April 11, 2019

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: California Independent System Operator Corporation
Dispatch Operating Target – Tariff Clarification

Docket No. ER19-___-000

Dear Secretary Bose:

The California Independent System Operator Corporation (CAISO) submits this tariff amendment to clarify existing dispatch principles for reliability demand response resources (RDRR).[1] Specifically, the CAISO proposes to clarify that RDRR will be eligible for dispatch if the CAISO issues a warning notice, without any additional conditions. CAISO tariff section 34.7(13) currently provides that the CAISO may make RDRR eligible for dispatch (1) after issuance of a warning notice, and (2) immediately prior to a need for the CAISO to attempt to obtain assistance from neighboring balancing authorities. This tariff clarification would remove the condition that allows RDRR to be eligible for dispatch only immediately prior to canvassing other balancing authorities.

The CAISO adopted the current dispatch procedures consistent with a 2010 settlement agreement (Settlement) filed with and approved by the California Public Utilities Commission (CPUC) on reliability demand response issues. The CAISO, California investor-owned utilities, ratepayer advocates, large customers, and demand response providers were all parties to the Settlement. In late 2018, the CPUC adopted Decision 18-11-029 clarifying that the Settlement allows RDRR to be eligible for dispatch in the CAISO market immediately after issuance of a warning notice without any additional conditions. Consistent with the CPUC's clarification, the CAISO proposes to modify its tariff to allow the CAISO to make RDRR eligible for dispatch any time within a warning notice event.

[1] The CAISO submits this filing pursuant to Section 205 of the Federal Power Act (FPA), 16 U.S.C. § 824d, and Section 35.13 of the Commission's regulations, 18 C.F.R. § 35.13. Capitalized terms not otherwise defined herein have the meanings set forth in Appendix A to the CAISO tariff.

The CAISO vetted the proposed tariff clarifications through a robust and transparent tariff clarification stakeholder process. No stakeholder opposed the proposed clarifications. The CAISO requests that the Commission approve the proposed tariff modifications effective on June 11, 2019, *i.e.,* 60, days from the date of this filing.

I. Background

On June 24, 2010, in Decision 10-06-034, the CPUC approved the Settlement to conclude its demand response proceeding.[2] The Settlement required investor-owned utilities to transition their CPUC-approved retail emergency-triggered demand response programs into a CAISO reliability demand response product.[3] The Settlement specified the minimum operating and technical requirements for retail emergency-triggered demand response resources. The Settlement also required these resources be made available for dispatch under CAISO emergency operating procedures.

To fulfill the terms of the CPUC settlement, the CAISO developed the RDRR product and, on October 26, 2010, the CAISO Board of Governors authorized a tariff amendment filing to implement it. The Board of Governors memorandum approving the RDRR product noted that it would enable the CAISO "to dispatch these emergency-triggered programs when and where they are needed and, appropriately, reflect their value in the [CA]ISO market."[4]

On May 20, 2011, the CAISO filed its initial tariff amendment with the Federal Energy Regulatory Commission (Commission) to implement its RDRR product. The Commission rejected the CAISO's RDRR proposal,[5] and the CAISO subsequently submitted a compliance filing for the RDRR product and Commission Order No. 745[6] on March 14, 2012.[7] The Commission issued an order on July 18, 2013 accepting in part and denying in part the CAISO's

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2 *Order Instituting Rulemaking Regarding Policies and Protocols for Demand Response, Load Impact Estimates, Cost-Effectiveness Methodologies, Megawatt Goas and Alignment with California Independent System Operator Market Design Protocols* (January 25, 2007), Rulemaking 07-01-041.

3 *Decision Adopting Settlement Agreement on Phase 3 Issues Pertaining to Emergency Triggered Demand Response Programs,* June 25, 2010, available at: http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/119815.pdf.

4 The CAISO Board of Governors memorandum is included with this filing as Attachment C.

5 *Cal. Indep. Sys. Operator Corp.,* 138 FERC ¶ 61,117 (2012).

6 *Demand Response Compensation in Organized Wholesale Energy Markets*, FERC Order No. 745, 134 FERC ¶ 61,187 (2011).

7 *See Cal. Indep. Sys. Operator Corp.,* RDRR Compliance filing, Docket Nos. ER11-3616 and ER11-4100 (March 14, 2012).

compliance filing, and directed the CAISO to submit a further compliance filing.[8]

On August 19, 2013, the CAISO submitted a subsequent filing in compliance with the July 2013 Order,[9] with the currently effective language in section 34.7(13) of the conformed CAISO tariff.[10] This language provides general dispatch principles for RDRRs. The CAISO developed this "to be fully consistent with the terms of the CPUC settlement agreement and ISO emergency operating procedures."[11] In its August 19, 2013 Compliance Filing, the CAISO noted that it revised this section "to reflect the [dispatch] trigger more accurately, providing that the [CA]ISO may consider bids from reliability demand response resources prior to seeking assistance from neighboring balancing authority areas and entities not otherwise obligated to comply with [CA]ISO dispatch."[12] The Commission accepted this language in March of 2014.[13]

In late 2018, the CPUC issued Decision 18-11-029, which clarified that "the use of RDRR can occur anytime within the Warning Stage, in the case of In-Market dispatch and Out-Of-Market or exceptional dispatch."[14] The CPUC further noted that "This dispatch flexibility is consistent with the Settlement and [Decision] 10-06.034."[15] Based on this clarification, the CAISO seeks to update its dispatch principles for RDRR resources.

II. RDRR Dispatch Principles Tariff Clarification Stakeholder Process

On March 5, 2019, the CAISO issued a white paper proposing to update the CAISO's RDRR dispatch principles consistent with CPUC Decision 18-11-

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8 *Cal. Indep. Sys. Operator Corp.,* 144 FERC ¶ 61.047 (2013), P 62 fn. 47 (July 2013 Order).

9 *See Cal. Indep. Sys. Operator Corp.,* Transmittal Letter to RDRR subsequent Compliance Filing, Docket Nos. ER11-3616 and ER13-2192 (August 19, 2013) (August 19, 2013 Compliance Filing).

10 The language was initially added to section 34.5 in the CAISO's August 19, 2013 compliance filing, and later moved to section 34.7 in the CAISO's Order No. 764 compliance filing (*Integration of Variable Energy Resources*, FERC Order No. 764, 136 FERC ¶ 61,246 (2012)), *Cal. Indep. Sys. Operator Corp.,* 146 FERC ¶ 61,205 (2014).

11 August 19, 2013 Compliance Filing at p. 4.

12 *Id.*

13 *Cal. Indep. Sys. Operator Corp.,* 146 FERC ¶ 61,233 (2014).

14 *Decision Resolving Remaining Application Issues for 2018-2022 Demand Response Portfolios and Declining to Authorize Demand Response Auction Mechanism Pilot Solicitations*, D.18-11-029 (November 29, 2018) (CPUC Decision 18-11-029), at p. 40, included with this filing as Attachment D.

15 *Id*.

029.[16] The white paper included CAISO's proposed modifications to Tariff Section 34.7(13). The California Large Energy Consumers Association (CLECA) and Southern California Edison Company (SCE) submitted comments on the proposed tariff clarification. The CAISO held a public stakeholder call on March 15, 2019. Subsequently, the CAISO conducted outreach with CLECA, SCE, and the CPUC to address concerns raised during the stakeholder process.[17]

III. Proposed Tariff Modifications

The CAISO proposes to modify CAISO tariff section 34.7(13) to clarify when it will make RDRRs eligible for dispatch. The proposed tariff clarification reads as follows:

> **34.7 General Dispatch Principles**
>
> The CAISO shall conduct all Dispatch activities consistent with the following principles:
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> * * * * *
>
> (13) The CAISO may make Reliability Demand Response Resources eligible for Dispatch in accordance with applicable Operating Procedures either: (a) after issuance of a warning notice ~~and immediately prior to a need for the CAISO to attempt to obtain assistance from neighboring Balancing Authorities or imports~~; (b) during stage 1, stage 2, or stage 3 of a System Emergency; or (c) for a transmission-related System Emergency.

As a result of this tariff clarification, RDRR will be eligible for dispatch once the CAISO issues a warning notice, without any additional conditions. As noted in the CPUC's Decision 18-11-029, this clarifies that the CAISO can dispatch RDRR before the CAISO uses exceptional dispatch for non-resource adequacy resources within its balancing authority area.[18] The CPUC also noted that this dispatch flexibility is consistent with the Settlement and CPUC's decision approving the Settlement.[19] The CAISO Board of Governors originally approved the RDRR product on the basis that it would (1) integrate retail emergency-triggered demand response

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[16] The CAISO's White Paper is included with this filing as Attachment E.

[17] The proposed modifications are consistent with prior CAISO Board of Governor approval and do not constitute a policy initiative. As a result, the CAISO determined that a full stakeholder initiative process was not necessary for this tariff clarification.

[18] CPUC Decision 18-11-029, at p. 39.

[19] CPUC Decision 10-06-034.

programs into the CAISO market, and (2) fulfill the terms of the CPUC approved Settlement. This tariff clarification aligns the CAISO tariff with the Settlement and the CAISO's original intent in designing the RDRR product.

As the CAISO noted in comments filed in the CPUC proceeding, even with this tariff clarification, RDRR "the locational marginal price must reach the RDRR strike price (approximately $950/MWh) before RDRR-load is dropped, unless an exceptional dispatch is issued. This high bid price can still limit the use of RDRRs" despite the fact that it is eligible for dispatch any time after the issuance of a warning notice.

IV. Effective Date and Request for Waivers

The CAISO requests that the Commission make the tariff revisions contained in the instant filing effective June 11, 2019, *i.e.,* 60 days after the date of this filing.

In addition, the CAISO respectfully requests waiver of any other Commission regulations as may be necessary in order for these tariff revisions to become effective.

V. Communications

In accordance with Rule 203(b) of the Commission's Rules of Practice and Procedure,[20] communications regarding this filing should be addressed to the following individuals, whose names should be put on the official service list established by the Commission with respect to this submittal:

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California Independent System Operator Corporation
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[20] 18 C.F.R. § 385.203(b).

VI. Service

The CAISO has served copies of this transmittal letter, and all attachments, on the California Public Utilities Commission, the California Energy Commission, and all parties with effective Scheduling Coordinator Service Agreements under the CAISO tariff. In addition, the CAISO is posting this transmittal letter and all attachments on the CAISO website.

VII. Attachments

The following attachments, in addition to this transmittal letter, support the instant filing:

Attachment A	Revised CAISO tariff language that incorporate the proposed changes described above;
Attachment B	Proposed changes to the CAISO tariff in red-line format;
Attachment C	October 2010 CAISO Board of Governors Memo;
Attachment D	California Public Utilities Commission Decision 18-11-029.; and
Attachment E	Reliability Demand Response Resource Dispatch Clarification White Paper.

X. Conclusion

For the foregoing reasons, the Commission should accept the proposed tariff changes contained in the instant filing to become effective on June 11, 2019. Please contact the undersigned if you have any questions regarding this matter.

Respectfully submitted,

/s/ Jordan Pinjuv
Roger E. Collanton
General Counsel
Anna A. McKenna
Assistant General Counsel
Jordan Pinjuv
Senior Counsel

Counsel for the California Independent System Operator Corporation

Attachment A – Clean Tariff

Reliability Demand Response Resource Dispatch Clarification

California Independent System Operator Corporation

34.7 General Dispatch Principles

The CAISO shall conduct all Dispatch activities consistent with the following principles:

(1) The CAISO shall issue AGC instructions electronically as often as every four (4) seconds from its Energy Management System (EMS) to resources providing Regulation and on Automatic Generation Control to meet NERC and WECC performance requirements;

(2) In each run of the RTED or RTCD the objective will be to meet the projected Energy requirements and Uncertainty Requirements over the applicable forward-looking time period of that run, subject to transmission and resource operational constraints, taking into account the short term CAISO Forecast Of CAISO Demand or forecast of EIM Demand, adjusted as necessary by the CAISO or EIM operator to reflect scheduled changes to Interchange and non-dispatchable resources in subsequent Dispatch Intervals;

(3) Dispatch Instructions will be based on Energy Bids for those resources that are capable of intra-hour adjustments and will be determined through the use of SCED except when the CAISO must utilize the RTDD and RTMD;

(4) When dispatching Energy from awarded Ancillary Service capacity the CAISO will not differentiate between Ancillary Services procured by the CAISO and Submissions to Self-Provide an Ancillary Service;

(5) The Dispatch Instructions of a resource for a subsequent Dispatch Interval shall take as a point of reference the actual output obtained from either the State Estimator solution or the last valid telemetry measurement and the resource's operational ramping capability. For Multi-Stage Generating Resources the determination of the point of reference is further affected by the MSG Configuration and the information contained in the Transition Matrix;

(6) In determining the Dispatch Instructions for a target Dispatch Interval while at the same time achieving the objective to minimize Dispatch costs to meet the forecasted conditions of the entire forward-looking time period, the Dispatch for the target Dispatch Interval will be affected by: (a) Dispatch Instructions in prior intervals, (b) actual output of the

resource, (c) forecasted conditions in subsequent intervals within the forward-looking time period of the optimization, and (d) operational constraints of the resource, such that a resource may be dispatched in a direction for the immediate target Dispatch Interval that is different than the direction of change in Energy needs from the current Dispatch Interval to the next immediate Dispatch Interval, considering the applicable MSG Configuration;

(7) Through Start-Up Instructions the CAISO may instruct resources to start up or shut down, or may reduce Load for Participating Loads, Reliability Demand Response Resources, and Proxy Demand Resources, over the forward-looking time period for the RTM based on submitted Bids, Start-Up Costs and Minimum Load Costs, Pumping Costs and Pump Shut-Down Costs, as appropriate for the resource, or for Multi-Stage Generating Resource as appropriate for the applicable MSG Configuration, consistent with operating characteristics of the resources that the SCED is able to enforce. In making Start-Up or Shut-Down decisions in the RTM, the CAISO may factor in limitations on number of run hours or Start-Ups of a resource to avoid exhausting its maximum number of run hours or Start-Ups during periods other than peak loading conditions;

(8) The CAISO shall only start up resources that can start within the applicable time periods of the various CAISO Markets Processes that comprise the RTM;

(9) The RTM optimization may result in resources being shut down consistent with their Bids and operating characteristics provided that: (a) the resource does not need to be on-line to provide Energy, (b) the resource is able to start up within the applicable time periods of the processes that comprise the RTM, (c) the Generating Unit is not providing Regulation or Spinning Reserve, and (d) Generating Units online providing Non-Spinning Reserve may be shut down if they can be brought up within ten (10) minutes as such resources are needed to be online to provide Non-Spinning Reserves;

(10) For resources that are both providing Regulation and have submitted Energy Bids for the RTM, Dispatch Instructions will be based on the Regulation Ramp Rate of the resource rather than the Operational Ramp Rate if the Dispatch Operating Target remains within

the Regulating Range. The Regulating Range will limit the Ramping of Dispatch Instructions issued to resources that are providing Regulation;

(11) For Multi-Stage Generating Resources the CAISO will issue Dispatch Instructions by Resource ID and Configuration ID;

(12) The CAISO may issue Transition Instructions to instruct resources to transition from one MSG Configuration to another over the forward-looking time period for the RTM based on submitted Bids, Transition Costs and Minimum Load Costs, as appropriate for the MSG Configurations involved in the MSG Transition, consistent with Transition Matrix and operating characteristics of these MSG Configurations. The RTM optimization will factor in limitations on Minimum Run Time and Minimum Down Time defined for each MSG configuration and Minimum Run Time and Minimum Down Time at the Generating Unit.

(13) The CAISO may make Reliability Demand Response Resources eligible for Dispatch in accordance with applicable Operating Procedures either: (a) after issuance of a warning; (b) during stage 1, stage 2, or stage 3 of a System Emergency; or (c) for a transmission-related System Emergency.

Attachment B – Marked Tariff

Reliability Demand Response Resource Dispatch Clarification

California Independent System Operator Corporation

34.7 General Dispatch Principles

The CAISO shall conduct all Dispatch activities consistent with the following principles:

(1) The CAISO shall issue AGC instructions electronically as often as every four (4) seconds from its Energy Management System (EMS) to resources providing Regulation and on Automatic Generation Control to meet NERC and WECC performance requirements;

(2) In each run of the RTED or RTCD the objective will be to meet the projected Energy requirements and Uncertainty Requirements over the applicable forward-looking time period of that run, subject to transmission and resource operational constraints, taking into account the short term CAISO Forecast Of CAISO Demand or forecast of EIM Demand, adjusted as necessary by the CAISO or EIM operator to reflect scheduled changes to Interchange and non-dispatchable resources in subsequent Dispatch Intervals;

(3) Dispatch Instructions will be based on Energy Bids for those resources that are capable of intra-hour adjustments and will be determined through the use of SCED except when the CAISO must utilize the RTDD and RTMD;

(4) When dispatching Energy from awarded Ancillary Service capacity the CAISO will not differentiate between Ancillary Services procured by the CAISO and Submissions to Self-Provide an Ancillary Service;

(5) The Dispatch Instructions of a resource for a subsequent Dispatch Interval shall take as a point of reference the actual output obtained from either the State Estimator solution or the last valid telemetry measurement and the resource's operational ramping capability. For Multi-Stage Generating Resources the determination of the point of reference is further affected by the MSG Configuration and the information contained in the Transition Matrix;

(6) In determining the Dispatch Instructions for a target Dispatch Interval while at the same time achieving the objective to minimize Dispatch costs to meet the forecasted conditions of the entire forward-looking time period, the Dispatch for the target Dispatch Interval will be affected by: (a) Dispatch Instructions in prior intervals, (b) actual output of the

resource, (c) forecasted conditions in subsequent intervals within the forward-looking time period of the optimization, and (d) operational constraints of the resource, such that a resource may be dispatched in a direction for the immediate target Dispatch Interval that is different than the direction of change in Energy needs from the current Dispatch Interval to the next immediate Dispatch Interval, considering the applicable MSG Configuration;

(7) Through Start-Up Instructions the CAISO may instruct resources to start up or shut down, or may reduce Load for Participating Loads, Reliability Demand Response Resources, and Proxy Demand Resources, over the forward-looking time period for the RTM based on submitted Bids, Start-Up Costs and Minimum Load Costs, Pumping Costs and Pump Shut-Down Costs, as appropriate for the resource, or for Multi-Stage Generating Resource as appropriate for the applicable MSG Configuration, consistent with operating characteristics of the resources that the SCED is able to enforce. In making Start-Up or Shut-Down decisions in the RTM, the CAISO may factor in limitations on number of run hours or Start-Ups of a resource to avoid exhausting its maximum number of run hours or Start-Ups during periods other than peak loading conditions;

(8) The CAISO shall only start up resources that can start within the applicable time periods of the various CAISO Markets Processes that comprise the RTM;

(9) The RTM optimization may result in resources being shut down consistent with their Bids and operating characteristics provided that: (a) the resource does not need to be on-line to provide Energy, (b) the resource is able to start up within the applicable time periods of the processes that comprise the RTM, (c) the Generating Unit is not providing Regulation or Spinning Reserve, and (d) Generating Units online providing Non-Spinning Reserve may be shut down if they can be brought up within ten (10) minutes as such resources are needed to be online to provide Non-Spinning Reserves;

(10) For resources that are both providing Regulation and have submitted Energy Bids for the RTM, Dispatch Instructions will be based on the Regulation Ramp Rate of the resource rather than the Operational Ramp Rate if the Dispatch Operating Target remains within

the Regulating Range. The Regulating Range will limit the Ramping of Dispatch Instructions issued to resources that are providing Regulation;

(11) For Multi-Stage Generating Resources the CAISO will issue Dispatch Instructions by Resource ID and Configuration ID;

(12) The CAISO may issue Transition Instructions to instruct resources to transition from one MSG Configuration to another over the forward-looking time period for the RTM based on submitted Bids, Transition Costs and Minimum Load Costs, as appropriate for the MSG Configurations involved in the MSG Transition, consistent with Transition Matrix and operating characteristics of these MSG Configurations. The RTM optimization will factor in limitations on Minimum Run Time and Minimum Down Time defined for each MSG configuration and Minimum Run Time and Minimum Down Time at the Generating Unit.

(13) The CAISO may make Reliability Demand Response Resources eligible for Dispatch in accordance with applicable Operating Procedures either: (a) after issuance of a warning ~~notice and immediately prior to a need for the CAISO to attempt to obtain assistance from neighboring Balancing Authorities or imports~~; (b) during stage 1, stage 2, or stage 3 of a System Emergency; or (c) for a transmission-related System Emergency.

Attachment C – October 2010 Board of Governors Memo

Reliability Demand Response Resource Dispatch Clarification

California Independent System Operator Corporation

California ISO
Your Link to Power

California Independent
System Operator Corporation

Memorandum

To: ISO Board of Governors

From: Keith Casey, Vice President, Market & Infrastructure Development

Date: October 26, 2010

Re: **Decision on the Reliability Demand Response Product**

This memorandum requires Board action.

EXECUTIVE SUMMARY

The California Public Utilities Commission allows all forms of retail demand response programs to satisfy resource adequacy capacity requirements. Management has had long-standing concerns regarding the large megawatt quantity and restricted availability of retail emergency-triggered demand response programs that qualify as resource adequacy resources. We believe that resource adequacy resources should be available to prevent an emergency, rather than only being available to resolve an emergency that is already underway. In addition, the megawatt quantity of these conditional-use programs that count toward satisfying a load-serving entity's resource adequacy requirement should be capped. As part of its demand response proceeding (R.07-01-041), the CPUC approved a multi-party settlement agreement that resolved these concerns in a reasonable and mutually acceptable way and spawned the development of the reliability demand response product.

The California Independent System Operator Corporation is seeking the Board of Governors' approval of the proposed reliability demand response product. This new product will enable retail emergency-triggered demand response programs, e.g., interruptible, air-conditioning and agricultural pumping load programs, to integrate into ISO markets and operations. The product is scheduled to be implemented by spring 2012.

Management recommends implementation of the reliability demand response product to:

- Integrate retail emergency demand response programs into the ISO market;
- Reflect the value of these emergency resources in the ISO market;
- Gain access to these resources earlier in the ISO's emergency operating procedures;

- Limit the amount of emergency demand response resources that count towards satisfying the resource adequacy requirement of CPUC jurisdictional entities;
- Fulfill the ISO's obligations under the CPUC approved settlement agreement; and
- Add additional demand response capability to the ISO market by spring 2012.

In 2009, retail emergency-triggered demand response programs accounted for nearly 4% (approximately 2,150 MW) of the total resource adequacy capacity obligation of CPUC jurisdictional entities. This significant amount of resource adequacy capacity is not integrated into ISO markets and systems but is made available to the ISO operator only during an emergency through a manual process. A manual process does not provide the ISO operator clear visibility to the location and quantity of these emergency resources and does not allow the value of these resources to be reflected in the locational marginal price. The proposed reliability demand response product resolves these concerns by providing a wholesale market mechanism to integrate retail emergency demand response into the ISO market.

In addition to instigating the development of the reliability demand response product, the settlement limits the megawatt quantity of retail emergency demand response that can count toward satisfying the CPUC resource adequacy requirement to two-percent of the ISO all-time system peak (or 1,005 MW), which is based on an ISO operational evaluation of historic use, need to avoid firm load shedding, and other ISO and RTO practices. The settlement requires the investor-owned utilities to transition their CPUC approved retail emergency-triggered demand response programs into the ISO reliability demand response product, and makes these resources available for dispatch earlier under ISO emergency operating procedures. The settlement also requires that the utilities make efforts to promote and transition customers from emergency-triggered demand response programs into price-responsive demand response programs that align with the ISO market. With the implementation of the reliability demand response product, the ISO will be able to dispatch these emergency-triggered programs when and where they are needed and, appropriately, reflect their value in the ISO market.

> ***Moved, that the ISO Board of Governors approves the proposed reliability demand response product, as detailed in the memorandum dated October 26, 2010; and***
>
> ***Moved, that the ISO Board of Governors authorizes Management to make all necessary and appropriate filings with the Federal Energy Regulatory Commission to implement the proposed tariff change.***

BACKGROUND

The settlement addressed Management concerns regarding the quantity, use, and resource adequacy treatment of retail emergency-triggered demand response programs. Development of the reliability demand response product was a key element and outcome of the settlement. The settlement was supported by a broad cross-section of market participants, including the three California investor-owned utilities, two ratepayer interest groups, a large consumer representative and a demand response provider.

The settlement agreement outlined broad principles for the reliability demand response product, which was designed to:

- Be compatible with investor-owned utility emergency demand response programs;
- Meet minimum operating and technical requirements, including recognition of maximum resource availability limits;
- Be dispatched economically once the resource is made available for dispatch as specified in ISO emergency operating procedures;
- Recognize that the underlying customers have "high strike" prices;
- Have multi-reliability uses, including ISO system emergencies and utility local transmission and distribution system emergencies;
- Be available to all demand response providers, subject to applicable rules of the local regulatory authority;
- Be settled through the ISO market; and
- Be dispatchable by location and megawatt quantity.

The reliability demand response product proposed by the ISO and shaped by stakeholder input embodies these principles and fulfills an important ISO principle that the value of these emergency-triggered demand resources be reflected in the ISO market.

PROPOSAL

The reliability demand response product design ensures compatibility with, and the integration of, existing retail emergency-triggered demand response programs, such as interruptible load programs, direct-load control programs like air-conditioning cycling, and agriculture pumping programs. The reliability demand response product design will allow reliability demand response resources to offer energy economically in the day-ahead market, and any remaining uncommitted capacity thereafter to be bid as energy in the real-time through the ISO hour-ahead scheduling process.

The reliability demand response product will integrate large single or aggregated-demand response resources that may be configured to offer energy economically in the day-ahead market and, as a minimum requirement, can respond to a reliability event for the delivery of energy in real-time. Such dispatches are expected infrequently and with limited notice under an ISO issued warning notice as specified in ISO emergency operating procedures.

The reliability demand response product has multiple uses, including:

- Mitigating imminent or threatened operating reserve deficiencies;
- Addressing transmission emergencies on the ISO-controlled grid; and
- Resolving local transmission and distribution system emergencies.

To qualify as a reliability demand response product resource, the resource must be capable of delivering reliability energy in real-time, reaching its full curtailment in no longer than 40 minutes, and be dispatched by the ISO's automated dispatching system within a geographic location and for a specified megawatt quantity. The megawatt quantity that is available from a reliability demand response product resource during any particular hour is submitted to the ISO by the scheduling coordinator for the demand response provider in the hour-ahead scheduling process with a bid between the ISO bid cap and 95% of the ISO bid cap. Use of a bid range will enable a scheduling coordinator to use bid costs as a means to prioritize the dispatch of reliability demand response resources.

A reliability demand response product resource will participate in the ISO market as a supply resource, relying on the functionality and infrastructure the ISO recently implemented for its proxy demand resource product. The product also will include an option that allows reliability demand response product resources to receive a discrete dispatch. This feature will allow a resource to be dispatched to pre-specified megawatt levels, by hour, regardless of the resource's electricity consumption at the time of deployment. This will enable the integration of existing retail emergency-triggered demand response programs, such as the interruptible load programs, that require a discrete dispatch. Like other resources, reliability demand response product resources will be eligible to set the locational marginal price when they are the marginal resource.

POSITIONS OF THE PARTIES

Stakeholder process

The foundation of demand response resources is built on load adjustments made by retail electricity customers, and it is essential that the ISO closely coordinate its development of wholesale demand response products with the input of stakeholders that have retail interests and concerns. ISO staff engaged its stakeholders in a working group process in addition to its traditional stakeholder process to develop the details of the reliability demand response product. Between June and September 2010, ISO staff conducted three working group sessions, a stakeholder meeting, a stakeholder conference call, and provided four opportunities to provide formal, written comments on Management's proposal.

Stakeholders generally support the reliability demand response product proposal. Below is a discussion of the key issues that staff addressed and the design modifications that were made based on stakeholder feedback.

Day-ahead participation capability

Stakeholders strongly support this element of the proposal, which provides the ability for a reliability demand response product resource to participate economically in the day-ahead market, like a proxy demand resource, and as an emergency resource in real-time under the terms of this new product. Enabling reliability demand response product resources to participate in the day-ahead market allows the ISO and the demand response provider to capture additional value from resources that have the ability to respond economically in the day-ahead timeframe yet can curtail additional load in the real-time when required under a system or local emergency.

Performance incentive

Management originally proposed a performance incentive which was met with strong stakeholder opposition. In response, we removed this feature and will develop availability standards for these types of demand response resources under phase three of its standard capacity product initiative. Stakeholders support this approach.

Dispatching reliability demand response resources for local transmission and distribution system needs

The settlement agreement preserves the right for the investor-owned utilities to dispatch their emergency demand response resources to respond to local transmission and distribution system emergencies. These local emergency dispatches will occur outside of the ISO market and will not set the locational marginal price. Certain market participants felt that reliability demand response product resources should have the opportunity to set the locational marginal price in all instances. This cannot be accomplished. The dispatch of a reliability demand response product resource to address a utility's local emergency would have to be done through exceptional dispatch. Exceptional dispatch simply adds cost to the system, in the form of uplift charges, and does not have the desired effect of setting the locational marginal price. For this reason, the ISO finds that any benefits derived from the ISO dispatching a utility's use of its demand response programs to address a local system constraint are outweighed by the cost, complexity, and coordination of doing so.

Exceptional dispatch

Certain stakeholders felt that reliability demand response resources should not be subject to exceptional dispatches. Management will maintain the exceptional dispatch of reliability demand response product resources since the ISO cannot forego its ability to dispatch resources under its exceptional dispatch authority and allow a situation to worsen if system conditions are dire and a market application fails or does not commit a required resource that can resolve a pressing reliability concern. Thus, the ISO will preserve its exceptional dispatch authority of reliability demand response product resources with the expectation that this capability will be used judiciously and infrequently.

Prohibition against the reliability demand response product providing ancillary service and/or residual unit commitment capacity

Certain stakeholders felt that reliability demand response resources should be able to participate in the residual unit commitment and ancillary services market. However, Management determined that it is not feasible for reliability demand response product resources to offer these capacity services. This is due to the complexity associated with co-mingling the real-time energy bid associated with awarded residual unit commitment and/or ancillary service capacity and the energy associated with reliability demand response product resources, given the different dispatch parameters between the reliability demand response product and these capacity services. Demand response resources are eligible to provide these capacity services, along with day-ahead and real-time energy, through the proxy demand resource product.

MANAGEMENT RECOMMENDATION

Management requests Board approval of the reliability demand response product as detailed in this memorandum. The benefits of implementing the reliability remand response product is the integration of retail emergency-triggered demand response programs into the ISO market, enabling the value of these resources to be reflected in the ISO market and enhancing the reliable operation of the ISO controlled grid. Additionally, approval of the reliability demand response product fulfills the terms of the CPUC approved settlement agreement on the quantity, use, and resource adequacy treatment of retail emergency-triggered demand response programs.

Board of Governors **November 1-2, 2010** **Decision on Reliability Demand Response Product**

Motion

Moved, that the ISO Board of Governors approves the proposed reliability demand response product, as detailed in the memorandum dated October 26, 2010; and

Moved, that the ISO Board of Governors authorizes Management to make all necessary and appropriate filings with the Federal Energy Regulatory Commission to implement the proposed tariff change.

Moved: Doll **Second: Foster**

Board Action: **Passed**	Vote Count: **4-0-0**
Doll	Y
Foster	Y
Habashi	Y
Willrich	Y

Motion Number: 2010-11-G3

Attachment D – CPUC Decision 18-11-029

Reliability Demand Response Resource Dispatch Clarification

California Independent System Operator Corporation

Decision 18-11-029 November 29, 2018

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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
And Related Matters.	Application 17-01-018 Application 17-01-019

DECISION RESOLVING REMAINING APPLICATION ISSUES FOR 2018-2022 DEMAND RESPONSE PORTFOLIOS AND DECLINING TO AUTHORIZE ADDITIONAL DEMAND RESPONSE AUCTION MECHANISM PILOT SOLICITATIONS

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DECISION RESOLVING REMAINING APPLICATION ISSUES FOR 2018-2022 DEMAND RESPONSE PORTFOLIOS AND DECLINING TO AUTHORIZE ADDITIONAL DEMAND RESPONSE AUCTION MECHANISM PILOT SOLICITATIONS

Summary

This decision resolves the remaining issues from the applications for 2018-2022 Demand Response Portfolios. We adopt the following: 1) the prohibition of dual participation in Critical Peak Pricing and another demand response program for all new customers, beginning immediately upon the submittal of Tier One Advice Letters revising the tariff and until further notice; 2) the prioritization of third-party customers in the allocation of any remaining megawatts under the two percent reliability cap; 3) Auto Demand Response policies to be included in a revised Auto Demand Response Control Incentives Guidelines and Adopted Policies, and a process to pursue further technical refinements to the adopted guidelines and to Auto Demand Response; 4) a stakeholder process to develop an overall strategy proposal for battery storage controls in Auto Demand Response; and 5) guidelines for pilots targeting demand response and a regulatory process for submittal and approval of the pilot proposals.

In addition, the scope of this proceeding was amended to review the evaluation of and staff recommendations for the demand response auction mechanism pilot. The evaluation of the pilot has been delayed until December 2018. We conclude that, until the evaluation has been completed and reviewed by the Commission, the Commission should not authorize funding for additional auctions.

This proceeding remains open to review the evaluation of and staff recommendations for the demand response auction mechanism pilot, determine

a strategy and policies for battery storage controls in Auto Demand Response, and address demand response baselines. All other issues in this proceeding have been resolved.

1. Procedural Background

This proceeding commenced on January 17, 2017 with the filing of three applications to consider demand response activities and budgets for program years 2018-2022: Application (A.) 17-01-012 by Pacific Gas and Electric Company (PG&E), A.17-01-018 by San Diego Gas & Electric Company (SDG&E), and A.17-01-018 by Southern California Edison Company (SCE) (jointly, the Utilities). Decision (D.) 17-12-003 adopted demand response budgets for each of the three Utilities to conduct demand response programs, pilots and associated activities for program years 2018 through 2022. D.17-12-003 also determined the proceeding should remain open to consider the following issues: 1) clarity on dual participation rules,[1] 2) an approach to prioritizing resources under the current two percent demand response reliability cap,[2] 3) whether the Commission should maintain the current two percent demand response reliability cap,[3] 4) the reasonableness of SDG&E's proposed approach to determining the adopted price triggers for its Capacity Bidding program,[4]

[1] D.17-12-003 at 35.

[2] *Id.* at 40.

[3] *Id.* at 44.

[4] *Id.* at 74.

Footnote continued on next page

5) guidelines for the automated or Auto Demand Response technology incentive policy;[5] and 6) guidelines for developing proposals for pilots to target demand response activities in disadvantaged communities.[6]

Aside from the Utilities, the following entities are parties to this proceeding: Advanced Microgrid Solutions (AMS), Bosch Building Grid Technologies (Bosch), California Efficiency + Demand Management Council (Council), California Energy Storage Association (CESA), California Independent Systems Operator (CAISO), California Large Energy Consumers Association (CLECA), CPower, Inc. (CPower), Comverge, Inc. (Comverge), ecobee, Inc. (ecobee), Electric Motorwerks, Inc. (Electric Motorwerks), EnergyHub, EnerNOC, Inc. (EnerNOC), Joint Demand Response Parties,[7] Nest Labs, Inc. (Nest), OhmConnect, Inc. (OhmConnect), Olivine, Public Advocates Office of the Public Utilities Commission (Cal Advocates) formerly known as the Office of Ratepayer Advocates,[8] Solarcity Corporation (Solarcity), The Utility Reform Network (TURN), and the Utility Consumers Action Network (UCAN).

On January 22, 2018, SDG&E filed its proposal describing the method used to determine its Capacity Bidding program price triggers, pursuant to D.17-12-003 at Ordering Paragraph 26. On February 5, 2018, the Joint Demand Response Parties filed comments to SDG&E's proposal.

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[5] *Id*. at 79.

[6] *Id*. at 146.

[7] The Joint Demand Response Parties are CPower, EnerNOC, Inc., And EnergyHub.

[8] The Office of Ratepayer Advocates was renamed the Public Advocates Office of the Public Utilities Commission pursuant to Senate Bill No. 854, which the Governor approved on June 27, 2018.

During the month of February 2018, the Commission hosted three workshops in this proceeding. On February 13, 2018, the Administrative Law Judge facilitated a workshop to discuss issues related to the demand response dual participation policy. On February 14, 2018, the staff of the Commission's Energy Division (Energy Division or Staff) facilitated a workshop to discuss issues related to the demand response two percent reliability cap. On February 15, 2018, Staff facilitated a workshop to discuss the *Assigned Commissioner's Proposal for Demand Response Pilot Plans to Benefit Disadvantaged Communities*.

Over the next two months, the Utilities filed documents pursuant to the directives of D.17-12-003. On February 20, 2018, the Utilities filed proposed guidelines for the Auto Demand Response technology incentive policy, pursuant to D.17-12-003 at Ordering Paragraph 29. On March 30, 2018, the Utilities filed two reports: *Demand Response Reliability Cap Workshop Report*, pursuant to D.17-12-003 at Ordering Paragraph 12, and the *Report of the Supply Side Working Group on the Demand Response Two Percent Reliability Cap*, pursuant to D.17-12-003 at Ordering Paragraph 13. On April 16, 2018, CLECA, the Joint Demand Response Parties, and PG&E filed comments to the March 30, 2018 *Demand Response Reliability Cap Workshop Report*.

On May 8, 2018, the assigned Administrative Law Judge facilitated a workshop to discuss the guidelines for the Auto Demand Response technology incentive policy, as proposed by the Utilities.

The assigned Administrative Law Judge issued a ruling on June 15, 2018 directing parties to respond to a series of questions on the following issues: 1) the straw proposal for demand response pilot plans to benefit disadvantaged communities, 2) dual participation rules, 3) the Auto Demand Response technology incentive policy, and 4) managing/modifying the two percent demand response reliability cap. Parties filed responses to the questions on July 20, 2018[9] and reply comments on August 3, 2018.[10]

On May 22, 2018, the assigned Commissioner issued an *Assigned Commissioner's Amended Scoping Memo and Ruling*, (Amended Scoping Memo) amending the scope to include the consideration of the Demand Response Auction Mechanism pilot (Auction Pilot) evaluation and extending the statutory deadline for the proceeding to July 17, 2019.

The Administrative Law Judge held a status conference on June 18, 2018 to further describe the matter and allow for questions. This was followed by a workshop on July 26, 2018 to present the preliminary results of the Auction Pilot evaluation and discuss next steps, given the evaluation delay. On August 6, 2018, the Administrative Law Judge issued a ruling requesting parties to respond to questions regarding next steps for the Auction Pilot. Responses were filed on August 17, 2018[11] and reply comments were filed on August 24, 2018.[12]

[9] The following parties filed responses to the questions in the June 15, 2018 Ruling: CESA, CLECA, CAISO, ecobee, Joint Demand Response Parties, Nest, OhmConnect, Olivine, PG&E, Cal Advocates, SDG&E, and SCE.

[10] The following parties filed replies: CESA, CLECA, ecobee, Joint Demand Response Parties, OhmConnect, PG&E, Cal Advocates, SDG&E and SCE.

[11] The following parties filed responses to the questions in the August 6, 2018 Ruling: CESA, CLECA, Joint Demand Response Parties, OhmConnect, Olivine, PG&E, Cal Advocates, SDG&E, and SCE.

[12] The following parties filed reply comments to the August 6, 2018 Ruling: CLECA, Joint Demand Response Parties, OhmConnect, Olivine, and SCE.

This proceeding remains open to review the evaluation of the Auction Pilot and consider the evaluation recommendations. All other issues in the proceeding are resolved.

2. Issues Before the Commission

The following sections describe the seven issues of this proceeding: 1) dual participation rules, 2) prioritizing resources under the current two percent reliability cap, 3) the current two percent demand response reliability cap, 4) SDG&E's approach to determining price triggers for its Capacity Bidding program, 5) Auto Demand Response technology incentive policy guidelines, 6) guidelines for developing proposals for pilots to target demand response activities in disadvantaged communities and 7) next steps for the Auction Pilot.

2.1. Dual Participation Rules

The Commission created the dual participation rules to increase the amount of cost-effective demand response available while ensuring that customers do not receive two payments for the same load reduction.[13] The rules also protect against double counting of load drop for resource adequacy purposes.[14]

In the past and prior to the integration of demand response with the CAISO market, customers were able to dually participate in two demand response programs, one being an energy program and one being a capacity program or one being a day-of program and one being a day-ahead program.

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[13] D.09-08-027 at Finding of Fact No. 41. See D.09-08-027 at 149 and 154.

[14] *Id*. at 50.

Footnote continued on next page

Over the past few years, the integration of demand response into the CAISO markets has created complexities leading to decreased opportunities for customers to dually participate. D.17-12-003 observed that conflicting policy statements have led to confusion about the dual participation rules.[15] D.17-12-003 determined that there was insufficient evidence in the record for the Commission to revise its policies on dual participation in a third-party demand response program and a utility administered demand response program.[16] This decision will determine whether the Commission should modify the dual participation rules.

2.2. The Two Percent Demand Response Reliability Cap

In D.10-06-034, the Commission adopted a settlement between the CAISO, the Utilities, CLECA, Cal Advocates, TURN, and EnerNOC, Inc. The parties to the settlement agreed to (among other things) a Commission-enforced annual cap designed to limit the capacity from reliability-based demand response programs to two percent of the recorded all-time coincident CAISO peak load (reliability cap or cap). D.17-12-003 discussed two issues related to this cap: 1) the potential for insufficient room for demand response resources under the cap and 2) the fairness of the current prioritization method for addressing allocation of the available capacity under the cap.[17] D.17-12-003 directed the Supply Side Working Group to review the reliability cap and make a recommendation on whether to maintain the cap.[18] On behalf of the working

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[15] D.17-12-003 at Finding of Fact No. 12.

[16] *Id*. at Finding of Fact 15.

[17] *Id*. at 40-44.

[18] *Id.* at Ordering Paragraph No. 13.

Footnote continued on next page

group, the Utilities filed a report on the group's recommendation. D.17-12-003 authorized Staff to hold a workshop, at which time parties to the proceeding would provide proposals for managing the megawatts under the cap.[19] The Utilities filed a report on discussions at a February 14, 2018 workshop; the report described three proposals for managing the megawatts under the cap. This decision determines how to manage resources under the current cap and determines whether the cap should be maintained or modified.

2.3. SDG&E's Approach to Determining the Price Trigger for its Capacity Bidding Program

In D.17-12-003, the Commission adopted SDG&E's proposals to modify its Capacity Bidding Program with two exceptions, one of which we address in this decision: The Commission adopted SDG&E's concept of a Capacity Bidding Program trigger based on price but required SDG&E to file a proposal describing the method to determine the price trigger. SDG&E timely filed its proposal describing the method by which it determines the Capacity Bidding Program price trigger. In response to the SDG&E filing, the Joint Demand Response Parties filed comments contending SDG&E did not adequately explain how its Capacity Bidding Program price trigger would function. This decision addresses whether SDG&E complied with D.17-12-003 and whether its approach to determining the price trigger is reasonable.

2.4. Auto Demand Response Technology Incentive Policy Guidelines

Decision 17-12-003 adopted a policy requiring the Utilities to provide Auto Demand Response technology incentives to participants of any supply side demand response program or activity (*i.e.,* pilot) that is not required to be

[19] *Id*. at Ordering Paragraph No. 12.

analyzed for cost-effectiveness. Pursuant to D.17-12-003, the Utilities timely filed a set of proposed guidelines to implement the policy. Early in 2018, parties agreed upon several elements of the proposed guidelines, which we affirm in this decision. During a workshop, parties discussed several aspects of the guidelines. Following the workshop, the Administrative Law Judge issued a ruling directing responses to questions about the guidelines. Additionally, the ruling included questions related to battery storage, which was not present in the marketplace at the time Auto Demand Response was established. This decision determines the guidelines to implement the Auto Demand Response technology incentive policy and other related Auto Demand Response issues.

2.5. Guidelines for Pilot Proposals to Target Demand Response in Disadvantaged Communities

D.17-12-003 did not find sufficient record to direct the Utilities to make immediate programmatic changes addressing demand response in transmission constrained areas and disadvantaged communities. However, D.17-12-003 initiated a stakeholder process for purposes of developing program changes. D.17-12-003 stated the following:

> We will issue a draft straw proposal in January 2018 providing guidelines for the Utilities to propose pilot projects targeting local capacity areas and [disadvantaged communities]. The straw proposal will also specify goals, definitions, and funding parameters for the Commission's consideration in a future decision in 2018. In the first quarter of 2018, the Energy Division shall hold a workshop to discuss the straw proposal. The Energy Division must seek input from organizations representing disadvantaged communities, ratepayer advocates, and other social or environmental justice organizations that may have an interest in furthering the goals of targeting demand response in low income or disadvantaged communities. A subsequent decision issued in this proceeding will adopt a final proposal and provide

guidelines to the Utilities to develop and seek approval for proposals based on the guidelines.

Pursuant to D.17-12-003, on February 7, 2018, the draft Assigned Commissioner's Office Proposal for Demand Response Pilot Plans to Benefit Disadvantaged Communities was issued. This draft straw proposal was discussed at the February 15, 2018 workshop. Subsequently, the Staff requested informal comments from the parties to finalize the draft straw proposal.

The June 15, 2018 Administrative Law Judges' Ruling Requesting Responses to Questions directed the parties to provide responses to questions on the Assigned Commissioner's Office Proposal for Demand Response Pilot Plans to Benefit Disadvantaged Communities (Proposal). Respondents addressed in their comments the merits of the Proposal, the definition of the disadvantaged communities, requirements for the pilots, purpose and goal, location criteria, and testing objectives. This decision considers the guidelines provided in the Proposal and determines a submittal and review process for the pilots.

2.6. Demand Response Auction Mechanism Pilot

The Demand Response Auction Mechanism pilot (Auction Pilot) was approved in D.14-12-024 to provide stakeholders an opportunity to gain experience in the CAISO market and increase the understanding of the CAISO market complexities. D.16-09-056 authorized the Energy Division to conduct an evaluation of the Auction Pilot and called for a final analysis with recommendations to be issued by the Energy Division no later than June 1, 2018.[20]

[20] D.16-09-056 at Ordering Paragraph No. 10.

Through the Auction Pilot, the Commission authorized annual demand response auctions in 2015, 2016, 2017, and 2018, with the expectation that the evaluation would be completed by June of 2018 and a determination of whether to adopt the auction mechanism as a permanent mechanism would occur during the summer of 2018.[21] The delay of the evaluation raises the question of how the Commission should address the absence of a demand response auction in 2019.

Following a July 26, 2018 workshop, which included a discussion of a potential lack of a demand response auction in 2019, the Administrative Law Judge issued a ruling directing parties to respond to related questions. This decision considers whether the lack of an auction in 2019 is harmful and whether the Commission should extend the pilot by authorizing another auction.

3. Resolution of Issues Remaining from D.17-12-003

This section addresses the remaining original issues from the March 30, 2017 Scoping Memo for this proceeding. Below we adopt the following: 1) the prohibition of dual participation in Critical Peak Pricing and Utility or third-party administered demand response programs for all new customers, beginning immediately upon the submittal by the Utilities of Tier One Advice Letters revising the tariff and until further notice; 2) the prioritization of third-party customers in allocating any remaining megawatts under the two percent reliability cap, but we do so with the demand response goal in mind; 3) several Auto Demand Response policies to be included in a new document, Auto Demand Response Control Incentives Guidelines and Adopted Policies, and the establishment of a process for parties and other interested participants to

[21] The 2018 auction was authorized with the recognition that the delivery performance would not be factored into the evaluation.

work together with Energy Division to pursue further technical refinements to the adopted guidelines and to Auto Demand Response itself; 4) a stakeholder process to develop an overall strategy proposal for battery storage controls in Auto Demand Response; and 5) guidelines for the pilots targeting demand response and a regulatory process for submittal and approval of the pilot proposals.

3.1. Dual Participation Rules

The record indicates that the implementation of dual participation in the Utility-administered Critical Peak Pricing and third-party demand response programs would require significant and potentially costly changes to already complex rules for a relatively low impact to customers. Given the decreasing enrollments in Critical Peak Pricing and the uncertainty surrounding the Auction Pilot and any permanent auction mechanism, we conclude that the Commission should prohibit dual participation in Critical Peak Pricing and Utility or third-party administered demand response programs for all new customers, beginning immediately upon the submittal by the Utilities of Tier One Advice Letters revising the tariff and until further notice. Existing direct-enrolled customers will be allowed to continue to dually participate in Critical Peak Pricing and Utility-administered demand response programs, in the currently enrolled program and capped at the current megawatt level. Previously executed Local Capacity Requirements contracts would also be allowed to continue to dually participate, if the contract currently includes dual participation as a contract term. As discussed below, we find this approach balances the principle of competitive neutrality with the Commission's responsibility to ensure appropriate use of ratepayer funding.

Pursuant to D.17-12-003, a workshop facilitated by the Administrative Law Judge was held on February 13, 2018 to discuss issues regarding dual participation of demand response programs. During the workshop, parties discussed the current rules of demand response dual participation (*see* Table 1). The Utilities also presented an overview of the CAISO and third-party direct participation rules,[22] which create further complexities to the implementation of dual participation. For example, the CAISO tariff does not currently permit a customer to enroll in two different registrations at the same time.[23] Additionally, Ordering Paragraph 8 of D.12-11-025 established, in Rule 24/32, the requirement that a utility automatically dis-enroll a customer from Critical Peak Pricing if the customer registers with a third-party provider in the CAISO market. The main points of the Utilities' presentation were: 1) double counting and double payments are prohibited; 2) recording and counting require visibility by the Utilities; and 3) customer choice should be supported but within the bounds of the current rules.

[22] Electric Rules 24 and 32 are rules for direct participation of demand response third-party providers in the CAISO demand response market. Rule 24 pertains to PG&E and SCE. Rule 32 pertains to SDG&E. Participation in the CAISO market is a requirement for winning bids in the auction pilot.

[23] *See* CAISO tariff, Section 4.5.1.1.3 and 4.13.2.

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Table 1[24]

Customers may participate in two demand response programs, if:

1. Customers are not paid twice for the same load reduction;
2. One program is day-ahead and the other is day-of;
3. Only one of the two programs may pay a capacity payment;
4. During simultaneous events and if both programs offer energy payments, one of the energy payments shall be withheld.

Currently, there are only a few options for dual participation for all demand response customers and fewer for customers of third-party providers. (*See* Table 2.) While Table 2 indicates seven instances where dual participation is permitted, only one of those instances has programs available to customers (see shaded cell). Parties note that dual participation opportunities have vanished with the discontinuation of the Demand Bidding Program and the Aggregator Managed Portfolio programs. Now the dual participation options for customers of third-party providers are: 1) Critical Peak Pricing with PG&E or SDG&E and Base Interruptible Program with a third-party aggregator or 2) Critical Peak Pricing with PG&E, SDG&E, or SCEand Capacity Bidding Program Day-Of with a third-party aggregator.

[24] Dual Participation rules as established in D.09-08-027.

Table 2
Dual Participation Currently Permitted
(Utility-Administered Programs in Bold)

		Integrated Energy Programs Day-Of Notice	Integrated Energy Programs Day-Ahead Notice	Non-Integrated Energy Programs Day-Of Notice	Non-Integrated Energy programs Day-Ahead Notice
					CPP*
Integrated Capacity Programs Day-Of Notice	**BIP, API, CBP-DO, PTR and Smart AC***				Permitted
Integrated Capacity Programs Day-Ahead Notice	**CBP-DA***			Permitted	
Non-Integrated Capacity Programs Day-Of Notice			Permitted		Permitted
Non-integrated Capacity Programs Day-Ahead Notice		Permitted		Permitted	

*Base Interruptible Program, Agricultural Pumping Interruptible, Capacity Bidding Program, Peak Time Rebate, and Critical Peak Pricing

In response to a June 15, 2018 Ruling, the Joint Demand Response Parties state that CPower, a third-party demand response provider, has experienced a rise in questions from customers regarding Critical Peak Pricing, noting that up to 75 percent of customers inquired about Critical Peak Pricing this year.[25] Contending that year-over-year statistics are not relevant, the Joint Demand Response Parties state that none of the third-party providers represented by the Joint Demand Response Parties collect or store statistics with respect to the number of customers who dis-enrolled from the Critical Peak Pricing because of registration with CAISO or declined to enroll because they preferred to stay in Critical Peak Pricing.[26] According to the Utilities, a total of 347 Critical Peak Pricing customers automatically disenrolled from Critical Peak Pricing due to participation in the Auction Pilot. (*See* Table 3.)

Table 3

Customers Disenrolled from Critical Peak Pricing 2016-2018[27]

Utility	Customers Disenrolled
PG&E	46
SDG&E	283
SCE	18

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25 Joint Demand Response Parties Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 5.

26 Joint Demand Response Parties Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 5-6.

27 PG&E Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 7; SDG&E Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 6; SCE Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 7.

Footnote continued on next page

Party comments to the June 15, 2018 ruling recommended a variety of approaches to resolving dual participation predicaments. SCE's approach to dual enrollment between Critical Peak Pricing and Base Interruptible Program is to cap the incentives paid to a customer at the maximum generation capacity charges under the tariff when events for both programs overlap.[28] However, it was unclear whether this approach could be duplicated with customers enrolled in a third-party provider demand response program. PG&E and SDG&E allow customers to be paid under both the Base Interruptible Program (for example) and Critical Peak Pricing when events overlap because they interpret the rules to allow a customer to be paid under one capacity and one energy program.

The Joint Demand Response Parties recommended modification of Electric Rule 24/32 to eliminate the automatic removal of customers from Critical Peak Pricing. Parties suggested that the Rule 24/32 firewall, which prevents two groups of utility staff from sharing information in order to ensure competitive neutrality, could be revised.[29] When asked how this could be implemented, SDG&E and PG&E recommended eliminating the firewall requirement to allow the non-program administration personnel at the Utilities to have access to the operational information for both the Utilities and the third-party providers.[30] In response to questions posed in a June 15, 2018 Ruling, the Joint Demand Response Parties argue the Commission should also review the rule against dual

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[28] SCE Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 9.

[29] Rule 24/32 Section C.1.a.(3). The two groups of utility staff include one group that implements Rule 24/32 and administers the auction mechanism and one group that administers utility demand response programs.

[30] PG&E Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 10 and SDG&E Opening Comments to June 15, 2018 Ruling, July 20, 2019 at 9-10.

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participation in two day-ahead programs, contending participation in the Auction Pilot or a future auction mechanism negates any dual participation opportunity.[31] In addition, PG&E asserts that exemption from the dual participation rules for Rule 24/32 participants is needed in order to absolve the need to maintain the one capacity/one energy program rule.[32]

To allow customers to dually participate in Rule 24/32 third-party demand response programs and Critical Peak Pricing, changes to the rule may need to be made including: 1) modification or elimination of the firewall requirement; 2) modification or elimination of the rule regarding participation in two day-ahead or day-of obligations; and 3) modification or elimination of the rule regarding participation in two energy or two capacity programs. These issues are complex and require significant time to understand the implications of each rule change and then reach consensus between the Utilities and demand response providers.[33] The record of this proceeding does not sufficient details regarding the breadth of the rule changes needed.

Furthermore, no party provided cost estimates for implementation of rule changes because no one knows at this time the extent to which the rules should be changed. As a result, the Commission has no indication of the costs for these changes. However, past spending to implement changes to the Utilities' information technology (IT) systems for third-party direct participation indicate these types of costs are not inconsequential. For example, the Commission

31 Joint Demand Response Parties Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 8.

32 PG&E Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 8.

33 CESA Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 10.

Footnote continued on next page

adopted total budgets of over $18 million in IT costs to implement a data set, modify the Customer Information Service Request Demand Response Provider form, and implement the click-through process.[34]

We should weigh the potential costs and resources required to implement changes to Rule 24/32 against the impact on customers of third-party providers. The record indicates the number of un-enrollments from Critical Peak Pricing have been low.[35] Third-party providers indicate lost opportunities by choosing not to enroll Critical Peak Pricing customers but can only provide anecdotal data at this time. Furthermore, the potential expense and resources expended for revising the rules may be questionable given declining enrollments in Critical Peak Pricing. Furthermore, PG&E states it is currently examining the value of continuing its Critical Peak Pricing program (Peak Day Pricing) "in light of increasing disenrollment due to customer opt-outs, disenrollments and migration of customers from bundled service combined with the shift to evening peak time of use rates."[36]

Lastly, we should weigh the costs of revising Rule 24/32 against the current uncertainty of the Auction Pilot. The need for these changes is directly related to the enrollment in the Auction Pilot. When the dual participation rules were established by the Commission, CAISO market integration had not begun and thus the rules did not take market integration into account. The evaluation of the Auction Pilot is currently being conducted by Energy Division; we do not

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[34] *See* Resolutions E-4868, E-4935 and E-4912.

[35] PG&E Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 7; SDG&E Opening Comments to June 15, 2018 Ruling, July 20, 2019 at 6 and SCE Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 7.

[36] PG&E Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 7.

know the results of the evaluation or the recommendations to be made by Energy Division. The Commission should wait until a final determination on a permanent auction mechanism is made before determining whether and how to modify rules to allow for dual participation in the auction mechanism and other demand response programs.

Given the unknowns of a permanent auction mechanism and the costs to implement changes to rules to allow for dual participation, it may not be prudent at this time for the Commission to modify rules to facilitate dual participation in Critical Peak Pricing and another demand response program. However, we are concerned about the current unlevel playing field that exists between the Utilities and the third-party providers. The Joint Demand Response Parties contend that even one benefit to remaining with utility service is one too many to tilt the competitive field away from the third-party. Hence, we find that in order to provide more balance to the playing field while ensuring that ratepayers are not paying twice for a single instance of load drop, it is reasonable to prohibit dual participation of Critical Peak Pricing and another demand response program for all new customers on an interim basis until further notice. For example, a current Critical Peak Pricing customer that has been newly accepted into the Base Interruptible Program will now have to choose one program over the other. Existing utility customers shall be allowed to continue to dually participate, if they are currently enrolled as a dual participant. We do not want to lose these committed megawatts. However, customers currently dually-enrolled shall only be permitted to do so within the currently enrolled programs and capped at the current level of megawatts.

While we recognize the value of dual participation to customers and the Commission, we must also recognize our responsibility over prudent ratepayer funding including preventing double payments. Once the Commission has made its determination on the future of the auction mechanism, we will be able to make a more informed decision on potential future dual participation. At that time, the Commission will revisit the issue of dual participation between third-party provider programs and Critical Peak Pricing. Until that time, we encourage third party providers to maintain records of instances where customers chose not to enroll in a third-party program in order to remain enrolled in Critical Peak Pricing.

In addition to the issues discussed above, during the February 13, 2018 workshop AMS gave a presentation on dual participation and the use of battery storage to provide incremental capacity behind the same meter. In its presentation, AMS asserted that its Local Capacity Requirements contracted resources are available for dispatch per contract provisions and that AMS is not using the same energy or capacity during Local Capacity Requirements availability hours for use under other programs where coincident dispatch occurs. AMS maintains that participating in demand response programs during the same time as a Local Capacity Requirements contracted resource does not violate the principles adopted in the Multi-Use Application (D.18-01-003 in Rulemaking 15-03-011 (energy storage)).[37] AMS' contentions and assertions stated above have not been tested in terms of dual participation of demand response resources or any other resource regulated by the Commission. At this time, there is no evidence regarding the viability of battery storage as incremental capacity in a demand response program. Furthermore, this issue is beyond the scope of this proceeding. Hence, we do not address the issue of

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[37] D.18-01-003 approved rules for allowing a resource to provide multiple services with different portions of the resource's capacity.

battery storage in terms of dual participation for customers enrolled in programs fulfilling Local Capacity Requirements contracts.

3.2. Two Percent Demand Response Reliability Cap

We agree with the party consensus that the settlement agreement should not be disturbed, and the two percent demand response reliability cap (reliability cap or cap) should remain unchanged. We confirm the use of Reliability Demand Response Resource (RDRR) can occur anytime within the Warning Stage, in the case of both In-Market dispatch and Out-Of-Market dispatch, otherwise known as exceptional dispatch. Given the collective concern regarding the frequency of notices, we conclude that the Commission should not allow RDRR to be triggered prior to the Warning Stage at this time. With respect to managing the resources under the cap, we find it reasonable to prioritize third-party customers in allocating the remaining megawatts, but we do so with the demand response goal in mind, ensuring that the needs of the grid are met. After providing a brief history of the reliability cap, we discuss our determinations in detail below.

3.2.1. History of the Two Percent Reliability Cap

In its objective to support the CAISO's efforts to incorporate demand response into market design protocols, the Commission capped emergency triggered demand response programs (also known as reliability programs) at current enrolled megawatt levels, in D.09-08-027. In D.10-06-034, the Commission adopted a settlement between the CAISO, the Utilities, CLECA, Cal Advocates, TURN, and EnerNOC, Inc. The parties to the settlement agreed that the freeze adopted in D.09-08-027 would be removed in May 2010 and replaced with a Commission-enforced annual limit designed to limit reliability-based program capacity to a specified percent of the CAISO's all-time coincident peak demand. Beginning in 2014 and forward, the agreed-upon limit was set at two percent of the recorded all-time coincident CAISO peak load. According to the settlement adopted in D. 10-06-034, the reliability cap could be revised after 2015.

In D.16-06-029, the Commission determined that it was not necessary to suspend the reliability cap in response to the Aliso Canyon gas storage facility leak, but suggested that the cap could be reviewed in the future.[38] D.17-12-003 acknowledged that PG&E reached its cap in late 2016 and has a waitlist for prospective Base Interruptible Program customers.[39] At that same time, SCE expected to reach or exceed its cap shortly[40] but SDG&E was well below its cap.[41]

3.2.2. Proposals for Allocating Resources Under the Cap

On March 30, 2018 the Utilities filed a report on a February 14, 2018 workshop attended by representatives of the Utilities, EnerNoc, CPower, CLECA, CAL Advocates, CAISO, the Council, the Industrial Brotherhood of Electrical Workers and Energy Division.[42] Pursuant to D.17-12-003, the report contained an overview of the workshop, areas of agreement and disagreement, and proposals from the Utilities, CLECA, and EnerNOC/Power, which we describe below.

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[38] D.16-06-029 at 34-36.

[39] D.17-12-003 at 42.

[40] *Id*. at 42-43.

[41] *Id*. at 43.

[42] *Pacific Gas and Electric Company's, San Diego Gas and Electric Company's and Southern California Edison Company's Filing of the Reliability Cap Workshop Report*, March 30, 2018 at 5.

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The workshop report explained that, to address allocation of the available capacity under the reliability cap, PG&E implemented a five-tier hierarchy.[43] The Joint Demand Response Parties maintain that the hierarchy implemented by PG&E is harmful to third-party providers.[44] The purpose of the workshop was to discuss how to manage the current reliability cap and determine how to prioritize resources under the cap.[45]

With respect to the Utilities' proposed approach, the Utilities agreed to consistently calculate and manage the reliability cap headroom across all three Utilities. The Utilities propose the following approach for programs where the Utilities are the demand response provider:

1. Remaining headroom will be assessed as part of the Protocols Report filing;
2. Headroom will be calculated as such: (Projected Load Impacts for Base Interruptible Program and Agricultural Pumping Interruptible) – (Projected Critical Peak Pricing Load Impacts for Dually-Enrolled Participants in Base Interruptible Program/ Agricultural Pumping Interruptible and Critical Peak Pricing) = Capacity Headroom
3. If the results of (2) indicate a utility is at or above 95 percent of its individual allocated cap, then enrollments of all reliability demand response resources will be suspended.
4. If the results of (2) indicate a utility is below 95 percent of its allocated cap, the following management process is implemented:
    a. A five-day request window will be established where aggregators and direct-enrolled customers will request headroom by submitting a request form indicating the

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43 *Id*. at 42, footnote No. 53.

44 *Id*. at 42 and footnote No. 54.

45 *Id*. at 4 citing D.17-12-003 at Ordering Paragraph No. 12.

program, service account number(s), incremental megawatts and physical address/location for which they are requesting the reliability cap headroom;

b. After the request window is closed, the Utilities will implement a 30-day verification period to verify eligibility and value buckets for each request in the following order: i) Requests for resources that would "de-island" existing resources;[46] ii) Requests for resources in Local Capacity Areas that have local capacity deficiencies but do not result in additional islanded resources; iii) All other requests that do not result in additional islanded resources; and iv) Requests that result in islanded resources.
c. With each value bucket, requests will be randomized and requestors will be notified of their place in the request queue. The highest priority value bucket will be exhausted before moving on to the next highest value bucket. Within each value bucket equal consideration will be given regardless of size of resource.
d. For programs where the Utility is the demand response provider, an aggregator or direct enrolled program participant must notify the utility of the megawatt requested in its enrollment request for each service account.
e. Reliability cap queue positions are forfeited if they are not used prior to the next five-day request window.

CLECA's approach begins with the recognition that the issue of the reliability cap is solely the allocation of remaining headroom under the cap.[47]

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[46] De-islanding is defined as "where a resource would enable another resource to be CAISO market integrated and, therefore, count for resource adequacy." See *Pacific Gas and Electric Company's, San Diego Gas and Electric Company's and Southern California Edison Company's Filing of the Reliability Cap Workshop Report*, March 30, 2018, Attachment 1 at Footnote No. 8.

[47] CLECA's approach is described in *Pacific Gas and Electric Company's, San Diego Gas and Electric Company's and Southern California Edison Company's Filing of the Reliability Cap Workshop Report*, March 30, 2018 at 9-12.

CLECA contends that if customers are in good standing they should be able to continue to participate. Pointing to the demand response principle that customers should be able to participate in demand response through a service provider of their choice, CLECA maintains that customers should not be required to participate in third-party programs. However, CLECA argues that the Auction Pilot reliability resources should receive a preference followed by all other reliability resources. CLECA contends this is guided by the principles of consumer choice and competition and the determination by the Commission to continue the roles of the Utilities as providers and administrators of demand response programs. CLECA supports the Utilities' recommended use of a lottery and value buckets for allocating the remaining headroom to provide an equal chance for customers who directly enroll in reliability demand response and those who participate through an aggregator. CLECA notes that this is similar to the lottery system used in the direct access cap allocation approach and Self-Generation Incentive Program (SGIP) funding.[48]

EnerNOC and CPower recommend the following hierarchy for allocating the available capacity: 1) Third-party providers with customers currently participating in Base Interruptible Program or the auction mechanism; 2) New third-party providers with customers wanting to participate in Base Interruptible Program or the auction mechanism; and 3) Utility customers participating in a reliability program.[49] EnerNOC and CPower maintain this hierarchy provides an

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[48] *Pacific Gas and Electric Company's, San Diego Gas and Electric Company's and Southern California Edison Company's Filing of the Reliability Cap Workshop Report*, March 30, 2018 at 12.

[49] EnerNOC and CPower's hierarchy is described in *Pacific Gas and Electric Company's, San Diego Gas and Electric Company's and Southern California Edison Company's Filing of the Reliability Cap Workshop Report*, March 30, 2018 at 12-16.

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opportunity for customer relationship continuity and growth for third-party providers. Further, EnerNOC and CPower assert that when third-party customer participation in Base Interruptible Program and the CAISO market are "roughly equivalent to the [Utilities'] share of reliability capacity, then the order can be revisited."[50]

3.2.3. Managing Resources Under the Two Percent Reliability Cap

We begin with a discussion of areas of agreement among parties. The workshop report states that parties at the February 14, 2018 workshop agreed on the following four points: 1) the annual Load Impact Protocols report should be the document where the available headroom for the Utilities, both individually and collectively, should be assessed; 2) if the Load Impact Protocols Report indicates one or more of the Utilities has exceeded its reliability cap, the utility should suspend enrollment of additional megawatts that will count against the cap; 3) although difficult to determine without further visibility, allocation of available headroom should be based on the value of the megawatt, with megawatts that can de-island existing megawatts given the highest value and those that would be islanded if enrolled given the lowest value; and 4) it will be difficult to design a durable reliability cap management approach until there is more clarity on whether megawatts that could count toward the reliability cap will be procured via a permanent auction mechanism.[51] No party filed opposition to these agreements. However, noting that de-islanding is not a key criterion for them, the Joint Demand Response Parties contend that they do not

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[50] *Pacific Gas and Electric Company's, San Diego Gas and Electric Company's and Southern California Edison Company's Filing of the Reliability Cap Workshop Report*, March 30, 2018 at 15.

[51] *Id.,* Attachment 1 at 16.

know what resources are islanded and where they are located. We find the first two points of agreements reasonable. The Commission should adopt these two points of agreements.

While we recognize the reasoning for prioritizing resources with megawatts that can de-island existing megawatts, there is nothing in the record of this proceeding that indicates that the third-party providers "have visibility as to whether any customers will reduce or not increase stranded demand response capacity."[52] CPower and Enel X assert that for this approach to succeed, the Utilities musts identify the islanded resources location, its capacity and the LSE. This not only results in a complex process for a small amount of capacity but could also result in running "afoul of customer privacy protections."[53] We conclude that a complex de-islanding requirement may result in unintended consequences, including unreasonable costs for a small amount of capacity. Hence, we do not adopt a de-islanding requirement.

With respect to the fourth point, we first conclude the megawatts procured through the auction mechanism (as currently configured in its pilot form) count toward the reliability cap. While CLECA contends the reliability demand response bid into the CAISO energy markets by third-party providers and being paid capacity by the Utilities through the Auction Pilot should not be counted towards the cap to the extent that those megawatts are participating in the

[52] CPower/EnelX Opening Comments to Proposed Decision, November 14, 2018 at 6-7.

[53] *Id*. at 7.

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CAISO energy markets, we disagree.[54] Pursuant to the settlement agreement in D.10-06-034, the CAISO agreed to develop a wholesale reliability demand response product; the reliability product would qualify as resource adequacy capacity *but would be subject to the megawatt limit (i.e., cap) if the utilities seek to count the megawatts for resource adequacy credit* (emphasis added).[55] The settlement clarified that the reliability product is *not* price-responsive but will be economically dispatched once triggered.[56]

Relatedly, the settlement allowed that resource adequacy megawatts from customers also participating in price-responsive demand response programs will not be counted against the limit.[57] Parties suggest that if the Commission required future auction mechanism contracts to economically bid into the CAISO markets, this would ensure that reliability megawatts procured through the auction mechanism are not limited by the reliability cap.[58] We do not address this issue at this time. Allocation of the megawatts from a permanent auction mechanism will be addressed when the Commission determines whether the auction mechanism should be permanent; that determination will be made in

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[54] *Pacific Gas and Electric Company's, San Diego Gas and Electric Company's and Southern California Edison Company's Filing of the Reliability Cap Workshop Report*, March 30, 2018, Attachment 1 at 11.

[55] D.10-06-034, Appendix A at Section A.4.b.

[56] *Id*. at A.4.e.

[57] *Id.* at C.2.c.

[58] *Pacific Gas and Electric Company's, San Diego Gas and Electric Company's and Southern California Edison Company's Filing of the Reliability Cap Workshop Report*, March 30, 2018 at Footnote No. 5; Utilities Opening Comments on the Reliability Cap Workshop Report, April 16, 2018 at 5-6; CLECA Opening Comments on the Reliability Cap Workshop Report, April 16, 2018 at 3; and Joint Demand Response Parties Opening Comments on the Reliability Cap Workshop Report, April 16, 2018 at 4.

Footnote continued on next page

this proceeding. Furthermore, as noted by CLECA, the Auction Pilot resources receive resource adequacy credit based on their contract capacity, which does not consider whether the contracted megawatts are delivered. Other demand response programs, including the Base Interruptible Program, are evaluated through the Load Impact Protocols, which review actual historical performance at times of grid need.[59] Hence, the determinations herein related to the reliability cap should be reviewed again when the Commission considers the evaluation of and related recommendations for the Auction Pilot.

Parties agreed to one last point: adding a reliability program open season in April to more closely align with the release of the Load Impact Protocol Report in April of each year.[60] CLECA, EnerNOC/CPower, and Cal Advocates express support for this modification.[61] The current November open season provides an opportunity for existing enrollees to make changes to their enrollments in the Base Interruptible Program and Agricultural and Pumping Interruptible Program.[62] The creation of an additional open season in April will allow for new enrollments only, after the previous year's November window and after the load impact reports are filed in April, which will indicate any available headroom under the cap.[63] We find it reasonable to adopt this additional open window for new enrollments. In addition, we modify the rules of the November open season

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[59] Utilities Comments on the Reliability Cap Workshop Report, April 16, 2018 at 3.

[60] *Id*. at 2.

[61] *Pacific Gas and Electric Company's, San Diego Gas and Electric Company's and Southern California Edison Company's Filing of the Reliability Cap Workshop Report*, March 30, 2018, at 25-26.

[62] SCE Opening Comments on the Proposed Decision, November 14, 2018 at 7.

[63] *Ibid*.

to only permit disenrollment and decrease in participation in demand response of existing customers.

We now turn to areas of disagreement. The three proposals for allocating the available megawatts up to the reliability cap (*i.e.,* headroom) can be encapsulated as: a) Utilities: treating aggregator and direct-enrolled customers equally, b) CLECA: giving preferential treatment to customers of the auction mechanism then treating remaining customers equally, and c) EnerNOC/CPower: giving priority to third-party customers over direct-enrolled customers.

The Utilities, supported by CLECA, contend their lottery proposal creates a level playing field between direct-enrolled customers and aggregator customers.[64] The Utilities indicate prior precedent for this approach, as a similar approach has been used for allocating available funding in the Self-Generation Incentive Program and to allocate available capacity for Direct Access customers.[65] CLECA highlights that megawatts from auction mechanism reliability resources should receive a preference with respect to headroom.

CLECA contends that its support for a lottery system with the addition of a priority for auction mechanism megawatts is guided by the principles of consumer choice and competition, and the recognition by the Commission that the Utilities should have two roles: that as a demand response program provider and that as a demand response program administrator.[66] Furthermore, CLECA

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[64] Utilities Comments on the Reliability Cap Workshop Report, April 16, 2018 at 2.

[65] *Id*. at 2 and Footnote Nos. 4 and 5.

[66] *Pacific Gas and Electric Company's, San Diego Gas and Electric Company's and Southern California Edison Company's Filing of the Reliability Cap Workshop Report*, March 30, 2018, at 19.

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alleges that the preference for third-party demand response is limited to competitively procured third-party demand response and not aggregators.[67]

Cal Advocates argues that other mechanisms better achieve specific Commission policy goals compared to a random lottery system and points to both the auction mechanism and the third-party aggregators.[68] Cal Advocates also points out that the current share of third parties providing Base Interruptible Program is much smaller compared to utility-procured Base Interruptible Program.[69] In support of increasing third-party provider participation in demand response, EnerNOC/CPower assert that their approach is fair to third-party providers "who were late to the game in accessing available capacity under the cap due to the timing of participation in the wholesale market."[70]

We return to the demand response goal and principles adopted by the Commission in D.16-09-056. As stated in Ordering Paragraph No. 7 of that decision, the goal of demand response programs is:

> *Commission-regulated demand response programs shall assist the State in meeting its environmental objectives, cost-effectively meet the needs of the grid, and enable customers to meet their energy needs at a reduced cost.*

In Ordering paragraph No. 8 of D.16-09-056, the Commission adopted several principles for demand response programs. Most relevant to this decision are the following two principles:

- *Customers shall have the right to provide demand response through a service provider of their choice.*

[67] *Id.* at 22 and 23.

[68] *Id.* at 23.

[69] *Id.* at 24.

[70] Joint Demand Response Parties Opening Comments on the Reliability Cap Workshop Report, April 16, 2018 at 4.

- *Demand response shall be market-driven leading to a competitive, technology-neutral, open-market in California with a preference for services provided by third parties through performance-based contracts at competitively driven prices, and dispatched pursuant to wholesale or distribution market instructions.*

The Utilities and CLECA assert that the Commission has not expressed a preference for all third-party provided demand response but only for third-party demand response obtained in a competitive manner, bid into the market, with contracts that pay for performance. We agree that our preference is for services procured competitively from third-party providers. However, the Commission has also stated that it will attempt to ensure that a broad array of demand response options, including demand response provider options, is offered to customers.[71] Hence, we affirm that the Commission is supportive of third-party demand response aggregators in cost-effective programs. The Commission is also supportive of customers having the right to provide demand response through a service provider of their choice.

As noted by Cal Advocates, the current share of third parties providing Base Interruptible Program is much smaller compared to utility procured Base Interruptible Program. In D.16-09-056, the Commission highlighted a concern about the competition playing field not being level and we found it reasonable to cap annual funding for demand response programs at the 2017 budget levels. To further promote third-party participation, the Commission should allocate the bulk of the remaining megawatts under the cap using a lottery for third-party providers only.

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[71] D.17-09-056 at 52.

The Utilities' arguments regarding customer choice are disingenuous. Customers will continue to have the choice of demand response providers. As pointed out by Cal Advocates, most of the customers participating in the Base Interruptible Program are utility customers and will continue to be able to participate in this program if they remain enrolled in the program. We underscore that the cap issue is the allocation of remaining headroom under the cap. Accordingly, we find it reasonable to prioritize third-party customers in allocating the remaining megawatts, but we do so with the goal of demand response in mind, ensuring that the needs of the grid are met. Hence, we adopt the following combined approach:

1. Remaining headroom will be assessed as part of the Protocols Report filing;
2. Headroom will be calculated as such: (Projected Load Impacts for Base Interruptible Program and Agricultural Pumping Interruptible) – (Projected Critical Peak Pricing Load Impacts for Dually-Enrolled Participants in Base Interruptible Program/ Agricultural Pumping Interruptible and Critical Peak Pricing) = Capacity Allocated. Capacity Headroom=Utility Allocated Cap (megawatts) – Capacity Allocated.
3. If the results of (2) indicates a utility is at or above 95 percent of its individual allocated cap, then enrollments of all reliability demand response resources will be suspended.
4. If the results of (2) indicates a utility is below 95 percent of its allocated cap, the allocation of the remaining megawatts will be through a lottery in the following order: a) Third-party resources from Local Capacity Areas that have local capacity deficiencies pursuant to CAISO; b) Utility customer resources from Local Capacity Areas that have local capacity deficiencies pursuant to CAISO; c) all other resources from third-party; and d) utility customer resources that would de-island existing resources. The

> higher priority buckets shall be exhausted before the resources from the next priority bucket are selected.

In comments to the proposed decision, SDG&E notes that it is still very much below subscribing 50 percent of its reliability cap and request that this allocation process be applicable only when a utility reaches 70 percent of its cap.[72] SDG&E asserts that requiring the multiple lotteries might hamper cost-effective subscription levels.[73] We recognize that, for a small utility, holding multiple lotteries could effect cost-effectiveness results. We will permit a first come, first serve approach until SDG&E reaches 50 percent of its reliability cap. This addresses the cost-effectiveness concern while preserving the desired level playing field.

3.2.4. Maintaining the Two Percent Reliability Cap

With respect to modifying the cap, the Supply Side Working Group met during February of 2018 and filed a report on its progress in this matter on March 30, 2018. The majority of the working group participants recommended the Commission not change the settlement adopted in D.10-06-034. Relatedly, D.10-06-034 established the trigger for reliability-based demand response product. The settlement adopted in that decision required that the parties not propose a change to the trigger for any year prior to 2015.[74]

In addition to recommending the Commission not change the settlement adopted in D.10-06-034, the Supply Side Working Group's report also noted that: 1) several participants, including Energy Division, CAISO, and Cal Advocates

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[72] SDG&E Opening Comments to Proposed Decision, November 14, 2018 at 3-4.

[73] *Id*. at 4.

[74] D.10-06-034 at 4-5, and A.4.1.

expressed interest in reviewing the triggers for the RDRR; 2) the CAISO generally does not support re-opening the settlement, but does support changes in the trigger that would make RDRR more like Proxy Demand Response; and 3) Cal Advocates supports CAISO's position to make necessary changes to the trigger so RDRR can be called prior to an emergency.

Subsequent to the filing of the Supply Side Working Group report, the Commission's Energy Division conducted research, which led to the following observations with respect to the reliability resource trigger:

- The intent of D.10-06-034 was to eliminate the anomalous treatment whereby emergency-triggered demand response counts for resource adequacy yet, unlike all other power that counts for resource adequacy, the CAISO currently procures exceptional dispatch energy or capacity before using this energy resource, a practice that has led to charges that ratepayers pay twice for this power.[75] Thus, D.10-06-034 sought to make RDRR more useful by moving the trigger from Imminent Stage 1 to prior to the CAISO's need to canvass neighboring balancing authorities and other entities for available exceptional dispatch energy/capacity.[76] However, pursuant to current practice, the RDRR resources do not appear to be available to CAISO before procuring costly exceptional dispatch energy/capacity.
- The historical data showed that CAISO called fewer warnings and emergencies in the post-settlement period than the period before and during the settlement years. On average, 3.9 warnings were issued annually prior to the settlement (from 1998 to 2006, excluding 2000 and 2001 when exceptionally high number of warnings were called) and 1.75 warnings were issued annually during the period of settlement (from 2007 to 2010); in comparison, on

75 D.10-06-034 at 2-3.

76 *Ibid*.

average, 0.5 warnings were issued annually in the post settlement period, from 2011 to 2017. In fact, reliability-based demand response programs were called twice by CAISO under a warning or stage 1 emergency in the 2010 to 2017 period (subsequent to the settlement). This suggests that RDRR resources were dispatched far less often post-settlement than the frequency the settling parties may have expected based on the frequency observed before and during the settlement period.

- The heat wave of August 28, 2017 to September 1, 2017 resulted in CAISO's annual peak load of 50, 116 megawatts (only 154 megawatts less than the all-time system peak in 2006). But conditions did not materialize for the CAISO to call a warning or a stage 1 emergency. Instead, CAISO issued a Restricted Maintenance Operations notice from August 28, 2017 through September 3, 2017 and a Flex Alert for August 29, 2017 and September 1, 2017.

The assigned Administrative Law Judge issued a Ruling directing parties to respond to questions on the two percent reliability cap. The questions asked parties whether the Commission should allow the use of RDRR anytime within the Warning Stage or in other stages prior to the Warning Stage, such as Alert Notice and/or Restricted Maintenance Operations.

We first provide some clarity regarding the dispatch of RDRR by the CAISO. There are two distinct options for dispatching or triggering RDRR, once a Warning Notice is issued by the CAISO: 1) In-Market dispatch of RDRR; and 2) Out-of-Market dispatch of RDRR, also referred to as Exceptional Dispatch. The CAISO explains that for In-Market dispatch even after the CAISO calls a Warning Stage and the RDRR is made available for In-Market dispatch, the locational marginal price must reach the RDRR strike price before RDRR load is dropped, unless an exceptional dispatch is issued.[77] Referencing the 2010 Settlement, the CAISO observes that the "effect of the settlement agreement is that the CAISO dispatches RDRR very late in its emergency operating procedure process, only after exceptionally dispatching non-resource adequacy resources, despite the fact that RDRR are resource adequacy resources.[78] CAISO reminds parties that RDRR was not designed as a resource that adds liquidity and competitiveness to the market.[79] With this understanding, the CAISO supports allowing dispatch of RDRR anytime within the Warning Stage.[80]

In contrast, other parties contend that the Settlement already provides the flexibility for RDRR to be dispatched as needed within the Warning Stage. With respect to In-Market dispatch of RDRR, PG&E and SCE—both parties to the Settlement—consider dispatch flexibility currently available and highlight the existence of the flexibility in their tariffs.[81] For Out-of Market or exceptional dispatch of RDRR, CLECA (another party to the Settlement), also believes that the Settlement provides flexibility to use this mechanism for system reliability reasons any time within the Warning Stage.[82]

Cal Advocates (yet another party to the Settlement) maintain that preventing the use of RDRR before the CAISO considers using exceptional dispatch of non-resource adequacy resources within its own balancing authority

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[77] CAISO Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 2.

[78] *Ibid*.

[79] *Ibid*.

[80] *Id*. at 1.

[81] PG&E Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 22 and SCE Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 25.

[82] CLECA Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 6.

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is in direct contradiction to the Commission stated intention in D.10-06-034: to adopt a trigger that would protect ratepayers from paying twice for the same capacity.[83] Cal Advocates recommends the Commission adopt additional flexibility in the RDRR trigger by allowing its use anytime within the Warning Stage.[84]

We confirm, as most parties agree, the use of RDRR can occur anytime within the Warning Stage, in the case of In-Market dispatch and Out-Of-Market or exceptional dispatch.[85] This dispatch flexibility is consistent with the Settlement and D.10-06.034.

With respect to allowing RDRR to be triggered prior to the Warning Stage, most parties do not support this additional flexibility. PG&E states that it does not believe it appropriate to trigger RDRR after issuance of a Restricted Maintenance Notice because this is not indicative of an imminent reliability event. PG&E notes that from January 2016 through June 2018, the CAISO issued 30 Restricted Maintenance Notifications and only 1 Alert, Warning or Emergency notification.[86] SCE and CLECA express concern about the frequency and nature of the notifications; SCE notes there have been 109 Restricted Maintenance Notices since 2008.[87] However, PG&E and SCE are amenable to discussing the pros and cons of triggering RDRR after issuance of an Alert Notice. Given the

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[83] Cal Advocates Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 17.

[84] *Ibid.*

[85] PG&E Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 22; Cal Advocates Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 16-17; SDG&E Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 22; SCE Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 25.

[86] PG&E Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 23.

[87] SCE Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 26 and CLECA Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 12-13.

collective concern regarding the frequency of notices, we conclude that the Commission should not allow RDRR to be triggered prior to the Warning Stage at this time. We also agree with the consensus that the settlement agreement should not be disturbed, and the two percent reliability cap should remain unchanged.

3.3. SDG&E's Method for Determining the Price Trigger.

The Commission adopted SDG&E's method for determining the price trigger for the Capacity Bidding Program in Resolution E-4819. Therefore, as discussed below, this issue is resolved.

Pursuant to D.17-12-003, on January 22, 2018, SDG&E filed its proposal describing the method by which it determines the Capacity Bidding Program price triggers. In its filing, SDG&E attached a copy of its advice letter 2936-E proposing its Capacity Bidding Program price trigger method. SDG&E stated that Resolution E-4819, adopted by the Commission on May 26, 2017, approved Capacity Bidding Program price triggers for SDG&E. The Joint Demand Response Parties contend the January 22, 2018 filing does not explain how SDG&E's Capacity Bidding Program price trigger would function.

According to Resolution E-4819, the Utilities used the Opportunity Cost Method to establish the price triggers. The Opportunity Cost Analysis Method is defined as a way to identify a minimum price trigger that relies on targeting a pre-specified number of economic event hours within the respective program maximums, such that events would remain available for reliability purposes.[88] Because the detailed data is protected as confidential under Section 583 of the Public Utilities Code, the Commission's Energy Division could only summarize

[88] Resolution E-4819 at 5.

how the Utilities implemented the Opportunity Cost method. The Energy Division described SDG&E's implementation of the method as follows: "SDG&E implemented the method by using a Statistical Analysis System software. SDG&E imported the historical raw energy prices and ran several price trigger scenarios with the 15,000 heat rate. Based on the output, SDG&E selected a trigger that is expected to result in five or fewer economic events per month."[89] The Commission approved SDG&E's method for establishing the price triggers and the resulting price triggers in Resolution E-4819.

Additionally, Resolution E-4819 required SDG&E to submit a Tier 2 advice letter on December 1, 2017 that: 1) updates the price triggers using data from January 1, 2015 through December 31, 2017; 2) analyzes the two approaches used for situations where the five monthly events could be exceeded in 2017; and 3) recommends the most effective for approach for approval. SDG&E timely submitted the advice letter. In Resolution E-4918, the Commission adopted the use of the Opportunity Cost approach again and updated SDG&E's price trigger based on 2015-2016 price analyses models. Noting that D.17-12-003 found SDG&E's proposal of a Capacity Bidding Program trigger solely based on energy price to be reasonable, the Commission found it reasonable to eliminate the heat rate trigger for the Utilities.[90] We find SDG&E's January 20, 2018 filing to be compliant with D.17-12-003. Furthermore, because the Commission adopted SDG&E's approach to the Opportunity Cost Method to establish the price triggers in E-4819 and, again, in E-4918, the issue should be considered resolved.

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[89] *Id*. at 6.

[90] E-4918 at 8-9.

3.4. Auto Demand Response Control Incentive Policy Guidelines

Pursuant to D.17-12-003, on February 20, 2018, the Utilities filed a set of proposed guidelines to implement the Auto Demand Response technology incentive policy adopted in that decision. The policy requires the Utilities provide Auto Demand Response technology incentives to participants of any supply side demand response program or activity (*i.e.*, pilot) that is not required to be analyzed for cost-effectiveness. As explained below, we revise the name of this policy for clarity and refer to it as the Auto Demand Response Control Incentive Policy (Control Incentive Policy). We adopt several aspects of the Utilities' proposed guidelines and related policies, which together constitute a new document, Auto Demand Response Control Incentives Guidelines and Adopted Policies (Guidelines). Within 45 days from the issuance of this proceeding, the Utilities will submit a Tier One Advice Letter updating their proposed Auto Demand Response Guidelines (see Attachment 1) to comply with the policies adopted in this decision. We also establish a process for parties and other interested participants to work together with Energy Division to pursue further technical refinements to the Guidelines and to Auto Demand Response itself. One of the principles of the Commission's demand response resources is that demand response should evolve to meet the needs of the grid. Accordingly, the process is set up in a way that the Guidelines will be a living document that will evolve with the demand response programs.

In addition, we acknowledge the absence of clear guidance regarding the eligibility of battery storage for Auto Demand Response control incentives. Hence, we establish a stakeholder process to develop guidelines for the eligibility of battery storage for Auto Demand Response control incentives and related issues. Until the Commission adopts guidance on the policy issues described below, the Utilities shall not provide Auto Demand Response incentives for battery storage controls except in the case of incentive applications received before October 26, 2018.

3.4.1. Auto Demand Response Definitions and Policies

The Commission's Energy Division facilitated an April 20, 2018 telephone conference call and the assigned Administrative Law Judge facilitated a May 8, 2018 workshop to discuss and further refine the Utilities' proposed guidelines. During the workshop, parties discussed terminology and definitions and agreed to use the term "control" when referencing the device for which customers receive an incentive in Auto Demand Response. Parties developed the following definition of an auto demand response control:

> *The ability to receive an automated demand response signal to enable the customer to participate in a demand response event for current models of demand response without any manual customer intervention.*

In response to questions in the June 15, 2018 Ruling, parties generally agree with this definition, but some suggest refinements. PG&E recommends deleting the words, "current models of demand response," from the definition. ecobee requests the Commission to qualify the definition to specify that a signal is not required to be received by a customer's end-use device.[91] The Joint Demand Response Parties request that the definition acknowledge that many controls either allow or require the customer to acknowledge the signal before it begins equipment shutdown and that customers have override authority when a

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[91] ecobee Opening Comments July 20, 2018 at 11.

signal is received. Furthermore, OhmConnect requests that the phrase "automated demand response signal" be shortened to just "signal."

We agree with the elimination of the words, "current models of demand response" as this qualifier would rule out new models of load shifting demand response, which the Commission is currently exploring. We do not adopt OhmConnect's proposal to eliminate the words "automated demand response" as the entire purpose of the incentive is to allow a customer to participate in demand response without manual intervention. Hence the signal must be automated. We note that ecobee's request to qualify the definition to specify that a signal is not required to be received by a customer's end-use device is unwarranted as we are defining the control and not the end-use device. The Joint Demand Response Parties requested acknowledgements are reasonable and should be included as footnote disclaimers to the definition.

Accordingly, we adopt the following definition for an Automated Demand Response control and its associated disclaimer:

> *The ability to receive an automated demand response signal to enable the customer to participate in a demand response event without any manual customer intervention.**
>
> **We note and recognize that many controls either allow or require the customer to acknowledge the signal before it begins equipment shutdown and that customers have override authority when a signal is received.*

Because we adopt the term, control, to specify for what customers receive incentives, we now refer to the policy as the Auto Demand Response Control Incentive Policy (Control Incentive Policy).

During both the telephone and workshop discussions, parties agreed upon several aspects of the proposed guidelines for the Control Incentive Policy. Parties voiced no objection to the definitions, background, purpose of the guidelines or the guiding principles as filed by the Utilities in the

February 20, 2018 proposed guidelines. Hence, we should adopt these aspects and the Utilities shall include them in the updated Guidelines to be submitted via a Tier One advice letter within 45 days of the issuance of this decision. Parties also agreed that because the Base Interruptible Program is a reliability program and is subject to a cost-effectiveness analysis it is not applicable to the newly adopted Control Incentive Policy.[92] Furthermore, parties agreed that in adopting the Control Incentive Policy, the Commission did not establish a requirement that the Utilities must provide Auto Demand Response control incentives for supply side programs subject to cost-effectiveness analyses nor did the Commission prohibit the Utilities from providing these incentives for supply side programs subject to cost-effectiveness. These two policies should also be adopted and added to the Guidelines. We also confirm that RDRR resources bid in the CAISO market through the Auction Pilot should not be eligible to receive Auto Demand Response control incentives. These resources are reliability resources and, again, the Commission previously stated that reliability programs are rarely dispatched and should not be eligible for these incentives.[93] This policy should also be added to the Guidelines for clarity; we address its implementation further below.

In response to the June 15, 2018 Ruling, parties support the recommendation that the Utilities should track the incremental load reduction provided by Auto Demand Response controls and determine whether the load reduction fully covers additional cost of the control incentives allocated to demand response programs. Accordingly, we should include this requirement

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[92] D.16-06-029 at 46-47, and 50.

[93] D.16-09-029 at 47 and 50.

in the Guidelines. The incremental load reduction shall be reported annually in the Load Impact Protocols.

We take this opportunity to correct a statement in Section 6.5 of D.17-12-003 that erroneously indicated that Auto Demand Response offers incentives to offset the cost and installation of behind-the-meter distributed energy technologies such as energy efficient devices, energy storage, electric vehicle charging stations, and controls that interoperate using generally accepted industry open standards or protocols. That statement cited to D.12-04-045 at 144. The corrected statement should read: Auto Demand Response refers to automated technologies that allow a customer's equipment or facilities to reduce demand automatically in response to a demand response event or price signal, without the customer taking individual action. The correct citation is to D.12-04-045 at the beginning of section 7.7.1.

3.4.2. Control Incentive Policy Applicability

We now turn to a discussion of the programs to which the Control Incentive Policy is applicable. The Utilities developed a matrix of the programs to which they consider the Control Incentive Policy applicable. Only SCE and CESA disagree with the matrix.

SCE requests the Commission include its Customized Auto Demand Response program to the matrix. No party opposes this request and we find it reasonable to include in the matrix. The Utilities shall include an updated version of the Matrix in the revised Guidelines.

CESA states that the matrix should include resources external to the portfolio and that these resources should be considered eligible to receive the control incentives because they are supply side resources.[94] Cal Advocates supports CESA's recommendation "if the incentives fund components of the project that are additional or incremental."[95] However, Cal Advocates does not support providing control incentives to contracted resources that already include automation technology.[96] SDG&E and SCE express concern regarding visibility into future solicitations and the ability to be certain it is procuring the least-cost best-fit resource because of the uncertainty of what costs are included in the bid.[97] Taking a different approach, PG&E suggests the Commission address this on a case-by-case basis with a rigorous process developed by stakeholders.[98]

Earlier in this proceeding, the Commission adopted a five-year budget for demand response activities and programs. The budget includes estimated Auto Demand Response control incentives. We cannot anticipate the procurement of demand response resources external to the portfolio because the related requests for offers are required to be technology-neutral and may not result in the procurement of demand response resources. Therefore, we cannot estimate the impact of those unknown resources on budgets for future control incentives. Furthermore, we agree with SCE and find that the ability of demand response resource contracts external to the portfolio to receive control incentives should be a contract term that is negotiated between the seller and the utility. The value of that contract term can then be evaluated properly through the least-cost best-fit analysis, thus ensuring appropriate ratepayer funding. We conclude that

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[94] CESA Opening Comments to the June 15, 2018 Ruling, July 20, 2018 at 17.

[95] Cal Advocates Opening Comments to the June 15, 2018 Ruling, July 20, 2018 at 12.

[96] *Ibid*.

[97] SCE Opening Comments to the June 15, 2018 Ruling, July 20. 2018 at 20-21.

[98] PG&E Opening Comments to the June 15, 2018 Ruling, July 20. 2018 at 17.

contracts outside of the demand response portfolio should not be eligible for auto demand response control incentives from the demand response portfolio budgets; ratepayer funding for any such control incentives should be factored into the contract itself. Customers of the Auction Pilot, being a demand response pilot, are considered eligible to receive Auto Demand Response control incentives. Control incentive policies for a permanent auction mechanism will be considered and determined following the completion of the Auction Pilot evaluation. We should adopt the matrix as recommended by the Utilities in the proposed guidelines, with the addition of SCE's large commercial, industrial, and agricultural Customized Auto Demand Response program. The final matrix shall be included in the revised Guidelines to be provided by the Utilities via its Tier One Advice Letter.

In discussing applicability, the issue arose of whether Auto Demand Response should be considered a program that Community Choice Aggregators could file an application for Commission consideration of whether the community choice aggregator's program is "similar". In D.17-10-017, the Commission established steps to implement the Competitive Neutrality Cost Causation Principle, which allow Community Choice Aggregation or Direct Access electric service providers to create and administer demand response programs on a level playing field with the Utilities. The purpose of the adopted steps is to determine whether a community choice aggregator or direct access provider's proposed demand response program is similar to a utility's demand response program, which then relieves their customers from cost recovery obligations of the similar utility program. Parties responded to the June 15, 2018 Ruling question regarding whether a community choice aggregator or direct access electric service providers could apply to the Commission for consideration of its auto demand response as a similar program.

CESA contends that because Auto Demand Response is recovered under distribution rates, it should be eligible for applying for similar status. However, as noted by PG&E, the Commission previously determined that Auto Demand Response is not a program.[99] We look to D.17-10-017, Ordering Paragraph 2, which defines the four requirements for a "similar" program. One of the four requirements is that the program can be classified as and can be demonstrated to be the same resource, either a load modifying or supply resource, as defined by the Commission. Auto Demand Response is an incentive for customers to purchase a control so that the customer can participate in either a load modifying or supply demand response program without manual intervention. Therefore, Auto Demand Response is neither a load modifying nor a supply resource. Hence, Auto Demand Response is not eligible for "similar" status. This policy should also be added to the revised Guidelines.

3.4.3. Behavioral Demand Response versus Auto Demand Response

Parties responded to the question of whether the use of a behavioral approach would allow eligibility for control incentives. ecobee, PG&E, SDG&E, and SCE contend that the control should be automated so that the response is reliable; otherwise it would contradict the definition of auto demand response control.[100] Also in opposition of providing incentives for behavioral approaches,

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[99] PG&E Opening Comments on June 15, 2018 Ruling, July 20, 2018 at 14.

[100] ecobee Opening Comments on June 15, 2018 Ruling, July 20, 2018 at 14 and PG&E Opening Comments on June 15, 2018 Ruling, July 20, 2018 at 16; SDG&E Opening Comments on

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Cal Advocates adds that there are already ratepayer-funded incentives available for energy management technologies that do not require automation.[101] The Joint Demand Response Parties and OhmConnect Inc. offer different views. The Joint Demand Response Parties maintain that in addition to any Auto Demand Response signal, the use of supplemental communications such as text or email should have no effect on eligibility for control incentives.[102] OhmConnect suggests that devices such as smart plugs be eligible for control incentives despite not being Open Auto Demand Response compliant.[103]

Auto Demand Response was created to encourage customers to participate in demand response programs with no manual interaction. Hence, a customer who does not plan to use the control to receive automated signals from the qualifying program in which they are enrolling is not eligible for an Auto Demand Response control incentive. We clarify that receiving a text or email communication *in addition to an automatic signal*, does not disqualify a customer from Auto Demand Response control incentives. As the purpose of the program is to eliminate manual interaction, only the cost of the control itself should qualify for the incentive, not the behavioral communication method. Lastly, we deny the request by OhmConnect to provide incentives for devices that are

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June 15, 2018 Ruling, July 20, 2018 at 16; and SCE Opening Comments on June 15, 2018 Ruling, July 20, 2018 at 20.

[101] Cal Advocates Opening Comments on June 15, 2018 Ruling, July 20, 2018 at 11, citing Assembly Bill (AB) 793 and Resolution E-4820 approving the Utilities advice letters to comply with AB 793.

[102] Joint Demand Response Parties Opening Comments on June 15, 2018 Ruling, July 20, 2018 at 12.

[103] OhmConnect Opening Comments on June 15, 2018 Ruling, July 20, 2018 at 14-15.

Footnote continued on next page

unable to receive an auto demand response signal. First, that defeats the purpose of the program: no manual intervention. Second, OhmConnect maintains extending incentives will help overcome barriers to adopting such devices including low awareness, a perceived lack of need, and discomfort with using smart plugs.[104] Overcoming these barriers is not the purpose of Auto Demand Response. Furthermore, as pointed out by Cal Advocates, there are alternative incentive opportunities available for these devices. These policies should be included in the revised Guidelines.

3.4.4. Auto Demand Response Control Eligibility Criteria

During the May 8, 2018 workshop, parties discussed the criteria for controls eligible for auto demand response incentives in terms of residential, commercial & industrial, and small & medium business customer classes. Parties agreed on one requirement for controls in all three classes of customers: the control must be able to receive an Open Auto Demand Response-compliant Auto Demand Response signal. Additionally, for commercial and industrial customers, the customer must be able to provide the anticipated kilowatt load reduction expected from end uses equipped with the control, as that is what determines the calculated incentive for that class of customers. In the case of the small & medium business customer class (and residential class customers obtaining an incentive to purchase a thermostat), the criteria depend upon the type of Auto Demand Response incentive, *i.e.,* it may be a deemed incentive based on an average kilowatt load reduction for the controlled end use and customer class (*e.g.* a thermostat for a residential air conditioner) or a fixed amount derived in another manner.

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[104] OhmConnect Opening Comments on June 15, 2018 Ruling, July 20, 2018 at 15.

After review of the responses and reply comments to the June 15, 2018 Ruling, we revise these criteria as follows:

- For residential, small and medium business customers, the control must be able to communicate and demonstrate operability using the current Open Auto Demand Response communication protocols and standards (currently OpenADR 2.0a or 2.0b) . The control may be located either on site or (as part of a control system) on site and at the manufacturer/demand response aggregator or provider cloud level. Only the customer is eligible for the Auto Demand Response control incentive, not the aggregator, demand response provider or manufacturer cloud portion of the control.
- In the case of the small & medium business customer class and associated end uses, residential customers receiving incentives for thermostats, and customers enrolled in SDG&E's Technology Deployment Program: the criteria depend upon the type of Auto Demand Response in which the customer is enrolled, such as a deemed incentive based on the average kilowatt load drop for the control in that sector.
- For commercial and industrial customers applying for calculated incentives, the control must be onsite and able to communicate and demonstrate operability using the current Open Auto Demand Response communication protocols and standards (currently OpenADR 2.0a or 2.0b). The Utility must also be able to verify 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

Party responses to the June 15, 2018 Ruling support the above revisions to the residential and small business criteria.[105] We find the revisions reasonable as they are also compliant with the California Energy Commission's Title 24 requirements.[106] With respect to the commercial and industrial customer classes, all three Utilities support the criteria from the workshop, but note the deemed incentive is based on engineering calculations to develop the estimated kilowatt of load reduction.[107] These criteria should be included in the revised Guidelines.

3.4.5. Future Revisions to the Guidelines

While we adopt the above revised criteria and include the criteria in the Guidelines, we do so while acknowledging the probability of future changes and the need to review the existing approach to incentive calculation. The record indicates variation in how each utility administers its calculated and deemed incentives.[108] Furthermore, PG&E questions whether the existing incentive calculation method of dollars per kilowatt based on load reduction potential is appropriate and suggests a review.[109] During the workshop, PG&E highlighted several factors the Commission should consider when adopting an incentive calculation approach: the incentive calculation method was developed more

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[105] ecobee Opening Comments on June 15, 2018 Ruling, July 20, 2018 at 11-12; PG&E Opening Comments on June 15, 2018 Ruling, July 20, 2018 at 12; Joint Demand Response Parties Opening Comments on June 15, 2018 Ruling, July 20, 2018 at 10; Nest Opening Comments on June 15, 2018 Ruling, July 20, 2018 at 9; and SDG&E Opening Comments on June 15, 2018 Ruling, July 20, 2018 at 11-12.

[106] PG&E Opening Comments on June 15, 2018 Ruling, July 20, 2018 at 12.

[107] PG&E Opening Comments on June 15, 2018 Ruling, July 20, 2018 at 12;

[108] PG&E Opening Comments on June 15, 2018 Ruling, July 20, 2018 at 12-13; SCE Opening Comments on June 15, 2018 Ruling, July 20, 2018 at 16-17; and SDG&E Opening Comments on June 15, 2018 Ruling, July 20, 2018 at 11-12.

[109] PG&E Opening Comments on June 15, 2018 Ruling, July 20, 2018 at 18.

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than ten years ago, the auto demand response market has changed "significantly" during that time, auto demand response control incentives were originally developed for large commercial customers, and auto demand response control incentives are increasingly marketed to other customer classes.[110] We find it reasonable for parties to begin to review the existing approach and develop a consistent approach that takes into account the factors described by PG&E.

In addition to the need to review the approach to calculating incentives for auto demand response controls, there are three aspects of the proposed guidelines where the record is incomplete and requires additional stakeholder input: 1) Ineligibility of RDRR; 2) frequency of incentives; and 3) calculating cost-effectiveness of incentives. We briefly describe these additional issues below.

- Ineligibility of RDRR: We have previously determined that RDRR resources bid in the CAISO market through the Auction Pilot are not eligible to receive Auto Demand Response control incentives. As noted by the Utilities, an approach must be developed to implement this policy.
- Frequency of incentives: Parties were asked how often control incentives should be available to customers; the responses vary across parties and range from three years in consideration of the ever-changing Title 24 standards,[111] to 7.5 years based on equipment amortization,[112] to 11 years

[110] *Id*. at Footnote No. 6.

[111] Joint Demand Response Parties Opening Comments on June 15, 2018 Ruling, July 20, 2018 at 12.

[112] PG&E Opening Comments on June 15, 2018 Ruling, July 20, 2018 at 16.

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based upon its useful life.[113] Parties suggest this issue be discussed and proposals be developed, which appropriately take into consideration the pace of evolution in the industry.

- Calculating incentives cost-effectiveness: During the May 8, 2018 workshop, participants discussed the Utilities approach to calculating the Auto Demand Response control incentive amounts applied to each program required for cost-effectiveness. In response to the June 15, 2018 Ruling, parties agreed that the approach should be consistent but there is no consensus at this time nor is there evidence to choose one of the three utility approaches over the others.

These four Auto Demand Response issues are complex and technical in nature and are more appropriately addressed by technical experts in a working group or workshop setting. Given the evolving nature of demand response and the associated technologies involved with Auto Demand Response, we anticipate the need to address additional issues in the future. Hence, it is more appropriate to address these technical and evolving issues on an ongoing basis rather than every three to five years in an application process. We conclude the Commission should adopt a stakeholder approach similar to that of the SGIP proceeding, another technically-focused program.

On an annual basis, the Utilities and Energy Division, seeking input from all stakeholders, will identify a set of issues to resolve (beginning with the set of four issues we establish herein for 2019.) With Energy Division input, the Utilities shall develop proposals to address the issues and serve the proposals on stakeholders by May 1 of each year starting with 2019. A proposal must rely

[113] SCE Opening Comments on June 15, 2018 Ruling, July 20, 2018 at 20. Also see SDG&E Opening Comments on June 15, 2018 Ruling, July 20, 2018 at 16 recommending 5-10 years based on the type of incentive.

upon current budget authorizations for implementation; otherwise the proposal is not appropriate for this process. The Utilities shall hold workshops and/or webinars, noticed to the most current demand response service list, to discuss the proposals. Based upon the discussions at the workshops, the Utilities shall serve, no later than August 15 each year, draft updated Guidelines incorporating the proposals to address the set of issues for that year. All stakeholders may provide informal comments to the service list on the draft guidelines; the Director of the Energy Division is authorized to establish a deadline to submit the comments. No later than September 1 of each year, the Utilities shall submit a Tier Two advice letter incorporating the proposals into the Guidelines and including all party comments in the advice letter. We anticipate this approach should be able to address the evolving needs of auto demand response while comporting with Commission policy directing the Utilities to align Auto Demand Response program rules and incentive levels.[114]

In comments to the proposed decision, PG&E pointed to the multi-party settlement approved in D.17-12-003, which provided for a collaborative stakeholder process to a) develop a list of residential Auto Demand Response enabled end-use devices to be considered for eligibility for an Auto Demand Response incentive and b) develop criteria to determine the order to evaluate load impacts attributable to the devices.[115] The annual Auto Demand Response process adopted in this decision replaces the stakeholder process adopted in D.17-12-003. Development of a list of residential Auto Demand Response enabled end-use devices to be considered for eligibility for an Auto Demand Response

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[114] D.12-04-045 at 143.

[115] PG&E Opening Comments to Proposed Decision, November 14, 2018 at 5-6. See D.17-12-003 at Section 4.1.5.

incentive from PG&E only and b) development of criteria to determine the order for PG&E to evaluate load impacts attributable to the devices are added to the list of issues to be discussed in 2019. To be clear, these two issues are only applicable to PG&E, as SDG&E and SCE were not parties to the approved settlement.[116]

3.4.6. Battery Storage and Auto Demand Response

In addition to the issues discussed during the phone conference and workshop, the Commission's Energy Division has concerns related to battery storage, not previously addressed in the Demand Response proceeding. The June 15, 2018 Ruling asked parties several questions regarding battery storage and Auto Demand Response. The questions addressed the specific issues of 1) incremental value of battery storage with Auto Demand Response controls participating in demand response programs relative to the incremental cost of those controls; 2) whether battery storage controls that include Auto Demand Response capabilities are eligible for incentives; 3) appropriate incentive levels; and 4) protecting ratepayer funding by preventing the same equipment from receiving more than one incentive.

The relationship of battery storage to Auto Demand Response is an emerging issue that was not initially contemplated by the Commission in this proceeding. Battery storage technology was not present in the marketplace at the time Auto Demand Response was established. In addition, battery storage was not discussed in the context of the $200/kW calculated incentive design the Commission approved in D.16-06-029. The Commission originally established Auto Demand Response to enable automated load reduction by building and

[116] D.17-12-003 at 14.

industrial end uses such as heating, ventilation and air conditioning systems, lighting, and industrial processes. It is not clear, at this time, if the scope of Auto Demand Response should be expanded to include controls for battery storage. We reiterate that Auto Demand Response refers to automated technologies that allow a customer's equipment or facilities to reduce demand automatically in response to a demand response event or price signal, without the customer taking individual action.[117]

However, battery storage is currently eligible for Auto Demand Response incentives in PG&E territory. For example, PG&E states that for non-residential customers, controls for battery storage is on the list of controls eligible for incentives in Auto Demand Response at PG&E. PG&E clarifies that in its service territory, battery storage controls, including hardware/software costs, are eligible for control incentives. PG&E explains that this is comparable to the hardware/software costs for Heating Ventilation and Air Conditioning, as well as lighting.[118] With respect to residential customers, PG&E has established a collaborative process with stakeholders to determine "if an Auto Demand Response control for a battery will be eligible for Auto Demand Response incentives in the future."

While we recognize that the time is ripe for establishing policies for battery storage in Auto Demand Response, the record is limited and not sufficient to approve policy guidelines for battery storage at this time. Accordingly, it is reasonable to authorize the Energy Division to work with the Utilities to expand the PG&E stakeholder process described above to develop an overall strategy

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[117] D.12-04-045 at 138.

[118] PG&E Opening Comments on June 15, 2018 Ruling, July 20, 2018 at 20.

proposal for battery storage. All Utilities shall participate in this stakeholder process and the members of the service list shall be invited to participate as well. The stakeholder process should address the following issues and develop a consensus proposal:

1) Should the Commission allow PG&E to continue to offer control incentives to non-residential customers for battery storage controls?
2) Should the Commission require SCE and SDG&E to offer this incentive?
3) Should the Commission allow residential customers to receive an incentive for battery storage controls?
4) Should the Commission limit the incentives to hardware and software costs as currently offered by PG&E?
5) Should the Commission adopt the same incentive structure developed in the annual Guidelines Update process or should the Commission adopt a separate incentive structure for battery storage controls, as recommended by Cal Advocates?
6) If the Commission adopts a separate incentive structure for battery storage controls, what should that structure entail?
7) What precautions should the Commission adopt to ensure ratepayers are not paying more than one incentive for the same control?

We recognize that stakeholders may not reach consensus on all seven issues. In order to ensure a complete record, the Utilities shall file an Auto Demand Response Battery Storage Stakeholder Report that includes consensus proposals, where appropriate, and alternate proposals where consensus has not been reached. The report should include technical details that explain all aspects of the report.

While SCE suggests using the mid-cycle application to adjust the budget accordingly to incentive proposals, these seven issues are policy issues that must be addressed within the formal proceeding. Hence, we authorize the Director of the Energy Division to hold the first stakeholder meeting no later than January 31, 2019. Stakeholders should immediately begin developing proposals for the seven issues to be discussed at the first meeting. An update on the status of the proposal shall be filed by the Utilities, no later than March 7, 2019. Unless otherwise directed by the assigned Administrative Law Judge, a final report recommending solutions to the seven issues shall be filed by the Utilities in this proceeding no later than April 15, 2019. If a consensus cannot be reached on each of the seven issues, the filed report should include descriptions of all proposals for each issue. Comments to the final report are due no later than May 1, 2019; replies shall be filed on May 10, 2019. Given the technical complexity of battery storage issues, the assigned Administrative Law Judge is authorized to extend the deadline for the final report through a Ruling, if deemed reasonable.

3.5. Pilots Targeting Demand Response in Disadvantaged Communities

Overall parties give broad support for the environmental and/or economic goals stated in the Proposal, but question the potential impact of local action in a disadvantaged community on the operations of nearby power plants. Parties in general support the testing of marketing and outreach efforts to increase enrollment and participation in disadvantaged communities, while learning more about the target population and the residents' ability to respond to demand response events.

The Proposal provides guidelines for the Utilities to follow while developing pilots as directed and funded by D.17-12-003. As such, we find the guidelines provided by the Proposal reasonable and consistent with past

Commission decisions, D.12-04-045 and D.16-09-056. Based on party comments, additional clarifications and guidance are provided in Section 3.5.2 and Section 3.5.3.

3.5.1. Definition of Disadvantaged Communities

The Proposal defines disadvantaged communities as "census tracts that score above 75th percentile using the CalEnviroScreen tool created by the California Environmental Protection Agency…plus an additional 22 census tracts that score in the highest five percent of CalEnviroScreen's pollution burden but do not have an overall CalEnviroScreen score because of unreliable socioeconomic or health data."[119]

No party objects to using the disadvantaged communities definition stated above, but some parties note the implementation challenges associated with using the proposed definition. For example, SCE notes that SCE identifies customers by zip code and disadvantaged communities are typically identified by more granular census tract, therefore it may be difficult to ensure that targeted customers are indeed located in disadvantaged communities.[120] That is, one zip code may cover communities identified as disadvantaged communities and others as well.

Based on the party comments, we find the proposed definition of disadvantaged communities reasonable and adopt it. The proposed definition is consistent with the definition adopted in the Integrated Resource Planning proceeding and will help with coordination between proceedings with respect to data analysis and recommendations.

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[119] Proposal at 3.

[120] SCE Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 4.

We also acknowledge that there may be implementation challenges associated with using the adopted definition. However, a pilot will provide the Utilities the opportunity to better identify those challenges and test innovative ideas to overcome those challenges.

3.5.2. Requirements for Pilots

In D.12-04-045, the Commission adopted the elements of pilot plans that all pilots requested in demand response applications should include.[121] Based on those elements, the Proposal listed the following criteria the Pilot Plans should include:[122]

- Consistency with the proposed purpose and goals for the pilot by specifying how the pilot is expected to contribute to policy recommendations and likelihood that the tested approach will lead to cost-effective programs designs;
- Method for identifying the community selected for the pilot;
- Test objectives that include a description of program design, outreach and deployment methods that have not been employed, and metrics to assess the success of the test objective;
- Budget and timeframe; and,
- Evaluation, measurement and verification plan.

While most parties agree that the proposed requirements are reasonable, appropriate and adequate for the purposes of the pilot, Cal Advocates recommends strengthening the pilot plan requirements to provide clear guidance to the Utilities and notes that the pilots should not duplicate similar efforts.

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121 D.12-04-045 at 182-183.

122 Proposal at 5-6.

We find that the requirements listed in the Proposal comport with the pilot plan requirements set forth in D.12-04-045, and therefore we adopt them. We also strengthen the proposed requirements by providing clarifications in the relevant sections below.

Regarding the data requirements for pilots, ecobee suggests that the Commission require the utilities to include the following data in their pilot proposal: certain demographic data, the proportion of customers with broadband connectivity, and the approximate percentage of residents who qualify as seniors, and other data.[123] We acknowledge the importance of availability of such demographic data. However, given the size of the pilot budget, we will not require the Utilities to include the data specified by ecobee in the pilot plans. Depending on the design of the pilot, and the availability of the data within the allocated budget, the Utilities are highly encouraged to include relevant quantitative data in their pilot proposals.

3.5.2.1. Purpose and Goal

The Proposal identifies the purpose of the pilots as enhancing the economic and/or environmental benefits that demand response program investments provide to disadvantaged communities.[124] According to the Proposal, the goal of the pilots is to improve existing demand response programs or develop new programs through policy recommendations that derive from the pilots to advance the purpose of the pilots.[125] Furthermore, the Proposal

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[123] ecobee Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 8 and 9.

[124] Proposal at 6.

[125] Proposal at 6.

Footnote continued on next page

envisions that advancing this purpose and goal can assist with 1) displacing gas plants in local capacity areas;[126] 2) reducing localized pollution from gas plant dispatch and cycling expected to increase with higher penetrations of renewables;[127] and, 3) providing economic benefits in disadvantaged communities through participation incentives and incentives for technologies. [128] Because this is a pilot program, the Proposal does not require the pilots themselves to demonstrate measurable environmental or economic impacts – but to identify actionable policy recommendations to advance these goals.[129] The Proposal also does not expect pilots to yield significant quantifiable emission reductions in and of themselves but to inform the development of actions that can be broadly implemented to yield such benefits.[130] Towards that end, the Proposal recommends that evaluation plans include a metric for assessing the range of pollution reduction potential if the tested design can be successfully implemented.[131]

Most parties agree with the overall purpose and goal of the pilots, seeking clarifications and noting challenges with different aspects of the proposed goal and purpose. For example, PG&E recommends that the Commission should better understand the relationship between energy consumption within a disadvantaged community or aggregation of disadvantaged communities and dispatch of nearby fossil fueled generation facilities. PG&E is not convinced that

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126 Proposal at 8-10.

127 Proposal at 11-12.

128 Proposal at 12.

129 Proposal at 8.

130 Proposal at 17.

131 Proposal at 17.

load reductions within a disadvantaged community or aggregation of disadvantaged communities will materially impact dispatch of generation facilities in or near disadvantaged communities and provides the following example: PG&E's Huron substation observed peak load in 2017 was approximately 7.5 MW. Load reductions from demand response of five percent would be 375 kilowatts, which PG&E considers to be insufficient to impact the dispatch of generation units in or near the city of Huron. On the other hand, PG&E informs that the peak load in the greater Fresno local capacity area, which includes the city of Huron, is 3,250 MW. Therefore, a five percent reduction in peak load would be 165 MW, which PG&E considers to be significant enough to impact the dispatch of nearby generation facilities.[132] Therefore, PG&E considers a local capacity area as the best choice for a pilot as load within a local capacity area is sufficiently large and program impacts can influence dispatch of generation units on the margin.[133]

Focusing on the economic benefits of the pilots, Cal Advocates recommends that the pilots should only provide incentive to residential and small commercial customers residing within the geographic footprint of a disadvantaged community to ensure that any economic benefits accrue to the appropriate customers.

D.16-09-056 adopted the following goal for all demand response programs: "Commission-regulated demand response programs shall assist the State in meeting its environmental objectives, cost-effectively meet the needs of the grid, and enable customers to meet their energy needs at a reduced cost."[134] We find

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[132] PG&E Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 5.

[133] PG&E Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 1-2.

[134] D.16-09-056 at 46.

that the overall purpose and goal identified by the Proposal is reasonable and comports with the goal adopted by D.16-09-056. However, because of the need to better understand the relationship between energy consumption in disadvantaged communities and the operations of local generation units and the limited size of the authorized budget for the pilots, the pilots should primarily focus on providing direct economic benefits to residential and small commercial customers residing or doing business within disadvantaged communities situated in local capacity areas.

In addition, even though it is not a requirement of the pilots, we highly encourage the Utilities to consider supply-side programs in their pilot plans. Ultimately, all demand response programs will follow the principle established by D.16-09-056:

> Demand response shall be market driven leading to a competitive, technology neutral, open market in California with a preference for services provided by third parties through performance based contracts at competitively determined prices, and dispatched pursuant to wholesale or distribution market instructions, superseded only for emergency grid conditions.[135]

Finally, we strongly encourage the Utilities to develop new, innovative or significantly improved program designs. In its comments, Nest encourages the Commission to maximize the value of ratepayer funds by leveraging proven existing programs honed for deployment in disadvantaged communities to drive demand response at scale in those communities.[136] We strongly disagree. As the

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[135] D.16-09-056 at 46.

[136] Nest Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 3-4.

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Commission determined in D.12-04-045, the purpose of a pilot is to test a new concept or program design that is intended to address a specific area of concern.[137] Therefore, proven existing programs do not qualify as a pilot.

3.5.2.2. Location

The Proposal states that focusing on local capacity areas with high proportions of disadvantaged communities within or near them means that pilots will provide economic participation benefits as well as help with reliability planning. Therefore, it proposes adopting the method and initial set of locations within each Utility territory proposed by Olivine as starting point for selecting pilot locations.[138] This method identifies communities or cities with disadvantaged communities that are within 20-30 miles of a gas peaker plant and also in a local capacity area.

No party objects to the proposed method to determine an initial set of locations. Parties appreciate the flexibility in choosing pilot locations and note again challenges associated with targeting disadvantaged communities. For example, SCE has no concerns with the proposal to focus on the communities identified by Olivine or others within SCE's service territory, but SCE states its intent to take advantage of efficiencies while selecting the most appropriate community for a particular pilot.[139] Similarly, SDG&E agrees with Olivine's approach, but appreciates the flexibility, should SDG&E choose to select another community other than one identified by Olivine. [140]

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[137] D.12-04-045 at 181-182.

[138] Proposal at 16.

[139] SCE Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 5.

[140] SDG&E Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 5.

The Joint Demand Response Parties also agree with the approach but notes resources must be bid at the sub-LAP scale. Therefore, according to the Joint Demand Response Parties, disadvantaged communities must be mapped both to the local capacity area and sub-LAP for purposes of accurately bidding resources into the wholesale market. The Joint Demand Response Parties seek guidance on how these resources will be solicited and the physical specifications of the areas and mapping customers to those areas.[141]

We acknowledge the challenges associated with the proposed approach. Therefore, we find the proposed locations included in the Proposal as a reasonable starting point and encourage all utilities to take advantage of efficiencies while selecting the most appropriate community for their pilot, with the goal of reducing implementation costs and increasing participation rates.

3.5.2.3. Test Objectives

The Proposal recommends that the pilot plans specify test objectives that: 1) maximize the purpose of the pilots; 2) are achievable; and 3) will yield useful data within the budgets provided. As examples, the Proposal lists the following test objectives:[142]

- New or improved marketing to cost-effectively increase enrollment, participation, retention;
- Operational modifications such as testing varying temperature set-points, cycling algorithms direct-controlled AC cycling programs to optimize load impacts and cost-effectiveness;
- More frequent economic dispatch – such as high renewable energy production periods; and

[141] Joint Demand Response Parties Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 2.

[142] Proposal at 17.

- Deployment of automated energy management technologies in disadvantaged communities to increase the value of demand response for providing local or flexible capacity.

No party opposes the proposed test objectives and several parties recommend test objectives. For example, PG&E proposes testing: 1) the ability of the Utilities and third-party demand response providers to develop programs that can effectively respond to a continuously streaming signal indicating air emissions intensity in a local capacity area; and 2) customer receptiveness to new demand response types of programs that are automated and have short duration events.[143]

Similarly, SCE proposes three actions for its pilots: 1) studying the barriers that may exist for adoption of demand response by customers in disadvantaged communities through a comprehensive market study; 2) launching a limited fuel substitution pilot that replaces heat pump water heaters powered by fossil fuels with electric water heaters; and 3) reviewing and evaluating existing demand response program event triggers to see if modifications can be made to align and mitigate peaker plant dispatch. [144] SDG&E recommends that the pilot focus on customer participation and not any tangible savings target, and proposes targeting demand response efforts in disadvantaged communities in coordination with SDG&E's low income and energy efficiency programs in order

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[143] PG&E Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 5-6.

[144] SCE Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 6-7.

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to reduce overall usage in the coastal areas where disadvantaged communities are located in SDG&E's territory.[145]

Among non-utility parties, while OhmConnect recommends testing increasing enrollment and participation of residential customers from disadvantaged communities in the third-party programs,[146] ecobee proposes testing different event messaging and notification strategies to evaluate and compare event performance. Olivine recommends testing objectives focusing on learning about how to best reach and engage with the members of disadvantaged communities, *e.g.* marketing approaches, cost benefits of deploying automated or energy management technologies.

Even though these proposed test objectives are not detailed enough for us to evaluate them, we are encouraged that the parties have numerous ideas to target demand response in disadvantaged communities.

Based on the party comments, we find the range of test objectives provided as examples in the Proposal reasonable. We are also interested in the following testing objectives for the pilots:

- Testing innovative marketing and outreach strategies to increase enrollment, participation and retention in disadvantaged communities;
- Testing operational modifications to signals (type, frequency, duration); and
- Allowing for technology neutral pilots, e.g. a fuel substitution pilot that replaces heat pump water heaters powered by fossil fuels with responsive electric water heaters.

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145 SDG&E Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 6.

146 OhmConnect Opening Comments to June 15, 2018 Ruling, July 20, 2018 at 6.

Designing pilot programs achieving these objectives will lead to economic benefits and help the Commission and the parties learn more about customers in disadvantaged communities and their needs.

With respect to the role of the third party providers in the pilot projects, we note that it is the Commission's policy to enhance third party-provided demand response. However, the goal of the pilots should not be to compare third-party and utility performances, but to test the pilot design objectives. Therefore, the Utilities are encouraged to use third-party providers for innovative marketing and outreach efforts, and possibly other test elements. However, they should not use the comparison of utility versus third party performance as a testing objective. If the Utilities choose a third party for their pilots, they must justify their choice of third party, or utility; and explain how the third parties would gain the necessary data for the pilot program.

Finally, SDG&E seeks recognition of their unique territory and requests flexibility in the design of their pilots. We encourage SDG&E to focus on removing barriers to participation, and economic benefits in a focused area of their service territory to maximize impact of the authorized budget; we also highly encourage using third-party innovators in SDG&E's territory.

3.5.2.4. Budget and EM&V

D.17-12-003 authorized $2.5 million for the Pilot Programs ($1 million for PG&E and SCE each, and $.5 for SDG&E) with ten percent set aside for evaluation. Given the size of the funding, the Utilities should coordinate as much as possible with other parties and each other to maximize the information to be gathered and lessons to be learned. Towards that end, proposals should leverage opportunities to expand or build on forthcoming pilots or other funded research.

SCE notes that Commission policy exempts pilots from meeting the cost-effectiveness threshold and interprets requirement of "methodologies to assess or model the potential cost effectiveness of the tested approach" as pertaining to measuring the cost-effectiveness of any program based on the pilot, not the pilot itself. SCE also notes that the requirement to identify a test and control may not be appropriate for all pilot designs. Given the limited size of the budget, the Commission does not require the pilot designs to include a test and control group. However, we encourage the Utilities to collaborate and coordinate with other utilities and parties to the extent possible in order to maximize the use of the authorized budget, which could enable them to identify a test and control group at a reduced scale.

3.5.3. Regulatory Process

PG&E seeks guidance on the regulatory process for submittal and approval of pilot proposals targeting demand response in disadvantaged communities.[147] Cal Advocates recommends the use of a Tier Two Advice Letter process, so that parties have an opportunity to review the pilot proposals. We find Cal Advocates' recommendation reasonable. Given the guidelines adopted

[147] PG&E Reply Comments to June 15, 2018 Ruling, August 3, 2018 at 2.

in this Decision, an advice letter process is appropriate for the review of pilot plans.

We direct each utility to submit a Tier Two Advice Letter that includes a Pilot Plan as described below for pilots no later than four months before the start of the pilot or 60 days after the issuance of this decision, whichever is earlier. Pilot Plans must comply with the requirements listed in the Proposal and adopted in this Decision. The Utilities shall include the following in their Pilot Plan to be submitted with their Advice Letter:

1. Target location (which disadvantaged communities in a local capacity area).
2. Strategy to target residential and small commercial customers in disadvantaged communities.
3. The amount and form of economic benefit for the participating customer, and third party, including the amount of capacity payments and how they would be allocated.[148]
4. If and how the proposed pilot will be bid into the CAISO market, *e.g.* as part of an existing program if it is not large enough to meet the CAISO requirements for aggregation size by sub-LAP.
5. Theory of the pilot intervention, *e.g.*, a logic model, and how it would meet the purpose and goal adopted in this Decision.
6. How the Utilities are coordinating with the Disadvantaged Communities Advisory Group.
7. If and how the Utilities are coordinating with each other in their proposed ideas and building off past and current pilots.
8. How to track cost-effectiveness for the purpose of informing future programs.

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148 Calculation of economic benefit for the participating customer should make explicit equity considerations that would reflect the relative value of capacity in a constrained area, and the relative difficulty of providing it in hot climate zones.

9. Justification for choice of a third-party or the Utility; and explanation for how the third parties would gain the necessary data for the pilots.
10. Customer protection measures that will be taken.

4. Auction Pilot

The evaluation of the Auction Pilot will be completed at the end of 2018. During the first quarter of 2019, stakeholders shall work with the Energy Division to develop a proposal for improvements to the auction mechanism based upon the evaluation results. The Commission will then consider whether to continue the auction mechanism as a permanent fixture of the demand response portfolio with the proposed improvements. Until that time, it is not reasonable to spend additional ratepayer dollars on the Auction Pilot, especially when the results will not contribute to the final evaluation. Accordingly, we decline to authorize funding for an additional auction solicitation for demand response at this time.

4.1. History of the Auction Pilot

D.14-12-024 adopted terms and conditions, with modifications, of a Joint Proposal.[149] Relevant to this Decision, the Joint Proposal recommended that the Commission proceed with a two-year pilot of a proposed demand response auction mechanism (Auction Pilot) with funding from the 2015-2016 bridge

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[149] D.15-02-007 modified D.14-12-024 by renaming the "Settlement Agreement: adopted in D.14-12-024 and instead calling it the "Joint Proposal." The signatories to the Settlement Agreement aka the Joint Proposal include Alliance for Retail Energy Markets, The California Independent System Operator (CAISO), California Large Energy Consumers Association (CLECA), Clean Coalition, Comverge, Inc., Consumer Federation of California, Direct Access Customer Coalition (DACC), EnergyHub/Alarm.com, EnerNOC, Inc., Environmental Defense Fund, Johnson Controls, Inc., Marin Clean Energy, Office of Ratepayer Advocates (ORA) (now known as the Public Advocates Office of the California Public Utilities Commission (Cal Advocates)), Olivine, Inc., PG&E, SDG&E, Sierra Club, SCE, and TURN.

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funding. The purpose of the Auction Pilot is to test: 1) the feasibility of procuring supply resources for resource adequacy with third-party direction participation in the CAISO market through an auction mechanism; and 2) the ability of winning bidders to integrate their provision of demand response into the CAISO market.[150] D.14-12-024 required that the Auction Pilot design, set-aside requirements, protocols, standard pro forma contracts, evaluation criteria and non-binding cost estimates be submitted as a Tier Three advice letter, no later than April 1, 2015. The Commission authorized budgets of $9 million for the 2015 auction, as approved in Resolution E-4728 and $13.5 million for the 2016 auction, as approved in Resolution E-4754.

Auctions were held in the Spring of 2015 and 2016, with load deliveries scheduled during 2016 and 2017. D.16-06-029 recognized that the Commission required a full evaluation of the Auction Pilot before it could determine whether to adopt the Auction Pilot as a permanent demand response procurement mechanism. Hence, D.16-06-029 authorized an additional pilot auction with a budget of $27 million and the Utilities held an auction in the Spring of 2017 with deliveries scheduled over a two-year period in 2018 and 2019.[151]

D.16-09-056 reiterated its concern regarding a full evaluation of the Auction Pilot and authorized the Commission's Energy Division to conduct an evaluation with a draft resolution, presenting a final analysis and recommendation issued by the Energy Division no later than June 1, 2018.[152]

Determining that business opportunities for demand response could be limited under the previously approved $27 million budget for the 2017 Auction

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[150] See D.14-12-024 at 12 and D.16-06-029 at 42.

[151] D.16-06-024 at Ordering Paragraph No. 19.

[152] D.16-09-056 at Ordering Paragraph No. 10.

Pilot solicitation, D.17-04-045 directed responses to questions regarding whether the Commission should approve an additional auction in 2018 for 2019 deliveries. In response, D.17-10-017 approved a 2018 auction for 2019 deliveries for the Auction Pilot. The Commission authorized PG&E and SCE a budget of $6 million each and SDG&E a budget of $1.5 million. This brought the total budget of the Auction Pilot to $63 million.

The Amended Scoping Memo, adding the evaluation of the Pilot to this proceeding, explained that preliminary results of the evaluation are mixed and, in some cases, inconclusive. While D.16-09-056 set a date of June 2018 for the Energy Division to present the results of the evaluation and its recommendations for the Auction Pilot, according to Energy Division staff, the preliminary results indicate the need for additional time to complete the evaluation. Staff anticipates a final evaluation and report by the end of 2018.

An August 6, 2018 Ruling asked parties whether the Commission should approve another year of the Auction Pilot and, if so, whether the Auction Pilot should and could be modified; *i.e.* modifications could be implementable within a 90-day timeframe. This decision addresses these issues.

4.2. Continuing the Auction Pilot is Not Prudent

The Commission is faced with three potential outcomes for this decision:

1) authorize an additional auction solicitation in 2019 with deliveries in 2020, based on the existing design and without the input of the Auction Pilot evaluation results;
2) authorize an additional auction solicitation in 2019 with deliveries in 2020 with improvements that can be implemented within 90 days, but without the input of the complete pilot evaluation results; or

3) delay any consideration of continuing the Auction Pilot or a permanent auction mechanism until the completion of the pilot evaluation; the full results of the evaluation will enable the Commission to determine the future of the auction mechanism.

We conclude that continuing the Auction Pilot or adopting a permanent auction mechanism should only be considered with complete results of the pilot evaluation and recommendations from the Energy Division for future auction mechanisms. Most parties to this proceeding support completion of the pilot evaluation prior to continuing the Auction Pilot or adopting a permanent auction mechanism. CLECA, Olivine, and Cal Advocates contend that expending ratepayer dollars on a fifth auction without a complete evaluation raises concerns. CLECA underscores that ratepayers still do not know the actual costs for resource adequacy capacity payments, whether the capacity was accurately included in supply plans; or whether the winning bidders of the auctions were dispatched by the market.[153] CLECA also points to utility advice letters asserting problems with the Auction Pilot including: the residential set-aside and requirements for a price cap above the average August price.[154] Also supporting the delay of another auction, SCE and PG&E highlight that there is no certainty that the winning bidders of the auctions are providing the services bought by these ratepayer dollars.[155]

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[153] CLECA Opening Comments on August 6, 2018 Ruling, August 17, 2018 at 5. See also Olivine Opening Comments on August 6, 2018 Ruling, August 17, 2018 at 3-4 and Cal Advocates Opening Comments on August 6, 2018 Ruling, August 17, 2018 at 4-5.

[154] CLECA Opening Comments on August 6, 2018 Ruling, August 17, 2018 at 7, citing SCE Advice Letter 3797-E, Attachment K at 22 and PG&E Advice Letter 5284, Attachment D at 25.

[155] SCE and PG&E Joint Opening Comments on August 6, 2018 Ruling, August 17, 2018 at 4. See also SDG&E Opening Comments on August 6, 2018 Ruling, August 17, 2018 at 1-2.

We agree that there are many unanswered questions regarding the success and efficacy of the Auction Pilot. Without these answers, if we authorized an additional auction in 2019 with little to no change, we risk spending ratepayer funds on an approach that may not meet the needs of the Commission or may not do so in a fair, efficient, and effective manner.

CPower and EnerNOC jointly assert they have expended a significant amount of time, energy, and money to get the Auction Pilot off the ground and are now faced with the potential of having these investments stranded for an uncertain period of time.[156] Hence, CPower and EnerNOC recommend the Commission authorize another auction to prevent "a gap and uncertainty in the demand response market where few other opportunities exist for demand response capacity procurement."[157] CPower, EnerNOC, and CESA contend that the reasons for authorizing an auction in 2018 are still reasonable for authorizing an auction in 2019: 1) limited opportunities for third-party providers in 2019; 2) to support the market for competitive demand response while the Commission determines how demand response will be procured in the future; 3) the opportunity to gain further evidence on whether the third-party demand response provider market may be consolidating; and 4) the opportunity to incorporate improvements into the Pilot design and test procurement guidelines for a permanent auction."[158]

The reasons presented by CPower, EnerNOC, and CESA do not address our responsibility to ratepayers to ensure prudent spending of ratepayer funds.

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[156] CPower and EnerNOC Opening Comments on August 6, 2018 Ruling, August 17, 2018 at 3.

[157] CPower and EnerNOC Opening Comments on August 6, 2018 Ruling, August 17, 2018 at 1.

[158] CPower and EnerNOC Reply Comments on August 6, 2018 Ruling, August 22, 2018 at 2 citing CESA Opening Comments on August 6, 2018 Ruling, August 17, 2018 at 4-10.

The Commission has supported the third-party market and continues to support third-party providers. However, we also must ensure that if another auction is authorized, it is done prudently (i.e., with complete results of the evaluation.)

We also should not rely on CPower, EnerNOC and CESA's justification that a 2019 auction would allow for additional data to be gathered. The evaluation is nearly complete at this point, with an anticipated release date of December 2018. Hence, any data from the additional auction will not be included in the evaluation report. SDG&E highlights that the Commission has four years of auctions from which to draw experience and lessons.[159] CPower, EnerNOC and CESA also recommend that the 2019 auction could include revisions to the Auction Pilot that can be implemented within 90 days. However, the most critical improvements needed may be related to bid prices and market performance and these issues are complex and require workshops and deliberations in order to build a record. This record development could not be completed in time for a spring 2019 auction. We agree that another auction could cost ratepayers more money for potentially dubious results.

Finally, with respect to the concern of limited opportunities, the Commission cannot guarantee consistent business opportunities or contract awards for every demand response provider. While limited, utility demand response programs are available to provide revenue and market continuity for the third-party providers.

When the Commission authorized an additional auction in D.17-10-017, we were nearly a year from receiving evaluation results. In making a determination in this decision, final evaluation results and recommendations are

[159] SDG&E Opening Comments on August 6, 2018 Ruling, August 17, 2018 at 1-2.

anticipated only weeks from now. The Commission should wait for the results and recommendations, then hold workshops based on the recommendations, develop a record, and issue a proposed decision that is based on the results, recommendations, and record.We touch briefly on the recommendation by OhmConnect that the Commission authorize a larger scale and longer-term auction in 2019 for deliveries beginning in 2020. OhmConnect contends that there is sufficient time to complete the Auction Pilot evaluation and conduct an expanded auction in 2019. Without any knowledge of the results of the final evaluation or Energy Division's recommendations, OhmConnect argues that there is ample evidence the pilot has met the objectives specified in D.14-12-024,[160] which was "to test: a) the feasibility of procuring supply resources for resource adequacy with third-party direct participation in the CAISO markets through an auction mechanism, and b) the ability of winning bidders to integrate their provision of demand response into the CAISO market." OhmConnect asserts the pilot has been a success because the Utilities have successfully procured third-party demand response for resource adequacy through four auctions. We strongly disagree with OhmConnect's assertion. Success will be measured by the six criteria agreed upon by the parties of this proceeding:

1) Were new, viable third-party providers engaged?
2) Were new customers engaged?
3) Were bid prices competitive?
4) Were offer prices competitive in the wholesale markets?
5) Did demand response providers aggregate the capacity they contracted, or replace it with demand response from another source in a timely manner?

[160] OhmConnect Opening Comments to August 6, 2018 Ruling, August 17, 2018 at 9.

6) Were resources reliable when dispatched, i.e., did customers perform appropriately?

Accordingly, it is reasonable to decline to adopt OhmConnect's proposal to authorize an expanded auction in 2019.

In comments to the proposed decision, OhmConnect and CPower/Enel X assert a lack of specificity regarding the steps following the issuance of the evaluation results of the Auction Pilot.[161] OhmConnect claims that the proposed decision does not provide in detail the actions the Commission will take to enable an auction for deliveries in 2020 in the event the evaluation indicates the auction mechanism should be continued. CPower/Enel X contend that the absence of a commitment to pursue consideration of another auction is troubling.[162] While the Commission has not ruled out the possibility of an auction for deliveries in 2020 and supports the continuation of reasonable mechanisms for deploying cost-effective demand response, without the evaluation results and the Energy Division's recommendations, the Commission cannot make any determination regarding the future of the Auction Pilot or the Auction Mechanism. Furthermore, it would not be appropriate to describe the next steps in detail. As described above, following the issuance of the evaluation results in December 2018, Energy Division will present its results at a workshop and the Administrative Law Judge will facilitate a discussion on the Energy Division recommendations. Next steps will be outlined in more detail with the issuance of the evaluation results.

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[161] OhmConnect Opening Comments to Proposed Decision at 3 and CPower/Enel X Opening Comments at 8.

[162] See also the Council Opening Comments to Proposed Decision at 7-8, CLECA Comments to Proposed Decision at 7-8, and Olivine Opening Comments to Proposed Decision at 5-6.

5. Next Steps for Demand Response

As discussed in Section 4 above, the Commission will consider the results of the evaluation on the Auction Pilot. Based on the results, the Commission will determine whether to continue the pilot, adopt the auction mechanism as is on a permanent basis, adopt a revised auction mechanism based upon the evaluation results, or decline to adopt any mechanism. We anticipate the results of the evaluation to be made public in December 2018. A workshop will be held in early 2019 to discuss the results and staff recommendations. A final decision on the staff recommendations will occur in mid-2019. That decision will close this proceeding.

However, the closure of this proceeding is not the end of demand response changes. We also anticipate a workshop report from the Load Shift Working Group to be filed in early 2019. The workshop report should provide the Commission with recommendations for new models of demand response that address the evolution of the grid, including the increase in clean energy solutions. We anticipate the opening of a new rulemaking to focus on these new models of demand response considering broad new ways to modernize demand response and continue improving its value to the grid.

6. Comments on Proposed Decision

The proposed decision of Administrative Law Judges Hymes and Atamturk in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on November 14, 2018 by the Council, CESA, CAISO, CLECA, CPower and Enel X North America Inc. (CPower – Enel X),[163] OhmConnect, Olivine, PG&E, SCE, and SDG&E, and reply comments were filed on November 19, 2018 by CLECA, CPower – Enel X, OhmConnect, PG&E, SCE, and SDG&E. In response, corrections and clarifications are made throughout this Decision. We address certain comments below.

In its Opening Comments, Olivine expresses concern regarding lack of consumer protections and recommends that "the [DAC] pilots should include guidelines on consumer protection, a customer 'bill of rights' and energy professions associated with the pilots should be required to be trained on those guidelines and customer rights."[164] Olivine suggests that these guidelines can be modeled on the consumer protection measures recently adopted for residential solar customers in D.18-09-044, but does not provide any further details.

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[163] Enel X North America, Inc. is formerly known as EnerNOC, Inc. On October 24, 2018, Enel X served a Notice of Name Change in this proceeding.

[164] Olivine, Opening Comments, November 14, 2018, at 4.

Due to lack of record on consumer protection measures for the pilots targeting disadvantaged communities, we will not adopt additional guidelines on consumer protection in this decision. However, we require that the Utilities include adequate consumer protection measures in their pilot proposals to ensure that customers living in the disadvantaged communities are not taken advantage of. The Utilities must inform the DAC Advisory Group on this matter and include in their Tier Two Advice Letters the consumer protection measures they propose to take as part of their Pilot Plans. Section 3.5.3 of this Decision is updated to accommodate this requirement. If the pilots are deemed successful and become part of the permanent utility demand response portfolios, the Commission could revisit the adequacy of consumer protection measures for this pilot or any other demand response programs in the future.

7. Assignment of Proceeding

Martha Guzman Aceves is the assigned Commissioner and Kelly A. Hymes and Nilgun Atamturk are the assigned Administrative Law Judges in this proceeding.

Findings of Fact

1. There are only a few existing options for dual participation for all demand response customers, under the current rules, and fewer for customers of third-party providers.

2. To allow for dual participation between the Critical Peak Pricing and the current demand response auction mechanism pilot, changes to Rule 24/32 may need to be made including: 1) modification or elimination of the firewall requirement; 2) modification or elimination of the rule regarding participation in two day-ahead or day-of obligations; and 3) modification or elimination of the rule regarding participation in two energy or two capacity programs.

3. The potential changes to Rule 24/32 are complex and require significant time to understand the implications of each rule change and then reach consensus between the Utilities and demand response providers.

4. The Commission has no indication of the costs for these changes; no party provided cost estimates for implementation of rule changes.

5. Past spending to implement changes to the Utilities' information technology (IT) systems for third-party direct participation indicate the costs are not inconsequential.

6. The number of unenrollments from Critical Peak Pricing have been low.

7. Third-party providers indicate lost opportunities by choosing not to enroll Critical Peak Pricing customers but can only provide anecdotal data at this time.

8. The potential expense and resources expended for revising the dual participation rules may be questionable given declining enrollments in Critical Peak Pricing.

9. The need for changes to Rule 24/32 is directly related to the enrollment in the Auction Pilot.

10. When dual participation rules were established by the Commission, integration of programs into the CAISO market had not begun and was not considered in the creation of the dual participation rules.

11. The future of an auction mechanism is unknown at this time.

12. It is not prudent to modify Rule 24/32 at this time to allow for dual participation in utility programs and the auction mechanism.

13. There is an unlevel playing field between the Utilities and third-party providers because participation in the utility program allows for possible dual participation.

14. Prohibiting dual participation with Critical Peak Pricing for all new customers until further notice will provide more balance to competition between the Utilities and third-party providers and ensure ratepayers are not paying twice for a single instance of load drop.

15. AMS contentions and assertions regarding battery storage has not been tested in terms of dual participation of demand response resources or other resources regulated by the Commission.

16. There is no evidence regarding the viability of storage as incremental capacity in a demand response program.

17. The issue of battery storage and dual participation is not in the scope of this proceeding.

18. No party opposed the following agreements made at the February 14, 2018 workshop: a) annual Load Impact Protocols report will assess the available headroom under the two percent reliability cap; b) if the Load Impact Protocols report indicates utilities have exceeded the cap, enrollment of additional megawatts will cease; and c) megawatts that can de-island existing megawatts have the highest value and those that would be islanded have the lowest value.

19. The following agreements made at the February 14, 2018 workshop are reasonable: a) annual Load Impact Protocols report will assess the available headroom under the two percent reliability cap; b) if the Load Impact Protocols report indicates utilities have exceeded the cap, enrollment of additional megawatts will cease; and c) megawatts that can de-island existing megawatts have the highest value and those that would be islanded have the lowest value.

20. The CAISO agreed to develop a wholesale reliability product which would qualify as resource adequacy capacity but would be subject to the reliability cap if counted for resource adequacy.

21. The CAISO reliability product is not price-responsive but will be economically dispatched once triggered.

22. Resource adequacy megawatts from customers dually participating in price-responsive demand response programs do not count against the two percent reliability cap.

23. Parties agreed that an additional reliability program open season in April, more closely aligned with the release of the Load Impact Protocol Report.

24. Having an additional open season in April will allow for new enrollments only, after the load impact reports determine the available headroom under the cap.

25. Holding an additional reliability program open season in April is reasonable.

26. The Commission prefers that demand response services are procured competitively by third-party providers.

27. The Commission plans to ensure that a broad array of demand response options is offered to customers.

28. The Commission supports the participation of third-party demand response aggregators in cost-effective programs.

29. The Commission supports a customer's right to provide demand response through a service provider of their choice.

30. The current share of third parties providing Base Interruptible Program is much smaller compared to utility procured Base Interruptible Program.

31. D.16-09-056 highlighted a concern that the demand response competitive playing field is not level and found it reasonable to cap further funding for demand response programs at the 2017 budget levels.

32. Customers continue to have the choice of demand response providers.

33. Customers participating in Base Interruptible Program are utility customers and will continue to be able to participate in this program if they remain enrolled in the program.

34. The cap issue is the allocation of remaining headroom under the cap.

35. It is reasonable to prioritize third-party customers in allocating the remaining megawatts while ensuring the needs of the grid are met.

36. Members of the Supply Side Working Group agree that the Commission should not change the settlement adopted in D.10-06-034.

37. There are two distinct options for dispatching or triggering Reliability Demand Response Resource: In-Market dispatch and Out of Market dispatch also referred to as exceptional dispatch.

38. After the CAISO calls a Warning State, the locational marginal price must reach the RDRR strike price before RDRR load is dropped, unless an exceptional dispatch is issued.

39. The use of RDRR can occur anytime within the Warning Stage, in the case of In-market dispatch and Out of Market or exceptional dispatch.

40. The use of RDRR anytime within the Warning Stage is consistent with D.10-06-034 and the Settlement adopted in that decision.

41. Most parties do not support allowing RDRR to be triggered prior to the Warning Stage.

42. According to Resolution E-4819, the Utilities used the Opportunity Cost Method to establish the price triggers for the Capacity Bidding Program.

43. The Energy Division summarized how the Utilities implemented the Opportunity Cost in Resolution E-4819.

44. The Commission approved SDG&E's method for establishing the price triggers and the resulting price triggers in Resolution E-4819.

45. In Resolution E-4918, the Commission adopted the use of the Opportunity Cost Method and updated SDG&E's price trigger based on 2015-2016 price analyses models.

46. D.17-12-003 found SDG&E's proposal of a Capacity Bidding Program trigger solely based on energy price to be reasonable.

47. D.17-12-003 found it reasonable to eliminate the heat rate trigger for the Utilities' Capacity Bidding Program.

48. SDG&E's January 20, 2018 filing is compliant with D.17-12-003.

49. Using the qualifier "current models of demand response" in the definition for auto demand response controls would disqualify new models of load shifting demand response for control incentives.

50. The purpose of automated demand response is to provide demand response without manual intervention.

51. Eliminating the words, "automated demand response" from the definition for auto demand response controls ignores the purpose of demand response.

52. The signal for a control must be automated.

53. Many auto demand response controls allow or require the customer to acknowledge the signal before it begins equipment shutdown.

54. Customers have override authority when auto demand response signal is received.

55. Because we adopt the term, control, to specify what customers use in return for receiving incentives, it is reasonable to modify the name of the auto demand response technology incentive policy and now refer to it as the Auto Demand Response Control Incentive Policy.

56. Parties voiced no objections to the definitions, background, purpose of the Control Incentive Policy guidelines or the guiding principles as proposed by the Utilities.

57. The Base Interruptible Program is a reliability program and is subject to a cost-effectiveness analysis.

58. Parties agreed that Base Interruptible Program is not applicable to the Control Incentive Policy.

59. Reliability resources are rarely dispatched.

60. D.16-06-029 concluded that reliability programs should not be eligible for auto demand response incentives.

61. The Utilities developed a matrix of the programs to which they consider the Control Incentive Policy applicable.

62. No party opposes the request of SCE to revise the matrix of programs to include its Customized Auto Demand Response program to the matrix.

63. In D.17-12-003, the Commission adopted a five-year budget for demand response activities and programs, which includes estimated Auto Demand Response control incentives.

64. The Commission cannot anticipate the procurement of demand response resources external to the portfolio because the related requests for offers are required to be technology-neutral and may not result in the procurement of demand response resources.

65. The Commission cannot estimate the budget impact of the unknown externally contracted demand response resources on future control incentives.

66. The ability of externally-contracted demand response resources to receive control incentives should be a contract term that is negotiated between the seller and the utility so that the contract term can be evaluated properly through the least-cost best-fit analysis.

67. Ordering Paragraph No. 2 of D.17-10-017 defines the four requirements for a program to be considered "similar" to a utility demand response program.

68. In order for a community choice aggregator or direct access energy service provider demand response program to be considered similar to a utility demand response program, the program must be able to be classified and is able to demonstrate that is classified as the same resource, either a load modifying or supply resource.

69. Auto Demand Response is an incentive for customers to purchase a control so that the customer can participate in either a load modifying or supply demand response program without manual intervention.

70. Auto Demand Response is neither a load modifying or supply resource.

71. Auto Demand Response was created to encourage customers to participate in demand response programs with no manual interaction.

72. There are alternate incentive opportunities for energy management technologies that do not require automation.

73. Party responses to the June 15, 2018 Ruling support revisions to the residential and small business criteria.

74. The proposed revisions to the control criteria are compliant with the California Energy Commission's Title 24 requirements.

75. The probability of future changes to Auto Demand Response exists.

76. The current approach to incentive calculations is diverse among the three utilities.

77. The following four issues are complex and technical in nature and are more appropriately addressed by technical experts: a) the approach to calculating control incentives, b) the implementation of the policy that RDRR is ineligible for control incentives, c) the frequency of control incentives; and d) calculating the cost-effectiveness of incentives.

78. Auto Demand Response and the associated technologies are evolving.

79. There will continue to be a need to address future issues related to Auto Demand Response and the associated technologies.

80. The relationship of battery storage to Auto Demand Response is an emerging issue that was not initially contemplated by the Commission in this proceeding.

81. Battery storage technology was not present in the marketplace at the time Auto Demand Response was established.

82. Battery storage was not discussed in the context of the dollars per kilowatt calculated incentive design the Commission approved in D.16-06-029.

83. Battery storage is currently eligible for Auto Demand Response control incentives in PG&E territory.

84. PG&E has established a collaborative process with stakeholders with respect to Auto Demand Response control incentives and battery controls.

85. The time is ripe for establishing policies for battery storage in Auto Demand Response.

86. The record is limited and not sufficient to include battery storage policies in the Guidelines adopted in this decision.

87. Parties give broad support for the environmental and/or economic goals stated in the Proposal, but they question the potential impact of local action in a disadvantaged community on the operations of nearby power plants.

88. Parties in general support testing marketing and outreach efforts to increase enrollment and participation in disadvantaged communities while learning more about the target population and the residents' ability to respond to demand response events.

89. The Proposal provides guidelines for the Utilities to follow while developing pilots as directed and funded by D.17-12-003.

90. The guidelines provided by the Proposal are reasonable and consistent with past Commission decisions, D.12-04-045 and D.16-09-056.

91. The Proposal defines disadvantaged communities as "census tracts that score above 75th percentile using the CalEnviroScreen tool created by the California Environmental Protection Agency…plus an additional 22 census tracts that score in the highest five percent of CalEnviroScreen's pollution burden but do not have an overall CalEnviroScreen score because of unreliable socioeconomic or health data."

92. The Proposal identifies the purpose of the pilots as enhancing the economic and/or environmental benefits that demand response program investments provide to disadvantaged communities.

93. The Proposal identifies the goal of the pilots as improving existing demand response programs or developing new programs through policy recommendations that derive from the pilots to advance the purpose of the pilots.

94. There is a need to better understand the relationship between energy consumption in disadvantaged communities and the operations of local generation units.

95. The Proposal provides examples for test objectives that maximize the purpose of the pilots; are achievable and will yield useful data within the budgets provided.

96. Most parties to this proceeding support completion of the pilot evaluation prior to continuing the Auction Pilot or adopting a permanent auction mechanism.

97. There are many unanswered questions regarding the success and efficacy of the Auction Pilot.

98. If the Commission authorizes another auction without these answers, the Commission risks spending ratepayers funds on an approach that may not meet the needs of the commission or may not do so in a fair, efficient, and effective manner.

99. The justifications presented by CPower, EnerNOC, and CESA for authorizing an auction in 2019 do not address the Commission's responsibility to ensure prudent spending of ratepayer funds.

100. The Commission has supported the third-party market and continues to support third-party providers.

101. Data from an additional auction in 2019 would not be included in the evaluation report.

102. The Commission has four years of auctions from which to draw experience and lessons.

103. Parties provide revisions to the Auction Pilot that can be implemented within 90 days.

104. The most critical improvements needed to the Auction Pilot are related to bid prices and market performance, which are complex and require more than 90 days.

105. Another auction would cost ratepayers more money and could result in dubious results.

106. The Commission cannot guarantee consistent business opportunities or contract awards for every demand response provider.

107. Demand response programs are available to provide revenue and market continuity for the third-party providers until a resolution on the auction mechanism occurs.

108. The Auction Pilot cannot be deemed a success simply because the Utilities successfully procured third-party demand response for resource adequacy.

109. Success of the Auction Pilot will be measured by the criteria agreed upon by the parties of this proceeding.

Conclusions of Law

1. The Commission should weigh the potential costs and resources required to implement Rule 24/32 modifications against the impact of no dual participation on third-party provider's customers.

2. The Commission should weigh the potential costs and resources against the current uncertainty of a permanent Auction Mechanism.

3. The Commission should wait until after a determination on a future auction mechanism is made before determining how to modify Rule 24/32 to allow for dual participation in Critical Peak Pricing and either a utility program and the auction mechanism.

4. The Commission should not address the issue of battery storage in terms of dual participation at this time.

5. The Commission should adopt the following agreements: a) annual Load Impact Protocols report will assess the available headroom under the two percent reliability cap; b) if the Load Impact Protocols report indicates utilities have exceeded the cap, enrollment of additional megawatts will cease; and c) megawatts that can de-island existing megawatts have the highest value and those that would be islanded have the lowest value.

6. Megawatts procured through the auction mechanism should count toward the reliability cap.

7. Allocation of the megawatts from a permanent auction mechanism should be addressed when the Commission determines whether the auction mechanism should be permanent.

8. Determinations made in this decision related to the reliability cap should be reviewed again when the Commission considers the evaluation of and related recommendations for the Auction Pilot.

9. The Commission should permit an additional reliability program open season in April of each year, if the Load Impact report indicates available headroom under the cap.

10. To further promote third-party participation in demand response, the commission should allocate the remaining megawatts under the Cap to third-party providers.

11. The Commission should not allow RDRR to be triggered prior to the Warning Stage.

12. The Commission should not change the Settlement adopted in D.10-06-034, including the two percent reliability cap.

13. The detailed data provided by the Utilities in the Opportunity Cost Method is protected as confidential under Public Utilities Code Section 583.

14. SDG&E's method for determining the price trigger for the Capacity Bidding Program should be considered resolved.

15. The Commission should refer to the Auto Demand Response Technology Incentive Policy as the Auto Demand Response Control Incentive Policy.

16. The Commission should adopt the following definition for auto demand response control: The ability to receive an automated demand response signal to enable the customer to participate in a demand response event without any manual customer intervention.

17. Reliability Demand Response Resources bid into the CAISO market through the Auction Mechanism should not be eligible to receive auto demand response control incentives.

18. Externally contracted demand response resources should not be eligible to receive auto demand response control incentives.

19. Customers of the Auction Pilot, being a demand response pilot, should be eligible to receive auto demand response control incentives.

20. Auto Demand Response is not eligible for "similar" status.

21. Receiving a text or email communication in addition to an automatic demand response signal should not disqualify a customer from receiving Auto Demand Response control incentives.

22. Given the adopted definition of a control, the cost of the automated control should qualify for the incentive and not the additional behavioral communication method.

23. The Commission should not authorize auto demand response incentives for devices that are unable to receive an auto demand response signal as it defeats the purpose of the program.

24. The Commission should adopt the following revised criteria for controls:

- For residential, small and medium business customers, the control must be able to communicate and demonstrate operability using the current Open Auto Demand Response communication protocols and standards (currently OpenADR 2.0a or 2.0b). The control may be located either on site or as part of a control system, on site and at the manufacturer/demand response aggregator or provider cloud level. Only the customer is eligible for the Auto Demand Response control incentive, not the aggregator, demand response provider, or manufacturer cloud portion of the control.
- In the case of the small & medium business customer class and associated end uses, residential customers receiving incentives for thermostats, and customers enrolled in SDG&E's Technology Deployment Program: the criteria depend upon the type of Auto Demand Response in which the customer is enrolled, such as a deemed incentive based on the average kilowatt load drop for the control in that sector.
- For commercial and industrial customers applying for calculated incentives, the control must be onsite and able to communicate and demonstrate operability using the current Open Auto Demand Response communication protocols and standards (currently OpenADR 2.0a or 2.0b). The Utility must also be able to verify 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.

25. The Commission should review: a) the approach to calculating control incentives, b) the implementation of the policy that RDRR is ineligible for control incentives, c) the frequency of control incentives; and d) calculating the

cost-effectiveness of incentives.

26. The Commission should adopt a stakeholder approach to address technical issues and evolving auto demand response issues on an ongoing basis rather than every three to five years.

27. The Commission should authorize the Energy Division to work with the Utilities to expand the PG&E stakeholder process to develop an overall strategy proposal for battery storage for eventual inclusion in the Guidelines adopted in this decision.

28. Because the guidelines provided by the Proposal are reasonable and consistent with Decision 12-04-045 and Decision 16-09-056, we should adopt them.

29. Because the proposed definition of disadvantaged communities is consistent with the definition adopted in the Integrated Resource Planning proceeding and will help with coordination between proceedings with respect to data analysis and recommendations, we should adopt it.

30. Because the pilot requirements listed in the Proposal comport with the pilot plan requirements set forth in D.12-04-045, we should adopt them.

31. Because the overall purpose and goal identified by the Proposal is reasonable and comports with the goal adopted by D.16-09-056, we should adopt it.

32. Because of the need to better understand the relationship between energy consumption in disadvantaged communities and the operations of local generation units and the limited size of the authorized budget for the pilots, the utilities should primarily focus on providing direct economic benefits to residential and small commercial customers residing or doing business within disadvantaged communities situated in local capacity areas.

33. Because all demand response programs must follow the principle established by D.16-09-056, the Utilities should consider incorporating supply-side programs in their pilot plans.

34. Because designing pilot programs achieving the test objectives stated in the Proposal and listed in this Decision will lead to economic benefits and help the Commission and the parties learn more about customers from disadvantaged communities and their needs, we find them reasonable.

35. Goal of the pilots should not be to compare third party and utility performances, but to test the pilot design objectives.

36. In order to show compliance with the requirements listed in the Proposal and guidance provided in this Decision, the Utilities should include the following in their Pilot Plan to be submitted with their Advice Letter: Target location (which disadvantaged communities in a local capacity area); strategy to target residential and small commercial customers in disadvantaged communities; the amount and form of economic benefit for the participating customer, and third party, including the amount of capacity payments and how they would be allocated; if and how the proposed pilot will be bid into the CAISO market, *e.g.,* as part of an existing program if it is not large enough to meet the CAISO requirements for aggregation size by sub-LAP; theory of the pilot intervention, *e.g.,* a logic model, and how it would meet the purpose and goal adopted in this Decision; how the Utilities are coordinating with the Disadvantaged Communities Advisory Group; if and how the Utilities are coordinating with each other in their proposed ideas and building off past and current pilots; how to track cost-effectiveness for the purpose of informing future programs; justification for choice of third party or Utility; and explanation for how the third parties would gain the necessary data for the pilots.

37. The Commission should ensure that if another auction is authorized, it is done so with complete results of the evaluation.

38. The Commission should not rely on CPower, EnerNOC, and CESA's justification that a 2019 auction would allow for additional data to be gathered.

39. The commission should wait for the complete results and recommendations of the Energy Division's evaluation of the Auction Pilot before authorizing additional auctions for the Auction Pilot or adopting a permanent auction mechanism.

O R D E R

IT IS ORDERED that:

1. Enrollment in Critical Peak Pricing and another utility or third-party administered demand response program is prohibited for all customers not currently dually-enrolled, beginning immediately and until further notice. Within 90 days of the issuance of this decision, Pacific Gas and Electric Company, San Diego Gas and Electric Company, and Southern California Edison Company (the Utilities) shall submit Tier One Advice Letters revising tariffs to implement this prohibition. Customers of the Utilities currently enrolled in Critical Peak Pricing and another demand response program may continue to dually participate in the specific demand response programs in which they had participated prior to October 26, 2018 and capped at the current megawatt level

2. The following reliability demand response policy statements are adopted:

a. *Reliability Demand Response Resource megawatts procured through the demand response auction mechanism pilot count toward the two percent reliability cap.*

b. *The Base Interruptible Program and Agricultural and Pumping Interruptible program open season rules are modified to only* *allow disenrollment or decreases in participation in demand response of existing customers. Any increase in participation levels or new allocations shall be performed as part of the adopted allocation parameters in Ordering Paragraph No. 5 of this decision.*

c. The use of Reliability Demand Response Resources can occur anytime within the California Independent System Operator Warning Stage, in the case of In-Market dispatch and Out-Of-Market or Exceptional dispatch.

3. As part of the Demand Response Annual Load Impact Protocols reporting requirements, Pacific Gas and Electric Company, San Diego Gas and Electric Company, and Southern California Edison Company (the Utilities) shall calculate the number of megawatts, if any, available under the two percent reliability cap. The Utilities shall calculate the number of remaining megawatts as follows:

Capacity Allocated = (Projected Load Impacts for Base Interruptible Program and Agricultural Pumping Interruptible) minus (Projected Critical Peak Pricing Load Impacts for Dually-Enrolled Participants in Base Interruptible Program/Agricultural Pumping Interruptible and Critical Peak Pricing)

Capacity Headroom = Utility Allocated Cap (megawatts) – Capacity Allocated.

4. Pacific Gas and Electric Company, San Diego Gas and Electric Company, and Southern California Edison Company (the Utilities) shall suspend all enrollments of reliability demand response resources if the calculated Capacity Headroom is at or above 95 percent of a utility's individual allocated two percent reliability cap.

5. If the calculated Capacity Headroom is between 50 and 95 percent of a utility's individual allocated two percent reliability cap, Pacific Gas and Electric Company, San Diego Gas and Electric Company, and Southern California Edison Company (the Utilities) shall allocate reliability demand response resources in the order indicated below, with a lottery in April for each item. If the calculated Capacity headroom is below 50 percent, a utility may allocate capacity using a first come, first served approach.

a. all third-party resources from Local Capacity Areas that have local capacity deficiencies pursuant to CAISO;
b. all utility resources from Local Capacity Areas that have local capacity deficiencies pursuant to CAISO;
c. all other resources from third-party customers;
d. all other utility customer resources;

6. The following Auto Demand Response Control Incentive policies are adopted:

a. Externally contracted demand response resources are not eligible to receive auto demand response control incentives.
b. Customers of the Demand Response Auction Mechanism Pilot (Auction Pilot), being a demand response pilot, are eligible to receive auto demand response control incentives unless customers are registered in Reliability Demand Response Resources (RDRR). RDRR bid in the California Independent System Operator market through the Auction Pilot are not eligible to receive Auto Demand Response control incentives.
c. Auto Demand Response is not eligible for "similar" status.
d. Receiving a text or email communication in addition to an automatic demand response signal does not disqualify a

customer from receiving Auto Demand Response control incentives.

e. For eligible automated controls, only the cost of the automated control qualifies for a control incentive.
f. Devices unable to receive an auto demand response signal are not eligible to receive auto demand response control incentives.
g. For residential, small and medium business customers, the control must be able to communicate and demonstrate operability using the current Open Auto Demand Response communication protocols and standards (currently OpenADR 2.0a or 2.0b). The control may be located either on site or as part of a control system, on site and at the manufacturer/demand response aggregator or provider cloud level. Only the customer is eligible for the Auto Demand Response control incentive, not the aggregator, demand response provider, or manufacturer cloud portion of the control.
h. In the case of the small & medium business customer class and associated end uses, residential customers receiving incentives for thermostats, and customers enrolled in SDG&E's Technology Deployment Program: the criteria depend upon the type of Auto Demand Response in which the customer is enrolled, such as a deemed incentive based on the average kilowatt load drop for the control in that sector.
i. For commercial and industrial customers applying for calculated incentives, the control must be onsite and able to communicate and demonstrate operability using the current Open Auto

Demand Response communication protocols and standards (currently OpenADR 2.0a or 2.0b). The Utility must also be able to verify 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.

7. No later than 45 days from the issuance of this decision, Pacific Gas and Electric Company, San Diego Gas and Electric Company, and Southern California Edison Company shall submit a Tier One Advice Letter updating the proposed Auto Demand Response Guidelines (as provided in Attachment 1) to include the policies adopted in Ordering Paragraph 6 above, comply with any other related aspects of this decision, and rename the document the Auto Demand Response Guidelines and Adopted Policies (Guidelines). The Guidelines are considered a living document that, together with the process we establish in Ordering Paragraph No. 8 below, will enable the Commission to address the evolving needs of Auto Demand Response.

8. Beginning in 2019, and on an annual basis, the Director of the Commission's Energy Division is authorized to work with Pacific Gas and Electric Company (PG&E), San Diego Gas and Electric Company, and Southern California Edison Company (the Utilities) and other stakeholders to identify a set of Auto Demand Response issues to resolve for that year. The set of issues to be resolved this year is identified in Ordering Paragraph 9 below. For future years, the set of issues shall be identified no later than October 31 of the prior year. With Energy Division input, the Utilities shall develop proposals to address the issues and serve them on stakeholders no later than May 1 of each year, beginning in 2019. The Utilities shall use the most recent and broadest demand response proceeding service list. The Utilities shall hold workshops or webinars,

noticed to the same demand response service list. Based upon the discussions at the workshops, the Utilities shall file, no later than August 15 of each year, draft updates to the Auto Demand Response Control Incentives Guidelines and Adopted Policies (Guidelines), incorporating the proposals to address the set of issues for that year. All stakeholders may provide informal comments to the service list on the draft updated Guidelines; the Director of the Energy Division is authorized to establish a deadline for submitting the informal comments. No later than September 1 of each year, the Utilities shall submit a Tier Two advice letter incorporating the proposals into the Guidelines and including all party comments in the advice letter.

9. The Auto Demand Response issues identified to be resolved in 2019 are as follows:

a. Review of the approach to calculate control incentives;
b. Implementation of the policy that Reliability Demand Response Resources are not eligible to receive auto demand response control incentives;
c. Determination of the frequency of control incentives;
d. Calculation of incentive cost-effectiveness; and
e. Development of a list of residential Auto Demand Response enabled end-use devices to be considered by Pacific Gas and Electric Company (PG&E) for eligibility for an Auto Demand Response incentive; and
f. Development of criteria to determine the order for PG&E to evaluate load impacts attributable to the devices.

10. The Director of the Energy Division is authorized to establish a stakeholder process to develop an overall strategy proposal for battery storage participation in Auto Demand Response. Pacific Gas and Electric Company (PG&E), San Diego Gas and Electric Company, and Southern California Edison Company (the Utilities) shall and other stakeholders may participate in the

process. The Utilities shall file an update on the progress of the group no later than March 7, 2019. Unless otherwise directed by the Assigned Administrative Law Judge, a final proposal recommending solutions to the issues below shall be filed no later than April 15, 2019. Comments to the filed proposal shall be filed on May 1, 2019; replies shall be filed no later than May 10, 2019. The assigned Administrative Law Judge is authorized to extend the deadline for the stakeholder report through a Ruling, if deemed reasonable. Until the Commission adopts guidance on the policy issues described below, the Utilities shall not provide Auto Demand Response incentives for battery storage controls except in the case of incentive applications received before October 26, 2018. The stakeholder process shall address the following issues:

a. Should the Commission authorize the Utilities to continue to provide auto demand response control incentives for battery storage controls to non-residential customers?

b. Should the Commission allow residential customers to receive an incentive for battery storage controls?

c. Should the Commission limit the auto demand response control incentives for battery storage to hardware and software costs, as currently provided by PG&E?

d. Should the Commission adopt the same incentive structure developed in the annual Guidelines update process established in Ordering Paragraph No. 8 or should the Commission adopt a separate control incentive structure for battery storage controls?

e. If the Commission adopts a separate control incentive structure for battery storage controls, what should the structure entail?

f. What precautions should the Commission adopt to ensure ratepayers are not paying more than one incentive for the same control?

11. No later than four months before the start of the pilot or 60 days after the issuance of this decision, whichever is earlier, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall each submit Tier Two Advice Letters that include Pilot Plans to comply with this Decision. Pilot Plans must comply with the requirements listed in the Proposal and adopted in this Decision and include all the information listed in Section 3.5.3 of this Decision.

12. Application (A.) 17-01-012, A.17-01-018 and A.17-01-019 remains open to review the evaluation of the demand response auction mechanism and consider whether the Commission should make the mechanism permanent, to consider policies regarding battery storage controls and to review demand response baselines.

This order is effective today.

Dated November 29, 2018, at San Francisco, California.

MICHAEL PICKER
President
CARLA J. PETERMAN
LIANE M. RANDOLPH
MARTHA GUZMAN ACEVES
CLIFFORD RECHTSCHAFFEN
Commissioners

ATTACHMENT 1

Proposed Draft Auto Demand Response Technology Incentive Policy Guidelines

As filed by Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company on February 20, 2018.

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

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)
And Related Matters.	Application 17-01-018 Application 17-01-019

JOINT INVESTOR OWNED UTILITIES (IOU) PROPOSED GUIDELINES FOR THE 2018-2022 AUTOMATED DEMAND RESPONSE TECHNOLOGY INCENTIVE (AUTO-DR) PROGRAM

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Dated: February 20, 2018

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

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)
And Related Matters.	Application 17-01-018 Application 17-01-019

JOINT INVESTOR OWNED UTILITIES (IOU) PROPOSED GUIDELINES FOR THE 2018-2022 AUTOMATED DEMAND RESPONSE TECHNOLOGY INCENTIVE (AUTO-DR) PROGRAM

In accordance with Decision 17-12-003, Ordering Paragraph 29, Southern California Edison Company (SCE) hereby submits draft guidelines to implement Auto Demand Response technology incentives. These draft guidelines were prepared jointly and are being served on behalf of Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E).

Respectfully submitted,

FADIA RAFEEDIE KHOURY
ROBIN Z. MEIDHOF

/s/ Robin Z. Meidhof

By: Robin Z. Meidhof

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Joint Investor Owned Utilities (IOU) Proposed Guidelines for the 2018-2022 Automated Demand Response Technology Incentive (Auto-DR) Program

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Abstract

Technical Assistance and Automated Demand Response (ADR) technology incentives offset capital costs incurred by customers who wish to enroll in demand response (DR) programs utilizing software and systems to effectuate load drop with no manual intervention. These technologies automate participation in DR events to ensure customers provide reliable load shed during DR program events. Although non-residential customers have been the primary customer class to be eligible for these incentives, the three electric investor owned utilities (IOUs) have also provided ADR technology incentives to mass market customers, including residential and small-to-medium business (SMB) customers, to increase customer's adoption on ADR enabled end-use technologies that can automate and provide reliable DR benefits.

The guidelines in this document provide the general program parameters for the IOUs automated demand response technology incentive offerings as approved by California Public Utilities Commission (CPUC) Decision (D.) 17-12-003.

While these guidelines are intended to provide additional information about the programs' parameters, as required in D.17-12-003 Ordering Paragraph 29, these guidelines also identify potential unintended consequences from policies and requirements from other CPUC decisions such as D.17-10-017 (Competitive Neutrality Cost Causation Decision), D.17-12-003 (2018-2022 DR Application Decision), and D.18-01-003 (Multiple Use Application Decision).

Abbreviations

AB 793	Assembly Bill 793
Auto-DR or ADR	Automated Demand Response Technology Incentive Program
BIP	Base Interruptible Program
BTM	Behind-the-Meter
CBP	Capacity Bidding Program
CCA	Community Choice Aggregation
CNCC	Competitive Neutrality Cost Causation
CPP	Critical Peak Pricing Program
CPUC	California Public Utilities Commission
DA	Direct Access
DR	Demand Response
DRAM	Demand Response Auction Mechanism Pilot
DRAS	Demand Response Automation Server
DRET	Demand Response Emerging Technology
EMS	Energy Management System
EE	Energy Efficiency
ESA	Energy Savings Assistance
ESP	Electric Service Providers
EUL	Effective Useful Life (of measure)
HVAC	Heating, Ventilation, and Air Conditioning
IOU or IOUs	Investor Owned Utility or Investor Owned Utilities
kW	Kilowatt
M&V	Measurement & Valuation
MW	Megawatt
OpenADR	Open Automated Demand Response
PDP	Peak Day Pricing Program
PG&E	Pacific Gas and Electric Company
PTR-ET-DLC	SCE Peak Time Rebate Enabling Technology Direct Load Control Program
RTP	Real Time Pricing Program
SCE	Southern California Edison Company
SDG&E	San Diego Gas and Electric Company
SGIP	Self-Generation Incentive Program
SMB	Small and Medium Business
SSP	PG&E Supply Side DR Pilot
TA&TI	Technical Assistance and Technology Incentives Program
TD	Technology Deployment
XSP	PG&E Excess Supply DR Pilot

Definitions

OpenADR – An open and standardized software protocol for electricity providers and system operators to communicate DR signals with each other and with their customers using a common language over any existing IP-based communications network, such as the Internet.

Dispatch or Dispatchable or DR Event – The act of reducing existing load at the Customer's facility(ies), in response to a signal or dispatch instruction from a Utilities' DRAS or automated dispatch system, for all or a portion of the Customer's electrical consumption during the demand response event duration.

Qualifying Measures – A measure that qualifies for ADR incentives must meet all of the following criteria:

(i) Must be operating or online at the Customer facility or premise;

(ii) Must be incremental or has not previously received ADR Program incentives for the specified measure; and

(iii) Must be Dispatchable under the requirements identified in Appendix A, Appendix B, and Appendix C.

Qualifying DR Program – A DR program, approved by the CPUC, in which the program's participant(s) are eligible to receive ADR incentives which automate a customer's participation in program events.

Background on the ADR Program

In late 2006, the Commission modified the IOUs' 2006-2008 Demand Response portfolios by adopting programs for 2007 and 2008 that encourage automated demand response for commercial, industrial, and agricultural customers.[1] The three California IOUs have administered the statewide Automated Demand Response Technology Incentive Program (ADR Program) since that time.

The ADR Program primarily provides incentives to non-residential customers that purchase and install ADR enabled technology at the customers' facility or site to automate their participation and load curtailment in a Qualifying DR program. Non-residential customers are able to pre-program their DR participation levels, referred to as "shed strategies," through an ADR-enabled energy management system or technology, which allows the facility or building to automatically participate in a DR event. The ADR system provides the customers increased flexibility (e.g., customizable load shed strategies) and ease-of-use without the need for manual response or intervention.

Reimbursement through the ADR Program was previously available for the purchase and installation of ADR enabled equipment to all non-residential customers. Non-residential customers must also have an interval meter, must enroll and participate in at least one Qualifying DR Program, must be able to demonstrate automated curtailment, and must demonstrate receipt of a DR signal from the utility's DRAS or utility's automated dispatch system.

In CPUC Decision (D.) 16-06-029, the Commission directed the Joint IOUs to adopt common program rules and incentives levels in an effort to achieve greater consistency between the IOUs' ADR Programs. In D.16-06-029, the Commission directed each utility to modify its ADR Program for large non-residential customers and offer a 2-part (60/40) incentive, limited to $200 per kW of verified Dispatchable load reduction, limited to 75 percent (75%) of the total project costs, which ever amount is lower. The first incentive payment is paid at 60 percent (60%) of the total eligible incentives and is paid after installation, M&V load shed test, and customer enrollment in a Qualifying DR Program. The customer is eligible for a portion or all of the remaining second incentive payment, up to 40 percent (40%), 12-months after the first incentive payment is issued. The second incentive is based upon the customer's average actual DR performance during the 12-month period.

PG&E and SCE also offer a deemed incentive of its ADR Program referred to as Auto-DR Fast Track and Auto-DR Express, respectively. These programs streamline the

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1 Administrative Law Judge's Ruling Providing Guidance on Content and Format of 2009-2011 Demand Response Activity Applications issued on February 27, 2008 in CPUC Rulemaking (R.) 07-01-041.

ADR application process and provide incentives for the installation of ADR enabled technologies specific to lighting and HVAC controls. By offering a pre-determined, validated estimate of peak demand savings for lighting and HVAC controls, SMB customers, may be ADR-enabled more efficiently and cost-effectively than through a site-specific calculated measurement and verification process.

Over the last few years[2], the IOUs have been providing incentives for residential technologies, such as ADR-enabled smart thermostats, in response to reliability issues, such as Aliso Canyon and in response to legislative matters, such as AB 793. The IOUs continue to refine and expand residential ADR incentives to provide incentives to other residential end-uses that are ADR-enabled.

Purpose

The purpose of these Joint IOU ADR guidelines is to identify previously unspecified program eligibility rules and requirements for the IOUs ADR Program (e.g. address program eligibility for ADR incentives offered to residential and SMB customers), in compliance with Ordering Paragraph (OP) 29 of D.17-12-003.

In addition to these Guidelines, there are other issues that touch upon and impact the ADR Program, so we request that the issues identified in the “Other Issues Section” be discussed with stakeholders at the CPUC ADR workshop.

These Guidelines will also address other ADR Program changes in compliance with the following ordering paragraphs:

- The IOUs shall provide Auto Demand Response technology incentives to participants of any supply side demand response programs/activities not required to be analyzed for cost-effectiveness. (D.17-12-003, OP 28)
- PG&E’s Automatic Demand Response Program is approved as amended. PG&E shall provide Auto Demand Response technology incentives to participants of any supply side demand response program/activity not required to be analyzed for cost-effectiveness. (D.17-12-003, OP 30)
- SCE’s Automated Demand Response Technology Incentive Program and Programmable Communicating Thermostat Incentive Program are approved as amended. SCE shall provide Auto Demand Response technology incentives to participants of any supply side demand response program/activity not required to be analyzed for cost-effectiveness. (D.17-12-003, OP 32)

[2] PG&E started to offer residential ADR incentive to Smart Thermostat in September 2017

- SDG&E's Auto Demand Response program is approved as amended. SDG&E shall provide Auto Demand Response technology incentives to participants of any supply side demand response program/activity not required to be analyzed for cost-effectiveness. (D.17-12-003, OP 34)

The appendices contained in these Guidelines summarize Utilities' ADR proposals submitted in their respective 2018-2022 DR Applications and highlight the changes to their respective ADR Programs in compliance with D.17-12-003.

- Appendix A – Proposed Program Rules and Eligibility Requirements for Utilities' Residential ADR Program
- Appendix B – Program Rules and Eligibility Requirements for Utilities' Established Large Non-Residential ADR Program (i.e. Customized ADR Program)
- Appendix C – Program Rules and Eligibility Requirements for Utilities' Established SMB ADR Program (i.e. Fast Track or Express ADR Program)

Guiding Principles

Guiding principles affect the implementation and administration of the Statewide ADR Program. Guiding Principles serve as a foundation upon which the original components of the ADR Program were established, and serve as basic criteria for other ADR incentive programs, such as a residential ADR incentive program.

Current Guiding Principles

Auto-DR Rules and Guiding Principles Adopted in D.09-08-027

- Authorizes Utilities to require a Qualifying DR Program enrollment and participation requirement to receive incentives.
- Required reporting of incentive commitments into Utilities' DR CPUC Monthly Report.
- Established consistent incentive amounts for the IOUs TA&TI

Auto-DR Rules and Guiding Principles Adopted in D.12-04-045

- Directed Utilities to fund ADR technologies that interoperate using generally accepted industry open standards or protocols (i.e. OpenADR).
- Implemented the 60-40 split incentive for all non-residential customers to improve cost-effectiveness and motivate customers to demonstrate load shed performance at the level the equipment was incentivized and designed to achieve.
- Authorized AMP as a Qualifying DR Program for PG&E's ADR incentives.

Auto-DR Rules and Guiding Principles Adopted in D.14-05-025

- Directed Utilities to create and implement a statewide ADR program.
- Streamline the ADR application process.
- Provide technical assistance to ADR customers.

Auto-DR Rules and Guiding Principles Adopted in D.16-06-029

- Modified eligible incentive amounts for IOUs Customized ADR Programs $200 per kW or 75% of total project costs, whichever is less.
- Re-affirmed 60-40 split incentive for Customized ADR incentives.
- Prohibits BIP as a Qualifying DR Program.

Discussion Items for ADR Workshop

As noted previously, the Joint IOUs have identified other CPUC requirements and policies that may need to be addressed in the Commission's ADR workshop. The Joint IOUs would like greater discussion and resolution or clarification of any potential inconsistencies.

Are Auto-DR Technology Incentives Intended for All Supply Side DR Programs?

In D.17-12-003, OP 28 directs ADR technology incentives to participants of *any supply side demand response program* or activity not required to be analyzed for cost-effectiveness.

Since the Base Interruptible Program (BIP) is a supply side DR program (integrated into the CAISO markets as Reliability Demand Response Resource (RDRR)), PG&E is seeking clarification as to whether to add BIP as an eligible Qualifying DR Program to receive an ADR incentive. This would require a modification from the 2017 DR Bridge Funding Decision, based on D.16-06-029 OP 23f, where PG&E's Reliability Demand Response Programs were deemed ineligible as a Qualifying DR Program for ADR incentives. PG&E is seeking clarification on whether D.17-12-003 reverses the 2017 Bridge Funding Decision. For the time being, PG&E will continue to exclude BIP from the list of Qualifying DR Programs for ADR incentives in the 2018-2022 DR program cycle. PG&E appreciates the opportunity to clarify this issue at the Commission's ADR workshop.

SCE does not plan to allow BIP (supply side DR programs) to be considered as an ADR Qualifying DR Program. SCE's AP-I and SDP programs are also not eligible for ADR incentives because these are direct load control programs where SCE installs devices (at no cost to the customer) to customers' equipment.

SDG&E agrees that clarification as to whether or not BIP is an eligible program that can receive ADR incentive would be beneficial. SDG&E notes that BIP is required to be analyzed for cost-effectiveness so in its opinion D.17-12-003, Ordering Paragraph 28 which states that “the Utilities shall provide Auto Demand response technology incentives to participants of any supply side demand response program/activity not required to be analyzed for cost-effectiveness” does not apply to BIP. However, the slash between activity and program does leave room for debate as to whether the clause “required to be analyzed for cost-effectiveness” modifies both the words “program” and “activity” and, therefore, SDG&E agree that clarification would be beneficial.

In addition, SDG&E supports a fair and level playing field between third party and utility programs and thereby agrees with PG&E opening comments on the proposed decision that DRAM participants bidding into the emergency RDRR product should not be eligible for ADR incentives when DRAM is no longer a pilot. This would be consistent with concepts in D.16-06-029 which states that reliability demand response programs are not eligible for ADR incentives.

Are DR Programs Subject to Cost-Effectiveness Still Qualifying DR Programs?

On page 79 of the decision 17-12-003, it stated that, “Accordingly, the Utilities shall offer Auto Demand Response technology incentives to customers of all supply side programs/activities *not subject to cost-effectiveness analysis*; this includes the Demand Response Auction Mechanism and, where applicable, pilots.”

PG&E’s Capacity Bidding Program is the only DR program that is subject to cost effectiveness and historically part of the qualifying DR programs for ADR incentive. PG&E interpreted that, both, Utility DR programs subject to cost effectiveness as well as supply side programs/activities not subject to cost-effectiveness analysis are qualifying DR programs for ADR incentive, and seeks confirmation of this interpretation from the Commission.

SDG&E agrees that customers enrolled on utility supply side programs which are subject to cost-effectiveness such as CBP and AC Saver should remain eligible for ADR and Technology Deployment (TD) incentives. Although D.17-12-003, page 79, explicitly calls out only programs/activities not subject to cost-effectiveness analysis it does not explicitly state that Utility DR programs subject to cost effectiveness are not eligible for ADR and TD incentives.

Does the Multiple Use Application Decision impact the ADR Program?

On January 17, 2018, the CPUC issued D.18-01-003 “Decision on Multiple Use Application Issues.” D.18-01-003 provides direction to the Utilities on how to promote the ability of storage resources to realize their full economic value when these resources are capable of providing multiple benefits and services to the electricity system. The Commission adopts eleven rules to govern the evaluation of multiple-use energy storage applications, along with definitions of service domains, reliability services, and non-reliability services, as reflected in Table 1 below.

Table 1. Domains: Reliability Services and Non-Reliability Services

Domain	Reliability Services	Non-Reliability Services
Customer	None	TOU bill management; Demand charge management; Increased self-consumption of on-site generation; Back-up power; Supporting customer participation in DR programs
Distribution[7]	Distribution capacity deferral; Reliability (back-tie) services; Voltage support; Resiliency/microgrid/islanding	None
Transmission	Transmission deferral; Inertia*; Primary frequency response*; Voltage support*; Black start	None
Wholesale Market	Frequency regulation; Spinning reserves; Non-spinning reserves; Flexible ramping product	Energy
Resource Adequacy	Local capacity; Flexible capacity; System capacity	None
*Voltage support, inertia, and primary frequency response have traditionally been obtained as inherent characteristics of conventional generators, and are not today procured as distinct services. We include them here as placeholders for services that could be defined and procured in the future by the CAISO.		

The definitions of service domains, reliability services, and non-reliability services set forth in D.18-01-003 conflict with DR policies and principles adopted in D.14-12-024. D.14-12-024, OP 4.a., states all demand response programs will need to meet resource adequacy rules to either reduce the resource adequacy requirement as a load-modifying resource or to count toward meeting the resource adequacy requirement as a supply resource.[3] Under this premise, DR programs that meet the bifurcation requirements shall receive RA and thus, under D.18-01-003 Table 1, DR programs are considered Reliability Services. But the Table lists customer participation in DR programs as “Non-Reliability Services.”

In addition, PG&E recognizes the MUA is intended to be rules for energy storage only but find the designation of Resource Adequacy as a Reliability Service in conflict with the aforementioned D.16-06-029 (OP 23f) that prohibits PG&E from offering Automated Demand Response incentives to any Reliability Demand Response Programs. PG&E recognizes that this may not be the intent of the ruling, however, further clarification is needed during the Commission’s ADR workshop.

[3] Complete implementation of bifurcation cannot occur until resource adequacy issues have been resolved.

Does the Competitive Neutrality Cost Causation Principle (CNCC) Apply to ADR Incentives?

On November 1, 2017, the CPUC issued D.17-10-017 "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 adopts steps to implement the CNCC Principle, which allows CCA or DA ESPs to create and administer their own "similar" DR programs, thus exempting the CCA or DA provider's customers from the costs of the Utility's "similar" DR program.

While D.17-10-017 specifically exempted funding pertaining to DRAM and pilots from the CNCC principle, it's unclear if the CNCC principle applies to the ADR Program. Since D.17-10-017 exempts DRAM and pilots from the CNCC principle, it would be prudent to also exclude the ADR Program since DRAM and pilots are eligible for Auto-DR incentives. But there are still many implementation questions that need to be answered as to how the existing CNCC principles impact the IOUs' ADR Programs. The Joint IOUs seek clarity from the CPUC at the Commission's ADR workshop regarding this matter.

Should third party DRPs with ADR enabled end-uses require authorization by manufacturer/service provider in order to qualify for ADR incentive?

In PG&E's reply comments to other parties' opening comments on the 2018-2022 DR Proposed Decision, PG&E stated that:

> *The Joint DR Parties indicate that only third-party DRPs with programmatic device control "authorized by both the manufacturer/service provider and the customer should be able to make the $75 PCT incentive available to their customers." PG&E assumes this comment, while directed at SCE's program, also applies to PG&E's proposed residential ADR Program. PG&E cautions that such policy would require all manufacturers and service providers to share their "authorized" third party partners with the utilities, and update this authorized list for ADR rebate processing. It is unclear to PG&E if all ADR enabling technology manufacturers and service providers would be willing to take on such a task. In addition, this new requirement would create additional administrative cost to the ADR Program when implementing product eligibility.*

PG&E believes that the ADR workshop will be an appropriate channel to discuss this suggestion by Joint DR Parties since all the parties that are interested in contributing toward ADR Program design will likely participate in the Commission's ADR workshop.

SCE and SDG&E support the Joint DR Parties' proposed requirement that "*only third-party DRPs with programmatic device control "authorized by both the manufacturer/service provider and the customer"* should be able to receive technology incentives. When third parties attempt to control devices without manufacturer and/or customer permissions, the manufacturer or customer cannot prohibit the device from being controlled by more than one demand response provider. In addition, SDG&E is committed to protecting customer privacy and therefore does not support 3rd party demand response providers adjusting customer technology settings by requiring customers to supply their technology passwords. Eligible third-party providers should be sending an open ADR or other open protocol signal to the manufacturer cloud with the permission of the manufacturer.

The 3rd party authorization section above is another example of how the existing ADR Program design does not cover all aspects of the residential market. The residential ADR technology market is far more complex than the non-residential ADR technology market due to the number of actors involved and the different business models of each actor. The existing ADR Program design was developed 10 years ago and focused on non-residential customers. PG&E notices that some of the program designs may not be conducive for mass market/residential customers or technology vendors. In conclusion, PG&E proposes using the Commission's ADR workshop to focus on the development of future ADR Program designs (such as residential ADR technologies' eligibility frequency and eligible devices) that fit better with the current and future technology paradigms, and use the information to propose program redesign proposals for the mid-cycle filing.

APPENDIX A - Proposed Program Rules and Eligibility Requirements for Residential ADR Incentives

IOU Program Name	SCE PCT Incentive Program		PG&E AutoDR Incentive Program	SDG&E Technology Deployment (TD) Program
Customer Segment	Residential *(Bundled Only)*	Residential & SMB (<200kW)	Residential	Residential
Qualifying DR Programs	PTR-ET-DLC	CPP, CBP Res Pilot, DRAM[4]	Res CBP, DRAM, Smart Rate, SSP and XSP	AC Saver, rate with events, DRAM[4]
Minimum DR Program Enrollment Requirement	No minimum DR program requirement at this time. Will evaluate the effectiveness and determine if changes need to be made in the mid-cycle review.		1 year or 1 DR season, depending on the DR program requirement	No minimum DR program enrollment requirement
Incentive/Rebate Amount	$75		$50 for Smart Thermostat. Incentive for other technologies (TBD)	$50
Incentive/Rebate Cap	One incentive per service account[5]		One rebate per household for Smart Thermostat. rebate cap for other incentivized technologies (TBD)	Two rebates/incentives per household
Incentive/Rebate Recipient	Bill credit issued to customer	Bill credit issued to customer *(eventually same process and payment structure as EE incentives; TBD in mid-cycle)*	Rebate check to customer	Gift card issued to customer
Frequency of Incentives	Technology Useful Life, subject to change at mid-cycle *(currently 11 years per the approved EE workpaper)*			5 years (depreciation period used in DR C/E calculations)
Evidence of Purchase	Device registration and verification w/ authorized 3rd party	Evidence of device registration and verification w/ an authorized 3rd party	Customer required to upload copy of receipt for Smart Thermostat. Evidence of Purchase for other technologies TBD	Device verification w/ authorized 3rd party
Controllability/Technology Registration Requirement	Authorized third-party must be able to receive OpenADR signal	Qualifying devices must be able to communicate to SCE's VTN or through an authorized third-party that communicates with SCE's VTN.	The ADR signal uses one or a combination of qualified open-based standards (OpenADR 2.0, Smart Energy Profile 1.1/2.0, or any other standard that is listed in the Smart Grid Interoperability Panel Catalog of Standards). Compliance testing can be done at the manufacturer's internet/cloud application level rather than at the end-use device level itself.	Currently, authorized third-party must be able to receive OpenADR signal. Other open standards may become eligible in the future.
Eligible Measures	PTR-ET-DLC Qualifying Thermostats	Qualifying Thermostats that meet the above requirement.	Smart Thermostat. Other technologies in the future based on the ADR stakeholder collaborative process	Controllable Thermostat. Other technologies in the future based on the stakeholder collaborative process
Application Process	PTR-ET-DLC Landing Page https://pages.email.sce.com/SCESmartBonus/	Online	PG&E eRebate and hardcopy application process (www.pge.com/rebates)	Online
Double Dipping Validation ***(cannot receive multiple incentives)***	During eligibility verification process, Customer's Service Account (SA) will be validated that only one incentive was issued to the SA based upon the EUL identified above.		During eligibility verification process, Customer's Service Account (SA) will be validated that only one incentive was issued to the SA based upon the EUL identified above.	During eligibility verification process the customer service account will be validated.

[4] Changes in red reflect modifications in compliance with D.17-12-003.

[5] Customers that receive a free smart thermostat through an existing ratepayer-funded incentive program or pilot are not eligible for an additional PCT incentive.

APPENDIX B – Proposed Program Rules and Eligibility Requirements for Large C&I ADR Incentives

IOU Program Name	SCE ADR Customized [6]	PG&E ADR Program	SDG&E ADR Program
Customer Segment	Large Commercial, Industrial, & Agricultural (must provide at least 30kW of automated load reduction)	Large Commercial, Industrial, & Agricultural	Commercial, Industrial, & Agricultural
Qualifying DR Programs	CBP, CPP, RTP, DRAM, or Other Qualifying Pilots[7]	PDP, CBP, DRAM, SSP and XSP	CBP, CPP, DRAM or Other Qualifying Pilots[7]
Minimum DR Program Enrollment Requirement	Must be enrolled in a Qualifying DR Program for at least 36 consecutive months		
Incentive Type	Calculated		
Incentive Structure	60% / 40% Split Incentive Payment		
Incentive Level	$200 per kW		
Incentive Calculation Methodology	Incentive calculated based upon verified load shed test *(e.g. subject to 2-hour M&V test)*	Incentive based upon engineering calculations and/or verified load shed test, whichever is lower	Incentive based upon engineering calculations and/or verified load shed test
Incentive Project Cap of Eligible Costs	75% of total actual eligible costs		
Incentive/Rebate Cap	$5 million per customer per funding cycle; Individual SAs requesting incentives >$200k must sign an LOA	Not Applicable	
Incentive/Rebate Recipient	Rebate check issued to customer		
Frequency of Incentives	One time. Customer can re-apply for incentives if they can demonstrate incremental kW.	Technology Useful Life, subject to change at mid-cycle	twice (based upon the 60/40 split payment methodology)
Evidence of Purchase	Customers must provide receipts for actual costs incurred	Customers must provide receipts for actual costs incurred	Customer required to provide invoices and/or documentation to support measure costs. Such documents must comply with SDG&E's Invoicing Guidelines and (6) Any other documents related to the Project, Project Site, measures, load reduction (kW) or otherwise requested by SDG&E.
DR Event Signal	Dispatch signal or instructions from SCE VTN to Customer VEN	Direct to building EMS or devices	
Controllability/Technology Registration Requirement	Customer's ADR device/client must be OpenADR 2.0 certified and be connected to Utility's DRAS[8] For PG&E, please refer to Controllability/Technology Registration Requirement in Appendix A.		
Eligible Measures	ADR enabled equipment that facilitates sitewide automatic load reduction such as controls for lighting, motors, pumps, fans, air compressors, process equipment, HVAC load control devices, etc.		
Application Process	Submission of hard copy ADR application and customer agreement		

[6] ADR Program incentives cannot be provided to customers that have received rebates, incentives, funding, or services for measures and/or costs from other utility, third party, or government (federal, state, or local) program funded by public purpose funds, taxpayers, or utility Request For Offer (RFO) solicitations, unless explicitly exempted.

[7] Changes in red reflect modifications in compliance with D.17-12-003.

[8] DRAM participants are not required to be connected to Utility's DRAS because DRAM participants receive dispatch instructions from their third-party demand response provider.

APPENDIX C – Proposed Program Rules and Eligibility Requirements for SMB ADR Incentives

IOU Program Name	SCE PCT Incentive	SCE ADR Express [9]	PG&E Fast Track	SDG&E Small Commercial Energy Management Pilot[10]	SDG&E TD Program
Customer Segment	See details in Appendix A	Small Retail Stores, Small Office (<100,000 sq ft), and Food Stores (including liquor stores)	SMB	SMB (with no less than 3 locations: =<20kW peak demand per site)	Commercial
Qualifying DR Programs		CBP, CPP, RTP, DRAM, or Other Qualifying Pilots[11]	PDP, CBP, DRAM, SSP and XSP	CBP, CPP, DRAM or Other Qualifying Pilots[11]	AC Saver, rate with events, CBP, DRAM[11]
Minimum DR Program Enrollment Requirement		Must be enrolled in a Qualifying DR Program for at least 36 consecutive months		Must be enrolled in a Qualifying DR Program for at least 24 consecutive months	One-Year
Incentive Type		Deemed		Calculated	Deemed
Incentive Structure		100% Up-Front			
Incentive Level		Up to $300/kW	$200/kW		TBD (based upon $100/kW)
Incentive Calculation Methodology		Incentive based upon pre-determined kW reduction potential of the specific measure		Incentive based upon verified dispatchable load reduction	
Incentive Project Cap of Eligible Costs		100% of project cost		Capped at 50% of the actual project cost (including the purchase price & costs for installation by a third-party)	Cost of the technology
Incentive/Rebate Cap		$1 million per customer per funding cycle (Incentive requests >$200k require a Letter of Agreement)	Not Applicable	$10,000 or cost cap, whichever is lower	
Incentive/Rebate Recipient		Rebate check issued directly to customer			Customer or Vendor/Installer
Frequency of Incentives		One time. Customer can re-apply for incentives if they can demonstrate incremental kW.	Technology Useful Life, subject to change at mid-cycle	One time	5 years, used in DR C/E calculations
Evidence of Purchase		Customers must provide receipts for actual costs incurred	Customers must provide receipts for actual costs incurred	Customers require to invoices and/or documentation to support measure costs. Such documents must comply with SDG&E's SBCP Invoicing Guidelines.	Device verification w/ authorized 3rd party
DR Event Signal		Dispatch signal or instructions from SCE VTN to Customer VEN	Direct to building EMS or devices	Direct to device or through manufacturer's cloud	Currently, authorized third-party must be able to receive an OpenADR signal. Other open standards may become eligible in the future.
Controllability/Technology Registration Requirement		Customer's ADR device/client must be OpenADR 2.0 certified and be connected to Utility's DRAS[12]. *For PG&E, please refer to Controllability/Technology Registration Requirement in Appendix A.*		The ADR signal uses one or a combination of qualified open-ADR standards (OpenADR 2.0a or 2.0b).	
Eligible Measures		Systems that control standard lighting and HVAC technologies		All controllable devices that meet communication protocol requirement are commercially available and are cloud based.	Controllable Thermostat. Other technologies in the future based on the stakeholder process
Application Process		Submission of hard copy application and customer agreement			TBD

9 ADR Program incentives cannot be provided to customers that have received rebates, incentives, funding, or services for measures and/or costs from other utility, third party, or government (federal, state, or local) program funded by public purpose funds, taxpayers, or utility Request For Offer (RFO) solicitations, unless explicitly exempted.
10 Part of AB793. Marketed as the Small Business Real Time Energy Manager (SBREM).
11 Changes in red reflect modifications in compliance with D.17-12-003.
12 DRAM participants are not required to be connected to Utility's DRAS because DRAM participants receive dispatch instructions from their third-party demand response provider.

Attachment E – White Paper

Reliability Demand Response Resource Dispatch Clarification

California Independent System Operator Corporation

Reliability Demand Response Resource Dispatch Clarification

White Paper

March 5, 2019

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1. Executive Summary

The CAISO proposes to amend its tariff to clarify when it will dispatch reliability demand response resources (RDRR). CAISO tariff section 34.7(13) currently provides that the CAISO may make RDRR eligible for dispatch in accordance with the applicable Operating Procedures either: (a) after issuance of a warning notice and immediately prior to a need for the CAISO to attempt to obtain assistance from neighboring Balancing Authorities or imports; (b) during stage 1, stage 2, or stage 3 of a system emergency; or (c) for a transmission-related system emergency. Consistent with the California Public Utilities Commission's (CPUC) recent Decision (D.) 18-11-029, the CAISO proposes to clarify that RDRR is eligible for dispatch after issuance of a warning notice without any additional conditions.

2. Stakeholder Engagement Plan

Date	Milestone
March 5, 2019	**White paper and tariff amendment**
March 11	**Comments due on white paper and tariff amendment**
March 15	**Conference call**
March 29	**File tariff amendment with FERC**

3. Background

On June 24, 2010, in D.10-06-034 the CPUC approved a multi-party settlement in its demand response proceeding (R.07-01-041) that required investor-owned utilities to transition their CPUC-approved retail emergency-triggered demand response programs into a CAISO reliability demand response product.[1] The settlement specified the minimum operating and technical requirements for retail emergency-triggered demand response resources. The CPUC settlement also required these resources be made available for dispatch earlier under CAISO emergency operating procedures.

To fulfill the terms of the CPUC settlement, the CAISO developed the RDRR product. On October 26, 2010, the CAISO Board of Governors authorized the RDRR product. The Board of Governors memorandum approving the RDRR product specifically noted that it would enable the CAISO "to dispatch these emergency-triggered programs when and where they are needed and, appropriately, reflect their value in the [CA]ISO market."

[1] *Decision Adopting Settlement Agreement on Phase 3 Issues Pertaining to Emergency Triggered Demand Response Programs,* June 25, 2010, available at: http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/119815.pdf.

On May 20, 2011, the CAISO filed its initial tariff amendment with the Federal Energy Regulatory Commission (FERC) to implement its RDRR product (Docket No. ER11-3616).[2] FERC rejected the CAISO's RDRR product proposal and the CAISO subsequently submitted a compliance filing for the RDRR product and FERC Order No. 745[3] (Docket No. ER11-3616 ad ER11-41-00) on March 14, 2012.[4] FERC issued an order on July 18, 2013 accepting in part and denying in part the CAISO's compliance filing (Docket No. ER11-3616 and Docket No. ER11-4100), and directed the CAISO to submit a further compliance filing.[5]

On August 19, 2013, the CAISO submitted a subsequent filing in compliance with FERC's July 2013 Order (Docket No. ER11-3616 and Docket No. ER13-2192),[6] with the currently effective language in section 34.7(13) of the conformed CAISO tariff.[7] This language provides general dispatch principles for RDRRs. This section was adopted "to be fully consistent with the terms of the CPUC settlement agreement and ISO emergency operating procedures."[8] In its August 19, 2013 compliance filing, the CAISO noted that it revised this section "to reflect the [dispatch] trigger more accurately, providing that the [CA]ISO may consider bids from reliability demand response resources prior to seeking assistance from neighboring balancing authority areas and entities not otherwise obligated to comply with an ISO dispatch."[9] This language was accepted by FERC in March of 2014.[10]

In late 2018, the CPUC issued D.18-11-029, which clarified that "the use of RDRR can occur anytime within the Warning Stage, in the case of In-Market dispatch and Out-Of-Market or exceptional dispatch. This dispatch flexibility is consistent with the Settlement and D.10-06.034."[11] Based on this clarification, the CAISO seeks to update the tariff's general dispatch principles for RDRR resources.

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[2] The CAISO's RDRR tariff amendment is available at http://www.caiso.com/Documents/2011-05-20_RDRRAmendment_ER11-3616-000.pdf.

[3] *Demand Response Compensation in Organized Wholesale Energy Markets*, FERC Order No. 745, 134 FERC ¶ 61,187 (2011).

[4] The CAISO's compliance filing is available at http://www.caiso.com/Documents/2012-03-14_ER11-4100_NetBenefits-RDRR_Comp.pdf.

[5] *Cal. Indep. Sys. Operator Corp.,* 144 FERC ¶ 61.047 (2013), P 62 fn. 47 (July 2013 Order).

[6] The CAISO's August 19, 2013, compliance filing is available at http://www.caiso.com/Documents/Aug19_2013Compliance-ReliabilityDemandResponseResourceER13-2192-000.pdf.

[7] The language was initially added to section 34.5 in the CAISO's August 19, 2013 compliance filing, and later moved to section 34.7 in the CAISO's Order No. 764 compliance filing (*Integration of Variable Energy Resources*, FERC Order No. 764, 136 FERC ¶ 61,246 (2012)), available at http://www.caiso.com/Documents/Nov27_2013_TariffAmendment-ComplianceFERCOrder764_ER14-495.pdf, *Cal. Indep. Sys. Operator Corp.,* 146 FERC ¶ 61,205 (2014).

[8] August 19, 2013 compliance filing at p. 4.

[9] *Id.*

[10] *Cal. Indep. Sys. Operator Corp.,* 146 FERC ¶ 61,233 (2014).

[11] *Decision Resolving Remaining Application Issues for 2018-2022 Demand Response Portfolios and Declining to Authorize Demand Response Auction Mechanism Pilot Solicitations*, D.18-11-029, dated November 29, 2018, at p. 40, available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M248/K670/248670669.pdf.

4. Proposed Resolution

The CAISO proposes to modify CAISO tariff section 34.7(13) to clarify when it will dispatch RDRRs.

Proposed Tariff Amendment:

34.7 General Dispatch Principles

The CAISO shall conduct all Dispatch activities consistent with the following principles:

* * * * *

(13) The CAISO may make Reliability Demand Response Resources eligible for Dispatch in accordance with applicable Operating Procedures either: (a) after issuance of a warning notice ~~and immediately prior to a need for the CAISO to attempt to obtain assistance from neighboring Balancing Authorities or imports~~; (b) during stage 1, stage 2, or stage 3 of a System Emergency; or (c) for a transmission-related System Emergency.

The CAISO will request that this clarification become effective July 1, 2019.

5. Next Steps

The CAISO will discuss this white paper and the proposed tariff amendment with stakeholders during a conference call on March 15, 2019. Stakeholders are asked to submit written comments by March 11, 2019, to initiativecomments@caiso.com.