BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021.	Rulemaking 20-11-003 (Filed November 19, 2020)

REPLY COMMENTS OF THE CALIFORNIA EFFICIENCY + DEMAND MANAGEMENT COUNCIL ON PROPOSED PHASE 2 DECISION DIRECTING PACIFIC GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY, AND SAN DIEGO GAS & ELECTRIC COMPANY TO TAKE ACTIONS TO PREPARE FOR POTENTIAL EXTREME WEATHER IN THE SUMMERS OF 2022 AND 2023

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The California Efficiency + Demand Management Council ("the Council") respectfully submits these Reply Comments on the Proposed Phase 2 Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2022 and 2023 ("Proposed Decision" or "PD"), mailed in this proceeding on October 29, 2021.

I. PG&E'S ARGUMENTS AGAINST WAIVING THE MCC CAP LIP PROCESS ARE UNSUPPORTED

Pacific Gas and Electric ("PG&E") supports procuring third-party DR through bilateral contracts but notes its concerns regarding waiving the Maximum Cumulative Capacity ("MCC") bucket cap and the Load Impact Protocol ("LIP") process for this DR capacity.[1] According to PG&E, waiving the MCC bucket cap "could be harmful to reliability, as the DR [resource adequacy ("RA")] product is a use-limited, variable output resource, and issues specific to third-party DR have not yet been addressed to the point where it is appropriate to expand the cap."[2]

PG&E provides no evidence to support the notion that procuring additional capacity, regardless of its use-limited or variable nature, would be harmful to reliability when the very purpose of this proceeding is to procure additional capacity to meet expected shortfalls in 2022 and 2023. However, even if the Commission shares PG&E's concerns, the current total amount of DR capacity in the form of investor-owned utility ("IOU") programs and third-party contracts

[1] Opening Comments of PG&E, at p. 10.
[2] *Id*.

is far below the 3,735 MW statewide cap based on the 8.3% DR MCC bucket. In the Joint Parties' January 28, 2021 Track 3B.1 proposal in Rulemaking ("R.") 19-11-009, it was estimated that accounting for IOU DR program, DR Auction Mechanism ("DRAM") contracts, and non-DRAM third-party DR Qualifying Capacity ("QC") that was awarded by the Energy Division through the LIP process, there was approximately 1,900 MW of DR in the market.[3] Since then, the overall aggregate DR capacity has remained relatively stable, so the amount of statewide headroom is approximately 1,800 MW. The Commission should disregard this concern.

Similarly, PG&E's concerns about waiving the LIP process are unsupported and fail to account for the alternative mechanism adopted in the PD to reinforce the reliability of the DR contracted through the bilateral process. PG&E claims that waiving the LIP process "removes rigor in the ex-ante estimation process and the linkage to ex-post performance."[4] As a general principle, the Council disagrees with the notion that analytical rigor in a DR QC valuation process guarantees that DR performance will match ex ante values. Furthermore, this ignores the PD's adoption of the penalty structure in PG&E's own Capacity Bidding Program ("CBP") to ensure that contracting DR providers will deliver on their commitments. To the Council's knowledge, PG&E has never expressed concern that its CBP penalty structure is insufficient to ensure performance by the DR aggregator participants in its own CBP, so it is unclear why PG&E would apply a double standard and imply that its CBP penalty structure cannot be effective when applied to third-party contracts. In addition, to the extent they are at least 1 MW in size, the underlying DR resources of the bilateral contracts will be subject to the RA Availability Incentive Mechanism ("RAAIM"), something the IOUs' own DR programs are currently not subject to.

Finally, PG&E has provided no alternative proposal for assessing the QC value of these DR resources. By urging the Commission to stick with the current LIP process, PG&E would by default limit this procurement to the 221 MW of August 2022 capacity awarded by the Energy Division, some or all of which may already be under contract in 2022. The Commission should disregard this concern as well and seek to procure significantly more incremental DR than the 221 MW of capacity approved through the LIP process. As a procurement floor, the

[3] Joint Track 3B.1 Proposal of the California Efficiency + Demand Management Council, CPower, Enel X North America, Inc., Leapfrog Power, Inc. and OhmConnect, Inc., submitted in R.19-11-009 on January 28, 2021, at p. 4.
[4] Opening Comments of PG&E, at p. 10.

Commission should be guided by the interim 5% procurement target for non-reliability, market-integrated DR that was adopted in Decision ("D.") 14-12-024, as modified by D.15-02-007. This translates into a statewide goal of 2,151 MW, as of June 2020.[5] Based on approximately 865 MW of August 2022 IOU QC values for the Base Interruptible Program ("BIP") and Agricultural Program – Interruptible, which are not counted under the 5% goal, of the approximately 1,900 MW currently in the market, an estimated 1,000 MW of DR applies to the goal. As the Council explained above, there is approximately 1,800 MW of headroom under the 8.3% DR procurement cap.

II. DRPS SHOULD BE FREE TO CHOOSE WHERE TO SELL THEIR DR

Southern California Edison ("SCE") expresses concern that DR providers who are awarded DR contracts through the bilateral solicitation will cannibalize existing DR RA resources and recommends that the PD be modified to 1) ensure that the contract costs are comparable to other options, and 2) specify that the contracts should be incremental to ensure that DR providers are not moving customers from existing DR programs such as CBP and DRAM.[6] If adopted, SCE's proposals would constitute highly inappropriate interventions by the Commission because it would dictate how DR providers manage their customers and could prevent them from reflecting their customers' financial requirements in contract costs.

Similarly, the Commission should not dictate pricing for any bilateral solicitation other than establishing a cost-effectiveness requirement to ensure that the cost of the DR capacity procured is no higher than its value. Any restrictions beyond that would defeat the purpose of a solicitation – to force bidding parties to compete for contracts. SCE does not specify what would constitute "comparable" in this instance, something the Commission should not leave up to the IOUs to decide. Similarly, the Commission should not dictate how DR providers allocate their customers among the DR programs and contracts the DR provider is involved in, a decision which is largely based on customer preferences. For instance, some customers participating in CBP may prefer to have fewer dispatches but are capable of responding very quickly on a 24x7 basis, so the DR provider may choose to shift them from CBP to the BIP.

If SCE is concerned about customers being shifted from DRAM contracts to these bilateral contracts, the Council notes that the DRAM Qualitative Criteria and Cost Adjustments

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[5] *Joint IOU Status Report on Progress Toward Interim Goal Approved in Decision 14-12-024*, June 12, 2020, R.13-09-011, at p. 3.

[6] Opening Comments of SCE, at p. 11.

that were adopted in D.19-11-040 provide a strong incentive for DR providers with DRAM contracts to deliver consistent with their commitments.[7] Specifically, the IOUs can effectively increase a DRAM bid by 10% if a DRAM bidder has terminated a contract and by 5% if the bidder has delivered invoices totaling less than 75% of the total contracted capacity. Therefore, SCE's concerns are unfounded and should be disregarded.

III. BILATERAL DR CONTRACTS SHOULD QUALIFY FOR AUTO DR INCENTIVES

The Council previously recommended that the Commission specify that participation in non-DRAM third-party DR contracts qualifies as an eligible program for the purpose of meeting the five-year requirement to participate in a market-integrated DR program under SCE's proposal to provide 100% upfront automated DR ("Auto DR") incentives.[8] However, the Joint DR Parties correctly recommend that all non-DRAM, third-party DR contracts qualify for all IOU Auto DR incentives, not only SCE's.[9] The Council supports this recommendation.

IV. A MINIMUM DISPATCH REQUIREMENT IS NEEDED TO INCENTIVIZE CUSTOMER AND THIRD-PARTY PARTICIPATION

PG&E opposes an Emergency Load Reduction Program ("ELRP") minimum dispatch requirement on the basis that it "is inconsistent with its purpose, which is to provide an emergency resource during times of grid stress and to minimize ratepayer cost", and because it "serves as a compensation mechanism to third-party aggregators."[10] The Council disagrees with PG&E's arguments because they disregard the very real needs of ELRP participants and third-party providers for an economic incentive to participate in the program. As the Council stated in its Opening Comments, there is often a very real cost to ELRP participants (direct-enrolled and third-party) and DR aggregators to participate in the program.[11] Even those customers already enrolled in a market-integrated DR program may choose to make the investments needed to provide incremental load reduction, beyond the amount committed through their respective DR program or contract, during ELRP events. Therefore, some degree of revenue certainty is needed to attract the scale that the Commission seeks in ELRP participation. The Commission

[7] Decision 19-12-040, at Table 5.
[8] Opening Comments of the Council, at p. 7.
[9] Opening Comments of the Joint DR Parties, at p. 12.
[10] Opening Comments of PG&E at p. 5.
[11] Opening Comments of the Council, at pp. 3-4.

should provide that certainty by retaining its proposed minimum dispatch requirements for subgroups A.1, A.3, and A.5, and adopt the Council's recommendation to also adopt 20-hour per season minimum dispatch requirements for subgroups A.2 and A.4, and Group B.

The Council also expresses its agreement with Sunrun's position that the ELRP should not supplant "the need for a sustainable, long-term capacity framework for BTM resources – starting with the establishment of a qualifying capacity value."[12] Even with minimum dispatch requirements, the ELRP will always be less reliable than a capacity-based DR program due to its voluntary nature. The Commission should explicitly state this in the final decision.

V. SMART THERMOSTAT INCENTIVES SHOULD BE STACKABLE UP TO THE COST OF THE DEVICE

SCE recommends that the Commission clarify that customers are prohibited from stacking the $75 smart thermostat incentive on top of other smart thermostat incentive programs.[13] The Council disagrees because, depending on the smart thermostat model, the $75 incentive approved in the PD may be insufficient to cover the full cost of the device. Like PG&E, the Council assumes that this incentive is stackable on top of other incentives and supports PG&E's proposed clarification that the technology incentive be limited to one per Service Account.[14] However, in instances when the stacked thermostat incentives exceed the cost of a smart thermostat, the Council continues to support a cap on the total incentive to ensure that incentive budget is only going toward thermostats.

Respectfully submitted,

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[12] Sunrun Opening Comments, at p. 4.
[13] SCE Opening Comments, at p. 9.
[14] PG&E Opening Comments, at p. 7.