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)

JOINT OPENING COMMENTS OF THE CALIFORNIA EFFICIENCY + DEMAND MANAGEMENT COUNCIL, CPOWER, ENEL X NORTH AMERICA, INC., LEAPFROG POWER, INC. AND OHMCONNECT, INC. ON PROPOSED DECISION ADOPTING LOCAL CAPACITY OBLIGATIONS FOR 2021-2023, ADOPTING FLEXIBLE CAPACITY OBLIGATIONS FOR 2021, AND REFINING RESOURCE ADEQUACY PROGRAM

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I. INTRODUCTION

The California Efficiency + Demand Management Council,[1] CPower, Enel X North America, Inc., Leapfrog Power, Inc. and OhmConnect, Inc. ("the Joint Parties") respectfully submit these Joint Opening Comments on the Proposed Decision Adopting Local Capacity Obligations for 2021-2023, Adopting Flexible Capacity Obligations for 2021, and Refining Resource Adequacy Program, mailed in this proceeding on May 22, 2020 ("Proposed Decision" or "PD"). 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 accompanying the Proposed Decision.

II. TESTING AND DISPATCH REQUIREMENTS

A. Third-Party Demand Response ("DR") should not be subject to a different testing standard from Investor-Owned Utility ("IOU") DR programs.

The Proposed Decision adopts Pacific Gas and Electric Company's ("PG&E's") tiered testing proposal of one two-hour test event per year for "stable" resources (Tier 1) and one four-hour dispatch per quarter for all other "new" and "changing" DR resources (Tier 2).[2] According to the Proposed Decision, the definition of "stable" would be determined in Track 4 of this proceeding but in the meantime, all third-party DR resources procured by non-IOU load-serving

[1] The views expressed by the California Efficiency + Demand Management Council are not necessarily those of its individual members.
[2] Proposed Decision, at p. 36.

entities ("LSEs") would be subject to the stricter testing tier.[3] Testing would occur at the resource level and all resources of a DR Provider ("DRP") within a given sub Load Aggregation Point ("subLAP") would be dispatched concurrently, with performance determined by the average over the test event duration.

As the Proposed Decision correctly noted, the Joint Parties are supportive in concept of a two-tiered testing regime but have significant concerns about several details adopted by the Proposed Decision. First, the Joint Parties strongly object to applying, on a default basis, the stricter testing requirement on all third-party DR resources procured by non-IOU LSEs. There is no evidence in the record to support any contention that this type of DR performs any differently than IOU DR programs. Though the Energy Division cited the California Independent System Operator's ("CAISO's") Q3 2019 Report on Market Issues and Performance ("DMM Report"), the Joint Parties explained in March 23 opening comments that it is highly likely that an overwhelming majority of the Proxy Demand Resources ("PDRs") that were examined in the DMM Report were associated with DR Auction Mechanism ("DRAM") contracts which are contracts to IOUs, not non-IOU LSEs.[4] Furthermore, the analysis cited in the DMM Report overlooks the fact that some DRAM contracts have performed well.

Regardless, the analysis contained in the DMM Report cannot be applied to third-party DR contracts with non-IOU LSEs. Conversely, there is evidence indicating that IOU DR programs do not always deliver on their full net qualifying capacity ("NQC") value. In Southern California Edison's ("SCE's") Opening Comments on Track 2 proposals, it states that "[t]he output of DR resources is largely variable throughout the month (potentially daily) and could range from zero MW to Pmax during those timeframes."[5] It has been clear that certain IOU DR programs have not possessed flat monthly capabilities; for example AC cycling DR programs have significant variability from one day to the next. The Joint Parties do not cite this as a criticism of SCE's or the other IOUs' DR programs. However, SCE's statement undermines the Proposed Decision's underlying basis for defaulting third-party DR contracts with non-IOU LSEs, which appears to be that this type of DR is somehow less reliable than IOU DR programs.

[3] Proposed Decision, at p. 36.
[4] Joint Opening Comments of California Efficiency + Demand Management Council, CPower, Enel X North America, Inc., Leapfrog Power, Inc., and OhmConnect, Inc. on Track 2 Proposals, Working Group Reports and March 5, 2020 Workshop (March 23, 2020), at p. 11,
[5] SCE Opening Comments on Track 2 Proposals (March 23, 2020), at p. 13.

Furthermore, given that the Proposed Decision directs third-party DR to continue to utilize the DR Load Impact Protocols ("LIPs") just as IOU DR programs must also, there is no difference in the qualifying capacity ("QC") valuation methodology that would otherwise warrant a stricter testing requirement for one type of DR relative to another, at least until the additional details of the testing regime are developed. In these circumstances, it would be discriminatory to place a disadvantage on third-party DR and the non-IOU LSEs who would purchase the DR capacity. In fact, unequal testing requirements contradict key neutrality principles adopted by the Commission in Decision ("D.") 16-09-056. In Finding of Fact 56 of D.16-09-056, the Commission found, "The Utilities' demand response programs and third-party provider demand response programs should be on a level playing field."[6] The Commission made other similar statements throughout this decision, "Utilities and third-party providers should fairly compete on a level playing field to vie for customers to enroll in their demand response programs,"[7] and "Because we have adopted a principle of market-driven demand response with a focus on competition, we will encourage the use of fair competition between the Utilities and third-party providers in demand response and will adjust accordingly to the outcomes of the competition."[8]

Finally, the application of different testing standards by default contradicts the reasoning cited by the Commission to maintain the use of the LIPs for third-party DR. The Proposed Decision states, "Multiple parties oppose an alternative to LIPs. San Diego Gas & Electric ("SDG&E") and PG&E oppose an alternative, noting that there should be parity in counting rules for DR."[9] The Proposed Decision should apply this same principle to testing requirements – there should be parity in testing rules for DR.

On a more practical level, a stricter testing regime would raise costs and depress the amount of DR available to be contracted from non-IOU DR providers. The stricter testing requirements could discourage customers from participating in non-IOU DR and increase the compensation needed by participating customers to account for the higher opportunity cost associated with more frequent and longer duration testing. The PD should be revised to default

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[6] D.16-09-056, at Finding of Fact 56.
[7] *Id*., at p. 52.
[8] *Id*., at p. 56.
[9] Proposed Decision, at p. 39.

both IOU and third-party non-IOU DR resources to Tier 1 testing until the details and definitions associated with the testing regime can be finalized

B. The Tier 2 testing requirement is excessive.

The Proposed Decision's proposed Tier 2 testing requirement is excessive, especially considering that the Commission has yet to define "stable" and "unstable" resources. Furthermore, given the sheer number of dispatch hours, requiring a four-hour test every quarter looks very much like a minimum dispatch requirement, something the Proposed Decision correctly declines to adopt. The Joint Parties recommend that the Tier 2 testing requirement be revised to one four-hour test event per Summer and Winter season.

C. A market dispatch should equate to a test event.

The Proposed Decision should specify that if a resource performs a market dispatch that meets the applicable testing requirement, it can forego a test event if the DRP chooses. For example, if a resource that is subject to the proposed Tier 1 testing requirement undergoes a two-hour market dispatch for the full capacity amount of the resource, that resource should be considered to have met its testing requirement. However, if the resource is not dispatched for a full two hours at its full capacity level, it should remain subject to the testing requirement until a test event occurs or a full market dispatch can be achieved. If the purpose of a testing regime is to ensure a DR resource is available, then the circumstances of its dispatch should be irrelevant.

The Commission should also allow market dispatches to satisfy the testing requirement because it will encourage DRPs to dispatch in the wholesale market and meet actual system needs rather than taking an outage while performing a test event at an arbitrary time. The CAISO has been clear that its preference is for DRPs to perform market dispatches rather than test events whenever possible so the Commission should accommodate this preference.[10]

D. Concurrent testing is unnecessary and defeats the purpose of a market dispatch.

The Joint Parties have significant concerns regarding the requirement that all of a DRPs' DR resources within a given subLAP be tested concurrently.[11] Concurrent testing ignores the possibility that DR resources are scheduled individually in the CAISO market so, when a DRP's resources in a subLAP must be tested, it is possible that some resources have already been dispatched in the CAISO market on a prior occasion within the test period. This is very common

[10] CAISO Consolidated Comments on All Workshops and Proposals (March 23, 2020), at p. 9.
[11] Proposed Decision, at p. 37

because DRPs typically group customers into resources based on similarities in their opportunity costs, response times, and willingness to be dispatched. A concurrent testing requirement could force some customers to conduct a test event even if they had already been dispatched economically during the test period. In addition, concurrent testing would prevent DRPs from performing randomized control testing ("RCT"), a method often used in statistical analysis for load types with high customer count, in which participants will be randomly split into multiple groups and tested on different days under similar conditions. RCTs can provide DRPs a more accurate assessment of load impact when conducting the load impact analysis under the LIPs.

With this said, if the purpose of the testing regime is to demonstrate that DR resources can deliver their full capacity, then the Commission's preference should be that the dispatch be used to meet a market need rather than simply "checking a box". The Commission should allow DRPs to exempt resources from test events if they have already been dispatched economically in the CAISO market at full capacity for a duration equal to or greater than the testing requirement.

E. Testing should only be required of resources that are under contract.

One area in which the Proposed Decision was silent regarding testing is under what conditions testing is required. There will be some instances in which some or all of a DRP's resources are not providing capacity under a contract. For instance, customers with little curtailable winter load would not be included in RA contracts for the winter months. In this instance, it would be unreasonable to require the DRP to test these customers when they are not providing capacity through a contract with an LSE. The Proposed Decision should be modified to specify that testing of a DR resource is only required when it is used by the DRP to meet contractual requirements. Because Tier 1 resources would only require one test per year, the single test would apply for any full- or partial-year RA contract; under the proposed testing frequency for Tier 2 resources as revised by the Joint Parties, testing would only be required when the resource was under contract during a full or partial season (i.e. winter or summer).

F. Addressing final testing rules in Track 4 is too late.

The Joint Parties have concerns about using Track 4 as the venue in which to develop the final details of the testing regime. The January 22 Scoping Memo ("Scoping Memo") did not specify a Track 4 schedule so it is unclear when the testing regime can be fully fleshed out.[12] Track 3 is scheduled to be completed in Q1 or Q2 of 2021 so it possible that Track 4 would not

[12] Scoping Memo, at p. 8.

be concluded until late 2021 or even early 2022. In the meantime, under the Proposed Decision's current proposal, third-party DR for non-IOU LSEs would be subject to an unjustifiably more rigorous testing regime for all of 2021 and possibly for all 2022, depending on when the Track 4 decision is approved.

Due to the annual RA solicitation timeframe, if permanent testing requirements are unresolved by May 1, 2021, this more frequent and more sustained testing will be reflected in the final load impact evaluations submitted by DRPs at the end of May 2021 that will serve as the basis of their responses to RA solicitations for 2022 delivery. Therefore, resolution of testing requirements should be resolved and approved by the Commission in Track 3 of this proceeding. If the Commission cannot revise the Track 3 scope, this issue could be addressed in the DR rulemaking where an appropriate amount of attention can be paid by Energy Division staff and interested parties.

III. MINIMUM DISPATCH REQUIREMENTS

The Proposed Decision correctly finds that there is an insufficient record to support adopting a minimum dispatch requirement at this time.[13] Furthermore, as the Joint Parties have recommended, any minimum dispatch requirement for DR should be considered within the broader context of all use-limited resources. Track 3 of this proceeding has already been identified in the Scoping Memo as the appropriate venue to discuss this broader issue and the Joint Parties reiterate their support for delaying any discussion of this issue to the broader use-limited resource discussions.

IV. LIPS AND ALTERNATIVES

A. The LIP provisions adopted by the Proposed Decision remain problematic.

The Joint Parties continue to note that there are significant problems with the LIPs regarding their application to determine the QC value of third-party DR and maintain that no other jurisdiction utilizes a similar process. The PD declines to adopt the Joint Parties' initial or revised DR Counting proposals and makes no substantive changes to the LIPs themselves. However, the PD adopts the clarification requested by the Joint Parties that ex post and ex ante load impacts should be required at the subLAP level.[14] The Proposed Decision also adopts the Joint Parties' proposal for a mid-year update to DRPs' load impact evaluations, subject to certain

[13] Proposed Decision, at p. 37.
[14] *Id.*, at p. 41.

thresholds, and provides guidelines for determining the load impacts of new resources without historical performance data or existing resources with significantly different expected performance relative to their prior performance.[15]

As an initial point, as the Joint Parties have explained, the LIPs have never been used for determining the QC values of third-party DRP's portfolios, so their accuracy in that application is unproven. In fact, this was the reason for the Proposed Decision's rejection of the Joint Parties' initial proposal to use the mechanism adopted for the DRAM.[16] Furthermore, the Proposed Decision cites SDG&E's argument that the LIPs are transparent and not burdensome but it ignored the Joint Parties' rebuttal that, based on the actual experience of DRPs, the cost to a DRP to hire an outside consultant to perform the load impact evaluations is considerable and can exceed the revenue from the DR resources being evaluated.[17] The reality is that there are very few consultants who possess the experience to perform load impact evaluations so, because DRPs are seeking them out simultaneously each year, it can be difficult or impossible to find a consultant to perform the analysis in addition to the evaluation itself, all of which can cost at a minimum a six figure value with a highly uncertain return. In addition to this financial burden, there is also an administrative burden on DRP staff to pull together the data needed by the consultant, which also carries an additional financial burden. SDG&E's opinion on this issue is completely irrelevant to the experience of a DRP and should not be used to justify using the LIPs for QC valuation.

The Proposed Decision provides little explanation for rejecting the Joint Parties' proposed revisions to the LIPs. The Joint Parties recommended several reasonable instances where the scope of the LIP analyses could be reduced when certain protocols were not germane to the determination of the DR QC value.[18] These revisions could reduce the cost and time required to perform load impact evaluations. That the Proposed Decision addresses none of them raises the question of whether the RA proceeding is the appropriate venue for developing revisions to the LIPs. The RA proceeding has too many issues that are a higher priority to the

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[15] Proposed Decision, at pp. 41-42.
[16] *Id.*, at p. 40.
[17] Joint Reply Comments of California Efficiency + Demand Management Council, CPower, Enel X North America, Inc., Leapfrog Power, Inc., and OhmConnect, Inc. on Track 2 Proposals, Working Group Reports and March 5, 2020 Workshop ("Joint Parties' Reply Comments on Track 2 Proposals") (April 2, 2020), at p. 13.
[18] Track 2 Proposal of California Efficiency + Demand Management Council, CPower, Enel X North America, Inc., and Leapfrog Power, Inc. (February 21, 2020), at pp. 13-19.

Commission than the minutiae of issues like the LIPs. Therefore, the Commission should create a forum or working group led by the Energy Division or a consultant retained by the Energy Division where parties can develop streamlined LIPs that can be used by both IOUs and DRPs for QC valuation of DR. The goal of the working group would be to update the LIPs so they can more simply and accurately measure the QC value of DR resources. The full LIPs should continue to be used for IOU DR programs for long-term planning but a more streamlined approach is appropriate for short-term planning.

B. Additional detail is needed regarding the mid-year enrollment update.

Though the Joint Parties do not support using the LIPs for QC valuation of third-party DR, we welcome the Proposed Decision's clarification that load impact evaluations must be performed at the subLAP level. The Joint Parties also appreciate the adoption of a mid-year enrollment update but there are several key problems that must be rectified for the update process to be usable by DRPs. The Proposed Decision was silent on the exact timeline for when this update process would occur so the Joint Parties recommend that the Energy Division be designated to develop this timeline through an informal process similar to the one used to develop the current load impact evaluation timeline.

Second, linking the trigger to actual customer enrollment as indicated in the CAISO's Demand Response Registration System ("DRRS") is highly problematic. Enrolling customers requires a significant amount of effort and resources, and requires customers be removed from other DR programs or IOU critical peak pricing rates, so DRPs will typically only recruit new customers if they have been awarded a contract and have an obligation to fulfill. In addition, these customers will be entered in a just-in-time fashion into the DRRS to minimize customer disruption. Because a DRP will need incremental growth in its portfolio as a precondition to respond to a solicitation, new customers will not be entered into the DRRS until after the DRP receives an award. For this update process to be workable, DRPs should be required to provide a revised load impact evaluation reflecting the updated enrollment forecast and any relevant supporting information. Otherwise, no DRP will likely be able to utilize the update process. A potential alternative and more simplistic approach that could be explored further within an LIP working group could entail the Energy Division scaling up a DRP's QC value in proportion to its revised enrollment forecast rather than updating the load impact analysis. This method would be best suited for residential DRPs because they are more likely to have a relatively homogeneous customer base.

Third, the Proposed Decision set a threshold of the greater of 20% or 10 MW change in a DRP's portfolio size to trigger an update. This threshold amount is far too large to be of use for some DRPs, especially residential DRPs and new entrants who may have relatively few megawatts in their portfolio relative to an established DRP with large non-residential customers. For some DRPs, a few MW represents a significant difference in their portfolio. The Joint Parties sympathize with the burden on the Energy Division of assessing the load impact evaluations but the update process should be fairly straightforward in that the methodology of the analysis would not have changed, only the enrollment input. The Joint Parties recommend that the update threshold be revised to the greater of 10 percent or 3 MW.

The Joint Parties support the Proposed Decision's approach for determining a QC value for new resources with no historical performance data or existing resources with significantly different expected performance.[19] The first option correctly allows established DRPs to apply their experience and familiarity with their customers to develop a QC estimate. The second option allows new entrants or those that are expanding their customer base (e.g. a residential aggregator expanding to non-residential customers) to use a reasonable proxy load impact in the absence of any first-hand data.

C. The Commission should adopt the Miscellaneous Provisions adopted by the Joint Parties.

Though the PD declines to adopt the Joint Parties' initial and revised DR Counting proposals, there are key details that, through the experience gained by the IOUs and DRPs with the DRAM, should be adopted to improve administrative efficiency and engender confidence among the Commission, IOUs, and non-IOU LSEs as to the reliability of third-party DR. The PD is silent on these issues but without their resolution, problems could arise in the implementation of third-party DR contracts. To the Joint Parties' knowledge, no party has objected to their adoption so the Commission should adopt them here. The Joint Parties reiterate them here:

- **Customer Movement Restrictions:** Limitations regarding intra-month customer location movements that were adopted for the DRAM are suitable for other third-party

[19] Proposed Decision, at p. 42.

DR to ensure that customers within a given DR resource are not counted simultaneously within a given month. Customer location movement between resources within a month should be prohibited, except under the following circumstances: 1) newly enrolled customers can be added to a resource; 2) a customer who ends its relationship with a DRP may be dropped from a resource; and 3) if the above changes make a resource trigger the 10 MW telemetry requirement, or have it drop below the 100-kW minimum Proxy Demand Resource size, resources may be split or combined mid-month to continue to meet CAISO market requirements.

- **Double-Counting:** Similar to restrictions on intra-month customer movements, the DRP must avoid any potential double counting of customer performance associated with service account movement permitted by the exemptions when invoicing Demonstrated Capacity ("DC").
- **Baselines:** The baseline method used for energy settlement at the CAISO must be the same as the baseline method used to invoice DC.
- **Data-Related Communication Protocols:** As was learned through painful experience in the DRAM, it is critical that an effective and transparent process be established for DRPs and IOUs to discuss problems related to the provision of revenue quality meter data ("RQMD"). DRPs need these data to settle in the CAISO market and are subject to penalties if they do not timely deliver it. In addition, and most importantly, these data are needed to invoice the LSE, even if the LSE is not an IOU. The following provisions should be adopted.
    - Each IOU and DRP shall designate a point of contact for all data delivery inquiries and notify the Commission's Energy Division, IOUs, and DRPs of any changes to this point of contact.
    - Each IOU shall facilitate a monthly call for DRPs to report or address data issues. These should not absolve the IOUs to expediently resolve data issues when these occur outside of the monthly call.
    - All DRPs shall perform troubleshooting prior to notifying an IOU of any data issues including: a) verifying the Application Programming Interface data request was correctly formatted; b) verifying the DRP's customer lists are updated including removing customers whose service accounts have been closed; and c)

verifying that missing data is not a result of a planned or unplanned outage where the IOU has notified the DRP.

- DRPs shall notify the IOU of data error using a standardized data template. Again, this should provide efficiencies for the IOUs in determining the root causes of issues and resolving the issues and for DRPs in reporting the issues.
- The IOU shall confirm receipt of inquiry within two business days and provide an estimated time of resolution of the inquiry.
- The IOU shall update the DRP on a regular basis and when the estimated time of resolution could change.
- The IOU shall confirm resolution of the inquiry and data delivery.

The Commission should take advantage of the lessons learned from the DRAM administration and adopt these same rules for third-party DR contracts with non-IOU LSEs.

D. LIP Confidentiality.

The Proposed Decision adopts a requirement that load impact evaluations and the QC values from a DRP's load impact evaluation shall be posted publicly to the maximum extent allowable, while protecting customer privacy and market sensitive information of DRPs by adhering to existing Commission policies regarding confidentiality.[20] The Joint Parties appreciate the Commission's commitment to protecting customer privacy and market-sensitive information. However, the existing confidentiality rules approved in D.06-06-066 are silent on exactly what data are protected in load impact evaluations and can be redacted. There is little information in the record on which to base any meaningful decision on this issue so the Joint Parties recommend that this also be considered in the LIP working group proposed above.

V. MAXIMUM CUMULATIVE CAPACITY ("MCC") BUCKETS

The Joint Parties strongly recommend that any specific changes to the MCC Bucket regime take place in Track 3 of this proceeding where consideration of the role all resource will play in the future RA construct is examined. However, to the extend the Commission takes this matter up now, the Joint Parties offer a number of comments.

The Proposed Decision addresses several important issues regarding the MCC Bucket regime including the adoption of a definition of "availability" for the purpose of determining

[20] Proposed Decision, at p. 44.

what MCC bucket a resource fits into, as well as a DR procurement cap.[21] The definition of "availability" warrants clarification and modification. The full proposed definition is:

- Holding aside use limitations or outages, a resource is physically capable of dispatching the entire capacity designated in the given bucket in any and all hours associated with the minimum criteria for that bucket;
- Holding aside use limitations or outages, the resource will economically bid or self-schedule (in the CAISO markets) the entire capacity designated in the given bucket in any and all hours associated with the minimum criteria for that bucket; and
- If the resource has use limitations, those limitations would not prevent bidding, self-scheduling, and dispatch during regular, specific hours associated with the minimum criteria for that bucket.

The Joint Parties are concerned that the first of the three parts is open to misinterpretation and recommend this language be revised. In saying, "Holding aside use limitations or outages, a resource is physically capable of dispatching the entire capacity designated in the given bucket in any and all hours associated with the minimum criteria for that bucket", this could be misinterpreted that a resource must be capable of dispatching for the entire number of hours in a given bucket. For instance, the DR bucket requires that qualifying DR be capable of dispatching between 4:00 p.m. to 9:00 p.m. on weekdays. This could be interpreted to mean that DR resources must be capable of dispatching for the entire five hours. This would be a significant departure from current RA requirements which require a capability to dispatch for four consecutive hours, not five. To avoid any confusion, this portion of the definition of "availability" should be revised to: "Holding aside use limitations or outages, a resource is physically capable of dispatching the entire capacity designated in the given bucket in any and all hours associated with the minimum criteria for that bucket <u>consistent with Resource Adequacy rules</u>."

A. No evidence has been provided to support a DR procurement cap.

The Joint Parties oppose a DR procurement cap and strongly believe that insufficient evidence has been introduced into the record to support one. This Proposed Decision fails to recognize the important role use- and energy-limited resources will need to play in a low or zero carbon future. Implementing a significant limitation on DR and behind-the-meter ("BTM")

[21] Proposed Decision, at pp. 48-50.

distributed energy resources that operate under the DR PDR model essentially relegates these low- and zero-carbon assets to the sidelines when the Commission should be working to grow them while ensuring grid reliability. It is time for the Commission to focus on innovative ways to include these resources while still ensuring reliability. Instituting a cap in isolation of the examination of all other resources is not the way to do this.

The Proposed Decision finds that the Energy Division's proposed 5.3 percent cap is somehow "consistent with the RA program's goal of ensuring reliability."[22] However, the Proposed Decision provides no explanation for how a DR procurement cap contributes to reliability, nor has any evidence been provided by any party showing that DR has been, or is in danger of being, over-procured. In fact, no studies have been put forth showing how much DR capacity is too much, particularly as this DR bucket will include any BTM technologies, such as battery storage, which can only contribute to grid reliability through the DR model. Without this information, capping DR procurement threatens to undermine the entire purpose of the RA regime – to ensure there is a sufficient amount of capacity to meet reliability needs. However, if the Commission insists on adopting a procurement cap, an 8.3 percent cap is significantly better than a 5.3 percent cap and has at least some basis of logic by reflecting the proportion of hours that DR resources must be capable of dispatching.[23] The Joint Parties recommend that the Energy Division monitor the amount of DR counting against the cap and post this information on the Commission's website for each LSE to ensure a consistent counting methodology and market transparency.

VI. CONCLUSION

The Joint Parties respectfully request that the Proposed Decision be modified for the reasons stated above. Those needed modifications to the Proposed Decision are included in Appendix A (Proposed Modifications to Findings of Fact, Conclusion of Law, and Ordering Paragraph) attached and incorporated by reference hereto.

[22] Proposed Decision, at p. 50.
[23] Joint Parties' Reply Comments on Track 2 Proposals (April 2, 2020), at pp. 5-6.

Respectfully submitted,

June 11, 2020

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APPENDIX A

**CALIFORNIA EFFICIENCY + DEMAND MANAGEMENT COUNCIL, CPOWER, ENEL X NORTH AMERICA, INC., LEAPFROG POWER, INC. AND OHMCONNECT, INC.
PROPOSED FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDERING PARAGRAPHS FOR THE
PROPOSED DECISION ADOPTING LOCAL CAPACITY OBLIGATIONS FOR 2021-2023, ADOPTING FLEXIBLE CAPACITY OBLIGATIONS FOR 2021, AND REFINING THE RESOURCE ADEQUACY PROGRAM**

The California Efficiency + Demand Management Council, CPower, Enel X North America, Inc., Leapfrog Power, Inc. and OhmConnect, Inc. propose the following modifications to the Findings of Fact, Conclusions of Law, and Ordering Paragraphs in the Proposed Decision Adopting Local Capacity Obligations for 2021-2023, Adopting Flexible Capacity Obligations for 2021, and Refining the Resource Adequacy Program, mailed in R.19-11-009 on May 22, 2020 (Proposed Decision).

Please note the following:

- A page citation to the Proposed Decision is provided in brackets for each Finding of Fact, Conclusion of Law, or Ordering Paragraphs for which a modification is proposed.
- Added language is indicated by **bold type**; removed language is indicated by **bold strike-through**.
- A new or added Finding of Fact, Conclusion of Law, or Ordering Paragraph is labeled as "**NEW**" in **bold underscored** capital letters.

PROPOSED FINDINGS OF FACT:

13. [70] To promote transparency and treat all DR resources equally, it is reasonable to require LIP reports and the QC values from a DR provider's LIP results to be posted publicly **with appropriate customer protections**.

~~**15. [71] Energy Division's Option 4b proposal to revise the MCC buckets is a reasonable approach, with modifications.**~~

~~**16. [71] It is prudent to consider a higher DR cap given the numerous measures adopted to ensure the effectiveness of DR resources. The Joint DER Parties' proposed approach is reasonable to set the initial DR cap.**~~

[NEW] The current confidentiality rules approved in Decision 06-06-066 do not address customer data of third-party DR providers.

[NEW] Stakeholders will benefit from a working group to address additional changes to the Load Impact Protocols and associated confidentiality protections.

PROPOSED CONCLUSIONS OF LAW:

10. [72] ~~**Energy Division's Option 4b proposal to revise the MCC buckets should be adopted, with modifications. An 8.3 percent cap on DR resources should be adopted.**~~ **Any consideration of a DR procurement cap should be considered in Track 3 with other resources.**

[NEW] A working group should be established to develop 1) a streamlined set of LIPs for QC valuation for IOU and third-party DR provider DR, and 2) develop confidentiality protections for DR customers not currently protected by D.06-06-066.

PROPOSED ORDERING PARAGRAPHS:

13. [76] **A two-tiered testing regime is adopted for IOU and third-party DR resources:**

(a) Tier 1: One two-hour test event or market dispatch at full capacity for "stable resources" per year; and

(b) Tier 2: One four-hour test event or market dispatch at full capacity for "unstable resources" per Summer and Winter season.

~~**Third-party demand response (DR) resources, procured by non-investor-owned utility load-serving entities, shall be subject to the following testing requirements:**~~

~~**(a) The DR resource must dispatch for four consecutive hours during the Resource Adequacy measurement hours in of the delivery year.**~~

(~~**b**~~**c**) The test must be done at the resource ID level and all resources within the same sub-Load Aggregation Point must be dispatched concurrently **unless they have already been economically dispatched at full capacity for the duration required by the applicable testing tier**.

(d) A test is not required if a resource has been economically dispatched at full capacity for the duration required by the applicable testing tier.

(e) The testing requirement is only applicable to a third-party DR resource when it is under contract.

(f) The definition of "stable resource" and "unstable resource" should be resolved and approved in Track 3 of this proceeding; until then, both IOU and third-party DR resources shall comply with the Tier 1 testing requirements.

15. [76] The following clarifications to the Load Impact Protocol (LIP) process for third-party demand response (DR) resources are adopted:

(a) Ex post and ex ante load impacts are required at the subLoad Aggregation Point level.

(b) Mid-year updates are permitted to reflect changes in customer enrollment if the change is reasonably large. In the compliance year, **~~on a biannual basis,~~** Energy Division shall update qualifying capacity (QC) values based on **DR providers' revised enrollment forecasts ~~the actual customer enrollment volume associated with that resource in the California Independent System Operator's Demand Response Registration System~~**. LIP results will be updated if QC values vary by more than **~~20~~10** percent, or **~~10~~3** MW, whichever is greater.

17. [77] For a particular maximum cumulative capacity bucket, "availability" is defined as follows:

(a) Holding aside use limitations or outages, a resource is physically capable of dispatching the entire capacity designated in the given bucket in any and all hours associated with the minimum criteria for that bucket **consistent with Resource Adequacy rules**;

(b) Holding aside use limitations or outages, the resource will economically bid or self-schedule (in the California independent System Operator markets) the entire capacity designated in the given bucket in any and all hours associated with the minimum criteria for that bucket; and

(c) If the resource has use limitations, those limitations would not prevent bidding, self-scheduling, and dispatch during regular, specific hours associated with the minimum criteria for that bucket.

18. [78] The revised maximum cumulative capacity (MCC) buckets are adopted as follows:

Category	Availability	Maximum Cumulative Capacity for Bucket and Buckets Above
DR	Varies by contract or tariff provisions, but must be available Monday – Friday, 4 consecutive hours between 4 PM and 9 PM, and at least 24 hours per month from May - September	**TBD in Track 3~~8.3%~~**
1	Monday – Friday, 4 consecutive hours between 4 PM and 9 PM, and at least 40 hours per month from May – September	16.0%

2	Every Monday – Friday, 8 consecutive hours that include 4 PM – 9 PM	22.2%
3	Every Monday – Friday, 8 consecutive hours that include 4 PM – 9 PM	34.8%
4	Every day of the month. Dispatchable resources must be available all 24 hours.	100% (at least 56.1% available all 24 hours

All demand response (DR) allocations to load-serving entities (LSEs) through the Cost Allocation Mechanism and investor-owned utilities' DR allocations shall count towards an LSE's MCC bucket.

[NEW] The Energy Division shall convene a LIP working group to develop 1) a streamlined set of LIPs for QC valuation for IOU and third-party DR provider DR, and 2) develop confidentiality protections for DR customers not currently protected by D.06-06-066.