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)

OPENING COMMENTS OF THE CALIFORNIA EFFICIENCY + DEMAND MANAGEMENT COUNCIL ON ORDER INSTITUTING RULEMAKING

November 30, 2020

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The California Efficiency + Demand Management Council (the Council)[1] respectfully submits these Opening Comments on Order Instituting Rulemaking ("R.") 20-11-003 filed on November 19, 2020, with a "date of issuance" of November 20, 2020. These Opening Comments are timely filed and served pursuant to the Commission's Rules of Practice and Procedure and Ordering Paragraph 6 of R.20-11-003 (OIR).[2]

I. OVERVIEW

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.[3] Our member companies employ many thousands of Californians throughout the state. They include EE, demand response DR, and grid services technology providers, implementation and evaluation experts, energy service companies, engineering and architecture firms, contractors, financing experts, workforce training entities, and manufacturers of EE products and equipment. 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.

[1] The views expressed by the California Efficiency + Demand Management Council are not necessarily those of its individual members.
[2] R.20-11-003, Ordering Paragraph 6 established the due date for these Comments as being "within 10 days from the date that this rulemaking is issued." (R.20-11-003, at p. 21.) The "Date of Issuance" of R.20-11-003 was November 20, 2020, making the 10th day thereafter November 30, 2020.
[3] 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.

The Council is a party to numerous other Commission proceedings, including, but not limited to, the Integrated Resource Planning (IRP) rulemakings (R.16-02-007 and R.20-05-003), the Resource Adequacy rulemakings (R.17-09-020 and R.19-11-009), Demand Response (DR) rulemaking (R.13-09-011), and the Energy Efficiency Rolling Portfolio (R.13-11-005).

II.
SUMMARY

The Council appreciates the opportunity to comment on the preliminary scope of R.20-11-003. The Preliminary Scoping Memo casts a relatively wide net in exploring the available options to add demand-side and supply-side resource adequacy ("RA") capacity in time for Summer 2021 deployment. The Council is encouraged by the heavy focus on DR as a key component to preparing for potential additional reliability challenges in 2021. DR is uniquely positioned in this instance due to its comparatively rapid implementation timeline and lower cost relative to other resources. To procure more DR, third-party solutions should take priority given that DR providers ("DRPs") can typically recruit customers and deploy new resources faster than the investor-owned utilities ("IOUs") can.

In addition to pursuing new DR and other resources, the Commission should also be considering steps to accelerate deployment of new EE measures. Key to reducing the peak is reducing the baseline energy usage, and EE measures can be very effective in that regard. EE both reduces the aggregate amount of demand reduction needed by lowering the total amount of energy demand on the system, and provides clear locational and temporal impacts that has value at both the grid and localized level that can drive additional demand reduction incremental to event-based DR and RA programs. The Commission should include EE in the incremental resource planning effort for Summer 2021 and consider what steps can be quickly taken in the EE arena to reduce both baseload and net peak needs.

As a general principle, the Council recommends that the Commission focus its efforts on steps that can quickly bring the most amount of new capacity to bear with the least amount of regulatory effort. Specifically, the Council recommends the Commission:

1. Include DR participation options in any Flex Alert marketing efforts;
2. Direct the IOUs to conduct a supplemental Demand Response Auction Mechanism ("DRAM") solicitation;

3. Suspend the 8.3% per-load serving entity ("LSE") DR procurement cap that was approved as part of the revisions to the Maximum Cumulative Capacity (MCC) buckets in D.20-06-031;
4. Approve an expedited Qualifying Capacity ("QC") Update process;
5. Suspend the day-of adjustment caps for the Capacity Bidding Program ("CBP") and DRAM;
6. Temporarily modify EE cost-effectiveness and custom review standards; and
7. Establish smart thermostats as a new DEER database measure.

III.
RESPONSES TO THE COMMISSION'S QUESTIONS

The Council provides responses to the questions posed in the OIR.

1. Should the Commission consider directing the IOUs to design a new paid advertising program for distributing CAISO's Flex Alerts in various outlets, including social media? If so, how should the Commission authorize a budget dedicated to this purpose and what measures and budget level should be considered?

The Council is supportive of a new Flex Alert advertising program but only if it includes information on how to participate in DR. Flex Alerts may be an effective way to show customers that their efforts to reduce consumption for discrete periods of time can have a positive impact on the grid's reliability. For some customers who only want to reduce load when absolutely necessary as a "good Samaritan" action, informing them about Flex Alert may be sufficient. However, it seems reasonable to expect that some customers may also have an interest in being compensated for providing DR on a more regular basis going forward, so the Commission should take this opportunity to inform them of their available options. Flex Alert marketing should be used to advertise these opportunities to increase their benefits.

2. Should the Commission modify the Critical Peak Pricing (CPP) program to increase the number of allowed events per year, modify other attributes, or provide guidance on when the program should be dispatched?

There is likely not enough time to make any significant changes to the CPP program structure by Summer 2021. The ratemaking nature of the CPP program would entail a regulatory proceeding on rate structure and cost allocation that would likely require more time than is available. As discussed further below, the Commission should focus on taking steps to procure additional third-party DR.

3. Should the Commission explore potential options to encourage non-IOU LSEs to develop programs similar to CPP?

Encouraging non-IOU LSEs ("LSEs") to adopt CPP programs would be a good option to consider for the purpose of promoting medium-term DR growth. However, for the reasons described in the Council's response to the preceding question, there is likely not enough time for LSEs to implement new CPP programs by Summer 2021. Further adding to the amount of needed time, once a proceeding for developing LSE CPP programs is concluded, LSEs would then be required to build the systems to manage the billing, scheduling, and dispatching of their CPP participants.

Similarly, the timeline is too short for LSEs to develop other types of DR programs in time for 2021 implementation because again, a regulatory proceeding would be necessary, and the LSEs would likely have to build their billing, scheduling, and dispatching capabilities. Furthermore, the current process for LSEs to qualify for and begin receiving a portion of IOU DR program budgets to fund their own similar DR programs can be over one year pursuant to Decision 17-10-017.[4] It is possible that LSEs could develop their own DR programs that would be paid by increasing their rates rather than going through the process of claiming a portion of the local IOU's DR budget, but doing so would not overcome the time limitations associated with constructing the billing, scheduling, and dispatching capabilities.

A faster approach to adding new DR capacity for Summer 2021 deployment is for the Commission to focus its efforts on growing DR through third-party DR providers ("DRP"). These entities are much nimbler than LSEs and can move rapidly to bring more capacity online in 2021 with the appropriate procurement mechanisms. As will be discussed further below, new third-party DR capacity can be easily procured through a supplemental DRAM auction, and/or LSEs can directly procure from DRPs through their own supplemental Resource Adequacy solicitations. In the latter instance, as the Council discusses further below, an expedited DR QC Update process will be needed to bring additional DR capacity to market in 2021.

4. Should the Commission increase IOU marketing funds to increase enrollment in CPP or take other actions to increase customer participation in the program?

Increasing IOU marketing funds may be effective in increasing CPP enrollment, but the Council recommends a broader focus of any additional IOU marketing funds. Incremental

[4] D.17-10-017, Attachment 1.

marketing funding should be used to promote all IOU DR programs, including CPP. It is important to provide customers with options so that they can choose the DR program that best fits their respective preferences.

As part of this effort, the Commission should require any additional marketing include mention of the DRPs that participate in the IOUs' aggregator DR programs - the CBP and BIP, and the DRAM, and also clearly specify that customers are eligible for technology incentives regardless of whether they participate in an IOU DR program or enroll directly with a DRP.

5. **Should the Commission establish a new out-of-market and outside the RA framework emergency load reduction program (ELRP) that could be dispatched by CAISO/IOUs under specified conditions where participants are compensated only after the fact and based only on the amount of load reduction achieved during the dispatch window? If so, what are the key program design elements (e.g., dispatch conditions, compensation level, load reduction measurement considerations, target customer segments, etc.) that should be considered or incorporated? What other issues (such as interactions with existing supply-side and load-modifying programs) need to be considered in order to establish an ELRP? How should these issues be addressed?**

The Council appreciates the Commission's proposal to develop a new, energy-only emergency DR program. Consideration of an ELRP may be useful in attracting new DR participants who want to do their part during times of extreme duress on the grid but prefer to be paid to do so. However, a similar program was attempted in the past in the form of the Demand Bidding Program, which was ultimately eliminated due to low participation and poor cost effectiveness. Given the short period of time available to get in place additional capacity for Summer 2021, the Commission should focus its regulatory efforts on procuring additional third-party DR.

6. **Should the Commission allow BTM hybrid-solar-plus-storage assets to participate and discharge their available capacity in excess of onsite load (and thus export to the grid) and receive compensation for the load reduction, including exported energy, under ELRP? Should this capability be expanded to include BTM stand-alone storage as well? Are there any Rule 21 or safety and reliability considerations that need to be addressed to permit storage, with or without NEM pairing, to export energy while participating in the ELRP? How should any safety and reliability issues be addressed?**

The Council's above comments on an ELRP aside, any ELRP should allow the use of energy exceeding on-site load provided by BTM energy storage, stand-alone or hybrid resources paired with solar – though the latter category of resources on the Net Energy Metering ("NEM") tariff are already allowed to export under non-emergency circumstances. It is the Council's understanding that the Commission had requested some DER providers with BTM resources to export to the grid during the August heat event, which resulted in several thousand customers responding. This energy undoubtedly helped to improve reliability. During rolling blackouts, all energy is useful so any ELRP should be as inclusive as possible. However, any allowance for BTM storage exports under an ELRP should primarily be considered for 2021, and should not delay or supplant the Commission's consideration of BTM storage exports as Supply Resource or Load Modifying Resource DR for the 2022 delivery year and beyond.

7. **Should the Commission allow BTM Back-Up Generators (BUGs) to participate in and receive compensation under the ELRP? If so, are there any Rule 21, safety and reliability, or other considerations that need to be addressed in order to permit BUGs to operate to reduce load or export energy while participating in the ELRP? How should these issues be addressed?**

Yes, BTM BUGs should be eligible to participate in and receive compensation under an ELRP, to the extent that 1) a BTM BUG owner is not already enrolled in a DR program, or 2) the BUG provides net exports beyond a site host's load or DR-related load curtailment. The Council is fully supportive of the State's decarbonization goals but during times of extreme duress such as rolling blackouts, the top priority must be keeping the lights on and the grid stable. BTM BUGs provided a great deal of energy during the August heat event in the spirit of public safety with no compensation despite incurring significant operating costs and using valuable emissions permits. Expecting them to do so again without financial remuneration would be unfair and would likely result in fewer BUG owners providing their energy during future events. In the longer term, the Commission should ideally revamp its prohibited resources policy, specifically allowing for the use of all types of BUGs during extreme weather and reliability situations such as what we saw during the August and September 2020 heat events.

8. **Should the Commission consider expedited procurement, including through the cost allocation mechanism for additional reliability procurement (e.g., expansion of existing gas-fired resources) that could be online for Summer 2021 and 2022? If so, how could this occur in order for the additional capacity to be online on time to address summer reliability needs. If not, why not?**

Yes, the Commission should consider expedited procurement for Summer 2021 and 2022. Any procurement efforts should be open to all resource types. The Council takes no position on exactly what procurement mechanism for non-DR resources would be most effective or what cost recovery mechanism should be used, but any procurement should be completed and contracts executed by no later than May 1, 2021 to allow time for new capacity to be included in LSEs' July 2021 Supply Plans.

The amount of available third-party DR capacity is dependent on how much of it that has been awarded NQC values for 2021 but has not yet been contracted. Each year, IOUs and DRPs must submit a load impact evaluation for their respective DR portfolios that includes a forecast of the DR load impacts in the following year and beyond. The Energy Division assesses these evaluations and determines the RA value of each DR portfolio. For DRPs, their Net Qualifying Capacity ("NQC") values are listed in the Commission's NQC list posted on the RA Compliance page of its website. The process has already occurred for the 2021 delivery year so, based on the November 13, 2020 NQC list, there is only 231 MW of third-party DR RA capacity that can be sold in August 2021. Some or all of this capacity may already be under contract for 2021.

As such, if the Commission would like to see additional third-party DR RA capacity procured for Summer 2021, an expedited NQC Update process would be needed for any additional DR capacity that could be made available by DRPs. There is already an effort underway through the Supply Side Working Group to develop a process for updating a DRP's NQC values in Track 4 of the RA proceeding, but a decision on that issue is not expected until around mid-2021 at the earliest. Therefore, an expedited regulatory process would be needed to finalize a QC Update process in time to allow DRPs to bring additional capacity to the market in time for contract for Summer 2021 deployment.

Another significant barrier to procuring more DR capacity is the per-LSE DR procurement cap that was approved in D.20-06-031 as part of the Maximum Cumulative Capacity ("MCC") Bucket regime.[5] This decision adopted an 8.3% statewide limit on DR procurement (approx. 3,735 MW) but applied it to each LSE. In other words, each LSE is limited to meeting up to 8.3% of its RA requirements using DR; if an LSE chooses not to procure DR, then that headroom cannot be used by another LSE. Further exacerbating the problem, the IOU DR program RA capacity is allocated to all LSEs on a must-take basis according to their respective load ratio share, so some smaller LSEs are already close to or at their DR procurement cap. Consequently, some LSEs will not be able to procure additional DR even if they want to.

[5] D.20-06-031, at Ordering Paragraph 19.

OhmConnect, Leap, and the Council have presented a proposal to address this problem in Track 3.B of the RA rulemaking but a decision on this Track is not expected until June 2021, which would be far too late to have any effect on Summer 2021 procurement. The Commission should suspend the 8.3% per-LSE DR procurement cap until it can address the issue in its Track 3.B decision. Otherwise, efforts to procure additional DR capacity for 2021 will be severely impaired.

9. If the CEC, CAISO, or the CPUC conducts additional analyses regarding Summer 2021 load forecasts, should the Commission consider a mechanism to update RA requirements in April for the summer of 2021 or would it be appropriate for CAISO to use its capacity procurement mechanism (CPM) to procure additional capacity for the summer of 2021, should it be deemed necessary?

The Commission should reflect an updated Summer 2021 load forecast in the RA requirement if the RA requirement increases. Even if the updated load forecast was similar to the original one, the Commission should consider an increased Planning Reserve Margin ("PRM") for the July-October period to provide a larger buffer, which would have been useful to have this past August. The CAISO's CPM should only be used as it is now - as a short-term backstop procurement tool; the Commission should otherwise look to enable expedited procurement through a streamlined QC Update process and by suspending the MCC DR procurement cap as discussed above.

10. Should the Commission undertake a stack analysis of the amount of resources that would be necessary for Summer of 2021?

The Council has no comment at this time, but reserves its right to respond to other parties' comments.

11. Should the Commission consider requiring that load serving entities expedite the IRP procurement they have scheduled to come online? How would the Commission provide equitable incentives so that the expedited process does not disproportionately increase costs for that LSE? If so, please explain how this would work. If not, why not?

The Council has no comment at this time, but reserves its right to respond to other parties' comments.

12. Are there other opportunities for increasing supply for the summer of 2021 and/or reduce demand that the CPUC has not considered? If so, please provide details of these supply or demand resources and please explain how they can address reliability needs in the timeframe discussed in this OIR.

Alongside the recommendations made in these comments regarding DR, the Commission should also consider EE reforms that can be immediately implemented such that impacts will be realized in time for Summer 2021. As a demand-side resource, EE serves two key functions relating to increasing supply and decreasing demand during peak demand and net peak hours. First, EE reduces the aggregate amount of demand reduction needed by lowering the total amount of energy demand on the system. Second, EE has clear locational and temporal value that has value at both the grid and localized level that can drive additional demand reduction incremental to event-based DR and RA programs.

Beyond the necessary step of incorporating EE into the planning process for reliability, the Council urges the Commission to make temporary changes to programmatic and technical EE rules. As highlighted by the Council in numerous forums, the most pressing barriers facing EE include outdated cost-effectiveness testing methods, lengthy custom project review rules and procedures, mis-matched baseline policies, and broadly punitive discounts for attribution and savings realization.[6] While all of these represent areas ripe for reform, the most critical effort the Commission can undertake to ensure reliability is reforming cost-effectiveness. By moving to a Program Administrator Cost ("PAC") testing method, EE resources will be more appropriately aligned with other types of non-EE resources that are acquired by LSEs. Further, more EE projects will be deemed cost-effective using the PAC test.

This can be accomplished in two stages: first, the Commission should relax cost-effectiveness, and custom review rules and procedures in the near-term to ensure 2021 reliability needs are met. Relaxation of the overly-stringent rules and procedures currently in place to stimulate deployment of EE has been a key point of advocacy since the inception of the COVID-19 pandemic.[7] Consideration of near-term cost-effectiveness changes are within the scope of EE activities in response to COVID-19 in the Commission's EE proceeding (R.13-11-005), though

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[6] Note that the Council has provided the Commission specifics of what cost-effectiveness reforms would look like. Please refer to our Opening Comments for the IDER proceeding (R.14-10-003) dated 4/15/19 and the Potential & Goals Ruling (R.13-11-005) dated 5/22/20.

[7] Greg Wikler, CEDMC, "Urgent Request for Commission Action to Assist California's Energy Efficiency
Industry". April 2, 2020.
https://cedmc.org/wp-content/uploads/2020/05/2020.04.02-Council-Letter-to-President-Batjer-and-Commissioner-Randolph.pdf

no action has been taken to date.[8] The grid reliability issues this OIR seeks to alleviate are yet another reason to reform both cost-effectiveness and custom project review rules and procedures to enable the full and robust deployment of EE. In the longer term, the Council recommends broad reform of cost-effectiveness to enable a wide range of favorable outcomes, the details of which are noted in the comments noted in Footnote 4 above, as well as in a recent position paper.[9]

Another important EE-related step the Commission can take is to establish smart thermostats as a new DEER database measure as soon as possible. Making smart thermostats a deemed savings measure will standardize thermostat savings and give California program administrators the confidence to create multi-year smart thermostat programs and drastically increase the number of devices in the market. Ad-hoc changes to thermostat savings methodologies are currently being made through workpapers which are using flawed evaluation methods and outdated DEER prototype models to extrapolate savings. These workpapers have also generated heating and cooling savings values that change in identical climate zones based on the program administrator. If implemented, these workpapers will create a significant barrier to new smart thermostat deployment at a time when we need additional EE and DR resources in the market.

13. Should the Commission consider revisions to the reliability DR programs (Base Interruptible Program-BIP, Agriculture Pump Interruptible-API, AC cycling) that allow these programs to be triggered before the Warning stage (e.g., after an Alert in the day-ahead timeframe)? If so, under what conditions and how would this work? If not, why not?

The Commission should prioritize adding resources for Summer 2021 rather than making significant changes like these to the IOUs' reliability programs. The BIP and AP-I programs were dispatched over multiple consecutive days during the August heat event and performed well, despite increasing customer fatigue for what are meant to be emergency programs. We find that Warning Stage (30-minute-ahead) dispatches typically elicit adequate customer response for these types of emergency programs, and caution that moving to a more frequently dispatched program based on Flex Alerts or other day-ahead triggers might lead to significant

[8] "Assigned Commissioner and Administrative Law Judges' Ruling Addressing Impacts of COVID-19", issued July 3, 2020 in R.13-11-005
[9] CEDMC, "California's Cost-Effectiveness Approach Precludes Valuable Energy Efficiency". October 2020.

customer attrition. Otherwise, if the Commission would like to reassess this program and its performance requirements, it would need to rebalance the costs and benefits of the program to ensure that the incentives are commensurate with the risks and vice versa.

14. Are there other changes to the BIP that would make it more effective to meet load under a variety of conditions during the summer of 2021 (e.g., expansion of the 2% cap, mid-year enrollment, trigger notification time, etc.)?

The Commission should remove the 2% cap on reliability DR programs that was originally approved by D.10-06-034.

The Commission should also reconsider the structure and magnitude of BIP penalties in light of the increased likelihood of sustained heat events, multiple consecutive days of dispatches, and the customer fatigue that can result. Under the current tariffs, customers are assessed excess energy charges of $6/kWh for Pacific Gas and Electric ("PG&E"), between $10-12/kWh for Southern California Edison ("SCE"), and $4.50/kWh for San Diego Gas & Electric ("SDG&E") for energy consumed above a customer's Firm Service Level, which, in the instance of a momentary underperformance, can quickly offset any program benefits even if the customer has otherwise performed well over consecutive days of dispatches. Reconsidering BIP penalties vis-à-vis incentive levels would reduce customer attrition, attract new customers, and ensure the continued viability of this important resource in 2021 and beyond.

If any changes are to the BIP and AP-I are adopted, their enrollment windows should be revised so that current participants can leave the programs if they choose to, and new customers can join.

15. Should the Commission consider authorizing another variation of the IOUs' Capacity Bidding Program in which customers can be dispatched in the Real-Time Market (RTM) under specified conditions? If so, what should be the required program attributes and dispatch conditions?

SCE's and SDG&E's CBPs currently include a day-of option for dispatch in the RTM. PG&E discontinued its day-of option beginning in 2018 due to low participation and to improve the overall program's cost effectiveness. Reinstating the day-of dispatch option in the RTM for PG&E would bring all three IOUs' CBP programs more in line with the structure of DRAM, in which resources are required to bid into the day-ahead market but have the option to change their bid in the RTM if not picked up day-ahead. However, it is not clear how many customers this would attract.

Another revision the Commission should consider is expanding the CBP by adding a weekend option for an additional capacity payment. The current program only requires participation during non-holiday weekdays which is likely reflective of the traditional expectation that reliability issues will only occur during the week. However, as the State experienced on August 15, DR resources can be helpful on the weekends as well. BIP resources were dispatched over consecutive weekend days, and though the current CBP tariff does not include weekend events, several DRPs dispatched their CBP resources on Saturday, August 15. Unfortunately, their performance was not recognized by the IOUs for the purposes of calculating their capacity payments because the program tariff did not specify this as an option. If DRPs participating in CBP are going to be expected to dispatch during the weekend again in the future, the program tariffs need to be revised reflect this, so customers can be paid appropriately.

Another improvement to the CBP that has proven attractive to DR customers in PG&E's service area is to add a CBP Elect option, similar to the one being implemented by PG&E, to SCE's and SDG&E's CBP programs. CBP Elect allows customers 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. 99% 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.[10]

16. Should the Commission order a supplemental Demand Response Auction Mechanism (DRAM) auction to be held in early 2021 to procure additional DR resources for summer 2021 (e.g., July – September)? If so, what level of budget authorization should be considered and why?

The Commission should order a supplemental DRAM auction in early 2021 because it would be one of the fastest and most effective steps to add new capacity by Summer 2021. The rules are already in place and there is available DR capacity since the Commission reduced the aggregate DRAM budget from $27 million in 2019 to $14 million in 2020 (prorated to $12.78 million to reflect the partial-year delivery period). The Commission should also expand the delivery period to include October because high heat events can still occur then and because reliability needs may arise during wildfire season. The incremental budget authorization should be at least $13 million prorated to the number of months chosen by the Commission for the

[10] PG&E Advice Letter 5799-E, Attachment 1, at p. 17.

additional capacity, with each IOU's share weighted to reflect their respective CBP value for each month.

Like for the CBP, the DRAM contract should be modified to allow weekend market dispatches to be used for settlement purposes.

17. Should the Commission explore short-term measures to expand electric vehicle (EV) participation in currently available DR programs (IOU DR, DRAM, non-IOU LSE DR)?

The Council has no comment at this time, but reserves its right to respond to other parties' comments.

18. Should the Commission consider measures to minimize potential attrition and loss of capacity in existing utility DR programs, such as increasing incentives, reducing dispatch activity limits, and clarifying expectations regarding when programs are dispatched?

The single most important step that the Commission can take to minimize potential attrition in DR participation in general is to ensure that participants are being fully paid for their load curtailments. The largest barrier to this is the day-of baseline adjustment cap used for calculating capacity payment. It is extremely important to ensure that customers are paid for their load reduction during extreme heat events like the one experienced in August; otherwise, they may not continue to participate in the future.

The IOUs' CBP caps the day-of adjustment at +/- 40% and the Demand Response Auction Mechanism (DRAM) Pilot caps the day-of adjustment at +/- 20% for non-residential customers and +/- 40% for residential customers to calculate Demonstrated Capacity and subsequently, determine the capacity payment due to the DRP (who in turn compensates the customer). The sustained extreme heat event from August 14-19 resulted in such high and sustained customer loads relative to their baselines that even with the day-of adjustment, curtailed customer loads were, in many instances, still greater than the adjusted baseline, despite the customer's actions to provide significant real load curtailments to the CAISO system. Based on a preliminary analysis, Council DRP members estimate that actual load curtailments on average were approximately 100% greater than curtailments calculated using the day-of adjustment. On account of this, some DRPs received no credit for their customers' performance during this period and by extension, no compensation (in fact, some DRPs were penalized for under-performance) and therefore their customers received no compensation.

In addition to suspending the CBP and DRAM day-of adjustment, the Commission should also allow customers who participate outside of the program hours to use their performance for capacity payments. DRPs who dispatched their CBP and DRAM resources on August 15 were not compensated for their performance on this day because the CBP and DRAM rules prohibit using performance outside of the specified hours for calculating their capacity payments.

During the August heat event, DR customers across the state participated with great enthusiasm and responsiveness despite being curtailed on multiple consecutive days, for up to five hours per event. For many DR customers operating businesses or with children at home, this was a significant sacrifice. Customers not being paid for their performance will significantly dampen their enthusiasm for participating in DR in 2021 unless they are compensated for their performance in August and steps are taken to ensure that they will be appropriately compensated in the future should a similar heat event occur again. In the short term, the Commission should temporarily suspend the CBP and DRAM day-of adjustment caps pending a reassessment of these issues, and allow CBP and DRAM customers to use out-of-program hour dispatches to determine their capacity payments when those dispatches are requested by the IOU, CPUC, or CAISO.

IV.
REQUEST FOR PARTY STATUS

Pursuant to Rule 1.4(a)(2)) of the Commission's Rules of Practice and Procedure and Section 7 of R.20-11-003, by filing these responsive comments, the Council requests confirmation of party status, as provided in R.20-11-003, with the following individual to be listed as the appearance for the Council on the Party Service List for R.20-11-003:

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FOR: CALIFORNIA EFFICIENCY + DEMAND MANAGEMENT COUNCIL

V.
CONCLUSION

The Council appreciates this opportunity to provide these Opening Comments on the preliminary scope of R.20-11-003 (OIR).

Dated: November 30, 2020

Respectfully submitted,

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