BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	Rulemaking 21-10-002 (Filed October 7, 2021)

OPENING COMMENTS OF
THE CALIFORNIA EFFICIENCY + DEMAND MANAGEMENT COUNCIL, CPOWER, AND OHMCONNECT, INC. ON IMPLEMENTATION TRACK PHASE 3 PROPOSALS

Dated: February 24, 2023

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I. INTRODUCTION

The California Efficiency + Demand Management Council ("the Council"),[1] CPower, and OhmConnect, Inc. (collectively "the Joint Parties") appreciate this opportunity to submit its Opening Comments on the Implementation Track Phase 3 Proposals, submitted in this resource adequacy ("RA") proceeding on January 20, 2023. These Opening Comments have been timely filed and served pursuant to the Commission's Rules of Practice and Procedure and the instructions contained in the Assigned Commissioner's Scoping Memo and Ruling ("Scoping Memo"), issued on September 2, 2022. In addition, Administrative Law Judge ("ALJ") Chiv extended the due date for Opening Comments to February 24, 2023 and Reply Comments to March 3, 2023.

II. SUMMARY

The Scoping Memo identified several issues to be addressed in Phase 3 of the Implementation Track of this proceeding.[2] The Scoping Memo directed parties and the Energy Division to submit Implementation Track Phase 3 proposals regarding modifications to the Planning Reserve Margin ("PRM") and Qualifying Capacity ("QC") methodology, as well as other time-sensitive issues.[3]

On January 20, 2023, several parties and the Energy Division ("ED") submitted the following Implementation Track Phase 3 Proposals: Energy Division Proposals for Proceeding

[1] The views expressed by the California Efficiency + Demand Management Council are not necessarily those of its individual members.
[2] Scoping Memo, at p. 2.
[3] *Id.*, at pp. 3 and 6.

R.21-10-002 (“Energy Division R.21-10-002 proposals”), Proposal for Derating Thermal Power Plants based on Ambient Temperature, and Loss of Load Expectation and Slice of Day Tool Analysis for 2024. These Opening Comments only address the Energy Division R.21-10-002 proposals. The Joint Parties recommend that the Commission not adopt the Energy Division R.21-10-002 proposals to adopt a Proxy Demand Resource (“PDR”) bid cap, eliminate the Transmission Loss Factor (“TLF”) and PRM adders, expand minimum availability requirements for demand response (“DR”) resources, and derate DR resources to align with their test event performance.

III. THE COMMISSION SHOULD CONSIDER THE POTENTIAL IMPACTS OF THE ENERGY DIVISION PROPOSALS ON THE DR MARKET

The Joint Parties are extremely concerned by some of the Energy Division’s DR proposals, contained in the Energy Division R.21-10-002 proposals, due to the detrimental impact they will likely have on the DR market. Some proposals lack clarity and often do not include the underlying data or analysis to demonstrate that they are needed, or they cite outdated information. Furthermore, no consideration has been given to their impact, individually or collectively should more than one proposal be adopted, on the willingness of customers to participate in DR programs and the subsequent loss of DR capacity that would very likely occur. The Energy Division’s proposals stand in stark contrast with the positions of other state agencies such as the California Energy Commission (“CEC”), which consistently expresses strong support for the potential for DR to play a larger role in maintaining reliability. As a recent example, the CEC’s draft Clean Energy Reliability Investment Plan (“CERIP”) makes several statements in support of growing DR:

> While there has been growth in the deployment of demand side resources, including all types of distributed energy resources, the expansion has not been rapid enough to meet state goals. For example, demand response has declined rather than grown relative to demand increases. Demand-side resources provide direct benefit to customers, including reductions in utility bills, while also supporting clean energy goals, and would reduce the need for additional transmission. New strategies are needed to increase demand flexibility of existing resources and to enable pathways for the integration of many more. The state needs more market opportunities that advance demand reduction, including pathways that expand aggregation of many resources into virtual power plants.”[4]

[4] Draft CERIP Report, at p. 8.

> "Resounding feedback in the CEC's public workshops is for much greater deployment of demand side resources. The state needs additional strategies to expand deployment of these resources, especially in equity communities that lag other communities in the deployment of these resources."[5]

Similarly, the Joint Parties are pleased with the California Independent System Operator's ("CAISO") recognition in various forums that DR can play a critical role in supporting reliability. Even in areas of disagreement, the CAISO has been notably constructive in their willingness to engage on DR-related issues.

The Joint Parties respectfully urge the Commission to work with the CEC and CAISO to develop a common vision for DR to ensure that all three agencies are working toward common goals for this resource. Fundamentally, the key question is whether DR should be "part of the solution" toward meeting current and future reliability needs. If the answer is "yes", then it is critical to recognize that DR cannot operate on a comparable level to "steel in the ground" resources. By definition, DR requires participating customers to place a utility value on their electricity consumption. This utility value is unique to each customer and is dynamic, depending on, for example, the time of day or season, the number of consecutive dispatches, number of dispatches per month, etc. Some of the Energy Division proposals, though likely well-intentioned, inappropriately (and unrealistically) ignore this reality and instead seek to force DR to act more like conventional generation. However, in so doing, they would make DR less attractive to customers and DR providers, and consequently reduce the supply of DR capacity in the state. The Joint Parties respectfully urge the Commission to tread carefully and consider the potential for unintended consequences of approving proposals that may, on their surface, appear reasonable. The Commission should seek a balance between achieving the level of rigor it desires to see in the capabilities of DR and its desired level of DR penetration.

IV. COMMENTS ON DR PROPOSALS CONTAINED IN THE ENERGY DIVISION R.21-10-002 PROPOSALS

A. PDR-Specific Bid Cap: Adopt a $500/MWh PDR bid cap

The Energy Division proposes to adopt a bid cap for RA-eligible PDR that is set below the $950/MWh Reliability Demand Response Resource ("RDRR") trigger price and specifically

[5] Draft CERIP Report, at p. 8.

recommends a cap of $500/MWh.[6] The Joint Parties strongly disagrees that a bid cap is necessary because more recent data than the proposal has cited demonstrates that it is not needed to ensure PDRs are being scheduled in the CAISO market. Moreover, the proposed bid cap is arbitrary and would put third-party DR at a competitive disadvantage with investor-owned utility ("IOU") DR programs.

The proposal states that "multiple studies have found that many PDRs bid strategically to reduce their likelihood of being selected in the market, even on days when grid emergencies are anticipated based on the demand forecast."[7] To support this statement, the proposal cites the CAISO Department of Market Monitoring ("DMM") report on the 2020 heat event and the DRAM evaluation developed by Nexant (now Resource Innovations) and Gridwell Consulting.[8] These reports do not provide an accurate representation of current DR participation in the CAISO market; consequently, they do not demonstrate that the issue the proposal describes continues to persist. In fact, had more recent data been considered, the case for this proposal would be less compelling. For example, several more recent CAISO reports show robust DR market participation during the months of summer 2022:

- "During the month of June, PDR resources were consistently dispatched in both the day-ahead and real-time markets."[9]
- "During the month of July, PDR resources were consistently dispatched in both the day-ahead and real-time markets."[10]
- "During the month of August, PDR resources were consistently dispatched in both the day-ahead and real-time markets."[11]
- "During the month of September, PDRs were consistently dispatched in both the DAM and RTM."[12]

Importantly, the September 2022 Summer Market Performance Report observes that DR resources were dispatched at a pace and frequency appropriate to the prolonged Labor Day heatwave:

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[6] Energy Division R.21-10-002 proposals, at p. 10.
[7] *Id.*, at p. 9.
[8] *Id.*, at pp. 10-11.
[9] CAISO June 2022 Summer Market Performance Report, at p. 67.
[10] CAISO July 2022 Summer Market Performance Report, at p. 69.
[11] CAISO August 2022 Summer Market Performance Report, at p. 71.
[12] CAISO September 2022 Summer Market Performance Report, at p. 40.

> "The timing and magnitude of market-integrated demand response and non-market resource utilization coincided with the severity of the heat wave. At the start of the heat wave from August 31 to September 4, daily market demand response schedules ranged between 34 MW and 344 MW… The latter half of the heat wave saw larger amounts of resources being called upon with September 6 having the largest amount of market demand response and non-market resources called…"[13]

These findings suggest that existing market signals are sufficient to incentivize DR to dispatch when it is most needed. Had a $500/MWh bid cap been in place in September 2022, it is very likely that, rather than the dispatch of resources reflecting the severity of supply constraints, PDRs would have been exhausted prior to the worst days of the heat event. A bid cap of $500 would have resulted in most PDRs being dispatched for nearly every day between September 1st and September 8th in 2022, including for four hours on four consecutive days. Customer fatigue is a significant factor, especially if the bid cap proposal is combined with the proposal to increase DR availability requirements. Furthermore, such a relatively low bid cap would not account for spikes in natural gas prices, such as those that pushed market clearing prices well beyond $500/MWh during a stretch of days in December. This is critical because, in response to questions in the February 8 workshop on RA proposals, the Energy Division indicated that the market data they used to support this proposal did not take into account the recent extended spikes in natural gas prices which have put significant upward pressure on electric prices across the state.

The Joint Parties are also concerned about the potential impacts of an unreasonably low PDR bid cap on customer participation. During discussions at the February 8 workshop, the Energy Division indicated that they had not considered the potential impact that a $500/MWh bid cap would have on customer participation. This is an important omission because, as discussed above, each customer participating in DR has a unique opportunity cost that can sometimes be highly dynamic. Imposing a bid cap risks pushing those DR participants out of the market whose opportunity costs are higher than the bid cap. The Utility Reform Network ("TURN") made a similar point in its Rebuttal Testimony in the Emergency Reliability proceeding, stating:

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[13] CAISO September 2022 Market Performance Report, p. 39.

> 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 be fiat change customers' value of service, and attempting to do so would be a futile exercise.[14]

In sum, the proposal does not consider more recent data that would suggest a bid cap, particularly a $500/MWh bid cap, is neither necessary nor prudent.

The Energy Division's proposed bid cap also undermines third-party DR in general because it is far below Pacific Gas and Electric Company's ("PG&E's") $650/MWh Capacity Bidding Program ("CBP") bid cap. This would favor PG&E's CBP over third-party DR contracts because customers would be dispatched under lower prices, and more frequently, which would violate the Commission's competitive neutrality principles.

Since 2020, the Energy Division has put forward multiple proposals for a DR-specific and all-resource bid caps using the same data and arguments contained within the current proposal.[15] Following review of the proposals and the underlying evidence, the Commission has declined to adopt such a bid cap.[16] This most recent proposal provides no new or updated evidence to support the view that the Commission should now adopt a consequential policy that it has declined to adopt in prior proceedings. Therefore, the Commission should not adopt this proposal. Should the Commission ultimately adopt a price cap, it should only be low enough to ensure that PDRs are dispatched prior to RDRRs without undercutting DR participants' opportunity costs.

B. TLF and PRM Adders for DR Resources: Remove the TLF and PRM adders for DR resources

The Energy Division proposes to eliminate the TLF and PRM adders for DR resources for the purpose of reducing administrative burdens and to achieve parity with other resources.[17] The Commission should reject this proposal because it competes with the CEC proposal on this

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[14] Prepared Direct Testimony of Michael Peter Florio (Ex. TURN-01), at p. 17, lines 22-27.
[15] Energy Division Track 4 Proposals in R.19-11-009, at p. 7 and Energy Division Track 3B.2 Proposal in R.19-11-009.
[16] Decision ("D.") 21-06-029, at p. 25
[17] Energy Division R.21-10-002 proposals, at p. 18.

same issue, mischaracterizes the nature of the TLF and PRM adders, and would create a significant inconsistency with Load Modifying DR valuation.

The proposal states, "[b]ecause transmission-level losses and the PRM cannot be dispatched by the CAISO, they cannot be bid and are not incorporated into NQC values."[18] This statement over-simplifies a much more complex issue. As part of its current settlement process, Scheduling Coordinators true up Settlement Quality Meter Data ("SQMD") for the Distribution Loss Factor ("DLF") which represents the distribution-level losses that are avoided by the dispatch of a DR resource. The same avoided losses exist at the transmission level. In an ideal world, the CAISO settlement process would include a mechanism to gross up transmission losses in SQMD just as it currently does for distribution losses, which would allow them to be added to the QC value. The fact that the CAISO does not currently do this does not mean that transmission-level losses do not occur and are avoided by the dispatch of a DR resource.

Ordering Paragraph ("OP") 13 of D.21-06-029 correctly directed that the DLF be incorporated into all DR QC values because the CAISO settlement process trues up DR performance to reflect avoid distribution line loses. This allows for an "apples to apples" comparison of DR QC value to CAISO market performance. Because there is no TLF true-up in the CAISO settlement process, it may not be practical to add the TLF to DR QC values —it would upset the apples-to-apples comparison described above. The only remaining option is to continue reflecting the TLF as an RA credit until or unless the CAISO creates a mechanism to incorporate a TLF true-up into its settlement process.

Moreover, the proposal neglects to address the broader implications of creating a two-tiered value system in which market-integrated DR is valued less than DR that is operated outside the market. Specifically, the PRM and TLF will continue to be applied to Load Modifying DR as a credit against the RA requirement (reflected as a reduction to the load forecast), but the same treatment would not be afforded to Supply Side DR. Removing the PRM and TLF adjustments from Supply Side DR but retaining it for Load Modifying DR would introduce a large asymmetry in valuation from the perspective of DR cost effectiveness. In turn, this asymmetry in avoided capacity value would eventually lead to higher incentives for Load Modifying DR relative to Supply Side DR. Such an asymmetry already exists on a smaller scale: because Load Modifying DR reduces an LSE's demand forecast, and consequently its RA

[18] Energy Division R.21-10-002 proposals, at p. 19.

obligation, it also eliminates the incremental PRM that must be procured by the LSE. As such, the RA value of Load Modifying DR is grossed up by the full PRM.

Supply Side DR, on the other hand, currently only receives a portion of the PRM – the 9% representing forced outage and forecast error. The 6% associated with operating reserves and ancillary services was eliminated by D.21-06-029. Eliminating the remaining 9% would further widen this discrepancy. This asymmetry exists and would be deepened despite the two types of DR being the same exact same resource, the only difference being how they are dispatched (i.e., through a CAISO market schedule for Supply Side DR or a pre-determined trigger such as implied heat rate, weather conditions, system load, etc. for Load Modifying DR). In the absence of a thorough explanation for why Supply Side and Load Modifying DR should be valued differently for the purposes of RA, the full PRM and TLF should be retained for Supply Side DR just as it is for Load Modifying DR.

Another problematic element in this proposal is that the ED proposal directly competes with the recommendations put forward by the CEC's Supply Side DR ("QC") working group ("CEC Working Group"). The Commission tasked the CEC Working Group with examining this issue and providing recommendations for consideration in this proceeding. The resulting report is now complete, following months of stakeholder engagement, and will be debated in this proceeding. Because the Commission has already requested the CEC address this issue, the ED proposal should not be adopted.

C. RA Availability Requirements: Require DR resources to be available a minimum of four hours/day and a minimum of three days/week plus during all additional days declared as a Governor's state of emergency proclamations or CAISO's issuance of Flex Alerts

In this proposal, the Energy Division proposes to expand the availability requirements for DR resources. This proposal is missing key details and is unclear. The "Summary and Background" section proposes that "DR resources must be available a minimum of four hours per day, and a *minimum* of three days per week *plus* during all additional days declared as a Governor's state of emergency proclamations or CAISO's issuance of Flex Alerts." [emphasis original][19] However, the "Proposal" section proposes that "all RA resources must be available prior to when the CAISO issues a call for voluntary conservation under its Flex Alerts" and that

[19] Energy Division R.21-10-002 proposals, at p. 20.

"DR resources eligible for RA would be available for the minimum of three days *plus* the additional days during which a CAISO Flex Alert is called, up through the last day for which the CAISO has issued a Grid Warning or the Governor's Office, an Emergency notice."[20] [emphasis original]

First, it is the Joint Parties understanding that the proposal does not change the minimum availability requirements outside of emergency conditions. DR would still be required to be capable of dispatching for four hours per day, three days per week, for 24 hours per month. The proposal appears to amend this requirement to *also* include days where the grid is experiencing emergency conditions. Because 24 hours are not referenced in the proposal, it could be read that the proposal would augment the minimum capability requirements to four hours per day, three days per week for an unlimited number of hours per month under normal grid conditions. This is not sensible and should be rejected outright.

Even if the Joint Parties' understanding of the proposal is correct—the only change being the addition of emergency days to the capability requirement— the proposal is unworkable in its current form. Specifically, the proposal does not consider how the new availability requirements would be implemented in practice. It is usually not obvious to a DR provider that a Flex Alert or Emergency Alert will be called *before* it happens. As such, it is virtually impossible for a DR provider to *ensure* that its capacity is offered to the day-ahead market *ahead* of a Flex Alert. Even if the proposal is amended to state that the availability requirement is triggered only *after* a Flex Alert is actually declared, the declaration may come long after all bids have been submitted and the day-ahead market ("DAM") has closed. All DR providers submit bids in the DAM at 10:00 a.m. of the prior day. Because the days DR must be available are clearly laid out – Monday through Saturday, 4:00-9:00 p.m. – DR providers can schedule bids in a timely, effective and efficient manner. The proposed requirements would introduce uncertainty into bidding and operations. Also, EEA Notices are not always called a day in advance, and even Flex Alerts are rarely called by 10:00 a.m. the day before. Because of this schedule, situations could arise where an alert is called but the DAM has already cleared. While some resources may still be bid into the real-time market, this is not true of long-start DR. What the proposal would require DR providers to do in these instances – a Flex Alert is called but the DAM has closed – is not clear. The same is true of all other emergency declarations.

[20] Energy Division R.21-10-002 proposals, at p. 22.

Availability requirements must be defined in such a way that DR providers know precisely when they are required to bid into the DAM relatively well in advance of the close of bidding. Energy Division's proposal would not provide resource owners this clarity and should not be adopted.

D. Treatment of DR Resources Failing to Perform During Testing: Apply derates that correspond to performance during test events for a particular quarter

The Energy Division proposes to enforce performance requirements by de-rating the QC of third-party DR resources based on their performance during test events relative to their QC values.[21] The Commission should reject this proposal because it conflicts with the CEC's DR QC counting proposal, discriminates against third-party DR, and is based only on a subset of test data. This proposal is not developed and is inappropriate for adoption at this time.

First and foremost, this proposal is premature given the CEC's Supply Side DR QC working group report recently submitted into the record in this proceeding. This working group report contains a series of CEC recommendations that in aggregate serve as a proposal for a new DR QC counting methodology. Included in the CEC's proposal is a penalty mechanism, applied in an even-handed manner across both IOU and third-party DR, that would penalize under-performance relative to the supplied capacity. Stakeholders will have an opportunity to comment on the design of the penalty structure in this proceeding. It is not clear that an additional derate mechanism will be necessary under a framework that includes a penalty structure.

The proposal is also discriminatory in that it does not address penalties vis-a-vis the RA capacity credited to IOU DR programs. To the Joint Parties' knowledge, there is no quarterly 4-hour testing requirement across IOU DR programs. The application of such a requirement to third-party DR only is discriminatory in and of itself. Derating the RA capacity of third-party resources based on performance in these test events while IOUs face virtually no repercussions for under-delivery relative to the RA credited values deepens the negative impact of the discriminatory treatment. This represents a clear bias in favor of IOU DR programs which is very concerning.

The proposal also focuses solely on the testing results for Q2 and Q3 2022 despite the fact that the testing requirement went into effect in 2021. Thus, it is not clear how prevalent the issue truly is. A proposal of this magnitude should be based on long-term data, not that of two

[21] Energy Division R.21-10-002 proposals, at p. 25.

quarters. The proposal also provides no other underlying information to indicate the statistical significance of the numbers cited, including the number of test events considered, the distribution of results of those test events, the dates of the test events, etc. This is an important omission because it prevents parties the opportunity to vet the basis for this proposal.

While under-performance of DR resources should be examined and remedied to the extent possible, it should be done in a manner that is consistent across DR administrators and compatible with the broader QC process. This proposal attempts to do neither of these things and should not be adopted by the Commission.

V. CONCLUSION

The Joint Parties appreciate the opportunity to submit Opening Comments on the RA Implementation Track Phase 3 proposals.

Dated: February 24, 2023

Respectfully submitted,

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