BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	Rulemaking 19-11-009 (Filed November 7, 2019)

OPENING COMMENTS OF THE CALIFORNIA EFFICIENCY + DEMAND MANAGEMENT COUNCIL, CPOWER, ENEL X NORTH AMERICA, INC., LEAPFROG POWER, INC., AND OHMCONNECT ON RESOURCE ADEQUACY REVISED TRACK 3.B.1 PROPOSALS, SECOND REVISED TRACK 3.B.2 PROPOSALS AND TRACK 4 PROPOSALS

Dated: March 12, 2021

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I. INTRODUCTION

The California Efficiency + Demand Management Council[1] ("the Council"), CPower, Enel X North America, Inc., Leapfrog Power, Inc., and OhmConnect, Inc. (collectively, the "Joint Parties") respectfully submit these Opening Comments on the Revised Track 3.B.1 Proposals, Second Revised Track 3.B.2 Proposals, and Track 4 Proposals submitted in this resource adequacy ("RA") proceeding. The Revised Track 3.B.1 Proposals were submitted on January 28, 2021; the Second Revised Track 3.B.2 Proposals were submitted on February 26, 2021; and the Track 4 Proposals were submitted on January 28, 2021. These Proposals were submitted pursuant to the Assigned Commissioner's Amended Track 3B and Track 4 Scoping Memo and Ruling, issued in this proceeding on December 11, 2020 ("Amended Scoping Memo"). These Opening Comments are timely filed and served pursuant to Rule 14.3 of the Commission's Rules of Practice and Procedure and the instructions contained in the Amended Scoping Memo.

II. REVISED TRACK 3.B.1 PROPOSALS

The Joint Parties address selected parties' proposals below.

[1] The views expressed by the California Efficiency + Demand Management Council are not necessarily those of its individual members.

A. Pacific Gas and Electric Company Proposals

1. Elimination of the T&D Line Loss Factor

Pacific Gas and Electric Company ("PG&E") proposes to eliminate the T&D Line Loss Adder from the Net Qualify Capacity ("NQC") value of DR resources "on the basis of equity with other distribution-connected resources" because these other resources do not have a T&D Line Loss Adder embedded in their NQC value.[2] This proposal should not be adopted because the original reasons for adopting the T&D Line Loss Adder in Decision ("D.") 10-06-036 have not changed.

PG&E correctly cites that D.10-06-036 adopted the T&D Line Loss Adder for DR resources to reflect the avoided line losses on account of DR being provided behind the customer meter.[3] However, PG&E errs in equating all other distribution-interconnected resources with DR because distribution-interconnected resources deliver energy onto the distribution system which is then transported and delivered to meet loads. This act of transportation inevitably results in line losses. In contrast, DR resources impose no line losses because no energy is exported to the grid; in fact, the load curtailment <u>reduces</u> the amount of energy transported, thereby avoiding the line losses that would have otherwise occurred in the absence of the load curtailment. This fundamental difference between DR and distribution-interconnected resources has not changed since D.10-06-036 was adopted.

PG&E also claims that its proposal is consistent with the Final Root Cause Analysis finding that "'the total amount [of demand response programs] did not approach the amount of demand response credited against RA requirements and shown as RA to the CAISO.'"[4] It is unclear why PG&E would criticize the performance of its own DR programs. However, the Joint Parties address in detail in the attached Appendix the pitfalls of drawing conclusions based on overly broad statements such as the one cited by PG&E. However, suffice to say that the Final Root Cause Analysis also conceded that the statement cited by PG&E is not a settled issue, stating "[a]dditional analysis and stakeholder engagement are needed to understand the discrepancy between credited and shown RA amounts, the amount of resources bid into the day-ahead and real-time markets, and performance of dispatched demand response."[5] Therefore, this

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[2] Revised Track 3B.1 Proposals of Pacific Gas and Electric Company, Attachment 1, at p. 1-5.
[3] Id.
[4] Id.
[5] Final Root Cause Analysis Mid-August 2020 Extreme Heat Wave, at p. 111.

proposal should not be adopted because there is no technical basis nor is there a clear policy basis.

2. **Update the Load Impact Protocols ("LIPs") to use the net peak load to value DR resources.**

As part of PG&E's proposal for updating the allocation mechanism for DR program RA benefits, it recommends that the DR Load Impact Protocols ("LIPs") be updated to determine DR RA values at the net peak load rather than the gross peak load.[6] In concept, this sounds reasonable, but it should not be adopted in isolation. The proposal seeks to set net peak load as the planning standard in isolation from the broader question of whether RA requirements should be set based on the net peak load rather than gross peak load. If the Commission ultimately chooses to adopt a planning standard based on the net peak load as part of the RA structural reform being discussed in Track 3B.2, then it would certainly be logical to carry this standard over to the LIPs. But until then, creating a divergent standard will only create unnecessary complications.

B. California Independent System Operator Proposals

1. **Effective Load Carrying Capability (ELCC) for Variable-Output DR**

The California Independent System Operator ("CAISO" recommends that the Commission adopt an ELCC methodology to calculate the QC values for variable-output DR beginning in the 2022 RA year.[7]

The Joint Parties are open to discussing a reasonable ELCC methodology for DR, but the CAISO's proposed timeline is unrealistic given the large number of details that would need to be determined. Moreover, as the LIP process is already under way to qualify capacity for 2022 deliveries, it is clearly too late to make any changes to DR counting rules that would impact the 2022 RA compliance year. It would also be prudent for the Commission to first determine what RA regime will be in effect going forward before making such significant changes. For instance, it is not clear how an ELCC approach would work should the Commission adopt an energy sufficiency approach such as the Southern California Edison ("SCE")/California Community Choice Association ("CalCCA") proposal or the Energy Division proposal. Compatibility with PG&E's "Slice-of-Day" proposal might be more apparent because both have a resource

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[6] Second Revised Track 3B.2 Proposals of Pacific Gas and Electric Company, Attachment 1, at p. 1-8 to 1-10.

[7] Track 3B.1 Proposals of the California Independent System Operator, at pp. 18-22.

availability element, although PG&E is proposing to use the exceedance methodology for all resources. In general, the Commission should be careful not to invest significant time discussing major changes in this Track that may eventually be made moot by a concurrent decision in a parallel Track of this proceeding.

More substantively, and with the overarching question of the longevity of this proposal aside, the Joint Parties recommend that any ELCC methodology should increase transparency and reduce the complexity of the DR NQC assessment process. Though not explicitly stated in its proposal, the CAISO has stated that an ELCC methodology should be applied on top of the NQC values developed through the LIP process. This approach would only increase the complexity and further reduce the already poor transparency of the current DR NQC process because it would effectively involve two different systems for discounting DR. To avoid further complicating the DR NQC process, it would be necessary to either create a highly streamlined set of LIPs using load impacts at a higher percentile over which to apply the ELCC methodology or develop an altogether different approach to calculating the nameplate capacity of a DR program or resource upon which the ELCC factor could be applied. Regardless, one of the goals should be for a DRP to have as much transparency as possible as to what their NQC values would be under various circumstances so that they can develop the most effective resources possible.

The Joint Parties also recommend that if an ELCC methodology is ultimately adopted, it should allow for multiple ELCC factors at the program-, resource-, and DRP-level to reflect the significant variation in the availability of DR programs and underlying resource types. This approach will also have the benefit of providing an incentive for DRPs to maximize their respective resources' availability to the market if they know that their ELCC factor will be directly influenced by their own program design. Otherwise, a single ELCC factor across all DR programs and resources will inaccurately reflect the availability of different programs and underlying resources, and eliminate any incentive to improve the availability of DR resources.

The Joint Parties recommend that the Commission disregard the CAISO's proposed principles at this time.[8] Any effort to develop an ELCC methodology should naturally be based on some key principles but the first three of the CAISO's proposed principles have not been fully discussed and vetted in this proceeding, though they could be re-introduced should the

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[8] Track 3B.1 Proposals of the California Independent System Operator, at pp. 19-20.

Commission choose to investigate an ELCC methodology in greater detail. However, the CAISO errs in contending that using an ELCC methodology for DR is an industry-accepted capacity valuation methodology. In fact, no other wholesale market in the U.S. uses this approach, so the Commission should disregard this principle as well.

III. SECOND REVISED TRACK 3.B.2 PROPOSALS

The Joint Parties provide no detailed opening comments on the proposals to reshape the RA market but reserve the right to respond to parties' comments in replies. However, we observe that the Energy Division and SCE/CalCCA proposals to either replace or supplant the capacity sufficiency approach with an energy sufficiency approach are overly complicated (especially in the case of the Energy Division proposal) and lack sufficient detail, especially as they pertain to DR and other use-limited resources. The Joint Parties respectfully remind the Commission that the last energy-based reliability system that was implemented in California was catastrophically unsuccessful in maintaining reliability which led to the adoption of the current capacity-based model we have today.

PG&E's Slice-of-Day proposal has some merit because it maintains a capacity-based model while addressing the continued growth of use-limited resources. However, like the other proposals, it too needs additional development.

The Joint Parties recommend that the Commission identify in this track one proposal to explore further in this proceeding or a successor proceeding while preserving the option of retaining the current RA model should it become apparent it is not workable. Regardless of the approach adopted, the Commission should establish a realistic time frame to allow this process to play out without constraining itself to an artificial time frame that could force a premature and flawed decision.

IV. TRACK 4 PROPOSALS

A. Energy Division

Before commenting on individual proposals, the Joint Parties would like to express their strong concern regarding the approach taken by the Energy Division in its Track 4 revised proposal filing. In some instances (e.g., proposal B), instead of putting forth specific proposals, the Energy Division ("ED") seeks party feedback on several questions pertaining to potential changes to the capacity valuation of DR programs and resources only after the workshop process.[9] Presumably, the ED's intent is for parties to provide responses and replies to its questions to develop a sufficient record for the Commission to decide on potential changes to DR RA valuation. However, this approach bypasses the Track 4 workshop process, so parties will have no opportunity to ask questions of the eventual approach put forward in the Proposed Decision because a full proposal would have never been presented. In other instances (e.g., proposal C), the Energy Division puts forth proposals of significant consequence to the market consisting of only one or two sentences for party comment. This too bypasses the workshop process in which the ED should have provided parties the opportunity to respond to specific proposals.

1. DR MCC Bucket

First and foremost, the Joint Parties advise extreme caution in basing consequential policy changes on a quick reading of high-level findings of reports published in the wake of the August and September heat storms. Specifically, the Joint Parties are extremely concerned by the use of high-level conclusions and observations from the Final Root Cause Analysis, the Department of Market Monitoring's ("DMM") Q3 2020 Report on Market Issues and Performance ("Q3 2020 DMM Report"), and DMM's February 25 report on Demand Response Issues and Performance ("February 25 DMM Report") in DR-related proposals. Stakeholders have not been given an opportunity to comment on these reports in a formal setting, and all of them suffer from various degrees of errors of fact, errors of omission, and/or simplified or misleading conclusions as they relate to DR performance and availability during the August and September 2020 heat events. The Joint Parties want to be very clear that it is not impugning the intentions of the organizations and individuals authoring these reports. Unfortunately, however, the bolded top-line findings described in these reports lack important context and omit nuance that has painted an inappropriately negative image of DR as a resource. The route and uncontextualized citation of these top-line findings therefore risks inflicting serious damage not only to the reputation of DR as a resource, but also on the long-term DR market in California, something that is reflected in this proposal. To demonstrate this point, the Joint Parties provide in the Appendix below a detailed list of examples from the February 25 DMM Report.

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[9] Administrative Law Judge's Ruling on Energy Division's Track 4 Proposal, Appendix A, at p. 8.

The Joint Parties provide comments on specific proposals below.

2. Reassessing the 8.3% DR Procurement Cap

The Joint Parties strongly advise against any further downward revision of the MCC DR bucket cap. The ED's proposal to potentially lower the 8.3 percent DR procurement cap will not address the points of concern regarding DR market participation while crushing an industry at a time when the value of flexible demand appears on greatest display. In fact, in Track 3B.1 of this proceeding, the Joint Parties have put forward a parallel proposal describing the already-evident negative impact of the existing DR cap on the growth of this resource and presented several options to allow greater breathing room for third-party resources while maintaining grid reliability.[10]

Specifically, the Joint Parties explained that the 8.3% cap is not providing the headroom for growth that the Commission envisioned. In D.20-06-031, the Commission argues that the cap "provides for DR growth of approximately 100 percent over the current levels when accounting for the 15 percent PRM adder."[11] However, the envisioned room for growth only materializes if all LSEs were to procure DR resources up to the cap which has been shown to be an unrealistic assumption. Because MCC buckets are applied at the LSE level, if some LSEs do not choose to procure DR, any headroom in their own bucket is effectively lost to the market. This problem is compounded by the fact that IOU DR programs preempt independently contracted third-party DR in fulfilling the MCC bucket as they are allocated first to LSEs. This is inequitable and discriminatory.

The real-market experience of DRPs in the fall of 2020 showed that some LSEs were already hitting the DR procurement cap—with *just two sellers* approved to sell any significant amount of capacity outside of DRAM at the time.[12] If DRPs *were already* running into this issue when only two players were competing for contracts, one questions whether the existing 8.3% cap will offer enough of a market opportunity for DR with six DRPs, let alone a lower cap.[13]

Instead of *further* capping the DR MCC bucket, the Commission should adopt the January 28, 2021 Track 3B.1 Joint Parties proposal to provide relief from the current DR

[10] Joint Track 3B.1 Proposal of the California Efficiency + Demand Management Council, CPower, Enel X North America, Inc., Leapfrog Power, Inc., and OhmConnect, Inc.
[11] D.20-06-031, at p. 57.
[12] The Commission's October 14, 2021 NQC List shows that Sunrun received a small amount of DR capacity NQC through the LIP process, whereas Leap and OhmConnect received substantially more NQC.
[13] In the current LIP process for the 2022 RA year, six DRPs have submitted draft LIP Evaluation Plans.

procurement cap by 1) removing the application of the cap at the LSE-level or 2) applying the cap to third-party (i.e., non-IOU program) DR, and 3) allowing behind-the-meter resources that are able to meet the operational characteristics of MCC Bucket 1 to count toward Bucket 1.[14,15]

In his Rebuttal Testimony in R.20-11-003, The Utility Reform Network ("TURN") witness Florio provides compelling arguments against the per-LSE component of the DR procurement cap. TURN states:

> The 8.3% cap appears to be having a perverse impact on individual LSEs because of the large amount of IOU DR credits that are being allocated to other LSEs. While the IOUs themselves may be well below the cap level, this allocation can be highly constraining to non-IOU LSEs, who may lack foreknowledge of the amount of such credits that they will receive. Suspending the 8.3% cap for individual LSEs only for 2021 could allow greater DR procurement to meet summer peak and net peak needs.[16]

3. Minimum Dispatch Requirements

Adopting a minimum dispatch requirement for a market-integrated resource is counterintuitive, does not guarantee that the resource is available when it is really needed, and would drive DR participants out of the market. Forcing DR resources to dispatch an arbitrary pre-determined number of hours regardless of market conditions is a) anti-competitive as it would require that providers bid below their costs, including the opportunity costs of their customers, b) counterproductive for reliability as it could exhaust the resource prior to an actual grid emergency, and c) discriminatory, unless all other RA resources are also obliged to have an energy delivery requirement as part of broader RA reform . This issue was explicitly litigated and rejected in D.20-06-031 with the caveat that the Commission would "continue monitoring bidding behavior and performance of DR resources in the market and may adopt dispatch requirements in the future if we conclude that such requirements are needed to ensure that DR resources demonstrate and provide their assumed RA value."[17] The Commission has taken no such actions to support this proposal.

[14] Joint Track 3B.1 Proposal of the California Efficiency + Demand Management Council, CPower, Enel X North America, Inc., Leapfrog Power, Inc., and OhmConnect, Inc., January 28, 2021.
[15] The third option is contingent on no changes being made to MCC Bucket 1.
[16] Prepared Reply Testimony of Michael Peter Florio, The Utility Reform Network, R.20-11-003, at pp. 10-11.
[17] Decision 20-06-031, at p. 41.

4. Maximum Bid Prices

Establishing a bid cap for just one type of RA resource is discriminatory; a bid cap for all RA resources is currently being debated in Track 3B.2 of this proceeding. Moreover, any such cap will only serve to reduce DR capacity because all customers whose opportunity cost is greater than the combined bid cap and capacity payment will no longer be willing to participate in DR. TURN witness Florio explained this concept well in his Opening Testimony in R.20-11-003:

> 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.[18]

The Joint Parties also caution that once this Rubicon is crossed, the Commission will inevitably find itself under pressure to constantly adjust the bid cap to get the number of dispatch hours that it or other parties want to see. This would create a great deal of regulatory uncertainty for DRPs and customers who will have no assurance that their participation in DR will be economically viable. Moreover, a bid cap will result in artificial dispatches of DR resources as opposed to being dispatched during periods of greatest grid need. For example, a DRP could end up dispatching its resources early in a month only to have an extended heat wave strike at the end of the end when it would have been needed most.

5. Disallow Startup Costs for PDRs

This proposal appears to stray into the CAISO's jurisdiction and opens the door to the Commission dictating the bidding behavior of any wholesale market resource. The CAISO continues to possess the authority to request documentation on resource start-up costs, so it is unnecessary and improper for the Commission to perform this oversight role as well.

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[18] Prepared Direct Testimony of Michael Peter Florio, The Utility Reform Network, R.20-11-003, at p. 17.

6. **Adjust MCC Buckets to Eliminate Bucket 2 and Require Monday-Saturday Availability for the DR Bucket.**

The ED proposes to extend the DR Maximum Cumulative Capacity ("MCC") Bucket availability requirement from Monday-Friday to Monday-Saturday.[19] According to the ED, approximately 3,000 MW of RA that would have been available on weekdays was not available on the weekend days of August 15 and September 5-6, 2020 when CAISO peak load exceeded 44,000 MW.[20] This proposal is premature, is likely to result in unintended consequences, and should not be adopted.

On a practical basis, the ED proposal will very likely reduce the amount of DR capacity available to the CAISO because many DR customers with weekday-only operations will not be able to provide the same amount of load curtailment on a Saturday as they do during the week. On a more fundamental level, the ED proposal seeks to revise the MCC regime in response to a 1-in-30 weather event that coincided with several CAISO market failures that contributed to the loss or export of thousands of MW of capacity. The market failures have been, or are being, corrected. If the Commission chooses to plan to a 1-in-30 standard, then it should make a comprehensive reassessment of all aspects of the RA regime, including MCC Bucket availability requirements. The Joint Parties note that there have been many occasions since the 2000-2001 energy crisis that CAISO loads have reached 44,000 MW and no blackouts were required. With a statewide RA requirement of far above that level, there should have been a more-than-adequate supply of capacity.

With this said, there certainly could be value to DR being available on Saturdays but it should not be a requirement. If the Commission would like to promote broader DR availability, stakeholders should discuss additional incentives and alternate program structures that would allow DRPs with customers willing and able to curtail load on weekends and holidays to do so. For instance, a recent Proposed Decision in R.20-11-003 would establish a five-year Emergency Load Reduction Program ("ELRP") pilot that would allow existing DR program customers to voluntarily respond and receive energy-only compensation for incremental load reduction beyond their contracted capacity obligations and/or market awards. For DR programs that do not

[19] Administrative Law Judge's Ruling on Energy Division's Track 4 Proposal, Appendix A, at pp. 5-6.
[20] *Id.*, at p. 5.

carry a weekend or holiday availability requirement, the proposed ELRP would provide such an incentive for those customers that have additional load reduction capability during these times.

7. Demand Response Adders

i. Should the Commission require the investor-owned utilities to include their demand response resources on supply plans or are there barriers that must first be addressed?

The Joint Parties respectfully decline to respond but reserve the right to do so in replies.

ii. If demand response resources are not put on supply plans and the CAISO follows through with its proposed BPM revision, how can this capacity be counted?

The Joint Parties respectfully decline to respond but reserve the right to do so in replies.

iii. Should, and if so how should, the transmission and distribution (T&D) and/or the PRM adders be retained and accounted for in CAISO's system.

a. Is it appropriate to include the transmission and/or distribution adder in the Net Qualifying Capacity (NQC) value of a DR resource?

The T&D Line Loss Adder should be retained and included in the NQC value of a DR resource. The Council had submitted just such a proposal in the Supply Side Working Group in this proceeding and reproduces it here.

As some background, the NQC value of most DR (excluding Demand Response Auction Mechanism capacity) is determined by the LIPs, and separately adjusted for avoided T&D line losses through the T&D Line Loss Adder and the Planning Reserve Margin ("PRM"). The unadjusted NQC values of third-party DRP resources are provided on the Commission's NQC list and are used in the supply plans submitted by a DRP/LSE or their scheduling coordinator.

Currently, the T&D Line Loss and PRM adjustments for third-party DR resources are added to their NQC value by Commission Staff through the CAISO's Customer Interface for Resource Adequacy ("CIRA") as credits against the contracting LSE's RA requirement. However, in its proposed change to Reliability Requirements Business Practice Manual BPM (PRR 1280), the CAISO plans to eliminate the use of RA credits that do not net to a zero change to overall RA requirements. Because the T&D Line Loss/PRM credits do not meet that criterion, the CAISO would no longer allow them to be counted toward an LSE's obligation. PRR 1280 will effectively create a dual system in which the RA value of DR is different for the Commission and the CAISO, a paradigm that is confusing, inefficient, and once again imposes unnecessary regulatory hurdles to DR resources.

To address the differing valuation of DR at the Commission and the CAISO, at least in part, the NQC values approved by Commission Staff through the LIP process should explicitly include the T&D Line Loss adjustment. This is perfectly appropriate because recognition of a DR resource's avoided T&D line losses is already reflected in the CAISO energy market settlement process. CAISO measurement and settlement occurs at the point of interface with the CAISO grid (i.e., on the high-voltage system) and the customer meter data DRPs receive from the IOUs is measured at the end-customer's location (i.e., on the low-voltage distribution system) after line losses have been incurred. Because of this, CAISO requires that DRP scheduling coordinators convert Revenue Quality Meter Data ("RQMD") to Settlement Quality Meter Data ("SQMD"), which includes grossing up for avoided T&D line losses, when they submit data to the CAISO for settlement. Therefore, it is perfectly logical that the NQC should reflect what a DR resource can deliver to the point of grid interface, not to the end user's location, and this includes the T&D Line Loss Adder.

b. Would including adders subject DR resources to RAAIM penalties?

Including the T&D Line Loss Adder could cause a DR resource to be subject to RAIIM penalties if the resource is smaller than 1 MW and is then caused to exceed the 1 MW RAIIM threshold once the T&D Line Loss Adder is applied.

c. Are there technical barriers to including adders in a resources NQC value or CAISO systems that would need to be changed?

To the Joint Parties' knowledge, no technical barriers exist for including the T&D Line Loss Adder in a DR resource's NQC value.

B. California Independent System Operator

1. Discontinuing All Non-Net Neutral Credits

The Joint Parties have serious concerns about eliminating the Commission's current approach to reflecting the value of DR RA capacity unless it can be replaced with a system that preserves the avoided T&D Line Loss Adder, as explained above.

V. CONCLUSION

The Joint Parties appreciate this opportunity to provide these Opening Comments on the RA Track 3B.1, 3B.2, and 4 proposals.

Respectfully submitted

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APPENDIX

In this Appendix, the Joint Parties address some of the greatest areas of concern in the February 25 DMM Report, as it is the most comprehensive assessment of DR performance during the 2020 heat events. The arguments below also apply to the Final Root Cause Analysis and Q3 2020 DMM Report as all three reports are based on the same underlying data.

1. **Statement:** On August 14 and 15 in hours ending 19 and 20 (6:00-8:00 pm), about 73 to 77 percent of the demand response capacity in real-time reported to perform as scheduled.[21]

   Response: This statement is misleading because it does not mention the high likelihood of under-counting DR performance during the extreme heat events due to the artificially low day-of adjustments to the CAISO's DR baselines. This issue was briefly mentioned in the Q3 2020 DMM Report and in greater, though insufficient, detail within the February 25 Report.

   As some background, the amount of load curtailed by customers participating in DR programs during a DR event is generally determined by comparing a customer's actual load during the DR event to a baseline load level that is meant to approximate what the customer's load would have otherwise been absent the DR event. To ensure that the customer's baseline reflects the conditions during the DR event, its baseline is derived by taking the average load for each corresponding hour over prior "similar" days prior to the event, with the option of a "day-of adjustment." A "similar" day typically consists of the same type of day when no DR event occurred, which is most commonly a non-holiday weekday, because DR events are most prevalent on non-holiday weekdays.

   The day-of adjustment is designed to adjust the baseline to account for differences in overall load on the day of a DR event compared to the prior "similar" days and is calculated as the ratio of a) the average load preceding and/or following the DR event to b) the average load of the corresponding hours from the prior similar days. A day-of adjustment to the customer's baseline is appropriate if the customer's load immediately preceding and/or following the DR event is significantly greater than the corresponding hours that form the baseline during the prior "similar" days. In practical terms, this typically occurs when temperatures on the day of the DR event are significantly higher than the "similar" days that

[21] February 25 DMM Report, at p. 22.

serve as the basis for the customer's baseline. This adjustment, however, is capped at +/-20% (for commercial and industrial customers) and +/-40% (for residential customers). During sudden and intense heat storms such as the one that happened in August of 2020, even a 40% adjustment may be too low. Put another way, a customer's load on the day of such an event is, on average, more that 40% greater than their load during the "similar" days that form their baseline. In such an instance, even if customers show reductions during a DR event, their overall energy usage would still be higher than their calculated baseline, giving the appearance that they did not reduce load at all.

Once final Revenue Quality Meter Data ("RQMD") for the August and September dispatches are available from the IOUs, the Commission should consider performing an analysis using DRP customer data during the August and September heat storms and non-participating customer data as a control group to examine uncapped performance relative to capped performance to determine the magnitude of this problem.

2. **Statement:** About one-third of the 1,847 MW of resource adequacy capacity requirement met by demand response in August was not available or directly accessible to the ISO in real-time during periods of firm load curtailment.[22]

   Response: This statement is misleading because it could be interpreted to mean that DR resources were absent due to improper market practices when involuntary load curtailments occurred. In fact, long-start Proxy Demand Resources ("PDR") are not required to be available in the real-time market ("RTM") if they did not receive an award in the day-ahead market ("DAM"). The DMM notes this on page 9 of its report. At least a portion of the capacity that was not available/accessible to the CAISO represented these resources. In terms of third-party DR resources, it appears that about 53 MW of capacity was bid into the DAM but was not available to the CAISO in the RTM on August 14.[23] This matches nearly perfectly with the capacity represented by supply plan (third-party) long-start PDRs not committed in the DAM, as described by the DMM in its February 25 Report.[24] While market rules allowing long-start resources to not have a RTM obligation can be debated, one cannot

[22] February 25 DMM Report, at p. 2.
[23] Q3 2020 DMM Report, at Table 3.1.
[24] February 25 DMM Report, at Figure 2.3.

draw the conclusion from the bold, top-line findings that DR was simply "missing" due to bad behavior.

3. **Statement:** Some high load days in August and September (August 15 and Labor Day weekend) coincided with weekends and holidays, where a significant portion of demand response adequacy was not available. Both utility and supply plan demand response availability dropped significantly on weekends and holidays. When capacity was made available on weekends and holidays, this capacity was offered at higher prices than capacity offered on non-holiday weekdays.[25]

   Response: This statement is misleading because it could be interpreted to mean that DR resources were missing due to inappropriate market practices on weekends and holidays. In fact, DR resources are not required to be available on weekends and holidays to qualify as Resource Adequacy ("RA") resources. Importantly, despite not having an obligation to be available, many PDRs were *voluntarily* made available by DR providers ("DRP") during the weekend days of the 2020 heat events at the request of the Energy Division and IOUs. This voluntary presence of additional capacity due to high grid need should reflect positively on the resource. And while some bid prices may have indeed been high, it is perfectly understandable given that customers were being asked to curtail load outside of normal program hours. Furthermore, it is likely that, in many instances, PDRs had been dispatched on multiple consecutive days through Friday, so higher bid prices would reflect a higher opportunity cost of dispatching the same set of users. Once again, while availability of DR programs during the weekend can be debated, it is inappropriate to look at the figures depicting weekend and holiday availability and draw the conclusion that DRPs were acting in bad faith.

4. **Statement:** Based on supplier-submitted baseline and meter data, there is some evidence that baseline adjustments could have been limited in the upward direction by defined baseline adjustment caps. Based on self-reported meter data, certain customer loads on high load days may have deviated from historic days' load by factors greater than the ISO's baseline adjustments allowed. This could have resulted in self-reported performance values that were

[25] February 25 DMM Report, at p. 2.

lower than actual load reduction if baselines could not be adjusted sufficiently upward. However, DMM estimates that even if higher baseline adjustments were permitted, many demand response resources would still have shown to under-deliver compared to expected load curtailment in high load days in August and September 2020.[26]

Response: First, the Joint Parties appreciate DMM's acknowledgement of and attention to the fact that DR performance was likely undercounted during last summer's heat events. Because of this downward bias, the Commission and stakeholders should be careful in using any of the tables and figures showing DR performance during this period as basis for subsequent policy change constricting future growth of the resource. The Joint Parties support further review of this issue.

Second, the Joint Parties clarify that "self-reported" or "supplier-reported" data refers to performance calculations made by each entity's Scheduling Coordinator ("SC"). Due to issues experienced by the CAISO in calculating PDR performance when these resources were first integrated into the market, SCs, not the CAISO, have been performing and uploading performance calculations for the purpose of settlement as a matter of standard practice. The mention of "self-reported" should not be read as "unofficial" or "potentially biased".

Finally, the DMM's analysis of this issue, though appreciated, is incomplete. Through offline discussions, DMM informed the Joint Parties that in determining total uncapped performance shown in Figure 2.12 and 2.13, it only looked at DR resources that delivered less than their schedule under the existing adjustment cap. In effect, it looked at underperforming resources only and concluded that, without a cap, these resources would collectively continue to underperform, but not by as much. The figures do not include resources that performed largely at or above dispatched quantity, which again biases total performance downward. The Joint Parties suggest that for such work to be instructive, DMM should make "apples-to-apples" comparisons— i.e., make the same calculations originally published, but without a cap on the day-of adjustment.

[26] February 25 DMM Report, at p. 22.