Rulemaking No.: 20-11-003

Exhibit No.: Joint Parties-01

Witness Greg Wikler

Commissioner Marybel Batjer

ALJ Brian Stevens

OPENING PHASE 2 PREPARED TESTIMONY OF THE JOINT PARTIES (California Efficiency + Demand Management Council, ecobee Inc., Leapfrog Power, Inc., and Oracle)

Rulemaking 20-11-003
2021 Extreme Weather Event Reliable Electric Service

September 1, 2021

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I. EXECUTIVE SUMMARY

The Joint Parties are made up of the following parties: the California Efficiency + Demand Management Council ("The Council"), ecobee Inc. ("ecobee"), Leapfrog Power, Inc. ("Leap"), and Oracle.

- **The Council**: The Council is a statewide trade association of non-utility businesses that provide energy efficiency ("EE"), demand response ("DR"), and data analytics services and products in California.[1] Our 65+ member companies (including DR providers CPower, Enel, Google, Leap, OhmConnect, Oracle, and Olivine) employ many thousands of Californians throughout the state. They include EE, DR, and distributed energy resource ("DER") service providers, implementation and evaluation experts, energy service companies, engineering and architecture firms, contractors, financing experts, workforce training entities, and EE product manufacturers. The Council's mission is to support appropriate EE and DR policies, programs, and technologies to create sustainable jobs, long-term economic growth, stable and reasonably priced energy infrastructures, and environmental improvement.
- **ecobee:** ecobee is a leading developer of smart thermostats that facilitate cost-effective load management. ecobee is a vendor of automation technology that, if fully leveraged, can enhance grid reliability in the event of an extreme weather event using automated tools that do not require energy expertise or even active engagement. In 2019, ecobee introduced a new thermostat optimization platform to facilitate cost-effective customer load management. This platform, eco+,1 is a free software upgrade for consumers that has been pushed out to existing ecobee smart thermostats2 to improve the energy performance of residential

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[1] Additional information about the Council, including the organization's current membership, Board of Directors, antitrust guidelines and code of ethics for its members, can be found at http://www.cedmc.org. The views expressed by the Council are not necessarily those of its individual members.

HVAC systems by offering personalized energy efficiency, time-of-use, and demand response optimization.

- **Leap:** Leap is a Demand Response Provider ("DRP") founded in 2017 and headquartered in San Francisco, California. The company provides DR services to residential, commercial, industrial, and agricultural customers throughout the state of California. Through its technology platform, Leap enables distributed energy resource providers in California to become grid participants, both adding revenue for their customers and integrating additional demand-side resources into California electricity system. Leap believes that demand-side resources integrated into California's wholesale electricity market will play a key role in helping California achieve a resilient and zero carbon future.
- **Oracle:** Oracle (formerly Opower, Inc.) has delivered Opower's behavioral energy efficiency, demand response, and customer engagement services to over one hundred electric and natural gas utilities across ten countries and thirty-five states, including California. To date, these programs have saved nearly 30 terawatt-hours of energy. In 2020 alone, the Opower behavioral energy efficiency program is projected to drive over 350 GWh of savings across the three electric IOUs. Oracle appreciates this opportunity to provide input on the Commission's Order Instituting Rulemaking on Emergency Reliability ("OIR"). Oracle's comments are based on the 12+ years of behavioral DSM experience contained in the Opower platform, which has been implemented by more than 100 utilities around the world.

Rulemaking (R.) 20-11-003 is the Order Instituting Rulemaking ("OIR") to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021. On December 18, 2020, Administrative Law Judge ("ALJ") Stevens issued a Ruling Introducing a Staff Report and Questions to the Record and Seeking Responses from Parties in Opening and Reply Testimonies ("December 18 ALJ Ruling"). Attached to the December 18 ALJ Ruling is the Staff Proposal and Guidance to Parties for their January 2021 Proposals ("Staff Proposal and Guidance"). On December 21, 2020, Assigned Commissioner

Batjer issued an Assigned Commissioner's Scoping Memo and Ruling ("Scoping Memo").

On January 11, 2021, the DR Coalition[2] submitted the Opening Prepared Testimony of the DR Coalition. On February 10, 2021, ALJ Stevens issued a Ruling Identifying and Receiving Exhibits into Evidence. In this Ruling, the Opening Prepared Testimony of the DR Coalition was received into evidence as Exhibit ("Ex.") DRC-1. The DR Coalition proposed revisions to the investor-owned utilities' ("IOU") DR programs, a supplemental Demand Response Auction Mechanism ("DRAM") Pilot budget, a behavioral DR program, an Emergency Load Reduction Program Pilot, and a pathway to rapidly distribute 100,000 smart thermostats for deployment in IOU or third-party DR programs.[3] In addition, on January 19, 2021, the DR Coalition submitted the Rebuttal Prepared Testimony of the DR Coalition which was received into evidence as Ex. DRC-2 on February 10, 2021.

On January 11, 2021, ecobee submitted the Opening Testimony of Tamara Dzubay on behalf of ecobee Inc. which made the following recommendations: (1) direct funding to modernize the Flex Alert program to incorporate smart thermostats during grid emergencies, (2) remove the IOU account number enrollment requirement of existing Bring Your Own Thermostat DR programs, and (3) increase the amount and availability of smart thermostat rebates available through existing electric IOU programs.[4] On February 10, 2021, ecobee's Opening Testimony was received into evidence as Ex. ECOB-1.

Subsequently, the Commission issued Decision ("D.") 21-03-056 which was the Decision directing Pacific Gas and Electric Company ("PG&E"), Southern California Edison Company ("SCE"), and San Diego Gas & Electric Company ("SDG&E") to take actions to prepare for potential extreme weather in the Summers of 2021 and 2022.

On July 21, 2021, the Council submitted the Reply Prepared Testimony of the Council ("Ex. Council-01"). In Ex. Council-01, the Council addressed the Supplemental

[2] The DR Coalition are comprised of the Council, Google LLC, Leapfrog Power, Inc., NRG Energy, Inc., OhmConnect Inc., Oracle, Tesla, Voltus, Inc., and Willdan.
[3] Ex. DRC-1, at p. 5.
[4] Ex. ECOB-1, at p. 2, lines 18-23.

Testimony of PG&E and Supplemental Testimony of California Environmental Justice Alliance ("CEJA") which were submitted in this proceeding on July 7, 2021.[5] In Ex. Council-01, the Council generally supported the PG&E Power Saver Rewards Pilot and the CEJA Just Flex Rewards Pilot.

On August 10, 2021, Assigned Commissioner Batjer issued an Amended Scoping Memo and Ruling for Phase 2 ("Amended Scoping Memo"). The Amended Scoping Memo states that "[a]ll proposals submitted by parties, but not addressed in the Phase 1 decision, may be considered in this Phase. If a party recommends such a proposal, it shall refer to the proposal in its Opening Testimony or Opening Brief."[6] The Amended Scoping Memo also states that Phase 2 of this proceeding will examine additional supply and demand-side resources and changes to current requirements needed to meet Governor Newsom's July 30, 2021 emergency proclamation ("Governor's Emergency Proclamation") which include modifications to existing supply-side demand response programs and new demand response programs or pilots.[7]

On August 16, 2021, ALJ Stevens issued a Ruling Issuing Developed Staff Concepts Proposal Document and Seeking Comment in Opening Testimony Due September 1, 2021 ("August 16 Ruling"). Attached to the August 16 Ruling is the "Energy Division Staff Concept Paper Proposals for Summer 2022 and 2023 Reliability Enhancements" ("Staff Concept Proposals").

By this Testimony, Ex. Joint Parties-01, the Joint Parties continue to support the proposals set forth by the DR Coalition in Ex. DRC-1 and by ecobee in Ex. ECOB-1, neither of which were adopted in D.21-03-056. Pursuant to the guidance provided in the Amended Scoping Memo as well as the August 16 Ruling, the Joint Parties re-submit some of the Phase 1 DR Coalition and ecobee proposals, propose additional new ones, and address the Staff Concept Proposals. For the sake of simplicity, the Joint Parties have combined its proposals with responses to Energy Division proposals.

[5] Ex. Council-01, at p. 1.
[6] Amended Scoping Memo, at p. 6.
[7] _Id_., at pp. 4-5.

II. SUMMARY OF THE JOINT PARTIES' TESTIMONY

The Joint Parties submit the following recommendations to the Commission:

- Emergency Load Reduction Program ("ELRP")
    - Increase the ELRP incentive to $2/kWh for all participants with no additional load curtailment commitment than is already required under the pilot's rules.
    - Base Interruptible Program ("BIP") customers should be compensated for ELRP event hours that are not overlapping with BIP events.
    - A day-of trigger for Group B ELRP participants should be added.
    - Group B ELRP participation should not be conditioned on a bid cap.
    - ELRP should be opened to direct-enrolled and third-party residential customers on an opt-in basis.
    - Flex Alert should be added as a potential ELRP trigger for residential and non-residential participants and DR aggregators must have an avenue for receiving compensation for broadly automating a response to Flex Alerts during system emergencies.
    - ELRP Group B should be expanded to include non-DR customers.
- Demand Response Auction Mechanism ("DRAM")
    - The Commission should adopt a supplemental 2022 auction and an expanded 2023 budget.
    - The Commission should not adopt additional DRAM requirements in this proceeding.
- Electric Vehicle/Vehicle to Grid Integration ("EV/VGI") Aggregation Pilot
    - The Commission should:
        - Extend eligibility to residential customers.
        - Confirm the eligibility for V1G or V2G aggregations of at least 25 kW of incremental load reduction ("ILR") in a single IOU territory to participate in Group A.3 as part of a standalone VGI-focused pilot.

            - Base ILR settlements on electric vehicle supply equipment ("EVSE") submetering data if located behind a host site meter, to review interconnection rules to enable streamlined and affordable access to EVSE with bi-directional capabilities, and to guarantee at least 30 hours of ELRP dispatches per season.

- If the Commission does not adopt a supplemental 2022 DRAM auction and augmented 2023 DRAM budget, it should approve an IOU solicitation for bilateral DR contracts.
- Smart Controllable Thermostats ("SCT") Related Changes to Energy Efficiency Programs.
    - Limiting SCT deployment to specific climate zones is discriminatory and would limit incremental load curtailment.
    - Customers receiving a smart thermostat incentive should be required to enroll in a DR program.
    - The Commission should accelerate the use of the combined EE-DR cost effectiveness test, especially for SCT incentives.
    - The administration of Automated Demand Response ("ADR") technology incentives, and specifically the incentives for SCTs, should be extended to third-party DRPs that provide California Independent System Operator ("CAISO")-integrated DR programs.
- The Commission should raise, eliminate, or suspend the 8.3% DR procurement cap.
- The Commission should direct Flex Alert cross-marketing with other DR programs.
- Customers should not be required to provide their customer account number to enroll in BYOD programs.
- The Commission should allow prohibited resources using Renewable Portfolio Standard-eligible biofuels for all DR programs.
- Capacity Bidding Program ("CBP")

- The Commission should explicitly authorize use of the CAISO's new baseline options for CBP and DRAM capacity settlement.
- The Commission should approve an SCE and SDG&E CBP Elect.

III. JOINT PARTIES PROPOSALS AND RESPONSE TO THE ENERGY DIVISION PROPOSALS

A. ELRP

1. The ELRP Incentive Should be Increased to $2/kWh for All Participants.

The Governor's Emergency Proclamation created a state-funded DR program with a very similar design to the ELRP with the primary difference that the incentive is up to $2/kWh rather than the $1/kWh ELRP incentive. This significantly higher incentive appears to be proving more attractive among some current and potential ELRP participants than the ELRP itself. The discrepancy in incentive levels has provided an unfortunate disincentive to ELRP participation. Some DRPs have experienced customers considering enrolling in the ELRP, but with the issuance of the Emergency Proclamation, are now sitting on the sidelines waiting for an increased ELRP incentive to be offered to them. If the Commission is committed to the success of the ELRP, it must be more attractive to DR providers ("DRP") and customers.

The Energy Division's Staff Concept Proposals to apply this higher incentive to Group A.1 customers and Group A.2 aggregators is certainly a good start but the higher incentive should also be applied to Group A.3 and A.4 customers as well as all Group B customers.[8] There is no good reason why all ELRP customers should not be compensated equally when their load curtailments have the same value to the grid, especially if the goal is to maximize curtailed load during ELRP events.

In addition, the higher incentive should not be conditioned on a committed amount of load curtailment. This would be counter to the purpose of the ELRP as a voluntary, best-efforts pilot and could prove counterproductive because it would discourage those customers who are unable to commit to a sufficiently-defined response from participating.

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[8] Staff Concept Proposals, at p. 7.

2. BIP Customers Should be Compensated for ELRP Event Hours That Are Not Overlapping with BIP Events.

In approving the ELRP, D.21-03-056 directed that Group A.2 (BIP Aggregators) customers may only be compensated for Incremental Load Reduction ("ILR") below the customer's pre-committed Firm Service Level ("FSL") when the ELRP event coincides with a BIP event.[9] In other words, BIP customers cannot be compensated for ELRP events if they occur outside of an event or on a day when a BIP event does not occur.

The Joint Parties recommend the Commission revise this policy because it unnecessarily limits the ability of BIP customers to provide often significant load reduction when reliability conditions do not warrant a BIP dispatch. This would encourage BIP customers to maintain their load reductions following the conclusion of a BIP event and to provide their curtailment on days when a BIP has not been called. The Joint Parties recognize the potential concern that a BIP event may be called on the same day of an ELRP event which could render the customer unavailable to curtail load under the BIP. To counter that concern, Group A.2 customers would maintain their responsibility to respond to a BIP event, even if it occurs on the same day after an ELRP event. Should a partially- or fully-overlapping BIP event occur during an ELRP event, customers would only be compensated for their ILR below the FSL while both program events overlap.

3. A Day-Of Trigger for Group B Participants Should be Added.

The Joint Parties strongly support the Energy Division proposal to add a day-of trigger in response to a CAISO Alert, Warning or Emergency ("AWE") declaration.[10] This will add additional load curtailment potential on days when the CAISO's AWE declaration is made for the same day which occurred on a handful of occasions in July of this summer. During these events, Group A ELRP participants were dispatched but Group B customers were not. Had IOUs been directed to implement involuntary load shedding on those day, the economic cost and interruption to peoples' lives would have been at least partially avoided through the Group B customers' added curtailment

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[9] D.21-03-056, Attachment 1, at p. 10.
[10] Staff Concept Proposals, at p. 8.

capability. Even in the absence of blackouts, this was a suboptimal outcome because highly motivated customers were standing by on these days to curtail their load or were already being dispatched in the day-ahead market, and the grid was unable to benefit from their incremental contributions.

4. The Commission Should Not Condition Group B ELRP Participation on a Bid Cap.

The Joint Parties continue to have a philosophical objection to any form of energy market bid cap because it will almost always eliminate those potential or existing DR customers whose opportunity costs lay above the bid cap. This outcome would be at odds with the primary purpose of this proceeding, which is to add additional supply- and demand-side resources. Should the Commission ultimately adopt a bid cap, it should be expressed in the form of a percentage of the market bid cap to ensure flexibility in the event the CAISO market bid cap ever increases in the future. In other words, the proposed $900/MWh bid cap would translate into a 90% bid cap under a $1000/MWh CAISO market cap and $1800/MWH should the CAISO market cap ever be increased to $2000/MWh.

5. ELRP Should be Opened to Direct-Enrolled and Third-Party Residential Customers on an Opt-In Basis.

The Joint Parties fully support the Staff proposal to open Group A.1 participation in the ELRP to residential customers,[11] but this should be done on an opt-in basis only because of the significant potential for free ridership for this type of program and the potential for delays when the customers enroll with a third party.

The Joint Parties want to draw a distinction in this instance between an opt-out ELRP versus an opt-out behavioral DR ("BDR") program. An opt-out BDR program can be effective on the condition that 1) customers already enrolled in a DR program are not forced off that program in the process of their being defaulted to the BDR program, and 2) the process for customers to opt-out to enroll in another DR program is simple and seamless.

[11] Staff Concept Proposals, at pp. 8-9.

It is understandable that the Commission would want to take every reasonable measure to maximize customer load curtailments when they are needed most but compensating customers for incidental, rather than intentional, load curtailment defeats the purpose of a DR program which should be to motivate active load curtailment. Furthermore, automatically enrolling residential customers in ELRP could create friction when these customers attempt to authorize third-party access of their data through Electric Rule 24/32 or when they attempt to enroll with a third-party provider. Though the Energy Division proposed that customers would simply be removed from ELRP when enrolling in a supply-side program, the reality is that delays have occurred due to lengthy IOU timelines by which a customer can be removed from an existing DR program. Alternatively, if eligible Group B customers are expanded to include non-DR customers (similar to Group A.1 customers) and were thereby not required to participate in the CAISO market, or if the IOUs were required to implement instantaneous unenrollment, then this "friction" problem should be eliminated.

The Commission should take the additional step of opening Group B participation to residential customers as well. Residential aggregators and DRPs have been highly effective in enrolling large numbers of customers and can easily deploy them as either ELRP-only customers or in conjunction with their participation in CBP, DRAM, or load-serving entity ("LSE") contract. This optionality that DRPs could provide would be attractive for residential customers because it would avoid a one-size-fits-all approach. In addition, any potential concerns about incrementality for dual participating residential customers (i.e., customer participating through a DRP in both the ELRP and a supply-side program) would be addressed just as they currently are with non-residential Group B customers. If the Commission also approves Group B to include non-DR customers (i.e., customers not also enrolled in a supply-side program), the incrementality issue would be moot.

The Joint Parties recognize that the Staff's proposal to provide bill credits to direct-enrolled customers would not be workable for Group B residential customers.[12] Instead, performance could be measured, and payments made directly to third parties in

[12] Staff Concept Proposals, at p. 9.

a similar manner to how it is done for the residential Capacity Bidding Program ("CBP"). The Joint Parties invite IOU feedback on this proposal, especially with regard to the technical feasibility, in their respective Reply Testimonies.

The Energy Division's proposal is silent on exactly what baseline would be used to determine the ILR of residential participants. The Joint Parties recommend that the Commission adopt a 5-in-10 baseline to maintain consistency with the IOUs' respective residential CBP (in the case of PG&E and SCE) or residential CBP Pilot (in the case of SDG&E). The reasons for adopting this baseline for residential customers do not change simply due to a change in DR program. Furthermore, a 5-in-10 baseline is more accurate than a 10-in-10 baseline during extreme heat events, which likely best represents the conditions under which the ELRP would be called. As was seen during the August and September 2020 heat events, temperatures during a heat event are often significantly greater than the days and weeks leading up to the event. So, under a 10-in-10 baseline, the prior ten "similar" days used to calculate the baseline are based on much cooler weather which reduces the amount of measured load curtailment.[13] Conversely, a 5-in-10 baseline can more easily incorporate the hotter days leading up to the event day which more accurately reflects the prevailing conditions during the actual DR event.

6. Flex Alert Should Be Added as a Potential ELRP Trigger for Residential and Non-Residential Participants and DR Aggregators Must Have an Avenue for Receiving Compensation for Broadly Automating a Response to Flex Alerts during System Emergencies.

The Energy Division proposal to add a day-ahead Flex Alert trigger for residential (should the ELRP be opened to them) and non-residential customers is sensible because it is an established brand and there is an existing communication infrastructure in place in the form of marketing and notification channels.[14] The conditions under which the CAISO calls a Flex Alert are fairly subjective which would be a concern if the

[13] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/demand-response-workshops/workshop-pdfs/ious_workshop-slide-deck.pdf
Starting on slide 229 see utility DR program evaluations compared to CAISO's evaluation of DR show that weather sensitive resources were undermeasured by CAISO in the final root cause analysis by the use of a 10 in 10 baseline.
[14] Staff Concept Proposals, at p. 9.

CAISO's Flex Alert served as a "hard" trigger in which the ELRP was required to be dispatched; however, because the IOUs have the flexibility to dispatch the ELRP at their discretion, there would be no danger of the CAISO exercising undue influence over out-of-market DR program dispatch. This trigger would also work with the opt-in approach discussed above because the updated Flex Alert marketing could provide information on how to enroll in ELRP with either IOUs or third-party providers. As discussed further below, Flex Alert marketing should be harnessed to promote participation in all IOU and third-party DR programs.

Presumably, a Flex Alert trigger for residential customers would be utilized through the California Energy Commission's ("CEC's") Market Informed Demand Automation Server ("MIDAS") which, among other things, will allow automation service providers to retrieve Flex Alert signals from the CAISO.[15] Through the MIDAS RESTful API, automation service providers and DR aggregators can now retrieve Flex Alert signals from the CAISO. This information can be used to automate customer end-uses but automation service providers and DR aggregators are needed to provide a broad automated response to the Flex Alerts, so the Commission must clarify how they will receive compensation for responding to Flex Alerts.

The Joint Parties recommend the Commission direct the IOUs to enter into agreements with vendors to signal devices not already enrolled in an existing DR program for this purpose, like the one already authorized for SDG&E.[16] Alternatively, the Commission could order the IOUs to forego the formal enrollment process for residential customers to get a CAISO Resource ID; this step, which at first glance would appear to be simple, has a significant impact on reducing participation rates to as low as 3% because many customers do not know their utility account number.[17] DR aggregators

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[15] The MIDAS is now publicly available at https://midasapi.energy.ca.gov.
[16] D. 21-03-056, at p. 39.
[17] Source: Energy Division's Evaluation of Demand Response Auction Mechanism – Final Report [Public Version – Redacted] at (Jan. 4, 2019), available at https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442460092 (citing EnergyHub, "Optimizing the demand response enrollment process"

must have an avenue for receiving compensation for broadly automating a response to Flex Alerts during system emergencies.

7. The Commission Should Expand Group B to Non-DR Customers.

The current ELRP rules governing Group B require that participating third-party customers be enrolled in a Proxy Demand Resource ("PDR"). The Joint Parties suggest that this is unnecessary if the customer is not already participating in a supply-side DR program. This only complicates participation, especially for customers who have no desire to participate in a supply-side capacity-based DR program.

B. EV/VGI AGGREGATION PILOT

Along with extending eligibility to residential customers, the Joint Parties support confirming the eligibility for V1G or V2G aggregations of at least 25 kW ILR in a single IOU territory to participate in Group A.3 as part of a standalone VGI-focused pilot. We also support the proposals to base ILR settlements on EVSE submetering data if located behind a host site meter, to review interconnection rules to enable streamlined and affordable access to EVSE with bi-directional capabilities, and to guarantee at least 30 hours of ELRP dispatches per season.

As discussed above, this latter piece on guaranteed revenue is particularly important if the Commission wants to encourage customers to install EVSE with bi-directional capabilities, which can be considerably more expensive than existing deployed smart EVSE that are solely capable of V1G functionality. To further encourage VGI pilot participation, the Joint Parties recommend establishing an up-front rebate for bi-directional EVSE purchase and installation, as well as reduced (or eliminated) interconnection application fees, in exchange for agreeing to participate through the duration of the ELRP pilot.

We would modify, or at least seek clarification on, proposed pilot element 1.3.iii. pertaining to virtual aggregations being "permitted" between separately-metered EVSE and a parallel host site meter. As proposed, these virtual pairings would never be allowed to result in a negative (net exporting) billing interval. Given that the pilot would be housed within Group A.3 that enables compensation for exporting Rule 21 resources, we question why this element was included in the proposal. If the rationale stems from a billing system issue, we recommend that resolving this issue be the focus of the Commission's directive, rather than not allowing net exports in this instance.

C. DRAM MODIFICATIONS

1. The Commission Should Approve a Supplemental 2022 Auction and an Expanded 2023 Budget.

In the view of the Joint Parties, other than ordering the IOUs to execute bilateral DR contracts, the DRAM remains one of the most efficient and effective way to procure significant amounts of DR capacity. The rules and infrastructure are already in place, so the only thing needed to increase DRAM procurement is to increase the budget. Therefore, the Joint Parties fully support a partial-year supplemental auction for June-December in the 2022 delivery year and an expanded budget for the 2023 auction. As the Staff proposal indicated, approximately 200 MW of August 2022 capacity were procured in the 2022 auction with a budget of $14 million.

The Joint Parties recommend a supplemental budget of $13 million for the 2022 and 2023 delivery years for a total of $27 million per year. In the Joint Parties' estimation this incremental budget would likely deliver approximately 150-175 MW of additional capacity for a total of approximately 350-375 MW per year in 2022 and 2023. This calculation is based on the drop off in procured DRAM capacity from the 2019 delivery year (with a total budget of $27 million) and the 2020 delivery year (with a budget of $14 million, prorated for a partial-year delivery). In 2019, a total of 369.94 MW of DRAM capacity was procured, whereas 206.05 MW were procured in 2020. This total augmented budget is consistent with the total budget for the two DRAM auctions for 2019 delivery, which was approved in D.19-07-009.[18] Given that the supplemental 2022 auction would be for the June - December period, the Commission should prorate the budget using the same methodology used in D.19-07-009 to calculate the prorated budget for the June – December 2020 auction. This methodology applied the weighted value of capacity used in each IOU's Capacity Bidding Program to each IOU's share of the annual budget.[19] The weights used were 86% for SCE, 95%

[18] D.19-07-009, at Ordering Paragraph 2.
[19] *Id.*, at pp. 32-33.

for PG&E, and 96% for SDG&E.[20] Maintaining the current budget split of $6 million/$6 million/$2 million for PG&E, SCE, and SDG&E, respectively, the $13 million 2022 supplemental prorated budget would be $5.29 million ($5.57 x 0.95) million for PG&E, $4.79 million ($5.57 million x 0.86) for SCE, and $1.78 million ($1.85 million x 96%) for SDG&E.

If the Commission were to adopt this proposal, the RFO schedule would need to be condensed because the DRAM Sellers' June supply plans will be due on April 1, 2022. Using the general timeline for the 2020 prorated auction, Joint Parties propose a tentative schedule for the supplemental 2022 auction and welcome IOU feedback in their Reply Testimony:

Table 1: Proposed Schedule for Supplemental 2022 DRAM RFO

Event	Date
Commission Phase 2 decision	11/18/21
IOUs issue supplemental DRAM RFO	11/25/21
DRAM RFO bidder's webinar	12/1/21
DRAM RFO package due	12/15/21
Cure period begins	1/7/22
Cure period ends	1/15/22
IOU notifies bidders of selection and sends final PA for execution	1/28/22
Advice letter filing for executed purchase agreements	2/22/22
June supply plans due for DRAM contracts	4/1/22

[20] Decision 19-07-009, at p. 33.

2. The Commission Should Not Adopt Additional DRAM Requirements in This Proceeding.

The Commission should refrain from using this proceeding, which is meant to procure additional supply-side and demand-side resources, to make changes to the existing DRAM requirements. The highly compressed timeline leaves very little time to consider changes to rules that were adopted in 2019 only after several workshops and rounds of party comments. Furthermore, the Commission risks circumventing the current DRAM evaluation process in which the Independent Evaluator assesses all aspects of the DRAM to inform recommended changes.

The Joint Parties fully support good performance by DRAM Sellers, but the Energy Division's proposed requirements are highly arbitrary and would be very disruptive to the DRAM market.[21] Any changes to DRAM requirements should be based on a well-informed record and developed through the processes that the Commission has adopted rather than haphazardly ramming them through in an expedited proceeding.

In response to the specific proposed changes, the Joint Parties continue to oppose an energy market bid cap. Though the latest proposal does not require a cap, it does attempt to coerce DRAM Sellers to self-impose one by discounting the value of bids for day-ahead only resources if they do not bid at $500/MWh or lower in the CAISO day-ahead market ("DAM"). Furthermore, a $500/MWh bid cap would prevent DRAM Sellers from accounting for their customers' use limitations and opportunity costs as their remaining number of monthly dispatches and hours approach their limits. This same argument applies to the proposed $900/MWh bid cap for resources participating in the CAISO's real-time market ("RTM").[22] The practical consequence of this would be fewer participating customers and less available capacity which would defeat the whole purpose of expanding the DRAM budget.

The DR Coalition addressed the dangers of a bid cap in its Phase 1 Opening Testimony[23] and The Utility Reform Network ("TURN") witness Florio summarized this

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[21] Staff Concept Proposals, at pp. 10-12.
[22] _Id_., at p. 8.
[23] *See, e.g.,* Ex. DRC-1, at p. 24, lines 12-26.

point perfectly in TURN's Phase 1 Opening Testimony response to the question of whether the Commission should adopt a PDR bid price cap:

> For all of the reasons I have discussed above, my answer to the staff question is a firm "NO". Because DR energy bids reflect the customer's value of service, the only thing that a bid cap would achieve is the elimination of those customers with a value of service higher than the DR bid cap from price-responsive DR programs like PDR. The result would be continued consumption by those customers and even higher market prices, as well as more emergency conditions on the grid due to the loss of DR MWs. Regulation cannot by fiat change customers' value of service, and attempting to do so would be a futile exercise.[24]

The proposal that a PDR be prohibited from being removed from a Supply Plan appears to be based on a misunderstanding that Supply Plan resources can have a zero MW value.[25] That is not the case. With this said, it is often necessary for some resources to be removed from Supply Plans in instances when the underlying customers provide seasonal load curtailment or when a resource's customer composition changes significantly to force consolidation with another resource.

The proposal to adopt a penalty structure based on the monthly Supply Plan relative to the contract capacity may have merit but is not supported by the record.[26] As stated above, the Commission should not seek to make significant changes to the DRAM in the absence of an assessment and recommendation by the DRAM Independent Evaluator.

The proposal to require capacity awarded in a supplemental 2022 auction and 2023 auction to be counted against the QC limit established through the 2021 and 2022 Load impact Protocol ("LIP") processes appears to be another attempt to fundamentally change the DRAM rules with no problem statement and with no supporting record. Furthermore, the CEC is already in the process of developing a DR QC methodology that would replace the LIPs, so linking DRAM QC values to a process that may not be utilized for much longer could very likely render this proposal moot, if adopted.

[24] Prepared Direct Testimony of Michael Peter Florio (Ex. TURN-1), at p. 17, lines 21 through 27.
[25] Staff Concept Proposals, at pp. 11-12.
[26] _Id_., at p. 12.

The Joint Parties also do not support the Energy Division proposal to require all LSE contracts with third-party DRPs to adhere to any DRAM requirements without a clear problem statement and a robust record to support it.[27] The Joint Parties see merit in allowing third parties to use the current DRAM qualifying capacity ("QC") methodology and we proposed this exact same approach in Track 2 of the Resource Adequacy ("RA") proceeding (R.19-11-009). However, DRPs have made significant investments to go through the LIP process for the 2022 RA year and it would be extremely unfair for the Commission to pull the rug out from underneath them and open the door for any DRP to contract with LSEs regardless of whether they have gone through the LIP process.

3. If the Commission Does Not Adopt a Supplemental 2022 Auction and Augmented 2023 Budget, It Should Adopt a Bilateral DR Solicitation.

Should the Commission choose not to approve a supplemental DRAM budget for 2022 and 2023, the Joint Parties propose that the IOUs be directed to issue RFOs for bilateral DR RA contracts. This would allow the IOUs to more easily tailor the resulting contracts to meet their specific needs rather than relying on the standard DRAM Purchase Agreement. This procurement method is well-established through the now-expired Aggregator Managed Portfolio ("AMP") program and is another effective way for the Commission to direct procurement of a specified amount of DR capacity. Cost recovery could be done through the Energy Resource Recovery Account ("ERRA") so the Commission could avoid increasing the DRAM budget until such time that the DRAM becomes a permanent program.

D. SCT-RELATED CHANGES TO ENERGY EFFICIENCY PROGRAMS

The Joint Parties are strongly supportive of efforts to expand the deployment of SCTs. Through the underlying nature of load that is controlled through SCTs, these devices deliver load reductions during the net peak, which is exactly the time of day targeted in this proceeding. Below, the Joint Parties address the Energy Division's SCT proposals and propose additional ones.

[27] Staff Concept Proposals, P. 12.

1. Limiting SCT Deployment to Specific Climate Zones is Discriminatory and Would Limit Incremental Load Curtailment.

The Joint Parties are generally supportive of targeted marketing efforts to customers with the greatest load drop potential. However, this should not be done at the expense of the participation of other customers and therefore, the Joint Parties cannot support the component of the Energy Division proposal to limit installation of SCTs to the hottest climate zones, which comprise roughly only a quarter of California households.[28] It is not clear what would be gained by limiting SCT uptake so it would be counter-productive to exclude the remaining three quarters of customers from all climate zones to provide load curtailment, even if the magnitude of load curtailment in cooler climate zones would likely be less. California is not in a position to turn away any reductions that a customer is interested and willing to provide.

Furthermore, the inclusion of thermostat optimization savings and the upcoming EE-DR cost effectiveness test will likely render all smart thermostats to be cost effective, regardless of the associated climate zone.[29] Evaluating present-day smart thermostats using the cost-effectiveness metric of total system benefits should render the measure cost-effective throughout the state, and the Commission should not limit a smart thermostat incentive program to certain climate zones based on erroneous and outdated analyses.

2. Customers Receiving a Smart Thermostat Incentive Should be Required to Enroll in a DR Program.

The Joint Parties support requiring DR participation with any new SCT incentive. However, more operational thought is needed on how to minimize friction for the opt-in process including education on what programs are offered and facilitating movement between programs after the initial opt-in. To ensure that these customers provide the most “bang for the buck”, they should be encouraged to enroll in market-integrated DR programs rather than ELRP only, as these programs have the greatest demonstrated load reduction potential.

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[28] Staff Concept Proposals, at pp. 18-19.
[29] SWHC039-04

3. The Commission Should Utilize Combined EE-DR Cost Effectiveness Tests.

The Joint Parties support accelerating the use of the Combined EE-DR Cost Effectiveness test, particularly for SCTs, and agree with the recommendations from the Energy Division proposal.[30] Utilizing a combined EE-DR cost effectiveness test will likely result in all smart thermostats to be cost effective, regardless of the associated climate zone.

4. Third Parties with CAISO-Integrated DR Programs Should be Permitted to Administer Technology Incentives Directly to Customers.

The administration of AutoDR technology incentives, and specifically the incentives for SCTs, should be extended to third-party DRPs that provide CAISO-integrated DR programs.

a. Problem Statement

The process for a California customer to receive a rebate for an AutoDR-capable technology is inequitable and cumbersome, for three reasons:

- **Customers of third parties must undergo a confusing process to access the rebate.** The Commission found in D.17-12-003 that customers should be allowed "to access available Auto Demand Response technology incentives, whether they choose to use the technology in a utility-administered or third-party supply side program not subject to cost-effectiveness."[31] However, as third parties have repeatedly raised to the Commission, the IOU processes are lacking due to conflicting messaging (e.g., a lack of clarity in steps to receive the rebate, or customer confusion that they must first enroll in a utility program) in the separate process administered on the IOU's website.
- **The rebate process is lengthy.** The process for a customer participating in DR to receive the technology rebate requires customers to first sign up for a program, purchase the thermostat, apply for the rebate, and then wait for the rebate to be returned to the customer. This can take between several days or multiple months.

[30] Staff Concept Proposals, at p. 20.
[31] D.17-12-003, at p. 183.

- **The rebate process potentially precludes low- and medium-income ("LMI") customers.** The rebate process, by definition, requires customers to effectively make a down payment on a smart thermostat. Even with the knowledge that the payment will be recouped through a rebate, due to the uncertain time frame and need for an initial cash investment, many customers that would greatly benefit from a smart thermostat are unable to invest in one.

b. Proposed Solution

Third parties with CAISO-integrated DR programs should be permitted to administer technology incentives directly to customers rather than requiring all customers to undergo the IOU-administered rebate process. The procedural steps for third parties would be as follows:

1. The DRP markets and provides the rebate up-front to customers, in a manner that the DRP deems to be the most effective.
2. The DRP applies for reimbursement from the IOU for the value of the administered rebate(s). As part of the application, the DRP provides the necessary verification data to the IOU, including identifying information (such as service account number) and confirmation of device connection.
3. Upon verification, the IOU delivers reimbursement payment within 30 days directly to the DRP.

This proposal improves on the existing paradigm in two ways. First, customers are able to complete the entire rebate process with one party in one session. The customer could receive the entire rebate by only needing to interface with its DRP of choice, rather than forcing the customer to visit an unfamiliar rebate process on the IOU website. Second, the DRP willingly takes on additional risk in exchange for streamlining the customer process. The DRP can choose how to administer the rebate, including providing the entire rebate incentive to the customer as a discount at the time of the device purchase. This process would both expedite the rebate process (customers would effectively have the full rebate immediately) and make the process equitable for LMI customers (by taking the financial risk off of the customer and putting it on the DRP supplying the customer with a device).

The Joint Parties propose that this policy modification spans at least through 2022, which coincides with the end of the current DR program cycle, as determined in D.17-12-003. The policy should be re-visited in advance of 2023 either within the next DR program application proceeding or through this Emergency Reliability proceeding.

c. Policy Justification

Smart thermostats are an effective tool to reduce residential load during net peak. Programs related to the DR capabilities of smart thermostats were approved in D.17-12-003 and recent IOU LIP reports to those programs cite load reductions of up to 0.54 kW to 0.59 kW per household, on average.[32]

Furthermore, DRPs have reported similar numbers, with OhmConnect stating in its 2020 LIP report that customers with automation technology like WiFi thermostats provide 0.68 kW of average impacts, which is over four times greater load reduction during DR events compared to customers without such technology.[33]

SCTs are unique in that they can provide not only DR benefits, but also energy efficiency benefits. As the Energy Division articulated in its August 11, 2021 "Summer 2022-2023 Reliability: Proposal Guidance to Parties", the CPUC is developing a Cost Effectiveness tool that will correctly apply the dual EE-DR benefits, increasing the cost effectiveness of the smart thermostats and further justifying the aggressive deployment of those devices.

Due to these benefits, Energy Division and other stakeholders in this proceeding have been extremely supportive of increasing the number of thermostats installed in California. Energy Division has devoted an entire section of its August 16 Proposal towards strategically marketing thermostats. PG&E has recently filed supplemental testimony in support of a pilot thermostat program.[34] Consumer advocates such as CEJA and Sierra Club have detailed the need for thermostat incentives as a way to engage LMI communities in a meaningful and affordable way.

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[32] *See "2020 Load Impact Evaluation for Pacific Gas & Electric Company's SmartAC Program," at p.2 and "SCE 2020 Demand Response Executive Summary," at p. A-33.*

[33] *See* "2020 Load Impact Evaluation for OhmConnect's DR Resource Final Report", at p. 9.

[34] *See* Pacific Gas and Electric Company Emergency Reliability OIR - Power Saver Rewards Pilot Supplemental Testimony, submitted July 7, 2021, at pp. 5-6.

In spite of the benefit of smart thermostats, the support from stakeholders, and the previous explicit language by the Commission to support customer eligibility for rebates when enrolled in a non-IOU program, the existing pathways to claim those technology incentives are burdensome and confusing. This was discussed in the Protest of California Efficiency + Demand Management Council, CPower, Enel X North America, Inc., and OhmConnect, Inc. to Advice Letter (ALs) 5799-E, 4182-E, and 3522-E and in Testimony filed in this proceeding by the DR Coalition. Therefore, policy modifications are needed to streamline this critical rebate process.

This policy modification is also justified because it is purely additive to existing policies and will further support grid reliability. The proposal, if adopted, will augment the pathways by which a customer, and particularly a LMI customer, will be able to claim a rebate on an eligible device. This proposal does not propose any replacement of the existing flows developed and administered by the IOUs for both their own DR programs and customers of third-party DRPs that wish to use the utility flow to facilitate a rebate.

There has been precedent for rebates to be administered by third-parties in California. For example, SDG&E ran an EE rebate program, in which third-party vendors could offer a rebate as an upfront discount and then be reimbursed by SDG&E. This general approach has also been used extensively by solar installers through the California Solar Initiative.

d. Estimate of Policy Impact (MW)

Using a conservative assumption of roughly 0.5 kW of reduction per thermostat, this program could add 50 MW if 100,000 customers utilize this rebate by Summer 2022. 100,000 customers is a low number given that Rule 24/32 registrations far exceed 200,000, and it is our understanding that a majority of those residential customers do not have enabling devices.

e. Implementation Requirements

This policy would simply need to be approved by the Commission. The Joint Parties propose that as part of the approval, the Commission direct the IOUs to jointly develop a Tier 1 Advice Letter with stakeholders, including DRPs, that outlines a process for DRPs to become established vendors of AutoDR-capable technology. This advice letter should also describe how established vendors are then able to receive reimbursement from the IOUs following verification of the device installation and program enrollment. Following approval of the advice letter, the policy would immediately go into effect.

f. Potential Risks

The intent of this proposal is to create little to no potential risk created through this policy modification. Crucially, the policy is intended to place full financial risk on the DRPs that are willing to utilize the policy. Participating DRPs can choose whatever means they wish to incentivize their customers to install the thermostats, but the DRPs will not receive the rebate for the technology until it is proven to be put on the wall and enrolled in a DR program.

In addition, the eligible thermostats would only be the ones that have been previously approved as an Auto DR-enabling thermostat. For reference, both SDG&E and SCE list these program-approved thermostats on dedicated webpages.

Several parties raised objections to this policy proposal in Rebuttal Testimony in Phase 1 of this proceeding. We have considered these objections, and strongly believe that this proposal alleviates those stated concerns.

First, SDG&E suggested that this policy would "eliminate important safeguards and would result in potentially significant ratepayer costs for thermostats that are never installed or that are not adjusted to drop load when needed."[35] The Public Advocates Office similarly claims that customers would be provided incentives "regardless of the customer's provider or participation in a DR program."[36] In this proposal, the thermostats would need to be installed and proven to be enrolled in the DR program as a condition for the rebate to be released to the DRP. This process would prevent customers from receiving incentives but not actually participating in a DR program.

[35] Prepared Rebuttal Testimony of San Diego Gas & Electric Company Regarding Demand Response Proposals, submitted on January 19, 2021, (Ex. SDGE-5), at p. 4, lines 8-10.
[36] Opening Brief of the Public Advocates Office, submitted on February 5, 2021, at p. 23.

Second, SDG&E seems to fear that "a flat payment per thermostat instead of a payment for performance would eliminate the third-party DRP's incentive to ensure that the customer installs the thermostat and signs up to signal the thermostat."[37] This argument is moot because the flat payment rebate is already available but only when administered on SDG&E's website. The Joint Parties are merely proposing to also allow that rebate to be administered on the DRP website. The actual rebate structure would remain exactly the same.

Third, SCE "recommends that any adopted pilots or proposals must comply with D.18-11-029"[38] which would entail that "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)...[and that] Only the customer is eligible for the Auto Demand Response control incentive."[39] The proposal is that only devices deemed eligible by the IOU for rebates would also be eligible for the rebate administered by the DRP. In addition, the design of the proposal is that the customer receives the full rebate back, but the DRP can choose the form it is administered (e.g., check or online payment).

E. MISCELLANEOUS DR PROPOSALS

1. The Commission Should Raise, Eliminate, or Suspend the 8.3% DR Procurement Cap.

If the Commission's intent is to increase the amount of DR deployed in 2022 and 2023, it must either raise, eliminate, or temporarily suspend for the 2022-2023 delivery years, the 8.3 percent DR procurement cap adopted in D.20-06-031 as part of the Maximum Cumulative Capacity ("MCC") Bucket regime.[40]

In D.20-06-031, the Commission adopted several revisions to the MCC buckets. Among these revisions, the Commission capped the volume of DR capacity that a LSE is able to use to meet its System RA obligation at 8.3%.[41] According to this Decision,

[37] Ex. SDGE-5, at p. 4, lines 16-18.
[38] Reply Brief of Southern California Edison Company (U338-E), submitted on February 12, 2021, at p. 12.
[39] *Id*., at pp. 12-13.
[40] D.20-06-031, at Ordering Paragraph 19.
[41] *Id*., at Ordering Paragraph 10.

the cap is intended to address the Commission's concerns around the risks to system reliability arising from the proliferation of use-limited resources.[42] Importantly, in imposing the cap, the Commission argued that the cap would not limit the growth of DR in the foreseeable future, stating: "a cap will not stifle the growth of DR within any timeframe and will allow sufficient time for an upward revision to the cap if an adjustment is warranted in the future."[43] The Commission based this reasoning in part on the fact that "the cap on the DR bucket will allow for a doubling of supply-side DR."[44]

While the purported space for market growth is true in theory, in practice, such room does not necessarily materialize. In fact, real market experience by some DRPs following the adoption of D.20-06-031 has provided evidence to the contrary. Specifically, DRPs approved to sell RA capacity outside of the DRAM have experienced instances in which LSEs were unable to procure their desired amount of DR due to cap constraints. This problem was observed in 2020 when only a handful of DRPs were approved to sell RA (having gone through the LIP DR QC process); however, additional DRPs have participated in the 2021 LIP process for the 2022 RA year which will leave more DR capacity chasing the same amount of headroom under the cap. At the same time, some LSEs are likely nowhere near reaching their cap but that headroom cannot be used by other LSEs so it will go unused.

Further exacerbating this problem for DRPs is the fact that IOU DR program RA capacity gets "first dibs" when being allocated among LSEs. Therefore, any growth in IOU DR programs that occurs through this proceeding will further squeeze out third-party DR. Below, we describe the issue in greater detail and propose potential solutions to this problem that would result in more equitable treatment of third-party DR resources while continuing to ensure system reliability.

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[42] D.20-06-031, at p. 55.
[43] *Id.*, at p. 57.
[44] *Id.*

a. The MCC Bucket Cap on DR Has the Unintended Consequence of Effectively Capping DR at Below 8.3% Levels.

In D.20-06-031, the Commission states that the 8.3% cap "translates to 3,735 MW of the current peak RA requirement."[45] Consequently, the cap "provides for DR growth of approximately 100 percent over the current levels when accounting for the 15 percent PRM adder."[46] While this may be the case at the system level, MCC buckets are applied at the level of each LSE. LSEs have varying resource mix and cost preferences, and the MCC buckets set limits on the amount of capacity an LSE may procure from certain types of resources, but an LSE is under no obligation to procure any resources from the DR bucket. Some may decide to procure little or no DR resources (other than what is allocated to them from IOU DR programs) while others prefer a relatively greater share of DR in their portfolios. So, if an LSE chooses not to procure DR up to its 8.3% cap, the resulting "headroom" is not available to other LSEs that might be interested in procuring greater amounts of DR capacity. If several LSEs choose not to procure DR up to their cap for any reason, the overall cap of 3,735 MW will be effectively reduced by an amount equal to LSEs' unused headroom which will limit DRPs' opportunities to sell their capacity.

DRPs have observed this issue in practice. In conversations with potential counterparties in the Fall of 2020, multiple LSEs indicated that they would like to procure incremental DR but were nearly at their MCC cap. While such an outcome may be acceptable in a competitive market environment - an entity is not entitled to contracts if there are no willing buyers - it is harmful and distortionary in a market where interested buyers do exist but are precluded from purchasing the product. Therefore, even though the 8.3% cap does, in theory, translate to an approximate doubling of current DR capacity at the system level, the LSE-level implementation of the cap all but ensures that, in practice, the cap is much lower.

b. The Cap Uniquely Prejudices Third-Party DRPs.

IOU DR programs (including both economic and emergency-triggered DR) currently represent the vast majority of existing DR capacity in the state (see Table 2).

[45] D.20-06-031, at p. 57.
[46] *Id*.

RA credit for these programs is allocated to LSEs on a pro rata basis upon receipt of their year-ahead RA obligations. LSEs are then able to procure additional DR from third-party DRPs until their respective 8.3% bucket cap is reached. In allocating IOU DR credits first, the Commission reinforces a system in which IOU DR preempts third-party DR resources in filling the MCC bucket. This, in addition to the fact that IOU DR is a must-take resource while procurement of third-party DR is optional, represents obvious preferential treatment of IOU DR programs over third-party DR.

Table 2: Approved August 2021 Capacity from DR Resources

	IOU	DRAM	Non-DRAM Third-Party	Totals
PG&E	401.6	95.38	186.12	683.1
SCE	976.93	115.07	61.45	1153.44
SDG&E	17.05	26.51	19.2	62.76
	1395.58	**236.96**	**266.76**	**1899.3**

At a basic level, this is inequitable and prejudicial to third-party DR. It also overtly contradicts the principles of DR, as adopted by the Commission in D.16-09-056, which notes that "DR shall be market-driven […] with a preference for services provided by third-parties through performance-based contracts at competitively determined prices."[47]

c. Proposals to Address the DR Procurement Cap.

For the reasons explained above, the existence of the cap serves as a barrier to DR procurement. The Commission can alleviate this problem by adopting one of the following three potential solutions:

- **Apply the 8.3% cap at the system- rather than the LSE-level only.** The statewide cap would remain in place, but LSE-specific procurement would not be

[47] D.16-09-056, at Ordering Paragraph 8.

affected to the extent that the cap is not reached. Going forward, the Commission could monitor the DR procurement ratios for each LSE.

- **Apply the cap to unallocated DR only.** This approach would apply solely to third-party RA contracts with LSEs to meet RA requirements, provide local reliability, or satisfy long-term procurement requirements.
- **Increase the per-LSE DR procurement cap.** This approach would maintain the per-LSE element of the MCC bucket regime while simply providing more headroom. Candidly, the Joint Parties have no well-reasoned recommendation for a revised cap but propose a 100 percent increase from 8.3 percent to 16.6 percent to ensure that additional IOU and third-party DR can be procured.

2. The Commission Should Direct Flex Alert Cross-Marketing with Other DR Programs.

The Flex Alert marketing should also utilize cross-marketing with IOU, LSE, and third-party DR programs, including critical peak pricing ("CPP"), as well as smart thermostat incentives. The circumstances and urgency surrounding Flex Alerts provide an excellent opportunity to present customers with opportunities to be compensated for reducing their load on a more frequent basis. To this end, one of the campaign's priorities should include growing DR program participation and adoption of smart thermostats. Converting customers from casual energy savers to more committed, regular performers will create additional valuable clean capacity.

All Flex Alert media and materials should include reference to a page on the Flex Alert website where the available DR programs and technology incentives can be found, including participating DRPs for aggregator programs. The Flex Alert DR page should clearly state that consumers can be paid to conserve energy and should include information on available DR programs and smart thermostat incentives so customers can easily access additional information.

3. Customers Should Not be Required to Provide Their Customer Account Number to Enroll in Bring Your Own Device ("BYOD") Programs.

The Commission should authorize customer enrollment in IOU BYOD DR programs using only their name and address for identification rather than utility account numbers, in order to increase customer enrollment.

There are existing IOU BYOD DR programs in California that currently require customers to provide their utility account number to enroll. This requirement provides an unnecessary hurdle for customers and results in these programs having very low enrollment rates compared to the other utility BYOD DR programs across the country. In the Joint Parties experience, the most successful BYOD programs only require the customer's name and address for enrollment. Based solely on ecobee's Phase 1 Opening Testimony in this proceeding, the Joint Parties estimate at least 20 MW of incremental load curtailment could be delivered by addressing this problem, and it would be reasonable to expect more potential when accounting for other third parties operating in the BYOD space. Therefore, the Commission should order the IOUs to allow enrollment of eligible customer thermostats in existing demand response programs without requiring the customer to provide their utility account number.

4. The Commission Should Allow Prohibited Resources Using Renewable Portfolio Standard ("RPS")-Eligible Biofuels for All DR Programs.

The Commission should allow BIP participants with prohibited backup generators ("BUGs") to participate in all DR programs on the condition that they are powered with RPS-eligible fuels (e.g., biofuels or renewable natural gas) or green hydrogen. This could restore a significant amount of DR that was lost when the prohibited resources policy came into effect, while remaining consistent with the State's climate initiatives and Loading Order. Providing an accurate estimate of incremental capacity is difficult, but the Joint Parties estimate that several tens of MW could be added to DR programs through this change.

F. CBP AND DRAM ENHANCEMENTS

1. The Commission Should Explicitly Authorize Use of the CAISO's New Baseline Options for CBP and DRAM Capacity Settlement.

In D.21-03-056, in response to parties' concerns that the day-of adjustments to retail and wholesale DR baselines were causing DR performance to be undercounted during extreme heat events, the Commission directed the IOUs to work with the CAISO to explore baseline options during stressed system conditions.[48] The IOUs were

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[48] Decision 21-03-056, at Ordering Paragraph 11.

permitted to use the new baseline options for their respective CBPs and DRPs were permitted to utilize them for the DRAM.[49] The CAISO subsequently convened the DR Customer Partnership Working Group on April 22 where it proposed to allow DRPs to request an alternative day-of adjustment factor for May-October 2021 while the CAISO developed a broad-based control group methodology that could be used by all DRPs.

This decision language was unclear in whether it was the intent of the Commission that the CAISO's alternate baseline be applicable to energy market settlement only or capacity payment settlement as well. The Joint Parties request the Commission specify that the CAISO's alternative baselines are applicable to the calculation of CBP capacity incentive payment and DRAM contract payments. Because the alternative day-of adjustment factor is currently only approved by the CAISO for use in 2021, the Joint Parties request that the Commission request the CAISO to extend its alternative day-of adjustment factor for the May-October 2022 and 2023 periods.

2. The Commission Should Approve an SCE and SDG&E CBP Elect.

A significant improvement to the CBP that has proven attractive to DR customers in PG&E's service area is the CBP Elect option. CBP Elect allows customers, with their aggregators, to specify at what price they would like to be bid by the IOU into the CAISO market. This option is attractive to customers because they have more control over how they are dispatched by ensuring that their respective opportunity costs are reflected in PG&E's CAISO market bids. Ninety-nine percent of customers participating in PG&E's CBP were enrolled in CBP Elect in 2019, so it is clear that there is significant interest in it.[50] According to PG&E, CBP Elect resulted in a 35% increase in active customers in its program.[51] SCE and SDG&E should be directed to create their own CBP Elect programs to grow enrollment and associated capacity.

[49] Decision 21-03-056, at Ordering Paragraph 11.
[50] PG&E Advice Letter 5799-E, Attachment 1, at p. 17.
[51] PG&E Advice Letter 5799-E, Attachment 1, at pp. 16-17.

APPENDIX A

STATEMENT OF QUALIFICATIONS

Greg Wikler

STATEMENT OF QUALIFICATIONS OF GREG WIKLER

Q1 *Please state your name and business address.*

A1 My name is Greg Wikler and my business address is 1111 Broadway, Suite 300, Oakland, CA 94607. The offices of the California Efficiency + Demand Management Council are located at the same address.

Q2 *Briefly describe your present employment.*

A2 I am the Council's Executive Director. In that role, I oversee the day-to-day operations of the Council leading staff, managing Board activities, and connecting with members. I also direct the Council's regulatory advocacy efforts. My detailed resume is attached.

Q3 *Please summarize your professional and educational background.*

A3 My expertise in California's clean energy industry spans more than three decades. Furthermore, I have supported California's demand response (DR) industry in a wide variety of roles, including: applied research; technology assessment; market potential and goalsetting studies; program design, implementation, and evaluation; and regulatory support. My experience in California DR dates back to the 2001 energy crisis where I led a team to implement a third-party DR program for the California Energy Commission. A few years later during the 2006 energy crisis, I was invited by state leaders and researchers from the Lawrence Berkeley National Laboratory (LBNL) to develop California's first-ever automated demand response programs. These efforts ultimately led to the development of the OpenADR communication standards. In 2011, I joined DR aggregator EnerNOC as director of regulatory affairs. In that role, I contributed to EnerNOC's California's DR program implementation efforts. In 2014, I joined Navigant Consulting as Managing Director where I directed a number of DR program evaluation studies for Southern California Edison and LADWP. I also advised LBNL through all phases of their ongoing statewide DR potential studies. In mid-2019, I accepted the position of Executive Director for the California Efficiency + Demand Management Council. Among my many duties, I direct all of our DR regulatory and legislative advocacy efforts. I received my Bachelor's degree in Energy Economics from the University of California at Davis and my Master's degrees in Economics and Urban Planning from the University of Oregon.

Q4 *Have you previously testified on behalf of the Joint Parties or the California Efficiency + Demand Management Council, before the California Public Utilities Commission?*

A4 Yes. I previously sponsored the following Testimony submitted in this Emergency Reliability proceeding (R.20-11-003): Opening Prepared Testimony of the DR Coalition, submitted on January 11, 2021 (Ex. DRC-1); Rebuttal Prepared Testimony of the DR Coalition, submitted on January 19, 2021 (Ex. DRC-2); and Reply Prepared Testimony of the California Efficiency + Demand Management Council, submitted on July 21, 2021.

Q5 *What is the purpose of your testimony?*

A5 The purpose of my testimony is to is to sponsor Exhibit Joint Parties-01, the Opening Phase 2 Prepared Testimony of the Joint Parties, submitted on September 1, 2021, in R.20-11-003 (Emergency Reliability).

Q6 *Was Exhibit Joint Parties-01 prepared by you or under your supervision?*

A6 Yes.

Q7 *Are the statements made in your testimony true and correct to the best of your knowledge and belief?*

A7 Yes.

Q8 *To the extent that Exhibit Joint Parties-01 contains expressions of opinion, do they represent your best professional judgment?*

A8 Yes.

Q9 *Do you adopt Exhibit Joint Parties-01 as your sworn testimony in R.20-11-003 (Emergency Reliability)?*

A9 Yes.

Q10 *Does this conclude your statement of qualifications?*

A10 Yes, it does.

Gregory A. Wikler

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Professional Summary

Greg Wikler has nearly 35 years of work experience advancing energy programs including demand-side management (DSM) resources, energy efficiency (EE), demand response (DR), distributed generation (DG) and Smart Grid programs for the electric and gas industries.

In addition to his program work, Greg has conducted national, regional and utility-specific demand-side management (DSM) market potential and load forecasting studies, technology assessments, integrated demand-side resource program designs, economic assessments and evaluation studies.

Over the years, Greg has directed dozens of DSM and Smart Grid Market Assessment Studies. His leadership in the industry also included developing guidebooks for EPRI on DSM potential methods and approaches and conducting various trainings on these topics. He has developed a number of Smart Grid potential models and tools over that timeframe that have resulted in advancing policies and programs that promote Smart Grid initiatives.

He is currently directing a distributed energy resource (DER) potential studies for Consolidated Edison of New York and the California Public Utility Commission. He recently completed assessments of targeted DER potentials for SaskPower, Puget Sound Energy, and Hawaiian Electric. He also provides support on DER market assessments and Smart Grid programs for the governments of South Korea, Thailand and Saudi Arabia. In the past, Greg pioneered the development of California's AutoDR industry and the subsequent OpenADR standards.

Greg is involved in various Smart Grid policy initiatives in California and other US states through a number of projects, providing leadership and insights on new legislation (e.g., SB350 in California), new methods for measurement and verification, market design improvements, cost-effectiveness approaches, and identification of new areas for market potentials. Further, he has either led or has had significant involvement in stakeholder processes related to demand-side management and Smart Grid program development efforts in several US states, including California, Colorado, Hawaii, Pennsylvania, Missouri, Iowa, and Washington.

Areas of Expertise

- ***Regulatory policy analysis and support:*** Implementation of legislative mandates, analysis of policy initiatives, expert testimony, stakeholder management and advocacy
- ***Market analysis and strategic planning:*** Potential studies for all distributed energy resources: EE, DR, distributed solar, combined heat and power; program design; IRP; Smart Grid
- ***Technology and market assessments of new products and services:*** Emerging technology review, analysis of market opportunities, assessment of hard-to-reach markets, DER analysis
- ***Economic and cost-benefit analysis:*** Input development (impacts, costs, lifetimes), cost-effectiveness model development and analysis, strategic assessment
- ***End-use data and engineering analysis***: Survey research, engineering simulation, load shape analysis, end-use technology characterization, impact and process evaluations

Recent Professional Experience

Executive Director, California Efficiency + Demand Management Council, Oakland CA (2019-Present)

Responsible for the day-to-day operations of the Council leading staff, managing Board activities, and connecting with members. In this capacity, the following activities are included:

- Supervises the Council's two staff members and four part-time consultants on various activities related to the organization's operations
- Manages the 16-member Board of Directors
- Leads all Council regulatory activities and engagements at the California Public Utilities Commission, the California Independent System Operator, and the California Energy Commission.
- Leads all Council legislative activities and interactions with the legislature and Governor's Office.
- Collaborates with industry partners including high-ranking officials at California's four investor-owned utilities, stakeholder groups, and other influential actors in the California clean energy space.

Managing Director, Navigant Consulting, San Francisco CA (2014-2019)

Led numerous ***Consulting Engagements*** and ***Managed*** dozens of consulting staff on topics including:

- ***EE, DR and DER Market Potential Studies*** for California Public Utilities Commission (CPUC), Southern California Edison (SCE), LADWP, Salt River Project, Entergy New Orleans, Arkansas utilities, Xcel Energy, PSE Energy, Con Edison, SaskPower, Hawaiian Electric, National Grid, Orange and Rockland, and Eversource
- ***Market Characterization Assessments*** for SCE, Con Edison, Xcel Energy and Orange and Rockland
- ***EE Policy Implementation*** for California Energy Commission (SB350 2018-19), Con Edison (NYNE 2018-19), and Arkansas utilities (PWC 2014-15)
- ***EE and DR EM&V Studies*** for CPUC, PG&E and SCE

Director of Regulatory Affairs, EnerNOC, Walnut Creek CA (2011-2014)

Addressed DR, EE and smart-grid issues in R***egulatory Venues*** throughout the US, including:

- Led industry collaboration in California on ***EE program design and process reforms*** for upcoming regulatory cycles
- Engaged with policymakers and researchers to ***develop comprehensive frameworks*** for measuring savings associated with non-equipment EE measures including operational efficiency and strategic energy management programs
- Supported positions to ***advance automated technology*** approaches for DR program implementation

Vice President/Senior Research Officer, Global Energy Partners, Walnut Creek CA (2000-2010)

Conducted ***Applied Research Studies*** and ***Program Implementation Support,*** including:

- For the *Electric Power Research Institute (EPRI)* and the *Edison Electric Institute*, developed national estimates of energy efficiency potential

- For the *Federal Energy Regulatory Commission (FERC)*, conducted an analysis of demand response potential for the U.S. as a whole and for each of the 50 states
- For *Philadelphia Electric Company,* led a multidisciplinary team that developed PECO's Energy Efficiency and Conservation Plan as required according to Pennsylvania Act 129
- For *Consolidated Edison of New York,* directed a series of studies that evaluated end-use energy consumption and energy efficiency potentials
- For *NV Energy,* assessed the feasibility of DR programs targeted to commercial and industrial customers in southern Nevada
- For *PG&E and SCE*, directed the turnkey implementation of Automated Demand Response (Auto-DR) Programs

Work History

Executive Director, California Efficiency + Demand management Council, Oakland CA	2019 – Present
Managing Director, Navigant Consulting, San Francisco CA	2014 – 2019
Director, EnerNOC, Walnut Creek CA	2011 – 2014
Vice President, Global Energy Partners, Walnut Creek CA	2000 – 2010
International Advisor, Electricity Generating Authority of Thailand (EGAT), Bangkok Thailand	1999 – 2000
Vice President, NEOS Corporation, Lafayette CA	1995 – 1999
Project Director, Barakat & Chamberlin, Oakland CA	1989 – 1995
Senior Economist, ADM Associates, Sacramento CA	1987 – 1989
Graduate Researcher, Univ. of Oregon Bureau of Governmental Research & Service, Eugene OR	1985 – 1987
Research Associate, National Economic Research Associates (NERA), Los Angeles CA	1983 – 1985

Leadership Positions

Director, Association of Energy Services Professionals 2011-2020 (www.AESP.org)

Director, California Efficiency + Demand Management Council 2009-2019 (www.CEDMC.org)

Education

Master of Science, Economics	University of Oregon
Master of Urban Planning	University of Oregon
Bachelor of Science, Energy Economics	University of California at Davis

Selected Expert Testimony

- New Orleans City Council Utility, Cable, Telecommunications and Technology Committee on behalf of Entergy New Orleans (Docket No. UD-17-03). September 2017
- Nevada Public Utilities Commission on behalf of EnerNOC (Dockets 13-07002 and 12-06053). October 2012 and October 2013
- Pennsylvania Public Utilities Commission on behalf of Philadelphia Electric Company (Docket No. M-2009-2093215). July 2009

- Minnesota Public Utilities Commission on behalf of Otter Tail Power, Missouri River Energy Services, Heartland Power, and Central Minnesota Municipal Power Agency (Docket No. TR-05-1275). January 2008
- Hawaii Public Utilities Commission on behalf of Hawaiian Electric Company (Docket No. 05-0069). August 2006

Selected Publications

- “Integrated Demand-Side Management Programs.” AESP Magazine, July 2019 (forthcoming)
- “Are Non-Wires Solutions the Next Big Thing and If So What Does that Mean for our Businesses?” AESP Magazine, July 2018
- “Intersection of DER, Energy Efficiency DR: Three Initiatives that Fit and Complement.” Public Utilities Fortnightly, October 2016
- “When Two Roads Meet: The Intersection of EE/DR and Distributed Energy Resources.” AESP Magazine, August 2016
- “Managing and Integrating DR in a Clean Energy Grid: The Hawaii Case Study.” Presentation at Peak Load Management Alliance conference, San Francisco, CA, April 2016
- “Study of Demand Response for Short-term and Long-term Power Crisis of Thailand.” Presentation at DR World conference, Orange County, CA, October 2015
- "Behind the Curtain: The Relationship between Behaviour and Operational Savings." Presentation at the 9th Annual Behaviour, Energy and Climate Change (BECC) conference, Sacramento, October 2015
- "Developing a Data-Driven National Development Plan for Combined Heat and Power in Saudi Arabia." With Ahmad Faruqui, Turki Al-Shehri, Jurgen Weiss, Ryan Hledik, Keith Downes, and Amjad Alkam. Proceedings of the ACEEE Summer Study in Energy Efficiency in Industry, August 2015
- "Accessing the Potential for an EE Resource Standard to Achieve 2030 Statewide Efficiency Goals." Presentation and expert panellist for Inter-agency Workshop on California's 2030 Efficiency Goals. IEPR Workshop, Sacramento, July 2015
- "Demand Response is Alive and Well: DR Opportunities in a Post-Order 745 World." With Stuart Schare and Brett Feldman. Electricity Policy.com, October 2014
- "Using More Energy Can Be a Good Thing: C&I Loads as a Balancing Resource for Intermittent Renewable Energy." With Christopher Ashley and Leigh Holmes. Proceedings of the ACEEE Summer Study on Energy Efficiency in Industry, August 2013
- "The Role of Regulatory Changes, Market Expansion, and Technologies to make Demand Response a Viable Resource in Meeting Energy Challenges: Experiences in Select Countries." With Bo Shen, Girish Ghatikar, Zeng Lei Jinkai Li and Phil Martin. Proceedings of the International Conference on Applied Energy ICAE 2013, July 2013
- "Energy Efficiency: Towards the End of Demand Growth." Contributing author with Fereidoon Sioshansi and Ahmad Faruqui for Chapter 1: Will Energy Efficiency Make a Difference." ISBN: 9780123978790. February 2013
- "Managing Electrical Demand through Difficult Periods: California's Experience with Demand Response." With Debyani Ghosh. Revue de l'Energie, No. 593. January/February 2010