoice(s) to demonstrate eligible costs for their respective incentives. If an applicant is applying for both programs, they should be required to disclose their participation and provide supporting documentation illustrating the separation of costs.

For energy storage system to be able to receive incentives from SGIP, applicants are required to provide a series of documents and information about the eligible equipment being installed, particularly around the associated project costs through a cost breakdown sheet. In addition, applicants must also provide a signed project cost affidavit that certifies and declares true the total project costs as mentioned in the cost breakdown sheet. Similarly, ADR applicants must provide the various costs associated with the project in the scope of work at the time of application. If required, additional invoices may be requested for costs above $5,000.

To prevent incentivizing and paying for the same equipment cost twice, CESA recommends that the ADR program adopt processes and materials that are in place in SGIP to account for incentives received from "other sources". SGIP incentive levels are adjusted and potentially reduced by a certain amount (50% or 100% of the other incentive amount) depending on whether other incentives are funded by IOU ratepayers.[17] While not an exact means to ensure specific project component costs are not incentivized a second time, some mechanism is already in place to address this issue. As an improvement, to look more granularly at specific ADR-associated project costs, it would be helpful if the initial application form (for each program) provided a checkbox or dedicated space where an applicant could declare the other incentive programs that they are applying for. This way, at the time of review, the IOUs will be aware that the applicants are participating in both programs. Additionally, once an applicant checks this box, applicants should be made to upload the cost breakdown sheet and associated ADR costs of the other program they are applying for. As a result, it will be made clear that the same equipment is not being incentivized twice and that the costs are separated. This is documentation that the applicant already has prepared to participate in either program, so this additional step will not generate any extra paperwork

V. RESPONSES TO QUESTIONS ON MANAGING AND/OR MODIFYING THE TWO PERCENT RELIABILITY CAP.

CESA has no comment on this topic at this time.

[17] *Self-Generation Incentive Program Handbook*, published on December 18, 2017. Section 3.2.6, p. 30. https://www.selfgenca.com/documents/handbook/2017

VI. CONCLUSION.

CESA appreciates the opportunity to submit these responses to the questions posed in the Ruling and looks forward to working with the Commission and stakeholders in this DR proceeding to address the aforementioned policy issues around dual participation.

Respectfully submitted,

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